2003 LONG RANGE PLAN

V O L U M E I

FOR

NEW HAMPSHIRE ELECTRIC COOPERATIVE

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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			

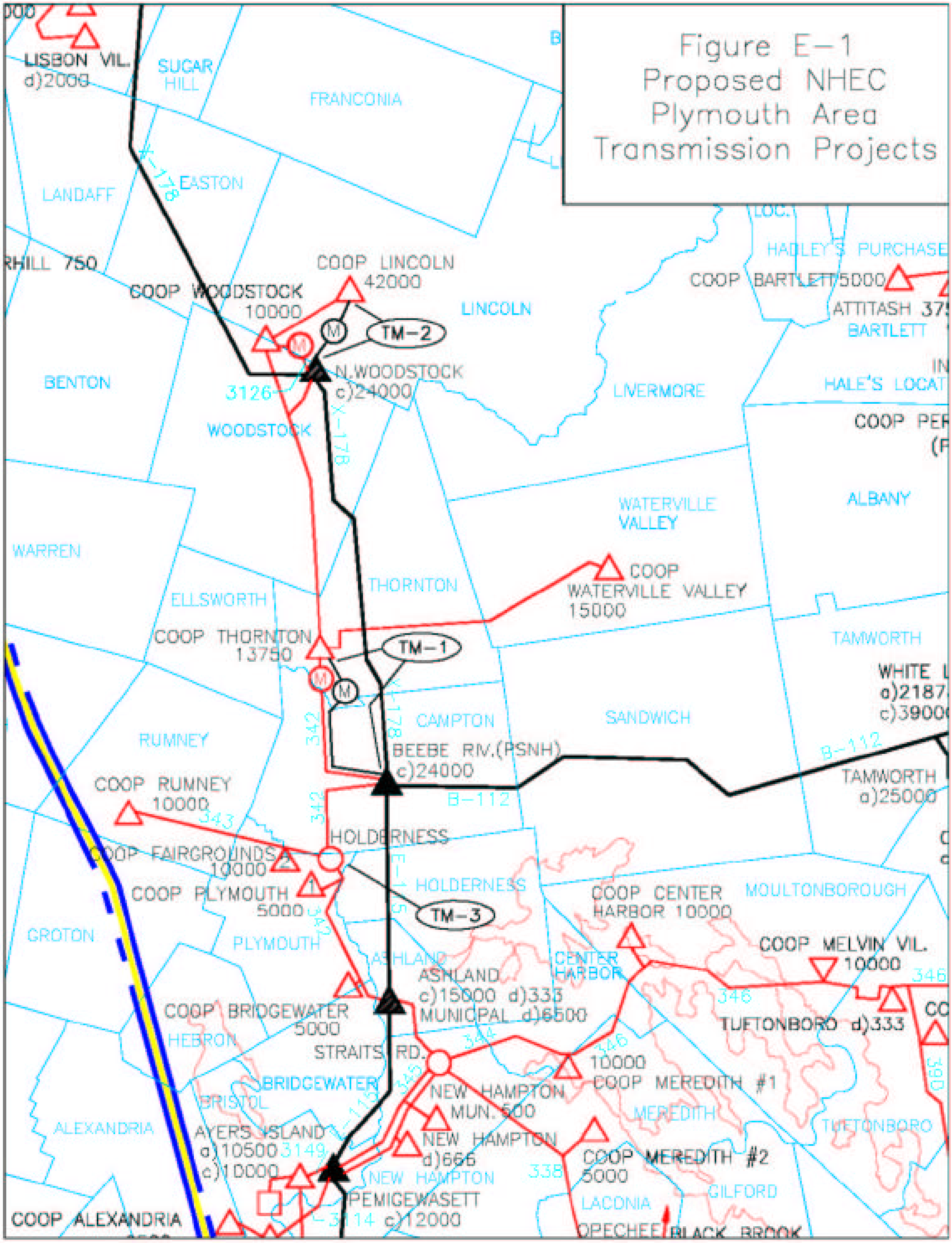


Figure E-1 Proposed NHEC Plymouth Area Trnasmission Projects

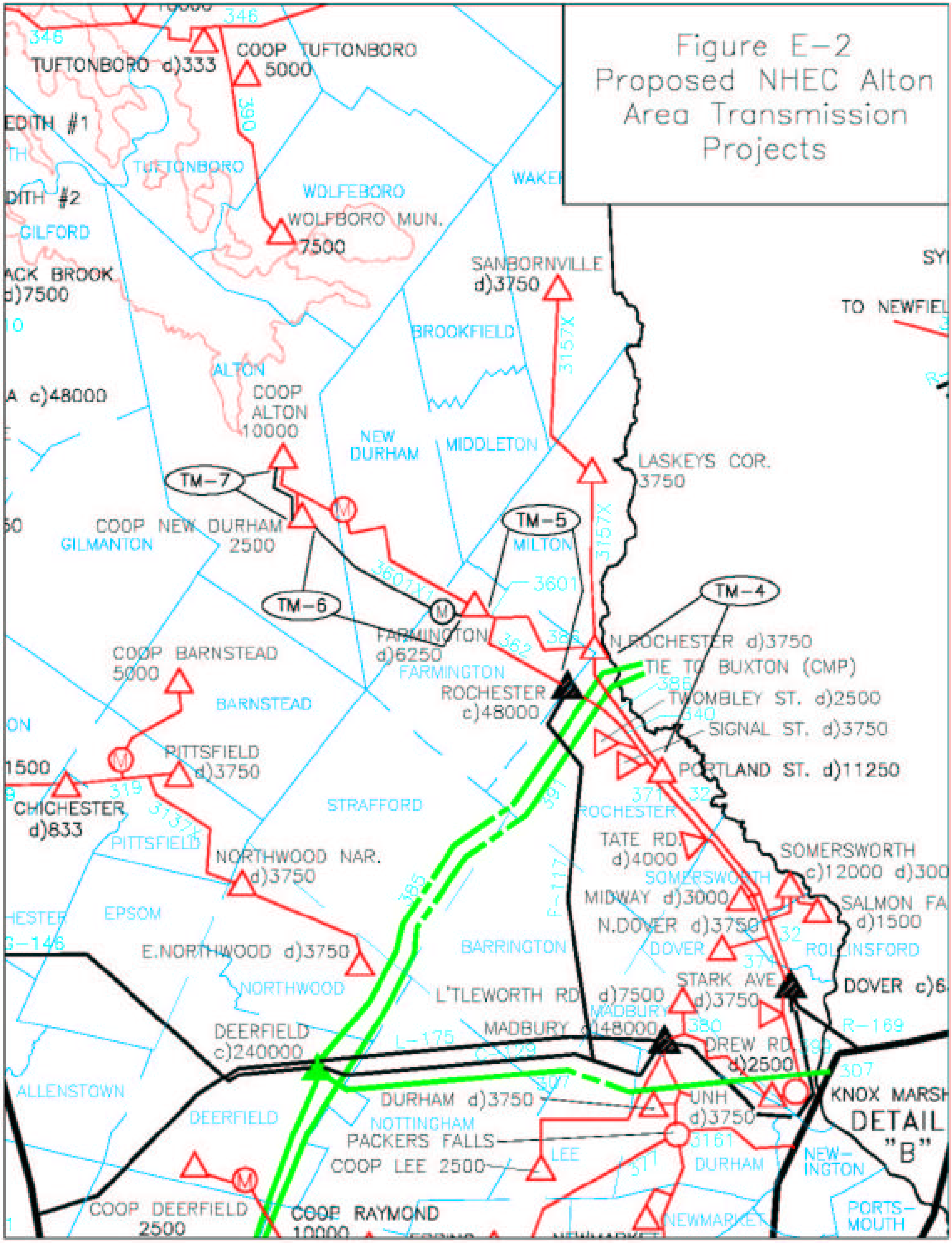


Figure E-2 Proposed NHEC Alton Area Trnasmission Projects

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.

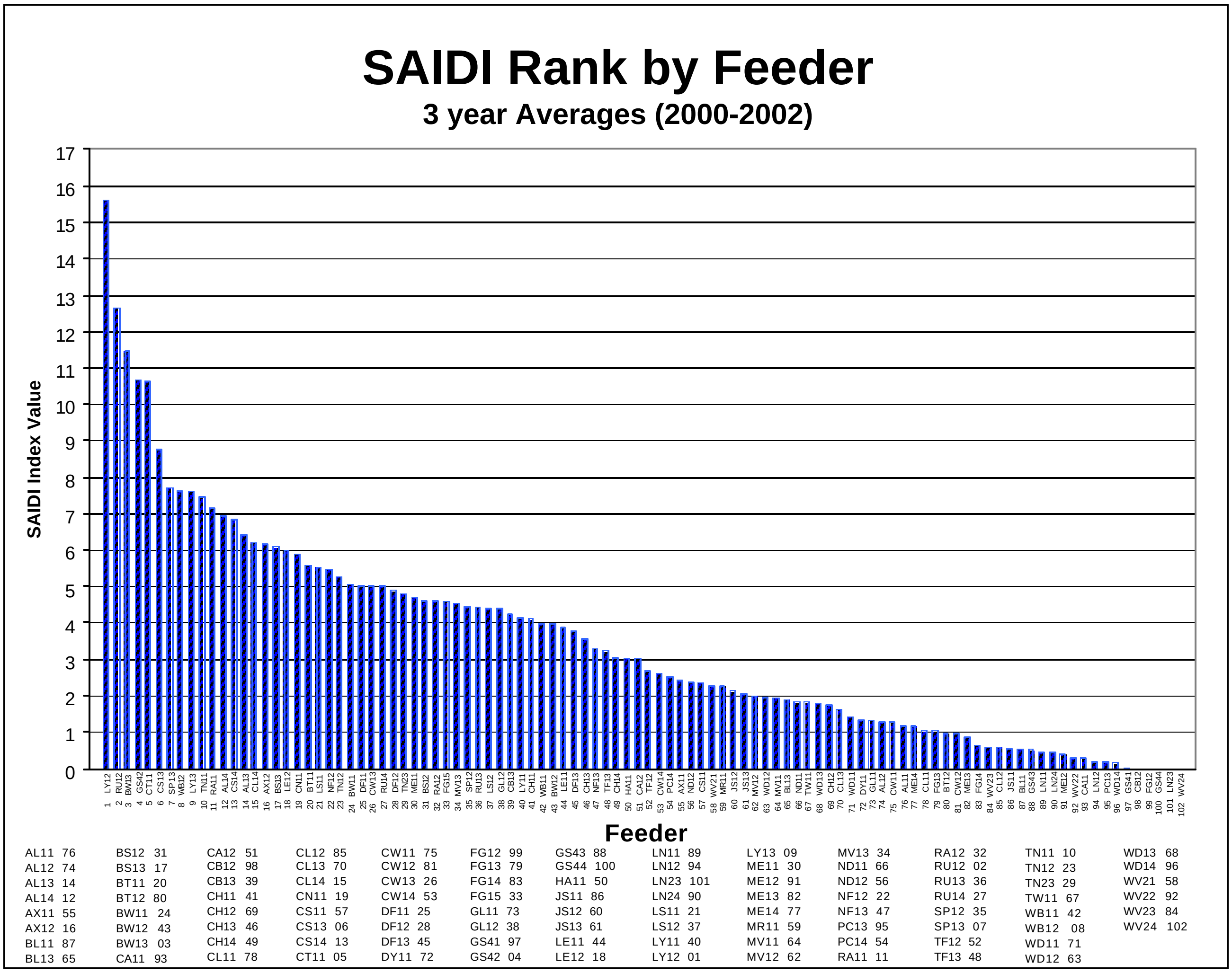
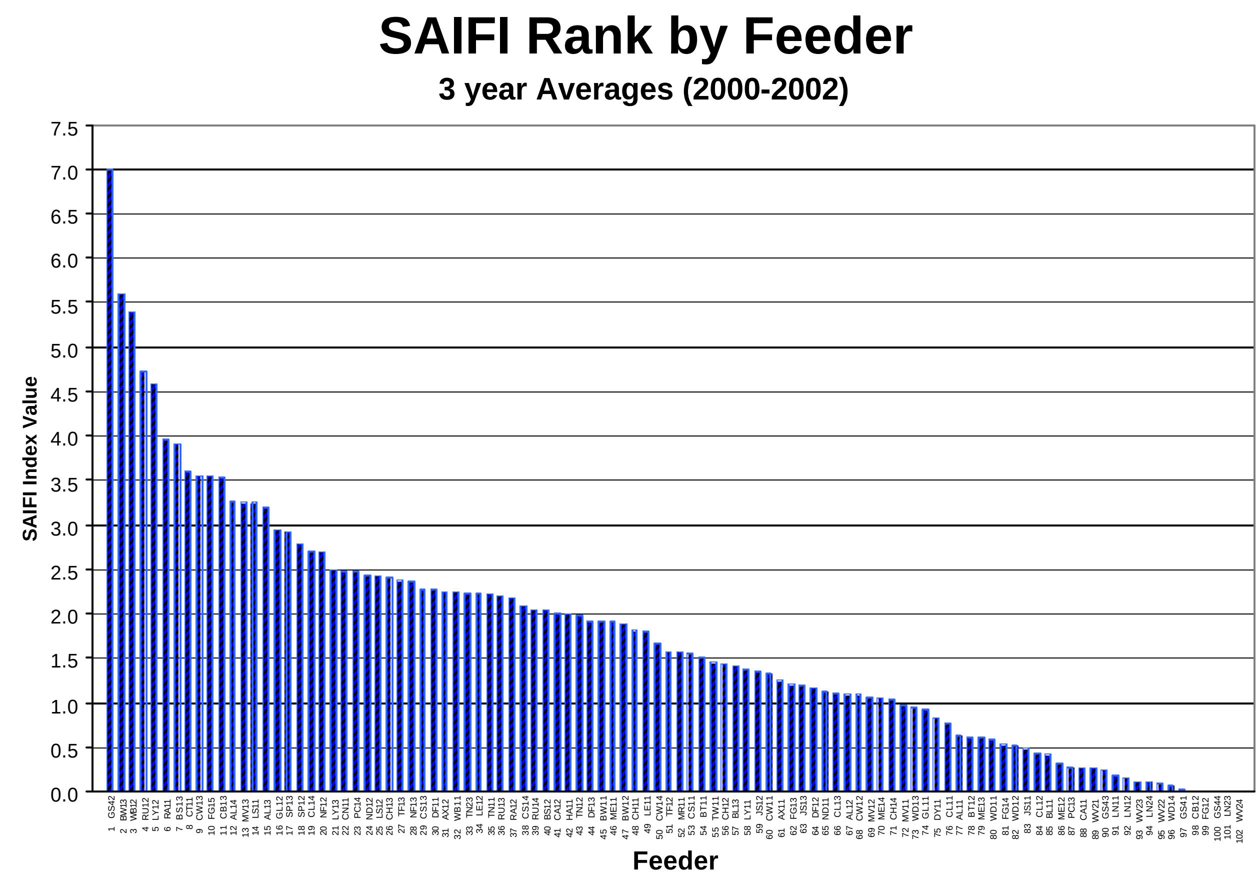


Figure E-3 SAIDI Rank by Feeder



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.

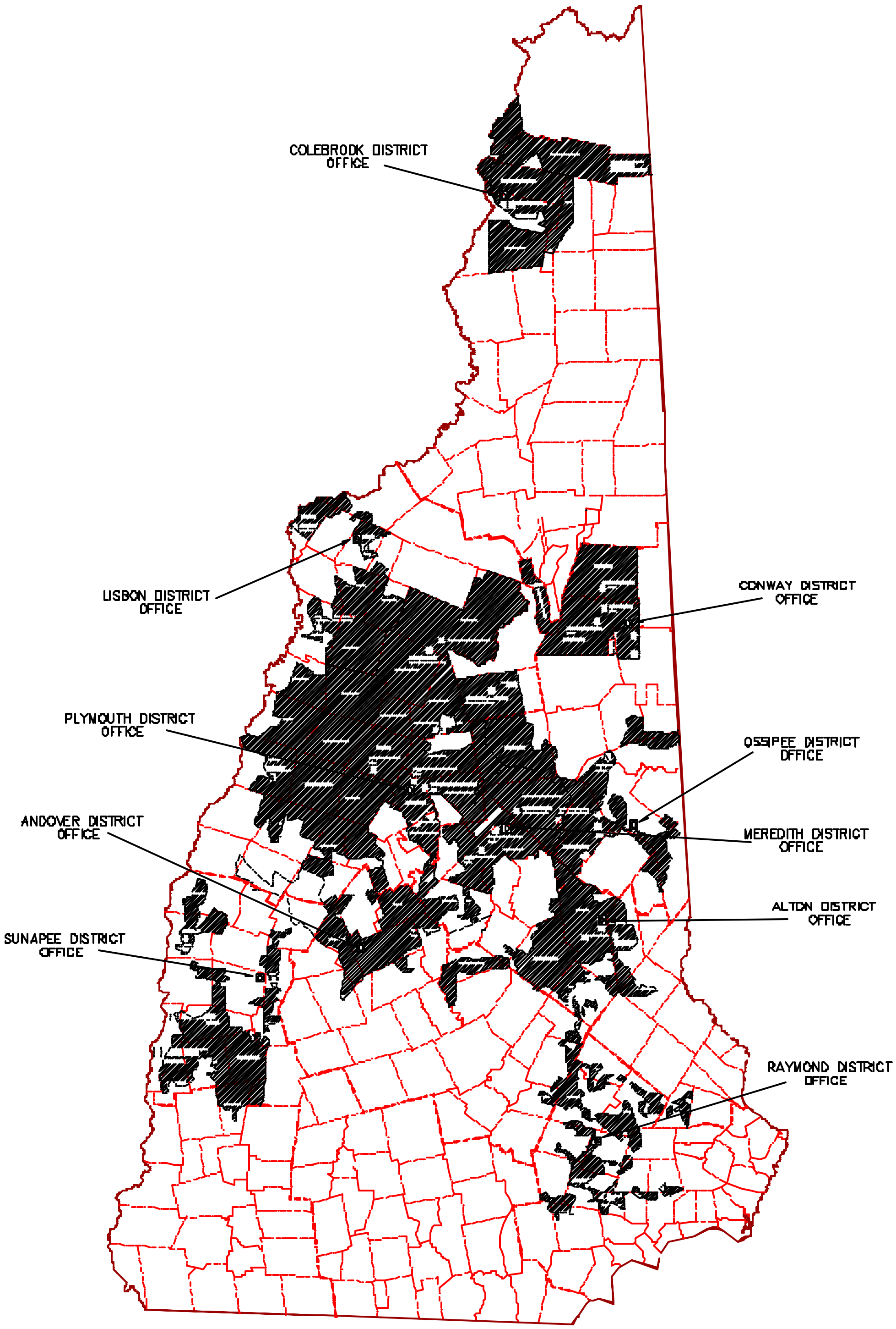


Figure 2-1 NHEC Service Area

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.

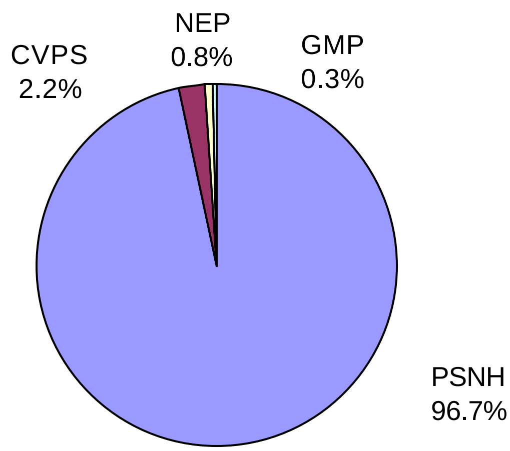


Figure 2-2 2002 NHEC Energy Requirements as Percent of Total Energy Requirements

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.

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[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		3Ø Power Rating @ 12.5 kV		3Ø Power Rating @ 24.9 kV		3Ø 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.

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[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.

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[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	<u>%</u>	
	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	<u>1.0</u>	
	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

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[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%	=	<u>7.5</u>
					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

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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:

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

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

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

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.

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6.0 Alton District

6.1 Load Analysis

The load analysis for the Alton District is presented in this section in detail both to provide the needed delivery points for this district and to illustrate the methodology used for all of the districts and delivery points.\

6.1.1 Overview

In 2002, the Alton District served 10,801 active accounts located in five counties and 14 towns in the southeastern part of New Hampshire bordering Massachusetts. This district serves about 15% of NHEC's total active accounts. Residential consumers predominate in this district interspersed with small commercial accounts that are found along the main highways. This district has grown faster than the total NHEC system in recent years with strong influences from the cities of Concord and Manchester and cross-border impacts from Massachusetts tourists and second home owners. Air conditioning is increasingly common for consumers in this area which has small impacts on energy sales but a significant impact on summer peak demands.

The Alton District electric system configuration includes the New Durham and Pittsfield delivery points. The New Durham and Alton substations are metered through the New Durham delivery point while the Barnstead substation is metered through the Pittsfield delivery point.

6.1.2 Data Sources and Availability

For the past two years, NHEC has produced an end-of-year revenue report that tabulates the number of active accounts by county and town but not by delivery point. NHEC prepared special analyses of customer billing data to provide the linkage of customers to delivery points and towns. The two data sources are not yet fully reconciled. For the Alton District, the end-of-year revenue report for 2002 indicated 10,801 active accounts. The customer billing data ties 8,864 of those accounts to towns and delivery points. This is a sufficiently large sample to provide the weighted population growth rates needed to drive the forecasts. Table 6-1 summarizes the 2002 linkages between town populations and active Alton District accounts for the Pittsfield and New Durham delivery points.

Table 6-1 Population and Active Alton District Accounts by Town

County	Town	2002 Population	2002 Active Accounts
Pittsfield DP			
Belknap	Barnstead	4,109	962
Merrimack	Pittsfield	4,076	67
Rockingham	Deerfield	3,996	293
Rockingham	Northfield	3,769	297
Rockingham	Nottingham	3,902	108
Pittsfield Total		**19,852**	**1,727**
New Durham DP			
Belknap	Alton	4,786	3,861
Belknap	Barnstead	4,109	97
Belknap	Belmont	7,060	103
Belknap	Gilford	7,087	101
Belknap	Gilmanton	3,224	1,722
Strafford	Farmington	5,974	172
Strafford	New Durham	2,325	1,081
New Durham Total		**34,564**	**7,137**
District Total			
Alton District Total Ex Overlap		**54,416**	**8,864**

The dominant towns served are Barnstead for the Pittsfield DP and Alton, Gilmanton and New Durham for the New Durham DP.

Peak demands for 2002 were 2,874 kW for Pittsfield and 10,388 kW for New Durham. Thus the two-factor model for these delivery points for 2002 is as follows:

Table 6-2 Two-Factor Model for Pittsfield and New Durham Delivery Points

Item	Pittsfield	New Durham
Population	19,852	34,564
Consumers	1,727	7,137
CPR	0.087	0.206
Peak Demand (kW)	2,874	10,388
DPC (kW)	1.664	1.456
Peak/Population	0.1448	0.3005

The Pittsfield delivery point features somewhat larger loads but the share of town population served is significantly smaller. The benchmark forecast was simply developed by multiplying the town population forecasts by 0.1448 for Pittsfield and by 0.3005 for New Durham. The 2023 benchmark forecast for Pittsfield was 3,977 kW.

6.1.3 Pittsfield Delivery Point

6.1.3.1 Base Forecast

The Alton District Manager felt that the benchmark forecast was too low primarily because the share of the town populations served by NHEC is growing rather than staying constant. The cooperative service territory is ideally situated to absorb much of the new rural growth while the larger urban populations remain stable or declining. To reflect this insight, a growth adder of 1.2% was used for each of the first five years and then for the five and ten year periods that complete the forecast horizon. The CPRs in the following table are calculated from the consumer and population forecasts. The consumer forecasts are developed using the following formula:

$$\text{Consumers}_n = \text{Consumers}_{n-1} + (\text{Population}_n - \text{Population}_{n-1}) * (\text{CPR}_{n-1} + \text{Adder}_n)$$

The adder for the future period is set equal to 1.2%. Thus, the number of active consumers in 2003 is equal to:

Consumers_{n-1}	1,727
Population Change	20,218 – 19,852 = 366
$\text{CPR}_{n-1} + \text{Adder}_n$	0.087 + 0.012 = 0.099
Consumers_n	0.099 * 366 = 36; 1,727 + 36 = 1,763

Table 6-3 Pittsfield Non-Coincident Peak Demand Base Forecast

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
1999	15,988				
2000	18,836				
2001	19,468				
2002	19,852	0.0870	1,727	1.664	2,874
2003	20,218	0.0872	1,763	1.666	2,937
2004	20,582	0.0874	1,799	1.667	2,999
2005	20,948	0.0876	1,836	1.668	3,062
2006	21,308	0.0878	1,872	1.669	3,125
2007	21,670	0.0880	1,908	1.671	3,187
2008	22,030	0.0882	1,944	1.672	3,249
2013	23,831	0.0891	2,124	1.676	3,561
2023	27,463	0.0907	2,492	1.683	4,193
Growth Rates					
2002 - 2003	1.84%	0.25%	2.09%	0.09%	2.18%
2002 - 2008	1.75%	0.24%	1.99%	0.08%	2.07%
2002 - 2013	1.67%	0.22%	1.90%	0.07%	1.97%
2002 - 2023	1.56%	0.20%	1.76%	0.05%	1.81%

Town populations in the service area are expected to continue healthy growth although the pace of the increase slows as the forecast horizon lengthens. The CPR also grows at a diminishing rate based on the assumption of a fixed adder applied to a growing base. Over the next two decades, the number of active NHEC consumers in the Alton District is expected to increase by 1.8% per year.

The District Manager also felt that the contribution of the average new consumer in the Alton District will be slightly higher than the historic average due to increasing home sizes and relatively fast growth of commercial compared to residential loads. The average new consumer is expected to have a peak demand contribution of 1.70 kW throughout the forecast horizon. Existing consumers are expected to continue at the 2002 peak of 1.664 kW. Since marginal consumers have slightly higher demands than the average consumer, the DPC continues to increase gradually.

The base forecast of peak demands for the Pittsfield delivery point anticipates growth at a rate of nearly 1.8% per year so that the peak reaches 4,193 kW by the end of the planning period. This represents an increase of about 5.0 % above the benchmark forecast.

6.1.3.2 Small Area Spot Loads and Adjustments

Alton District staff provided specific load locations as shown in Table 6-4 to support the Milsoft system modeling effort. No additional loads were included for the Pittsfield delivery point.

Table 6-4 Pittsfield Delivery Point Spot Loads

Circuit	Load Type	YEAR		
		2008	2013	2023
		Load (kW)	Load (kW)	Load (kW)
BS12	Housing (8-10 lots)	5	10	10
B13	Existing Elem School Increase	100	100	200
	Undeveloped Countryside	20	20	10

The history and forecast of Pittsfield demands are graphically summarized in the Figure below.

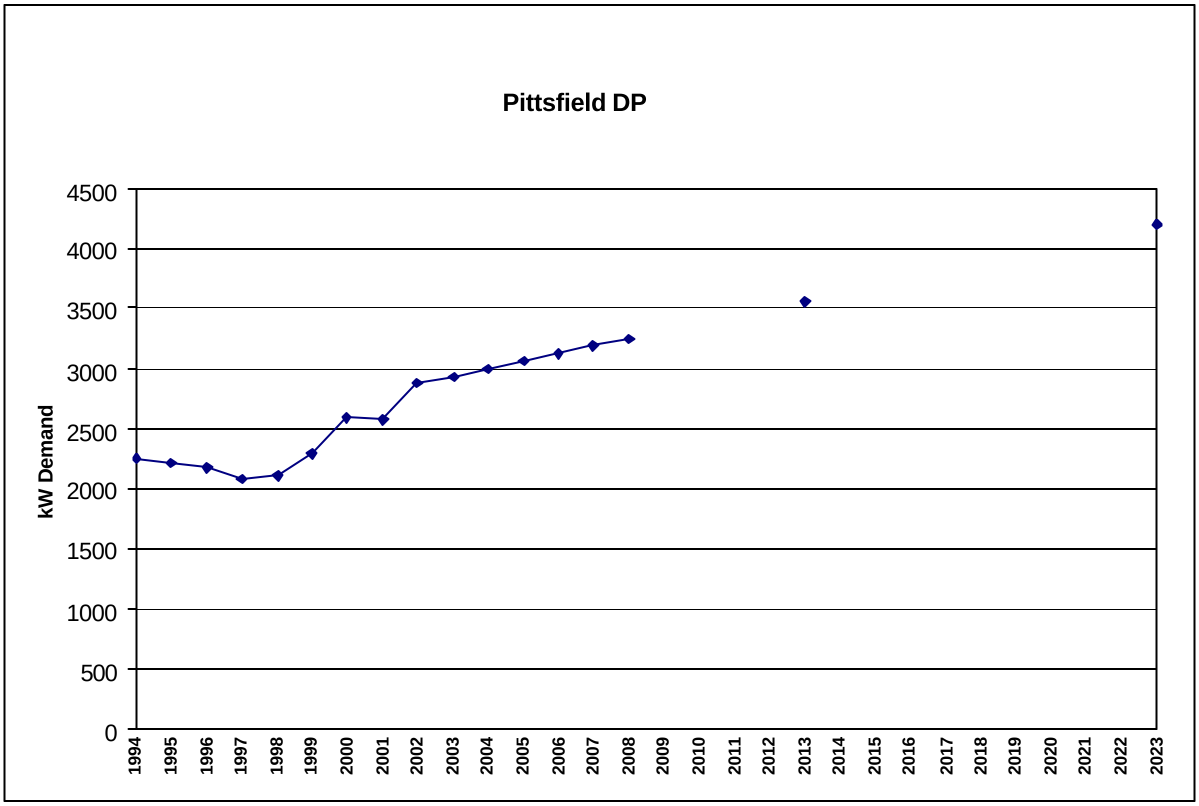

Figure 6-1 Historical and Forecasted Pittsfield Demands

6.1.4 New Durham Delivery Point

6.1.4.1 Base Forecast

The 2023 benchmark forecast for the New Durham delivery point was 13,747 kW. The District Manager expects that NHEC will retain a constant share of the service area population but felt that the demand per consumer will increase from the relatively low current level of 1.456 kW. The current figure is low because of the large number of summer camps served through this delivery point. New connects are expected to represent larger homes and businesses with average demands of 1.66 kW. The base forecast for New Durham anticipates annual growth to 2023 at a rate just above 1.6% to a figure of 14,578 kW.

Table 6-5 New Durham Non-Coincident Peak Demand Base Forecast

New Durham

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
1999	28,371				
2000	32,961				
2001	33,861				
2002	34,564	0.206	7,137	1.456	10,388
2003	35,094	0.206	7,246	1.462	10,592
2004	35,627	0.206	7,356	1.468	10,796
2005	36,158	0.206	7,466	1.473	10,999
2006	36,680	0.206	7,574	1.478	11,197
2007	37,204	0.206	7,682	1.484	11,396
2008	37,730	0.206	7,791	1.488	11,595
2013	40,366	0.206	8,335	1.510	12,586
2023	45,748	0.206	9,446	1.543	14,578
Growth Rates					
2002 - 2003	1.53%	0.00%	1.53%	0.42%	1.96%
2002 - 2008	1.47%	0.00%	1.47%	0.37%	1.85%
2002 - 2013	1.42%	0.00%	1.42%	0.34%	1.76%
2002 - 2023	1.34%	0.00%	1.34%	0.28%	1.63%

6.1.4.2 Small Area Spot Loads and Adjustments

Spot loading on the New Durham delivery point includes several subdivisions and camping facilities. Substation and circuit locations of those loads are shown in Table 6-6. In addition to those spot loads which are included in the base forecast, a new movie theatre and a new high school are anticipated. Load growth for those two large loads is also presented in this table. The theatre is expected to add 1,000 kW by 2013 while the high school anticipates a total load of 2,000 kW by 2013.

Table 6-6 New Durham Delivery Point Spot Loads

Substation	Circuit	Load Type	YEAR 2008 Load (kW)	2013 Load (kW)	2023 Load (kW)
Alton	AL11	Movie Theatre **		1000	
		Housing (10 lots)	10	10	10
		35 campsites	40	40	30
	AL12	High School **	1200	800	
		Housing (29 lots)	30	30	30
		Housing (20 lots)	20	20	20
	AL13	BoyScout Camp/Restaurant	300	200	
	AL14	Lakeview Estates (10 lots)	20	10	10
		Housing (26 lots)	20	20	20
		Housing (10 lots)	5	10	10
New Durham	ND12	Housing (26 lots)	20	20	20
		Housing (10 lots)	10	10	10
		Housing (15 lots)	20	10	10
	ND13	Housing (49 lots)	20	30	50

** These loads are in addition to the base forecast

Figure 6-2 provides a graphic history and both base and adjusted forecasts of the loads for the New Durham delivery point.

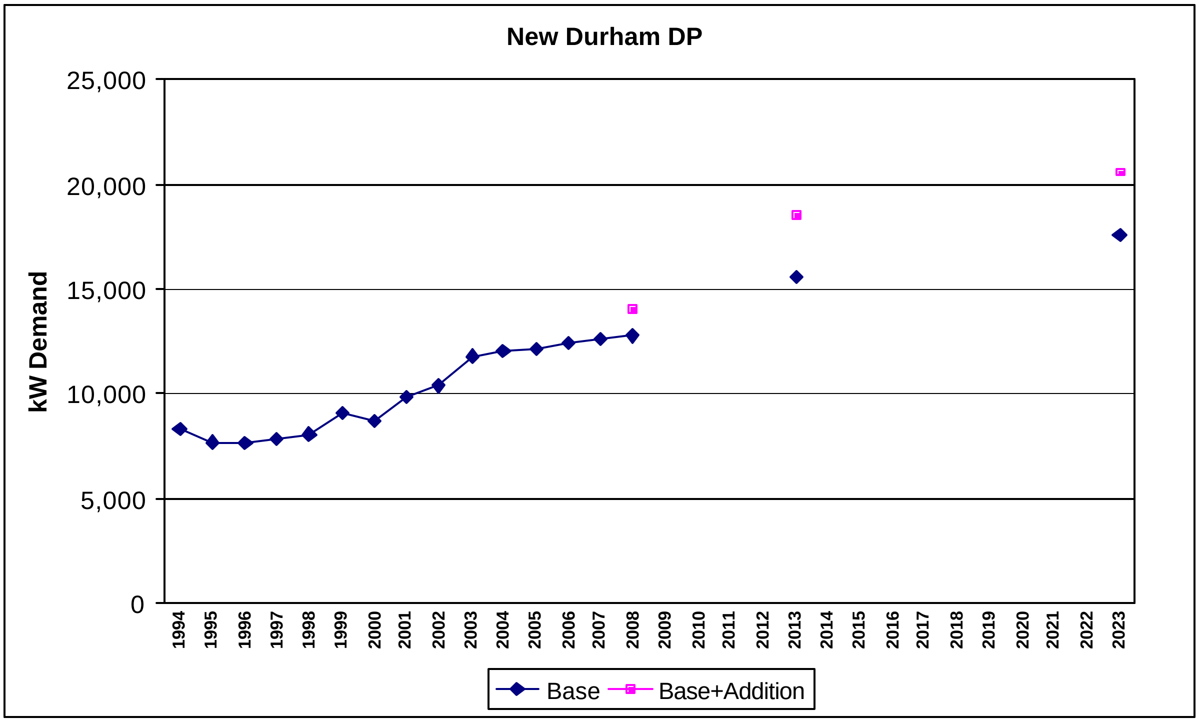

Figure 6-2 Historical and Forecasted New Durham Demands

6.2 Transmission System

6.2.1 Bulk Transmission System

NHEC's Alton District is served from PSNH's Rochester and Oakhill Substations. Rochester Substation is supplied by a radial 115 kV transmission line tap PSNH F117 of the Deerfield-Madbury 115 kV line. Although Rochester is supplied by a radial 115 kV tap line, the tap and Deerfield-Madbury lines have auto-sectionalizers and both Deerfield and Madbury substations have a more reliable 115 kV breaker and one-half protection scheme at each substation.

Oak Hill 115-34.5 kV substation is tapped on the Webster-Merrimack 115 kV line. This line is auto-sectionalized at the Oak Hill tap for improved reliability.

6.2.2 34.5kV Subtransmission System

Substation transformer capacity and base case, and coincident peak demands are depicted in Table 6-7 and are based upon an annual area load growth rate of 1.29 percent of both winter and summer coincident peak load conditions.

Table 6-7 Alton District 34.5 kV System and Load

PSNH Substation	115-34.5 kV Transformers		34.5 kV	Coincident Peak Loads (MVA)			
				Summer		Winter	
	Summer	Winter	Feeders	2003	2023	2003	2022
Oak Hill	1-52 MVA	1-69 MVA	2	30.3	35.9	26.5	34.2
Rochester	1-51, 1-54MVA	2-65 MVA	3	69.6	91.8	57.8	78.4
Madbury	1-49, 1-52 MVA	1-62, 1-64 MVA	4	76.7	84.9	92.7	102.6

6.2.3 Base System Performance

NHEC's Pittsfield delivery point and Barnstead distribution substation are supplied by PSNH 34.5 kV feeder 319 out of Oak Hill Substation. Oak Hill feeder 319 is looped with PSNH's Madbury 34.5 kV feeder 3137. There are no deficiencies under normal operating conditions in either 2003 or 2023.

NHEC's New Durham delivery point supplying the New Durham and Alton Substations is supplied from PSNH feeder 362 out of Rochester Substation. Rochester feeder 340 exceeds the 30 MVA design criteria with 30.2 MVA of load in 2003. PSNH is planning on developing a fourth Rochester 34.5 kV feeder in 2004 and tying it into the existing 34.5 kV feeder network near the current open point between Rochester feeder 362 and feeder 340. This facilitates the load relief of the 340 feeder and also achieves 34.5 kV feeder backup capability for the NHEC New Durham delivery point.

6.2.4 Contingency Performance

Rochester 115-34.5 kV Substation is supplied by a 115 kV radial tap of the Deerfield-Madbury C129 circuit. An outage to this line or tap would result in an outage to Rochester Substation. However, PSNH employs a more reliable breaker and one-half 115kV bus sectionalizing configuration at both Deerfield and Madbury Substations, and also employs field switching to rapidly isolate failures. Oak Hill Substation is served from the fully breakered Merrimack-Webster 115 kV line, which also has three-way switching at the Oak Hill Substation for more rapid fault isolation.

PSNH does not currently have full first contingency 34.5 kV capability to serve the New Durham delivery point at peak for a Rochester 362 feeder, or Rochester 115-34.5 kV transformer outage. NHEC's Alton and New Durham Substations and PSNH's Farmington Substation would need to remain unserved for these outages. However, the 2004 addition of the proposed fourth 34.5 kV Rochester circuit solves this deficiency.

Additional deficiencies develop in 2020 with insufficient 115-34.5 kV transformer summer capacity and in 2022 with Rochester feeder 362 mildly overloading. These deficiencies develop with a Rochester transformer outage. The solution to these contingent deficiencies is to upgrade

PSNH transformer capacity at Rochester in 2020 and add an additional 34.5 kV feeder exit at PSNH's Dover Substation in 2022.

Oak Hill 115-34.5 kV Substation is a single feeder and transformer substation. An outage to either feeder or transformer is equally critical. In 2003, an outage to either results in PSNH leaving load unserved at PSNH's Louden delivery point. Because of the relative position of the NHEC Pittsfield delivery point within the Oak Hill-Madbury 34.5 kV system adequate capacity exists and the Pittsfield load will be backed up. PSNH will also need to reconductor a section of the 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. PSNH will also need to add a second transformer to Oak Hill in 2004 in order to provide full contingent capability.

In 2023, the second Oak Hill transformer addition and the line reconductoring project with line capacitors are sufficient to provide full first contingency capability.

6.2.5 Historical Reliability

A review of the power supplier outages for the New Durham and Pittsfield delivery points indicates that both experienced an average of 1.67 power supplier outages for the time period of 2000-2003. This is within the NHEC design criteria limits.

6.2.6 Enhanced Subtransmission Reliability Alternative

The New Durham 34.5 kV delivery point serving New Durham and Alton Substations is served radially by Rochester feeder 362 over a 5 mile long PSNH feeder from PSNH's Farmington Substation. PSNH 34.5 kV Rochester feeders 362 and 386 are available near Farmington. Reliability could be improved to New Durham and Alton Substations if a second 34.5 kV feeder could be extended 5 miles from Farmington to New Durham and an additional 4 miles to NHEC's Alton Substation. This would provide a dual 34.5 kV feeder to both New Durham and Alton Substations. This dual feed could also be automated with SCADA or autonomous switching devices for automated fault isolation and restoration of service to Alton and New Durham Substations if suitable operating arrangements between NHEC and PSNH could be negotiated. Leaving aside the issue of NHEC or PSNH ownership, the major construction elements of this plan are:

1.	Portland Street – N. Rochester, Feeder 386, 4.68 miles, upgrade 1/0, 4/0 and 477 MCM ACSR to all 477 MCM ACSR	$604 K
2.	N. Rochester – Farmington, Feeder 362, 4.15 miles, upgrade 1/0, 4/0 and 477 MCM ACSR to all 477 MCM ACSR	$535 K
3.	Farmington – New Durham, New Feeder, 5 miles of 477 MCM ACSR	$630 K
4.	New Durham – Alton, New Feeder, 4 miles of 477 MCM ACSR.	$504 K
5.	Six 34.5 kV recloser/sectionalizers with local and remote SCADA control.	$210 K
	TOTAL	$2,483 K

Assuming an equipment failure could be confined to an individual line section of one 34.5 kV feeder, this alternative would eliminate 34.5 kV permanent outages to Alton and New Durham Substations.

6.3 Distribution System

6.3.1 General

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 6.5, Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 6.0 shows the 2003, 2008, 2013 and 2023 peak load levels for each substation, DP, MP and circuit using the existing system configuration and proposed system configuration.

6.3.2 New Substations, DP's and MP's

One new delivery point is recommended in the Alton District during this 20-year planning period for voltage, capacity, and reliability reasons. The new Belmont Delivery Point is located in the Township of Belmont, just east of the Village of Belmont. The new delivery point will provide load relief to the heavily loaded Circuit AL13 of the Alton Substation.

A PSNH owned 19.9/34.5 kV distribution line will provide service to the Belmont Delivery Point. The PSNH distribution line taps off the PSNH 34.5 kV 337 line and continues along Highway 106 just west of the Village of Belmont. Road construction was recently completed on Highway 106, and therefore the 398-X3 line has been upgraded to larger conductor. Furthermore, the 337 line is located between PSNH's Laconia and Webster 115 – 34.5 kV transmission substations providing looped capability during transmission system outages. The proposed project designated as BM-1, includes the addition of a 19.9/34.5-7.2/12.47 kV stepdown transformer rated at 5/7 MVA and voltage regulators. The Belmont Delivery Point is estimated to cost $200,000. The cost includes 0.5 miles of three-phase 336 ACSR to extend three-phase from the Belmont DP to the existing line of Circuit AL13. The entire main three-phase line between the Alton Substation and the Belmont DP will be 336 ACSR. This new Belmont Delivery Point will significantly improve the reliability as discussed in the Alton Circuit AL13 reliability section.

6.3.3 Substation, DP and MP Changes

The following table shows the projected kW for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for backup or for the ordinary replacement of aged transformers are shown in [**bold**]. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 6-8 Substation Transformer and Regulator Data

Name	Transformer							Voltage Regulator		
	Rating (kVA)					Est. Load (kW)	Capacity (%)	Size (AMP)	Est. Load (AMP)	Capacity (%)
	OA 55°	FA 55°	OA 65°	FA 65°	Win Season					
Alton Sub [1]	10,000	12,400	11,200	14,000	12,000	14,907	139	437	775	177
Alton Sub [1, 2]	**12,000**	**16,000**	**13,400**	**17,900**	**19,690**	14,907	85	**LTC**	775	**--**
Alton Sub [2, 3]	**12,000**	**16,000**	**13,400**	**17,900**	**19,690**	11,947	68	**LTC**	621	--
Belmont DP	**5,000**	--	**5,600**	--	**6,160**	2,460	45	**219**	128	58
New Durham DP	2,500	--	2,800	--	3,080	3,043	111	150	158	105
New Durham DP [4]	**--**	**3,125**	**--**	**3,500**	**3,850**	3,043	89	**219**	158	72
Barnstead Sub [5]	5,000	--	5,600	--	6,000	4,417	83	219	230	105
Barnstead Sub [2, 5]	**5,000**	**6,250**	**5,600**	**7,000**	**7,700**	4,417	64	**328**	230	70
Barnstead Sub [6]	**5,000**	**6,250**	**5,600**	**7,000**	**7,700**	3,385	49	**328**	176	54

[1] Estimated load is before transfer to Belmont DP.
[2] Upgrade to replace aged equipment. Projects AL-1 and BS-1.
[3] Estimated load is after transfer to Belmont DP.
[4] After installing fans.
[5] Estimated load is before transfer to the Lee DP in the Raymond District.
[6] Estimated load is after transfer to the Lee DP in the Raymond District.

Project AL-1 is the replacement of the existing 10 MVA transformer with a new 12/16/20 MVA transformer. The existing transformer was purchased in 1973 and is expected to need replacement due to age. The increase in size over the existing 10/14 MVA transformer is due to normal system and backup system configuration load projections.

Project BS-1 is the replacement of the existing 3-1,667 kVA transformers with a new 5/7 MVA transformer. The existing transformers were purchased in 1973 and replacement due to age is expected.

No conversion to a different distribution system operating voltage is recommended at any of the substations or delivery points. The distribution operating voltage is to remain at 7.2/12.47 kV.

6.3.4 Alton Substation Service Area

6.3.4.1 Existing System Review

The Alton Substation is forecasted to serve 14.9 MW of peak load in 2023. The Alton area is served by four 7.2/12.47 kV circuits: AL11, AL12, AL13 and AL14. Circuit AL11 serves approximately 22 percent of the total load, AL12 serves 19 percent, AL13 serves 36 percent and AL14 the remaining 23 percent.

Circuit AL11 exits the substation and splits into north and east feeders. The east feeder is about 2.5 miles in length and forms a tie with Circuit ND12 of the New Durham Delivery Point. The north feeder has a radial configuration and serves the majority of the members along the eastern side of Lake Winnipesaukee. The main three-phase line on this feeder is about five miles in length, while the single-phase taps continue about another five miles. The north portion of this circuit consists of both 336 and 3/0 ACSR while the south portion is mostly 4 CU. The 2013 peak load on the main single-phase line going east from the end of the three-phase line exceeds the maximum design limit of 50 amps and the line is therefore considered to have a capacity deficiency. There are no anticipated voltage problems on this circuit at the 20-year load level.

Circuit AL12 is approximately 6.8 miles long. The main three-phase line is 3.1 miles long and is 336 ACSR, except for a section of 1/0 ACSR and 350 AL near the substation feeder exit. Circuit AL12 has no ties to other circuits. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit AL13 is heavily loaded and the three-phase 336 ACSR feeder main about 15 miles long. There are a few three-phase taps off the main line, but mostly long single-phase taps. Voltage regulators are installed in the main three-phase line about 9 miles from the substation. There are major voltage and capacity problems on this circuit at the 2023 load level. An 8 volt drop occurs on the main three-phase line just 3.5 miles from the substation at the 2023 load level.

Circuit AL14 serves members on the western edge of Lake Winnipesaukee. Circuit AL14 is approximately 12 miles long and has no ties to other circuits. The main three-phase line is approximately 9 miles from the substation. There is a mixture of conductor sizes ranging from 4 CU to 336 ACSR along the main three-phase line. Two sets of voltage regulators are installed in the main line. The first set is approximately 4 miles from the substation and the second set is approximately 8.5 miles from the substation. The 2013 peak load on the main single-phase lines going northwest and west from near the end of the three-phase line exceeds the maximum design limit of 50 amps and these lines are therefore considered to have a capacity deficiency. The combination of small conductors on the three-phase feeder main and heavily loaded single-phase lines near the end of the circuit result in voltage drops at the circuit's extremities that exceed design limits.

6.3.4.2 Recommended Plan

On circuit AL11, project 301 is the conversion of old 6 CU operated at 2.4 kV to 1/0 tree wire operated at 7.2 kV. The existing line was built in the 1930's and is in poor physical condition. This project was included in year 3 of the 2001-2005 Construction Work Plan.

Project 302 is the replacement of three-phase 1/0 Hendrix cable with three-phase 336 Hendrix cable to increase the backup capacity at the tie point between circuits AL11 and AL13. This 0.4 mile project was included in year 3 of the 2001-2005 Construction Work Plan.

On circuit AL11, project AL-2 is the replacement of a vee-phase and single-phase 1/0 ACSR line with a new three-phase 4/0 ACSR line. The long single-phase line going east from the end of the existing three-phase is estimated to have 65 amps at the 2023 load level. This construction will allow the load in the area to be divided more equally over three phases to improve voltage in the area and load balance along the three-phase main line.

Project AL-3 is also proposed to divide the load for improved voltage and load balance. The recommended normal-open changes are shown on the Circuit Diagram.

On Circuit AL12, Project AL-4 is the conversion of single-phase 1/0 ACSR to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The load on this single-phase line is estimated at 45 amps at the 2023 load level. The 0.6 mile three-phase extension will improve load balance along the three-phase main line and will improve reliability by dividing the load over additional phases.

Circuit AL13 is one of the heaviest loaded circuits in the Alton District with over 5 MW at the 2023 load level. In addition to the proposed Belmont Delivery Point as discussed in Section 6.4.2, there are major line construction projects needed for voltage and capacity reasons.

Project AL-5 is the replacement of a single-phase 1/0 ACSR line with a three-phase 4/0 ACSR line. This project will provide the capacity needed to serve a new Boy Scouts Camp and restaurant.

Three projects are needed on the new Belmont DP Circuit to improve voltages at the extremities of some long single-phase lines. Two projects, BM-2 and BM-3, are single-phase 1/0 ACSR to three-phase 1/0 ACSR conversions to allow better balancing of loads. Project BM-4 is a short, single-phase 1/0 ACSR tie line accompanied by a configuration change to improve voltage at the end of the single-phase line.

On Circuit AL14, Project 308 is the replacement of old single-phase 6 CU with and new three-phase 1/0 ACSR line. The 0.5 mile three-phase extension will provide capacity relief to the single-phase line, will improve voltage at the end of the line by improving load balance along the three-phase main line and will improve reliability by dividing the load over additional phases. This project was included in year 3 of the 2001-2005 Construction Work Plan.

Project 309 is the conversion of old single-phase 6 CU operated at 2.4 kV to single-phase 1/0 ACSR operated at 7.2 kV. This project is part of NHEC's plan to retire aged 2.4 kV distribution facilities. This project was included in year 4 of the 2001-2005 Construction Work Plan.

Project AL-6 is the conversion of a single-phase 4 ACSR and 1/0 ACSR line to three-phase 1/0 ACSR. The single-phase line going west from the three-phase is estimated to have 67 amps at the 2023 load level. The 2.8 mile three-phase extension will provide capacity relief to the single-phase line, will improve voltage at the end of the line by improving load balance along the three-phase main line and will improve reliability by dividing the load over additional phases.

On Circuit AL14, Project AL-7 is the replacement of a three-phase 4 CU feeder main with a new three-phase 4/0 ACSR line. The existing line is aged and routed along difficult right-of-way. As can be seen in the reliability analysis Section 6.2, over 80% of the consumer-hours of outages have occurred within this area. If possible, the new line should be routed along Highway 11 road right-of-way. This project will provide a 6 volt improvement at the end of the line and enables removing the second set of line voltage regulators.

Project AL-8 on circuit AL14 is the replacement of 0.3 miles of single-phase 4 CU with a new three-phase 1/0 ACSR line to the Batchelder Mountain Estates area. The three-phase extension into the area will improve voltage at the end of the line by improving load balance along the three-phase main line and will improve reliability by dividing the load over additional phases.

6.3.5 Barnstead Substation Service Area

6.3.5.1 Existing System Review

The Barnstead Substation is forecasted to serve 4.4 MW of peak load in 2023. The Barnstead area is served by two circuits: BS12 and BS13. This substation is served from the PSNH Pittsfield metering point just a few miles southwest of the substation. NHEC owns this 34.5 kV transmission line. Circuit BS12 serves approximately 33 percent of the total load with BS13 serving the remaining 67 percent.

Circuit BS12 is approximately 12 miles long. The main three-phase line is 10 miles long and the first half is mostly 1/0 ACSR and the second half mostly 4/0 ACSR. Circuit BS12 has no ties to other circuits. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

The three-phase feeder main of Circuit BS13 is approximately 30.0 miles long and has no ties to other circuits. The first 17 miles are 336 ACSR and the remaining 13 miles are 1/0 ACSR. Two sets of voltage regulators are installed in the main line. The first set is approximately 14 miles from the substation and the second set is approximately 22 miles from the substation. It is forecasted that this line will serve about 3.0 MW of load at the 2023 load level and will therefore cause voltage deficiencies.

6.3.5.2 Recommended Plan

On Circuit BS12, there are no distribution system primary line construction projects anticipated as necessary for voltage and/or capacity reasons. However, projects based on improving reliability are discussed in Section 6.5.

To improve voltage and reliability on Circuit BS13, a three-phase tie-line to the Lee Delivery Point in the Raymond District is recommended. This tie will enable the transfer of approximately 800 kW of peak load at the 2023 load level from BS13 to Circuit LE11 of the Lee DP. The tie line, designated as project LE-6, divides the existing load and primary line exposure on Circuit BS13 over two circuits: BS13 and LE11. In addition to the feeder configuration changes, from a reliability perspective, increased tree trimming or the conversion of the remaining 336 ACSR

Hendrix cable or tree wire within the existing first and second zones of Circuit BS13 should be considered. Otherwise, the new shorter circuit BS13 after the re-configuration will still see no improvement in reliability, while the members re-located to Circuit LE11 will see a substantial improvement. The historical reliability review for this circuit can be seen in the reliability Section 6.5.

6.3.6 New Durham Delivery Point Service Area

6.3.6.1 Existing System Review

The New Durham delivery point is forecasted to serve 3.0 MW of peak load in 2023. The New Durham area is served by two 7.2/12.47 kV circuits: ND12 and ND13. Circuit ND12 serves approximately 63 percent of the total load and ND13 serves the remaining 37 percent.

Circuit ND12 exits the substation three-phase and then splits into north and east vee-phase radial feeders. The main three-phase line is approximately 1 mile long and ties to Circuit AL11 of the Alton Substation. The three-phase line conductor is 4 CU and 1/0 ACSR. The two longer vee-phase taps serve the majority of the load on this circuit. The east vee-phase feeder is about 2.5 miles in length and consists of 1/0 ACSR. The north vee-phase feeder is about 4.3 miles long and the end of the circuit is about 8 miles from the substation. The north vee-phase line consists of both 4/0 ACSR and 1/0 ACSR. The 2023 peak load on both vee-phase lines exceeds the maximum design limit of 50 amps per phase and the line is therefore considered to have a capacity deficiency. A small area near the end of one of the single-phase lines is expected to have low voltage at the 2023 load level.

Circuit ND13 is approximately 12 miles long and has no ties to other circuits. The main three-phase line is approximately 3.6 miles long. The main line conductor of ND13 is 1/0 ACSR. The 2023 peak load on the main single-phase line going southwest from near the end of the vee-phase line is close to the maximum design limit of 50 amps and is therefore considered to have a capacity deficiency. This deficiency and the unbalance caused by the heavily loaded single-phase line causes low voltage on the single-phase line.

6.3.6.2 Recommended Plan

On Circuit ND12, Projects ND-1 and ND-2 are the conversion of vee-phase 1/0 and 4/0 ACSR lines to three-phase by adding the third phase conductor. The conversion to three-phase will improve voltage at the end of the line by improving load balance along the three-phase main line and will improve reliability by dividing the load over an additional phase.

Project ND-4 is the replacement of a three-phase 4 CU line with a three-phase 336 ACSR line. This project is needed for tie-line capacity between the Alton Substation and New Durham Delivery Point. This project should be completed at the same time as Project AL-R1.

On Circuit ND13, Project ND-3 is a three-phase 1/0 ACSR tie line. The tie line will enable dividing a long heavily loaded single-phase line over additional phases and will thereby improve voltage and reliability. The amount of line exposure to the end of the circuit will be significantly reduced.

6.4 Distribution System Reliability

6.4.1 Historical Reliability

The Alton District has had lower than average distribution system reliability compared to the NHEC system average over the three-year study period. In particular, the district had the second worst SAIDI index. The following graph shows the resultant indices for each feeder as well as the entire Alton district.[1]

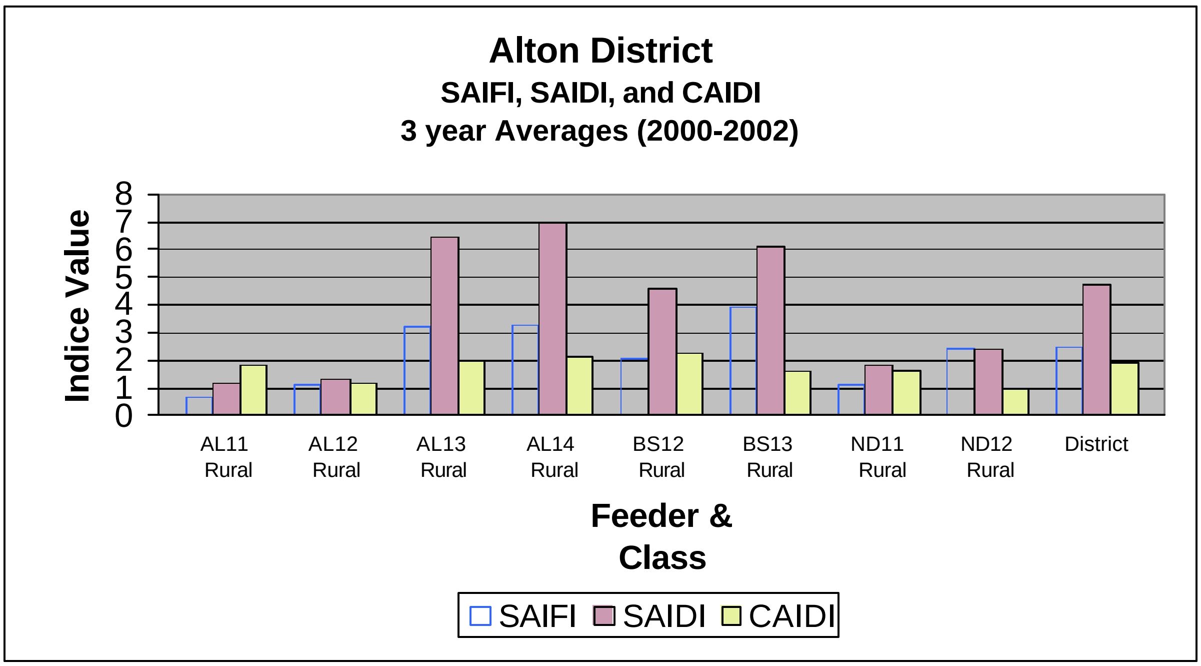

Figure 6-3 Alton District Historical Reliability Indices

6.4.1.1 SAIDI & SAIFI

All circuits except AL11, AL12, and ND11 exceeded either the SAIFI criteria of 2.0 or SAIDI criteria of 5.0 for rural classified feeders.

[1] Outages taking place on the Circuit BS13 of the Barnstead Substation were originally recorded under Raymond District outages. Even though this long feeder extends into the Raymond District, for the purposes of this study the data was modified so that the outages were reflected in the Alton District reliability analysis. The Barnstead Substation is linked to the Alton District throughout the entire study since it is physically located within the Alton District territory.

6.4.2 Circuits That Exceed Reliability Criteria

6.4.2.1 Circuit AL13

This feeder serves more than 2,000 members and had an average SAIDI of 6.44 during 2000-2002.[2] Outages by cause are shown in the following figure.

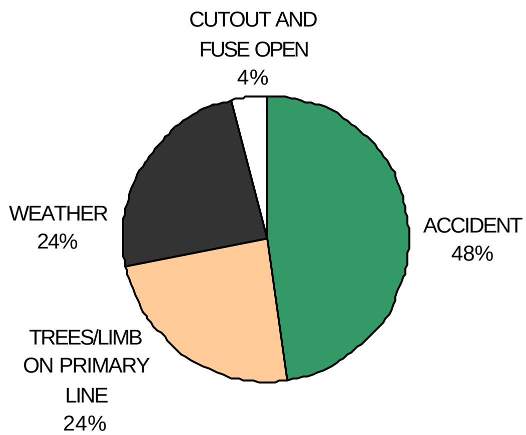

Figure 6-4 Circuit AL13 Percentage of Customer-Minutes Out by Outage Cause

Accident outage causes were almost 50% of the customer-minutes. More than 12,000 customer-minutes, or 35% of the total customer-minutes for all causes, were due to a single outage event in which a car-versus-pole accident occurred. After subtracting this long outage, the percent of causes by customer-minute can be seen in the following figure.

[2] One outage caused by a car hitting a pole in the first zone of protection caused all members to be without power for more than six hours. During restoration, each zone had to be placed back in service individually due to cold-load pickup problems, further causing accumulation of consumer-hours of outages.

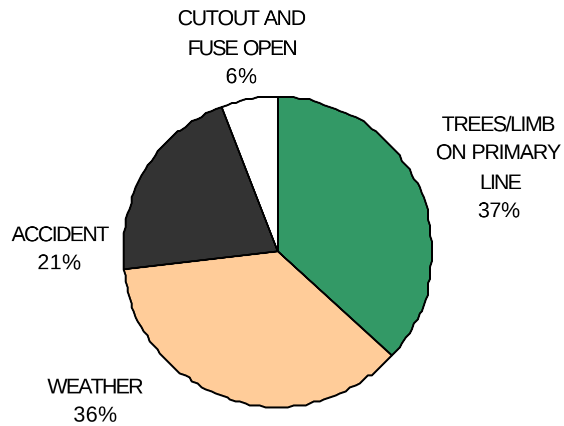

Figure 6-5 Circuit AL13 Customer-Minutes Out Excluding Major Accident

There were five feeder outages that were responsible for approximately 60% of the total outage minutes. Currently, there exists no backup source to this circuit that can provide support during a transmission, substation, or major feeder outage. Therefore, the new Belmont delivery point is recommended as discussed in Section 6.4.2, New Substations, DP's and MP's.

The Village of Belmont is served at the very end of circuit AL13 and is experiencing very poor reliability. Therefore, the new Belmont delivery point will significantly increase service to the village. The new delivery point should serve approximately one-half the load and contain one-half the amount of primary line exposure of the existing circuit AL13 of Alton substation. This will ideally improve reliability by a factor of four.

There is another three-phase line upgrade that will provide yet another tie from the Barnstead substation service area to circuit AL13. This project is discussed in greater detail in the circuit BS12 section 6.5.2.3 of the reliability review.

Projects AL-R3, AL-R4, and BM-R1 are recommended to improve looped capability on the existing long, heavily loaded, single-phase lines. These proposed tie-lines will allow greater flexibility in selecting future normal-open switch locations as well.

6.4.2.2 Circuit AL14

This circuit had the worst reliability of all the feeders in the Alton district. The following figure indicates the consumer-hours by cause.

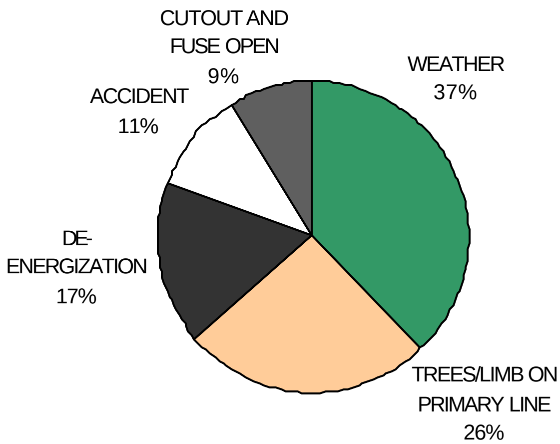

Figure 6-6 Circuit AL14 Percentage of Customer-Minutes Out by Outage Cause

There were only two feeder outages that contributed about 10% of the consumer-hours, although outages in the second zone of protection caused the reliability indices to significantly increase. Specifically, there were seven outages that caused the operation of reclosers AL14R13 in the three-phase line at the beginning of the second zone of protection, therefore disrupting service to more than 800 members for each occurrence. These outages caused about 25% of the total consumer-hours on this circuit. More importantly, 91 of the 137 total outages on circuit AL14 occurred within the second zone of protection. The following table shows outage information by zone for circuit AL14.

Table 6-9 Circuit AL14 Outage Information By Overurrent Protection Zone

Protection Zone[1]	Recloser Number	Phase	Outages	%	Consumer-Hours	%
1	AL14R	ABC	21	16	4,465	12
2[2]	AL14R11	AB	19	14	1,890	5
2	AL14R13	ABC	91	68	31,000	83
3	AL14R14	B	3	2	35	0
		Totals	134	100	37,390	100

[1] Recloser-to-recloser, excluding fuses.
[2] Vee-phase tap off the first zone of protection.

Approximately 60% of the consumer-hours in the second zone were due to tree contact and accidents, with each cause contributing about equal shares. Therefore, increased tree trimming, right-of-way clearing, and more detailed outage information due to weather causes should increase reliability within the second zone. Depending upon outage locations, additional overcurrent protection devices, and/or zones of protection may also prove to be beneficial. Furthermore, it appears the three-phase line in the second zone is routed along the older Highway 11D. If the 3.5 miles of primary line were re-located to the adjacent Highway 11 road right-of-way, increased operations and maintenance practicality may be noticed.

The possibility of new tie-lines or interconnections with neighboring utilities near the extremities of circuit AL14 proved to be insufficient. If these facilities develop in the future, the possibility of interconnection should be re-evaluated. Therefore, there are no distribution construction projects recommended for reliability purposes on this feeder. As previously mentioned, improved O&M and sectionalizing, plus further investigation into outage causes and locations appear to be the best solutions for reliability.

6.4.2.3 Circuit BS12

The outage indices for this circuit were slightly less than the district average, but were still higher than the NHEC system average. A SAIDI of 4.61 met the reliability criteria for a rural type feeder, but the SAIFI of 2.05 exceeded the reliability criteria. The consumer-hours of outages by cause for circuit BS12 can be seen below.

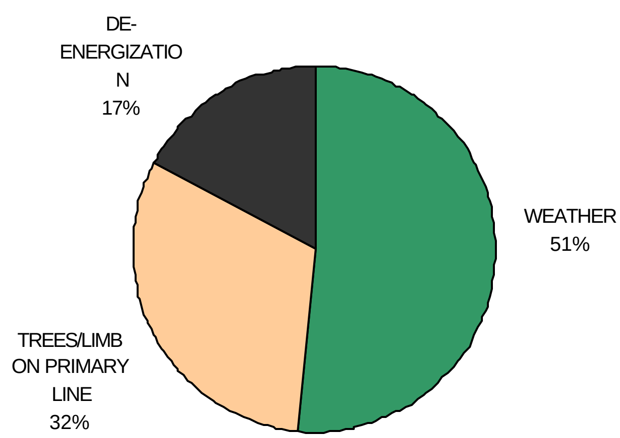

Figure 6-7 Circuit BS12 Percentage of Customer-Minutes Out by Outage Cause

The figure indicates that the majority of the consumer-hours were due to weather caused problems. More specific information should be logged for all future outages due to weather to assist in the reliability review and recommendations. Data examples include type of weather, what actually occurred as a result, and the type of equipment failure.

Three outages occurred within the first zone of protection, therefore causing entire feeder outages. These three outages, out of the 46 total, were accountable for about 60% of the consumer-hours. Furthermore, on average, each one of these outages lasted 2.4 hours, which significantly affected the SAIDI outage index. Project BS-R1, the conversion to three-phase to form a tie-line between circuits AL13 and BS12, will provide an alternate source to circuit BS12 that will improve reliability by reducing outage durations for substation or major feeder outages. This project is estimated to cost approximately $280,000. If the construction cannot be accomplished by using the proposed route, an alternate route is shown on the circuit diagram.

Projects BS-R2 and BS-R3 are recommended to provide looped capability to the existing single-phase lines. Due to difficult right-of-way access, BS-R3 should be installed underground.

6.4.2.4 Circuit BS13

This is the longest feeder in the Alton district, as well as one of the longest feeders on NHEC's system at a length of approximately 30 miles. This configuration caused feeder BS13 to experience a SAIDI of 6.8 and SAIFI of 3.91. Outages by customer-minutes can be seen in the following figure.

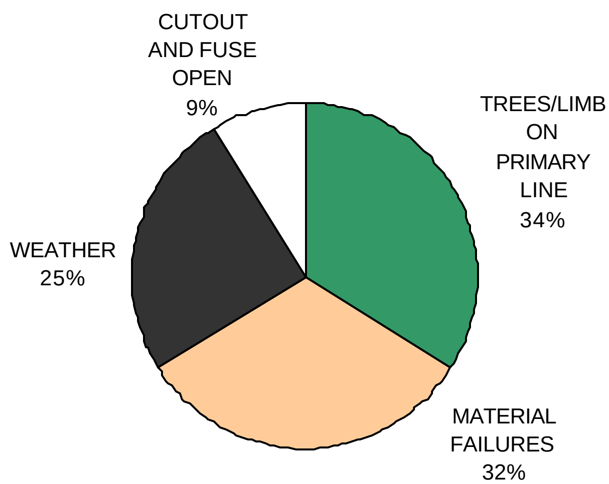

Figure 6-8 Circuit BS13 Percentage of Customer-Minutes Out by Outage Cause

The top three causes were relatively close with tree contact being the major cause at 34 percent. Interestingly, 88 percent of the consumer-hours from tree contact occurred within either the first or second zone of protection. A breakdown of consumer-hours by zone can be seen in the following table.

Table 6-10 Circuit BS13 Outage Information By Overurrent Protection Zone

Protection Zone[1]	Recloser Number	Phase	Outages	%	Consumer-Hours	%
1	BS13R	ABC	12	15	6,658	44
2	BS3R12	ABC	16	19	3,060	21
3	BS3R13	ABC	36	43	3,806	26
4	BS3R14	ABC	1	1	440	3
5	BS3R15	ABC	18	22	945	6
		Totals	83	100	14,909	100

[1] Recloser-to-recloser, excluding fuses.

Notice that 9,700 consumer-hours, or 65% of the total, occurred within the first or second zones. Of this 9,700, about equal amounts were due to either tree contact or material failures.

Project DF-R1 is a proposed three-phase tie-line with circuit DF12 in the Raymond district. The tie-line is recommended to provide backup capabilities between circuits BS13 and DF12. This project will provide major benefits if the three-phase tap of BS13 that heads south along Highway 43 experiences any significant growth. The existing Deerfield elementary school is located on this tap, and is expected to see an increase in load over the planning period. This three-phase tap can remain on the Barnstead substation due to the proposed project LE-6, which transfers about 800 kW of load from BS13 to LE12. But if this area experiences notable growth, the load on the three-phase tap may be transferred to circuit DF12 for voltage, capacity, and reliability purposes. The cost of project DF-R1 is about $425,000 for 5.0 miles of new three-phase 336 ACSR.

6.4.2.5 Circuit ND12

Surprisingly, circuit ND12 had a slightly higher SAIFI than SAIDI index, which is very uncommon compared to the vast majority of the NHEC circuit indices. This is due to the fact that there were outages that affected many members, but were of significantly shorter duration. Specifically, the average outage length was 1.06 hours. The consumer-hours by cause are shown in the following figure.

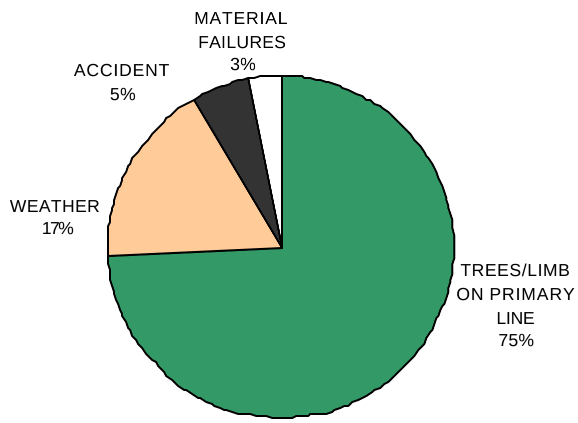

Figure 6-9 Circuit ND12 Percentage of Customer-Minutes Out by Outage Cause

The figure indicates that a tree contact problem is overwhelmingly contributing to the outages. The majority of these are occurring within the first zone of protection. In fact, about 76% of the consumer-hours occurred within this first zone.

Overall, though, this circuit's reliability is much better than average, and therefore does need any particular attention.

6.4.3 Circuits That Meet Reliability Criteria

6.4.3.1 Circuit AL11

This circuit met both SAIDI and SAIFI reliability limits. Service to NHEC members on the east side of Lake Winnipesaukee comes from this feeder. The main feeder does not appear to be routed along any major highway, and therefore may be surrounded by dense forestry contributing to the tree caused outages. For example, slightly less than one-half of the total customer-minutes were due to tree problems. Furthermore, the current NHEC Construction Work Plan indicates various sections of lines will be upgraded to tree wire, which should decrease outages due to tree contact.

Project AL-R1 is recommended for increased capacity between the Alton substation and New Durham delivery point during backup conditions. Construction project AL-R2 is a tie-line between the two long single-phase taps, which will improve reliability for 85 members.

6.4.3.2 Circuit AL12

Similar to Circuit AL11, this circuit is shorter in length and has experienced better than average reliability. Two-thirds of the outages were due to tree contact. Furthermore, two feeder outages contributed about half of the total consumer-hours. Both of these outages were also caused from tree contact.

There are no distribution construction projects proposed for reliability purposes on circuit AL12.

6.4.3.3 Circuit ND11

One of the most reliable circuits in the Alton district was circuit ND11, which met both SAIDI and SAIFI criteria. There was only one feeder outage, and it lasted less than an hour. The majority of consumer-hours of outage, approximately 60%, occurred within the second zone of protection along Merry Meeting Road.

There are no proposed projects for reliability purposes on this circuit.

6.5 Cost Estimates

A summary of the cost estimate for the proposed 5-Year, 10-Year and 20-Year Plans is provided in the following table. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in the previous sections and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 6.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 6-11 Construction Cost Summary

	2004-2008 Cost ($)	2009-2013 Cost ($)	2014-2023 Cost ($)	2004-2023 Cost ($)
New Tie Lines	0	97,720	0	97,720
Conversions and Line Changes	794,000	847,620	316,610	1,958,230
New Substations, DP's and MP's	200,000	0	0	200,000
Substation, DP and MP Changes	0	0	320,000	320,000
Total	994,000	945,340	636,610	2,575,950
Projects for Improved Reliability	504,680	62,820	12,760	580,260

Table 6-12 Substation Load Data Projections

Substation			Existing System Configuration				Proposed System Configuration		
Delivery Point			2003	2008	2013	2023	2008	2013	2023
or Meter Point			Load	Load	Load	Load	Load	Load	Load
Name	Ckt.	Season	kW	kW	kW	kW	kW	kW	kW
Alton Substation	AL11	W	1,654	1,776	2,919	3,251	1,776	2,919	3,251
	AL12	W	569	1,852	2,741	2,898	1,852	2,741	2,898
	AL13	W	3,545	4,152	4,677	5,345	1,850	2,090	2,385
	AL14	W	2,561	2,719	2,902	3,413	2,719	2,902	3,413
	Sub	W	8,329	10,499	13,239	14,907	8,197	10,652	11,947
Belmont DP		W	---	---	---	---	1,910	2,150	2,460
New Durham	ND11	W	1,418	1,536	1,661	1,905	1,536	1,661	1,905
Substation	ND13	W	805	868	954	1,138	868	954	1,138
	Sub	W	2,223	2,404	2,615	3,043	2,404	2,615	3,043
Barnstead Substation	BS12	W	1,098	1,185	1,268	1,445	1,185	1,268	1,445
	BS13	W	1,838	2,115	2,381	2,972	1,381	1,554	1,940
	Sub	W	2,936	3,300	3,649	4,417	2,566	2,822	3,385
Raymond District		W	**13,488**	**16,203**	**19,503**	**22,367**	**15,077**	**18,239**	**20,835**

Table 6-13 Construction Cost Details

(see following 2 pages)

Project Code	YR	Sub/Ckt	Project Description	Reason Code	@ Load (amps) [1]	Miles	Estimated Cost ($)
I. New Tie Lines							
ND-3	2013	New Durham / ND13	3ph 1/0 ACSR	C,D,V	35	0.90	61,200
AL-3	2013	Alton / AL11	1ph 1/0 ACSR	V	30	0.20	12,760
BM-4	2013	Belmont / East	1ph 1/0 ACSR	S	-	0.40	23,760
	Total New Tie Lines					1.50	97,720
II. Conversions and Line Changes							
301	2004	Alton / AL11	2.4 kV to 7.2 kV conversion	WP	-	-	190,000
302	2005	Alton / AL11	3ph 1/0 ACSR to 3ph 336 ACSR	WP	-	0.40	50,000
308	2005	Alton / AL14	1ph 6 CU to 3ph 1/0 ACSR	WP	-	0.50	50,000
309	2005	Alton / AL14	2.4 kV to 7.2 kV conversion	WP	-	2.50	130,000
AL-2	2013	Alton / AL11	1ph 1/0 ACSR to 3ph 4/0 ACSR	C,D,V	45	2.50	212,500
AL-4	2023	Alton / AL12	1ph 1/0 ACSR to 3ph 1/0 ACSR	C,D	45	0.60	51,000
AL-5	2013	Alton / AL13	1ph 1/0 ACSR to 3ph 4/0 ACSR	F	-	5.00	425,000
AL-6	2013	Alton / AL14	1ph 1/0 ACSR to 3ph 1/0 ACSR	C,D,V	45	2.80	190,400
AL-7	2005	Alton / AL14	3ph 4 CU to 3ph 4/0 ACSR	A,C,V	50	4.40	374,000
AL-8	2023	Alton / AL14	1ph 4CU to 3ph 1/0 ACSR	C,D	45	0.30	28,560
BM-2	2023	Belmont / East	1ph 1/0 ACSR to 3ph 1/0 ACSR	C,D	45	1.40	95,200
BM-3	2013	Belmont / East	1ph 1/0 ACSR to 3ph 1/0 ACSR	D,S	-	0.20	19,720
ND-1	2023	New Durham / ND12	2ph 4/0 ACSR to 3ph 4/0 ACSR (add 1)	C,D,V	45	2.80	36,400
ND-2	2023	New Durham / ND12	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)	C,D,V	45	2.40	31,200
ND-4	2023	New Durham / ND12	3ph 4 CU to 3ph 336 ACSR	A,B	50	0.60	74,250
	Total Conversions and Line Changes					26.40	1,958,230
III. Projects that have Potential Reliability Improvement							
AL-R1	2004	Alton / AL11	3ph 4CU to 3ph 336 ACSR			2.00	198,000
AL-R2	2007	Alton / AL11	1ph 1/0 ACSR			0.30	18,480
AL-R3	2008	Alton / AL13	1ph 1/0 ACSR			0.10	6,600
AL-R4	2013	Alton / AL13	1ph 1/0 ACSR			0.30	18,480
BM-R1	2013	Belmont / East	1ph 1/0 ACSR			0.40	23,760
BS-R1	2006	Barnstead / BS12	3ph 4/0 ACSR			3.20	281,600
BS-R2	2023	Barnstead / BS12	1ph 1/0 ACSR			0.20	12,760
BS-R3	2013	Barnstead / BS12	1ph 1/0 AL			0.30	20,580
	Total Potential Reliability Improvements					6.80	580,260
	Total of all projects					34.70	2,636,210
	Total by year for first 4 years (includes reliability projects)						
	2004					2.00	388,000
	2005					7.80	604,000
	2006					3.20	281,600
	2007					0.30	18,480
	2008					0.10	6,600
	2013					13.00	1,008,160
	2023					8.30	329,370
			Total			34.70	2,636,210

Reason Code(s)

A	To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life.
B	To improve **B**ackup between circuits and substations.
C	To provide additional **C**apacity.
D	To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
F	To accommodate **F**uture load.
S	To accommodate new **S**ystem configuration as a result of other projects.
U	To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
V	To improve **V**oltage.
WP	As per NHEC 2001-2005 Construction **W**ork **P**lan.

[1] @ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				
BM-1	2008	Belmont / East	New Delivery Point, 5/7 MVA, 19.9/34.5 - 7.2/12.47 l	200,000
			Total 2004-2008	200,000
BM-1	Project BM-1 is recommended when circuit load reaches 200 amps/phase or when voltage drop in substation regulator zone reaches 8 volts, whichever comes first.			
2009-2013 Time Period				
			None	
2014-2023 Time Period				
			None	
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				
			Total 2004-2008	0
2009-2013 Time Period				
			Total 2009-2013	0
2014-2023 Time Period				
AL-1	2023	Alton Substation	New 12/16/20 MVA 34.5 to 7.2/12.47 kV transformer	200,000
BS-1	2023	Barnstead Substation	New 5/7 MVA 34.5 to 7.2/12.47 kV transformer	120,000
			Total 2014-2023	320,000

Table 6-14 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
ALTON	AL11	2000	307	470	967		0.32	0.49	1.53
		2001	787	912	967		0.81	0.94	1.16
		2002	766	2,022	967		0.79	2.09	2.64
	Totals		1,860	3,404	2,901	Average	0.64	1.17	1.83
	AL12	2000	32	24	310		0.10	0.08	0.75
		2001	86	88	310		0.28	0.28	1.02
		2002	909	1,099	310		2.93	3.55	1.21
	Totals		1,027	1,211	930	Average	1.10	1.30	1.18
	AL13	2000	6,499	8,154	1,908		3.41	4.27	1.25
		2001	5,841	7,070	1,908		3.06	3.71	1.21
		2002	5,976	21,612	1,908		3.13	11.33	3.62
	Totals		18,316	36,836	5,724	Average	3.20	6.44	2.01
	AL14	2000	4,127	10,386	1,795		2.30	5.79	2.52
		2001	1,248	4,244	1,795		0.70	2.36	3.40
		2002	12,235	22,807	1,795		6.82	12.71	1.86
	Totals		17,610	37,437	5,385	Average	3.27	6.95	2.13
	BS12	2000	1,767	4,630	749		2.36	6.18	2.62
		2001	1,327	1,885	749		1.77	2.52	1.42
		2002	1,506	3,839	749		2.01	5.13	2.55
	Totals		4,600	10,354	2,247	Average	2.05	4.61	2.25
	BS13	2000	3,472	4,568	817		4.25	5.59	1.32
		2001	1,554	3,611	817		1.90	4.42	2.32
		2002	4,560	6,735	817		5.58	8.24	1.48
	Totals		9,586	14,914	2,451	Average	3.91	6.08	1.56
	ND11	2000	1,165	1,070	833		1.40	1.28	0.92
	North	2001	670	1,888	833		0.80	2.27	2.82
		2002	995	1,602	833		1.19	1.92	1.61
	Totals		2,830	4,560	2,499	Average	1.13	1.82	1.61
	ND12	2000	207	171	344		0.60	0.50	0.83
	South	2001	580	599	344		1.69	1.74	1.03
		2002	1,724	1,686	344		5.01	4.90	0.98
	Totals		2,511	2,456	1,032	Average	2.43	2.38	0.98
	District Total	2000	17,576	29,473	7,723		2.28	3.82	1.68
		2001	12,093	20,297	7,723		1.57	2.63	1.68
		2002	28,671	61,402	7,723		3.71	7.95	2.14
	Totals		58,340	111,172	23,169	Average	2.52	4.80	1.91

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side" Outages).*

7.0 Andover District

7.1 Load Analysis

The Andover District contains 3 delivery points, which accounted for about 4.8 percent of NHEC's load in 2002. The delivery points of Alexandria, Northfield, and Franklin had respective 2002 peak demands of 624, 3,118, and 4,800 kW. Alexandria and Franklin delivery points are winter peaking. Northfield has peaked twice in the fall, once in the summer and once in the winter in the last four years.

The Alexandria delivery point has about 6.6 percent as many consumers as population in the towns that it serves. Consumer growth is expected to exceed town population growth with the CPR increasing from 6.7% in 2003 to 7.5% in 2023. The number of active consumers served by this delivery point increases at an average annual rate of 1.9% compared to town population increases at an average annual of 1.4% over the 2002 to 2023 period.

The Alexandria demand per consumer was 1.42 kW in 2002, which is the second lowest figure for all NHEC delivery points. Demand per consumer is expected to remain constant over the forecast horizon, which yields an average annual load growth of 1.9%.

The forecasts of consumers and loads are shown in Table 7-1 and Figure 7-1.

Table 7-1 Alexandria DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	6,425				
2001	6,542				
2002	6,613	0.0664	439	1.421	624
2003	6,713	0.0668	449	1.421	638
2004	6,813	0.0673	458	1.421	651
2005	6,914	0.0677	468	1.421	665
2006	7,014	0.0681	478	1.421	679
2007	7,114	0.0686	488	1.421	693
2008	7,215	0.0690	498	1.421	707
2013	7,724	0.0710	548	1.421	779
2023	8,780	0.0746	655	1.421	930
Growth Rates					
2002 - 2003	1.51%	0.67%	2.19%	0.00%	2.19%
2002 - 2008	1.46%	0.64%	2.11%	0.00%	2.11%
2002 - 2013	1.42%	0.61%	2.04%	0.00%	2.04%
2002 - 2023	1.36%	0.55%	1.92%	0.00%	1.92%

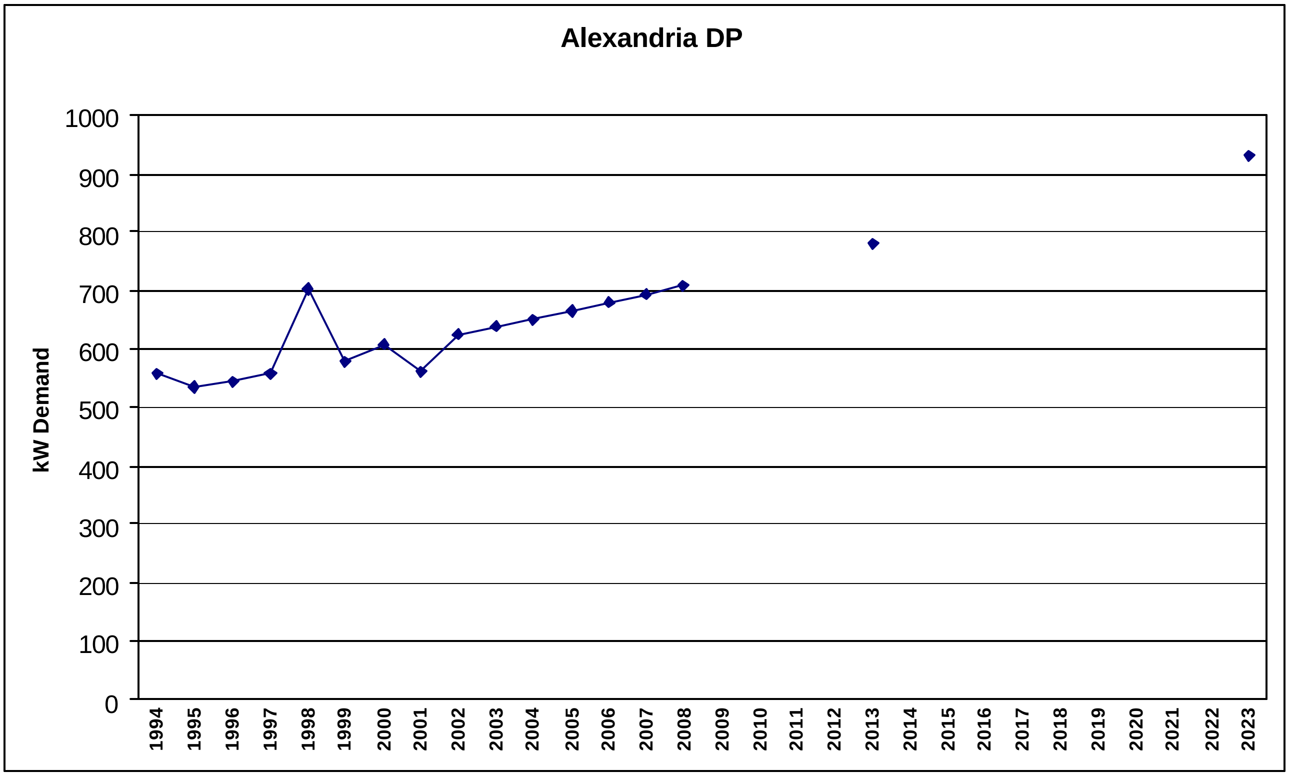

Figure 7-1 Historical and Forecasted Alexandria DP Demands

The Northfield delivery point serves low proportion of the service area population with a 2002 CPR of about 6.2 percent. The CPR is projected to increase slightly over the forecast period to about 6.5 percent. The average annual growth rate for consumers is 0.3%.

The demand per consumer for this delivery point was about 3.66 kW in 2002, the fifth highest on the NHEC system. This is primarily due to a large industrial load (Freudenberg Inc.). The DPC is expected to decrease to about 3.02 kW by 2023, since the new connections will reduce the effect of the large industrial load already being served. The forecasts of consumers and loads are shown in Table 7-2 and Figure 7-2.

Table 7-2 Northfield DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	13,243				
2001	13,576				
2002	13,814	0.0617	852	3.660	3,118
2003	13,989	0.0619	865	3.615	3,128
2004	14,163	0.0620	879	3.572	3,139
2005	14,338	0.0622	892	3.531	3,150
2006	14,509	0.0624	905	3.492	3,162
2007	14,681	0.0626	919	3.455	3,175
2008	14,854	0.0628	932	3.419	3,187
2013	15,718	0.0636	999	3.261	3,259
2023	17,488	0.0651	1,138	3.017	3,435
Growth Rates					
2002 - 2003	1.27%	0.30%	1.57%	-1.23%	0.33%
2002 - 2008	1.22%	0.29%	1.51%	-1.13%	0.37%
2002 - 2013	1.18%	0.28%	1.46%	-1.04%	0.40%
2002 - 2023	1.13%	0.26%	1.39%	-0.91%	0.46%

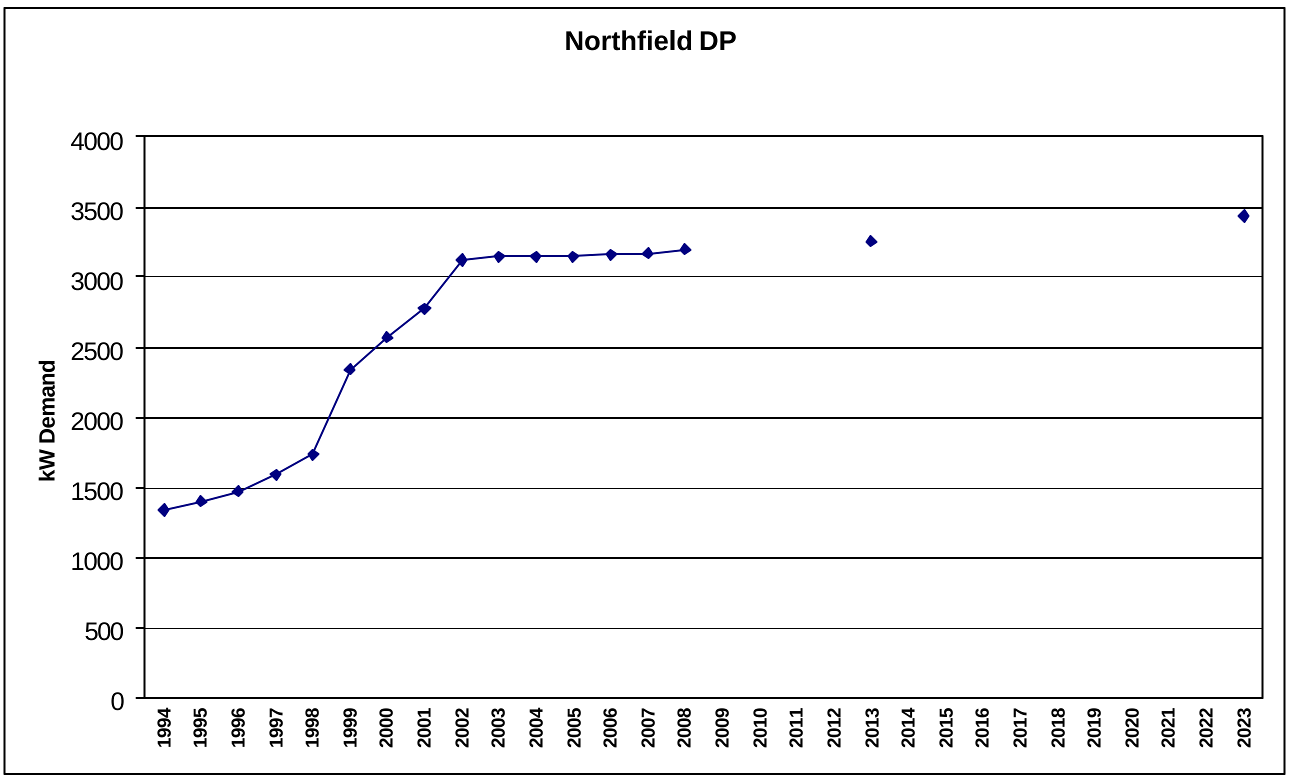

Figure 7-2 Historical and Forecasted Northfield DP Demands

The Franklin delivery point has about 14.4 percent as many consumers as population in the towns that it serves. Consumer growth is expected to match town population growth, at an average annual rate of about 0.8%. The 2002 DPC of 1.86 kW is below the NHEC system average, and is expected grow at an average annual rate of about 0.11% through 2013, and then diminish from 2013-2023. This growth pattern reflects district manager views that incremental homes on this system will be larger than average (2.0 kW per Consumer) for the next decade but then will return to current demand levels of 1.85 kW per consumer.

The forecasts of consumers and loads are shown in Table 7-3 and Figure 7-3. Included in the load growth forecast are three loads on the WB11 Circuit as shown in Table 7-4.

Table 7-3 Franklin DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	17,540				
2001	17,798				
2002	17,973	0.1439	2,586	1.856	4,800
2003	18,120	0.1441	2,612	1.859	4,855
2004	18,264	0.1441	2,632	1.861	4,899
2005	18,412	0.1441	2,654	1.863	4,945
2006	18,555	0.1441	2,674	1.865	4,989
2007	18,699	0.1441	2,695	1.868	5,033
2008	18,845	0.1441	2,716	1.870	5,078
2013	19,574	0.1441	2,821	1.879	5,301
2023	21,087	0.1441	3,039	1.864	5,666
Growth Rates					
2002 - 2003	0.82%	0.17%	0.99%	0.15%	1.14%
2002 - 2008	0.79%	0.03%	0.82%	0.12%	0.94%
2002 - 2013	0.78%	0.02%	0.79%	0.11%	0.91%
2002 - 2023	0.76%	0.01%	0.77%	0.02%	0.79%

Table 7-4 Franklin DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Webster	WB11	Proctor Academy	75	75	75
		Golf Course/Country Club	50	50	25
		Subdivision	20	10	10
	WB12	None			

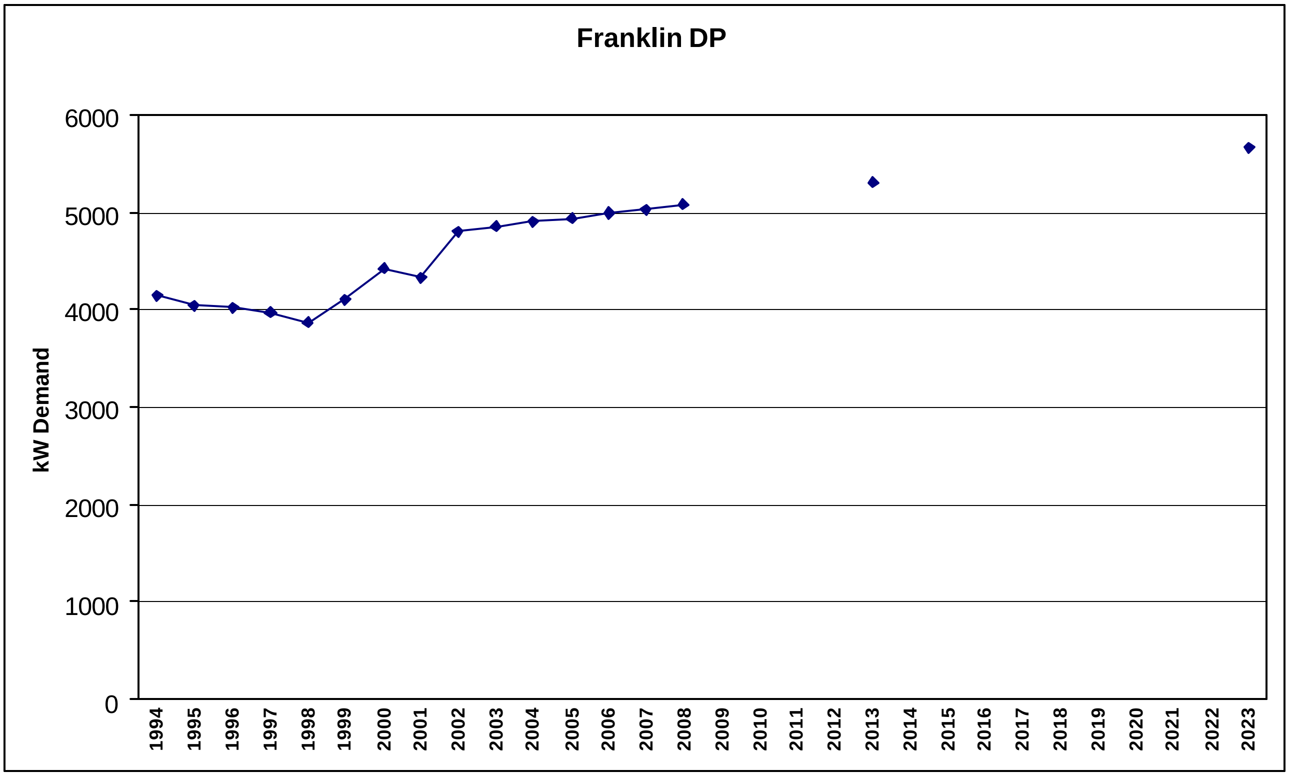

Figure 7-3 Historical and Forecasted Franklin DP Demands

7.2 Transmission System

7.2.1 Bulk Power Transmission System

NHEC's Andover District is served at 34.5 kV from PSNH's Laconia, Pemigewasett and Webster substations. These substations are supplied from the 115 kV system. Webster Substation is the area's major 115 kV bulk supply substation with six 115 kV circuits. Laconia and Pemigewasett Substations are each looped with two 115 kV lines. The second Webster-Laconia 115 kV circuit was developed and placed in service in 2003.

7.2.2 34.5 kV Subtransmission System

The Andover District is supplied at 34.5 kV at three delivery points by PSNH. NHEC's Alexandria Substation is served by the Pemigewasett 3114 feeder, and the Northfield and Franklin delivery points by the Webster-Laconia 398 feeder.

Substation transformer capacity and base case and coincident peak demands for planning purposes are reflected in Table 7.3 below. The coincident peak demands reflect PSNH and

NHEC coincident peaks in 2002/03 and forecasted peaks in 2023 and are based upon an annual growth rate of 1.76 percent in the summer peak and 0.93 percent in the winter peak.

Table 7-5 Andover District 34.5 kV System and Load

PSNH Substation	115-34.5 kV Transformer Summer Capacity	115-34.5 kV Transformer Winter Capacity	34.5 kV Feeders	Coincident Peak Loads – MVA Summer 2003	Summer 2023 [3]	Winter 2002	Winter 2023
Ashland	1-31 MVA	1-41 MVA	2	27.9	28.8	16.4	29.9
Pemigewasett	1-28 MVA	1-32 MVA	3	13.3	19.4	13.8	16.4
Laconia	2-51 MVA	2-64 MVA	5	63.6	89.4	45.9	65.7
Webster	1-17, 2-25 MVA	1-22, 1-31, 1-32 MVA	3	28.0	40.9	30.3	24.8

Base power flow studies for the summer 2003/2023 and winter 2002/2023 coincident peak conditions indicate there are no deficiencies after the PSNH construction and operating upgrades which were placed in service in June, 2003. PSNH completed the addition of a second 115 kV Webster-Laconia line which looped Laconia and rebuilt portions of the Webster-Laconia 337 feeder. PSNH also opened the Laconia-Webster 337 and 398 feeder loops which were operated closed and in a network configuration. In 2005, PSNH plans on increasing the capacity of the 115-34.5 kV transformers at Ashland and Pemigewasett substations. This additional substation transformer capacity is necessary to avoid contingent overloading of the existing transformers.

7.2.3 Contingency Performance

PSNH's Ashland, Laconia, Pemigewasett and Webster Substations are all looped at 115 kV. The outage of any single 115 kV circuit will not result in an outage to Laconia or Webster Substations. The 115 kV system supplying Ashland and Pemigewasett utilizes a line breaker electrically between Ashland and Pemigewasett for sectionalizing protection on the Webster-Beebe River 115 kV line. In this protective arrangement, a substation and serving 115 kV line section could be outaged simultaneously to preserve service to the other substation.

NHEC's Alexandria Substation is served from a radial tap of Pemigewasett 34.5 kV feeder 3114. Pemigewasett feeder 3114 is looped to feeder 3149 at the Ayers Island Hydro Plant. The loop tie between these feeders is rated at 17 MVA for a winter emergency and 12 MVA summer emergency and provides sufficient capacity to serve winter loads through the planning period but will be beyond summer capacity ratings in 2004.

NHEC's Franklin and Northfield delivery points are served from the Webster-Laconia 398 feeder loop and full first contingency capability exists through the planning period with the completion of PSNH's 2003 Webster-Laconia 115 kV and 34.5 kV upgrade projects.

The Webster-Laconia 337 and 398 feeders 34.5 kV feeder loops were operated closed in a network configuration. PSNH is now operating these loops open which will remove

[3] Reflects the addition of a new 115 – 34.5 kV substation at PSNH's Brentwood Substation

approximately 70 percent of the feeder exposure to outages for NHEC's Franklin and Northfield delivery points and thus lessen the feeder outages by the same percentage.

7.2.4 Historical Reliability

A review of the 34.5 kV subtransmission outages for the period of 2000-2002 indicated that Alexandria averages 0.67 outages per year, and Northfield and Webster have not experienced any outages during this time.

All annual outage rates are within the NHEC design criteria.

7.2.5 Construction Plan Summary

The following PSNH construction projects are planned for the PSNH system serving the Andover District.

Table 7-6 PSNH Subtransmission Construction Plan - NHEC Andover District

Location	Project	Year
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 capacity	2005
Ashland Substation	Increase 115-34.5 kV transformer capacity	2005

7.3 Distribution System

7.3.1 General

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 7.4, Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 7.0 shows the 2003, 2008, 2013 and 2023 peak load levels for each substation, DP, MP and circuit using the existing system configuration and proposed system configuration.

7.3.2 New Substations, DP's and MP's

One new substation is recommended in the Andover District during this 20-year planning period for voltage, capacity, and reliability reasons. The new Wilmot Substation is located in the

Township of Wilmot along Highway 11. The new substation will provide load relief and improved reliability to the heavily loaded Circuit WB11 of the Webster Substation.

7.3.3 Substation, DP and MP Changes

The following table shows the projected kW for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for backup or for the ordinary replacement of aged transformers are shown in [**bold**]. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 7-7 Substation Transformer and Regulator Data

Name	Transformer							Voltage Regulator		
	Rating (kVA)					Est.			Est.	
	OA 55°	FA 55°	OA 65°	FA 65°	Win Season	Load (kW)	Capacity (%)	Size (AMP)	Load (AMP)	Capacity (%)
Alexandria DP [1]	2,500	3,125	2,800	3,500	3,080	946	31	--	49	--
Northfield Sub	3,750	--	--	--	4,125	3,237	80	150	168	112
Northfield Sub [1, 2]	**5,000**	**6,250**	**5,600**	**7,000**	**6,160**	3,237	54	**219**	168	77
Webster Sub [3]	5,000	5,750	5,600	6,440	7,000	5,786	84	328	301	92
Webster Sub [2, 3]	**5,000**	**6,250**	**5,600**	**7,000**	**7,700**	5,786	77	328	301	92
Webster Sub [2, 4]	**5,000**	**6,250**	**5,600**	**7,000**	**7,700**	3,824	38	328	149	45
Wilmot Sub [1]	**5,000**	--	**5,600**	--	**6,160**	1,815	30	**219**	94	43

[1] Fans are not installed.
[2] Upgrade to replace aged equipment. Projects NF-1 and WB-1.
[3] Estimated load is before transfer to new substation.
[4] Estimated load is after transfer to new substation.

Project NF-1 is the replacement of the existing 3-1,250 kVA transformers with a new 5/7 MVA transformer. The existing transformers were purchased in 1968 and replacement due to age is expected.

Project WB-1 is the replacement of the existing 3-1,667 kVA transformers with a new 5/7 MVA transformer. The existing transformers were purchased in 1969 and replacement due to age is expected.

No conversion to a different distribution system operating voltage is recommended at any of the substations or delivery points. The distribution operating voltage is to remain at 7.2/12.47 kV.

7.3.4 Alexandria Delivery Point Service Area

7.3.4.1 Existing System Review

The Alexandria Delivery Point is forecasted to serve 946 kW of peak load in 2023. The Alexandria area is served by one 7.2 kV single-phase circuit (AX11) and one 7.2/12.47 kV three-phase circuit (AX12). Circuit AX11 serves approximately 24 percent of the total load and AX12 serves the remaining 76 percent.

Circuit AX11 is approximately 5.5 long and has no ties to other circuits. The main line conductor is 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period provided the voltage at the DP is 120 volts or higher.

On Circuit AX12, voltage regulators are installed in the main three-phase line approximately 1 mile from the DP. Just beyond the regulators, Circuit AX12 splits into north and west feeders. The west feeder continues with three-phase for another 2 miles and then single-phase lines continue for another 3 miles. The north feeder continues with vee-phase for about 5 miles and then single-phase lines continue for another 4 miles. Neither of the feeders have a tie to another circuit. The three-phase, vee-phase and most of the single-phase lines are 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period provided the voltage at the DP is 120 volts or higher.

7.3.4.2 Recommended Plan

There are no distribution system primary line construction projects anticipated as necessary for voltage and/or capacity reasons on either Circuit AX11 or AX12. Projects based on improving reliability are discussed in Section 7.4.

7.3.5 Northfield Substation Service Area

7.3.5.1 Existing System Review

The Northfield Substation is forecasted to serve 3.2 MW of peak load in 2023. The Northfield area is served by two circuits: NF12 and NF13. Circuit NF12 serves approximately 78 percent of the total load with NF13 serving the remaining 22 percent.

Circuit NF12 is approximately 13 miles long and has no ties to other circuits. The main three-phase line is approximately 6.5 miles long. The first 4 miles are 4/0 ACSR, the next 0.5 miles are 1/0 ACSR and then 2 miles of 336 ACSR. A voltage regulator is installed in the main single-phase line about 9.6 miles from the substation. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit NF13 is approximately 9 miles long and has no ties to other circuits. The main three-phase line is approximately 4.2 miles long and is 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

7.3.5.2 Recommended Plan

There are no distribution system primary line construction projects anticipated as necessary for voltage and/or capacity reasons on either Circuit NF12 or NF13. Projects based on improving reliability are discussed in Section 7.4.

7.3.6 Webster Substation Service Area

7.3.6.1 Existing System Review

The Webster Substation is forecasted to serve 5.8 MW of peak load in 2023. The Webster area is served by two 7.2/12.47 kV circuits: WB11 and WB12. Circuit WB11 serves approximately 82 percent of the total load and WB12 serves the remaining 18 percent.

Circuit WB11 serves approximately 48 percent of the total Andover District load. The three-phase feeder main is about 11 miles long and then splits into northwest and southwest feeders. The northwest three-phase feeder continues for another 4.5 miles and then single-phase for another 12 miles. The southwest three-phase feeder continues for 2 miles and then single-phase for another 4 miles. The 11-mile feeder main and the two- mile southwest feeder is 336 ACSR. The 4.5-mile northwest feeder is 1/0 ACSR. Two sets of voltage regulators are installed in the main line. The first set is approximately 5.3 miles from the substation and the second set is approximately 9.5 miles from the substation. Another voltage regulator is installed further out on the single-phase line on the northwest feeder. This circuit is considered to have a capacity and voltage problem since adequate voltage is being maintained through the use of multiple sets of voltage regulators and capacitor banks.

Circuit WB12 is approximately 11 miles long and has no ties to other circuits. The main three-phase line is approximately 7 miles long. The first 2 miles are 4/0 ACSR, the next one-mile is 4 CU, the next 3 miles are 2 ACSR and the last 1 mile is 4 CU. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

7.3.6.2 Recommended Plan

Circuit WB11 is the heaviest loaded circuit in the Andover District with 4.7 MW of load forecasted at the 2023 load level, which is causing voltage deficiencies. Therefore, a new substation near the west end of the main three-phase line is recommended due to the availability of PSNH facilities in the nearby area. Currently, PSNH's 115 kV M-127 transmission line, as well as the 34.5 kV 316 transmission line provide interconnection possibilities. Both sources are looped, and will therefore provide reliable service. The M-127 line crosses NHEC distribution facilities, while the 316 line is located approximately 4.0 miles from the nearest NHEC three-phase line. Therefore, due to the location of the 115 kV source, a new two-feeder substation, 115 – 7.2/12.47 kV, 5,000 kVA, is recommended. The costs between the two options are comparable due to an additional $400,000 in distribution costs for the 34.5 kV delivery point alternative. Furthermore, the 115 kV substation will provide additional reliability due to a two-feeder substation configuration compared to one feeder with the 34.5 kV delivery point option. The additional 4.0 miles of 336 ACSR distribution line needed with the 34.5 kV alternative causes more line exposure and would need to be routed along Highway 11 in PSNH's service territory. For purposes of this plan, the new Wilmot Substation is estimated to cost approximately $600,000. The proposed system map shows the 115 kV interconnection alternative, Wilmot Substation, and is designated as Project WL-1. The resultant circuit configuration and normal-open switch locations are also shown. The 34.5 kV option is also presented on the map as the Sutton Delivery Point and designated as WL-1 Alt. If the proposed 115 kV substation option cannot be accomplished, the 34.5 kV delivery point, along with the 4.0 miles of 336 ACSR distribution line, should be considered. Regardless of which project is implemented, about 1,800 kW of load and 675 members will be transferred from circuit WB11 to the new source.

Projects 313, 314 and 315 are all related to the conversion of old single-phase 4 CU lines operated at 2.4 kV to single-phase 1/0 lines to be operated at 7.2 kV. The existing lines are in poor physical condition. These projects were included in year 1 of the <u>2001-2005 Construction Work Plan</u>.

Project 317 is the replacement of an old single-phase 4A CWC line with a new single-phase 1/0 tree wire line. The existing lines are in poor physical condition. This project was included in year 3 of the <u>2001-2005 Construction Work Plan</u>.

On Circuit WB12, Projects 319 and 321 are the replacement of a three-phase 4 CU line with a three-phase 4/0 Hendrix cable line. The existing line was built in the 1930's and is in poor physical condition. These projects were included in year 3 of the <u>2001-2005 Construction Work Plan</u>.

Project WB-2 is the conversion of single-phase 1/0 ACSR to three-phase 4/0 Hendrix cable line. The load on this single-phase line is estimated at 45 amps at the 2023 load level. The 1.1 mile three-phase extension will improve voltage at the end of the line by improving load balance along the three-phase main line and will improve reliability by dividing the load over additional phases.

7.4 Distribution System Reliability

7.4.1 Historical Reliability

The overall reliability in the Andover district during 2000-2002 has been lower than the NHEC system average, ranking the third worst of all NHEC districts. The following figure shows the reliability for each of the Andover district feeders, as well as the district total.

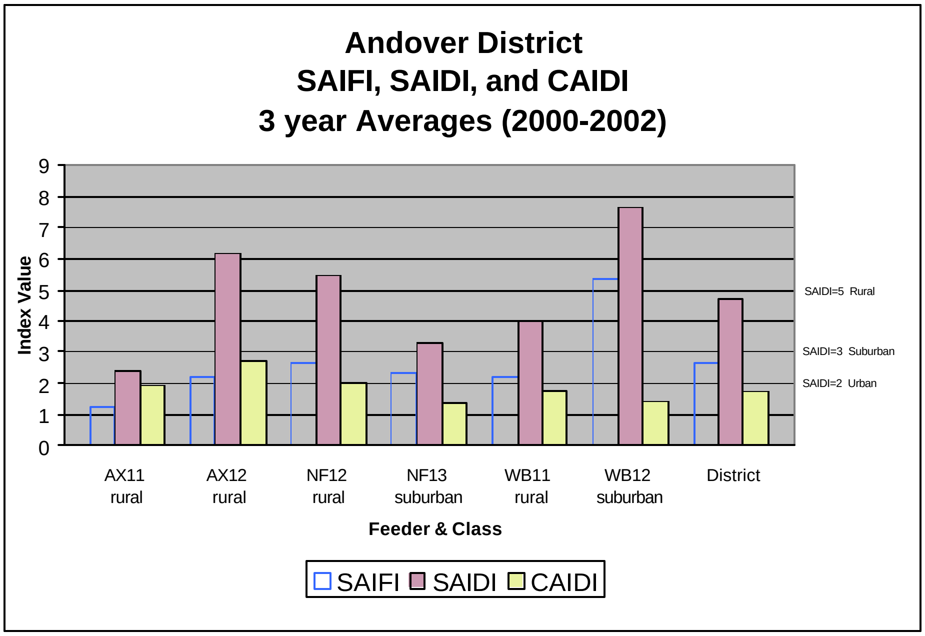

Figure 7-4 Andover District Average Reliability Indices

Further analysis indicated that the Andover District had the following outage cause contributions for the top five categories.

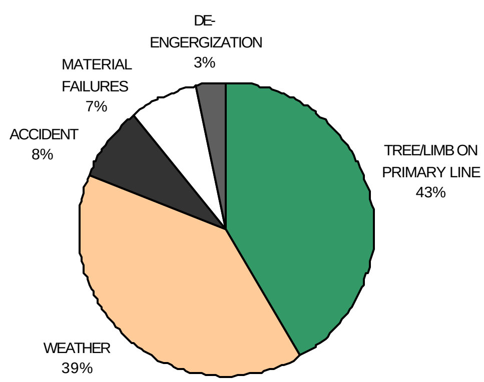

Figure 7-5 Andover District Percentage of Customer-Minutes Out by Outage Cause

Once again, the top two causes were tree contact and weather. Therefore, increased tree trimming or the conversion to underground or tree wire may prove to be beneficial on feeders that have a history of tree contact problems. Furthermore, detailed systematic outage record keeping for weather caused outages should be implemented.

7.4.2 SAIDI & SAIFI

All circuits except AX11 exceeded the SAIFI reliability criteria of 2.0. Circuits AX12 and NF12 exceeded the rural classified feeder SAIDI criteria of 5.0, while circuits NF13 and WB12 exceeded the suburban classified feeder criteria of 3.0 for SAIDI. Therefore, all circuits except AX11 were analyzed for potential reliability improvements.

7.4.3 Circuits That Exceed Reliability Criteria

7.4.3.1 Circuit AX12

This rural classified feeder had a SAIDI of 6.2 over the 2000-2002 period. The following figure shows the cause categories responsible for customer-minutes of outages on circuit AX12.

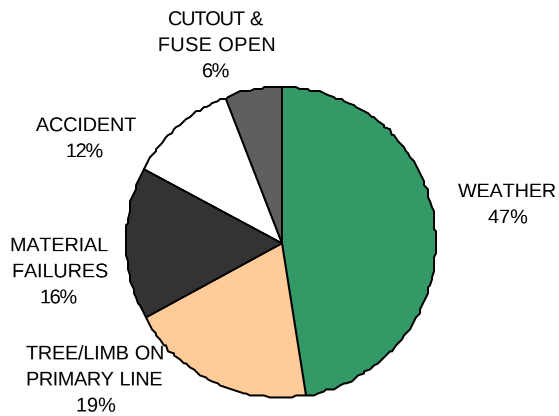

Figure 7-6 Circuit AX12 Percentage of Customer-Minutes Out by Outage Cause

There were 46 total outages on this feeder. Weather was responsible for the majority of both the number of outages and customer-minutes of outages. Even though there are about 300 members served by this feeder, only two weather caused outages affected more than 100 members per event (106), while the remaining affected less than 100 members per event. Therefore, obviously, this points to the fact that these outages were of significant duration. In particular, these eighteen outages averaged more than four hours. Due to a history of weather problems, any future weather related outage should be logged in greater detail, including the type of weather, what actually occurred as a result, and the type of equipment failure. This information will assist greatly in the future review and mitigation process.

About 55% of the consumer-hours of outages on this circuit occurred on the vee-phase tap that serves central Alexandria township. 42% of the customer-minutes on this tap were due to weather caused outages. As previously explained, future weather related outage information recorded in great detail may help determine reliability solutions. In the interim, a single-phase tie-line designated as Project AX-R1 will improve the backup potential for all the 130 members served in this area.

Project AX-R3 is needed to provide a backup source to the Alexandria Delivery Point. This project will work in conjunction with Project WB-2, which is recommended for voltage and capacity reasons. The Webster Substation and Alexandria Delivery Point are served by different transmission lines, and will therefore be able to serve each other in contingency situations during transmission, substation, or distribution outages. Because of the high number of outages on the main three-phase line of circuit WB12, this tie-line has a high potential for reliability improvement.

7.4.3.2 Circuit NF12

This circuit had the third poorest reliability in the district, in regards to the SAIDI index, with a value of 5.47. A summary of the causes of outages is shown the following figure.

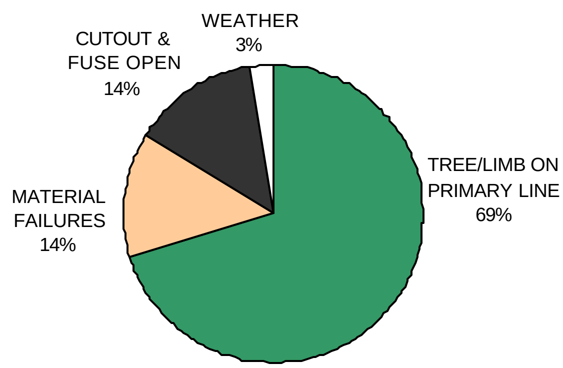

Figure 7-7 Circuit NF12 Percentage of Customer-Minutes Out by Outage Cause

Almost 70% of the consumer-hours of outages and 50% of the outage events were caused by tree contact. This circuit basically consists of three-phase first and second zones of protection, and a vee-phase and single-phase third zone of protection. The following table shows outage information by zone.

Table 7-8 Circuit NF12 Outage Information by Protection Zone

Protection Zone[1]	Recloser Number	Phase	Outages	%	Consumer-Hours	%
1	NF12R12	ABC	14	27	1,020	15
2	NF12R13	ABC	20	38	3,655	53
3	NF12R14	AC	18	35	2,220	32
			52	100	6,895	100

[1] Recloser-to-recloser, excluding fuses.

The majority of outages occurred within the second three-phase zone of protection. Nine outages caused the operation of at least one of the single-phase reclosers NF12R13. Of the nine outages, four caused an A-phase recloser operation, and two caused all three reclosers to operate.

Within the third zone of protection, there were five outage events that caused the A-phase recloser NF12R14 to operate and affect all 140 members on this phase. Only four of the eighteen outages within the third zone affected C-phase members.

Project NF-R1 is the addition of a single-phase tie-line in the third zone of protection area. This tie will allow phase diversification so that the 140 members currently served on the A-phase can be equally split over the A and C phases. Furthermore, four of the five outages affecting all 140 members on the A-phase in this area were due to tree contact. Therefore, increased tree trimming, as well as an overcurrent protection update should be considered.

7.4.3.3 Circuit NF13

This circuit exceeded the SAIDI criteria because of its' suburban classification. Outages by percentage of customer-minutes can be seen below.

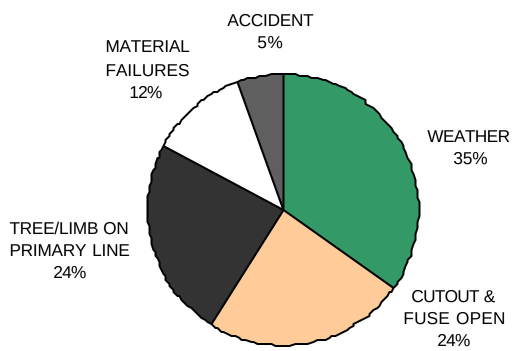

Figure 7-8Circuit NF13 Percentage of Customer-Minutes Out by Outage Cause

Three categories were responsible for over 80% of the customer-minutes, and were close in their contribution as well. There were 53 outages that occurred on this feeder, which seems excessive due to its' shorter length. It appears there were two feeder outages of short duration.

There appears to be no cost effective projects that will cause significant reliability impact on this circuit. Due to the existing SAIDI of 3.3 that is very close to the reliability criteria of 3.0 for suburban feeders, O&M or sectionalizing improvements maybe the best solution.

7.4.3.4 Circuit WB11

The SAIDI index of 3.99 on circuit WB11 was better than the district average SAIDI of 4.72. Therefore, overall, the reliability has been satisfactory. Although, due to the feeder configuration and location, there are some proposals that will even further help reliability. Outages by cause category can be seen in the following figure.

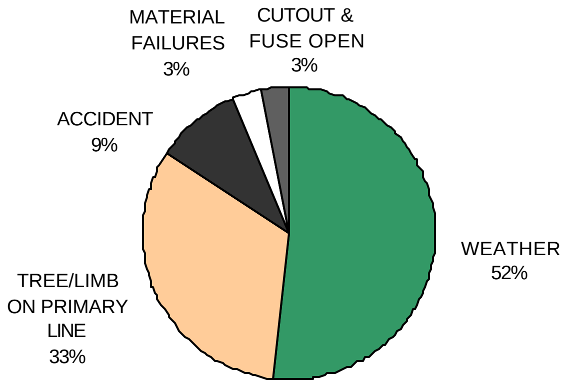

Figure 7-9 Circuit WB11 Percentage of Customer-Minutes Out by Outage Cause

Outages caused by weather were responsible for more than half the consumer-hours of outages, while tree contact outages ranked second at 33%.

Due the length of this feeder, an evaluation of outage information by zone was completed and can be seen in the following table.

Table 7-9 Construction Cost Summary

Protection Zone[1]	Recloser Number	Phase	Outages	%	Consumer-Hours	%
1[2]	WB11R	ABC	61	31	7,100	34
2[2]	WB11R14	ABC	53	27	5,440	26
3[3]	--	--	36	18	2,748	12
3	WB11R24	ABC	29	14	2,054	10
4	WB11R17	ABC	10	5	1,640	8
5	WB11R19	B	9	5	2,061	10
			198	100	21,043	100

[1] Recloser-to-recloser, excluding fuses
[2] Includes three-phase tap off first zone
[3] Taps off the main three-phase second zone of protection

The first zone of protection experienced one outage that affected all members, while the main three-phase second zone of protection experienced three outages affecting 1374, 1193, and 1074 members. The above table indicates that about 34% of customer-minutes occurred within the first zone of protection, with about half of these customer-minutes of outages due to the one feeder outage.

This circuit has experienced satisfactory reliability, and therefore there are no projects that can be justified for purely reliability reasons. Although, Project WL-1, the addition of another substation, as explained in the recommended plan for the Webster Substation area of the distribution system report section will improve reliability. The existing 1,900 members will be divided amongst three feeders of shorter length compared to the one long feeder. Furthermore, the new source will provide another backup to circuit WB11 during a transmission, substation, or major feeder outage.

Reliability Project WB-R2 is recommended for backup to the 220 members located on the two radial single-phase taps.

7.4.3.5 Circuit WB12

This feeder had the worst reliability in the Andover District with a SAIDI of 7.65. Not only did the SAIDI index exceed the suburban feeder classification, it also highly exceeded the rural feeder classification. Of particular interest, the SAIFI index was 5.39, which was one of the highest on the NHEC system over the 2000-2002 time period.

The following figure indicates the customer-minutes of outages by cause.

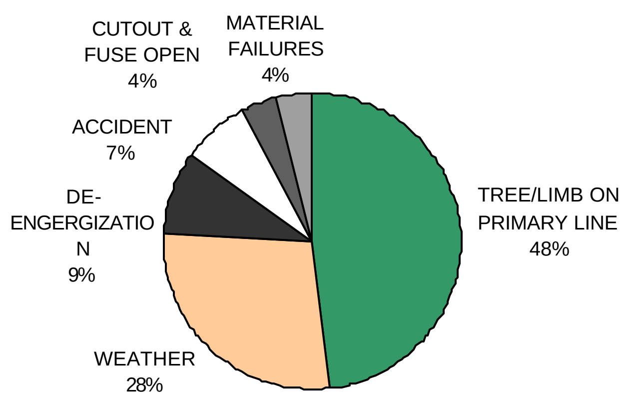

Figure 7-10 Circuit WB12 Percentage of Customer-Minutes Out by Outage Cause

This feeder basically consists of one long three-phase first zone on protection, with a long single-phase tap forming the second zone of protection. There were ten feeder outages affecting all members on this circuit accounting for 62% of the total customer-minutes. These outages caused the high SAIFI index of 5.39 as previously mentioned. A review of the outage locations within the first zone of protection may indicate what needs to be accomplished to improve the future reliability.

The majority of the main three-phase line will be rebuilt to 4/0 ACSR Hendrix as discussed in the recommended plan for the Webster Substation area of the distribution system report section. This construction may cause an increase in reliability for this circuit. In addition, the main three-phase recloser at the substation should be replaced with three single-phase reclosers, which will obviously improve reliability depending upon what type of faults are occurring along the main three-phase line.

For long duration transmission, substation, or major feeder outages, a new tie-line between circuits WB12 and AX12 is recommended. Since there have been many feeder outages on this circuit in the first zone of protection, this tie-line has a better chance of improving the reliability and backup capability of circuit WB12.

7.4.4 Circuits That Meet Reliability Criteria

7.4.4.1 Circuit AX11

There were only 11 outages on this circuit over the three-year period, and none of them were entire feeder outages affecting all members. Three longer outages were due to weather, therefore increasing this cause contribution to almost fifty percent. Due to less than 100 members currently served on this circuit, even the smallest of outages significantly affect the reliability indices.

Most of the members on this circuit are located along a long radial single-phase line. Therefore, a new single-phase tie-line, Project AX-R2, from the end of circuit AX11 to circuit AX12 is recommended. This will provide a looped configuration, which has potential reliability improvement to all 85 members on this feeder.

7.5 Cost Estimates

A summary of the cost estimate for the proposed 5-Year, 10-Year and 20-Year Plans is provided in the following table. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in the previous sections and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 7.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 7-10 Construction Cost Summary

	2004-2008 Cost ($)	2009-2013 Cost ($)	2014-2023 Cost ($)	2004-2023 Cost ($)
New Tie Lines	0	0	0	0
Conversions and Line Changes	750,000	93,500	0	843,500
New Substations, DP's and MP's	0	600,000	0	600,000
Substation, DP and MP Changes	0	0	240,000	240,000
Total	750,000	693,500	240,000	1,683,500
Projects for Improved Reliability	0	373,000	95,480	468,480

Table 7-11 Substation Load Data Projections

Substation Delivery Point or Meter Point Name	Ckt.	Season	Existing System Configuration 2003 Load kW	Existing 2008 Load kW	Existing 2013 Load kW	Existing 2023 Load kW	Proposed System Configuration 2008 Load kW	Proposed 2013 Load kW	Proposed 2023 Load kW
Alexandria	AX11	W	158	174	191	227	174	191	227
5000/7000 kVA	AX12	W	501	552	606	719	552	606	719
65 deg. w/o fans	Sub		659	726	797	946	726	797	946
Northfield	NF12	W	2,333	2,369	2,419	2,533	2,369	2,419	2,533
5000/7000 kVA	NF13	W	554	581	619	704	581	619	704
65 deg. w/o fans	Sub		2,887	2,950	3,038	3,237	2,950	3,038	3,237
Wilmot Substation	WI11	W	---	---	---	---	---	920	1,000
5000/7000 kVA	WI12	W	---	---	---	---	---	720	800
	Sub							1,640	1,800
Webster	WB11	W	3,870	4,097	4,340	4,741	4,097	2,700	2,941
5000/7000 kVA	WB12	W	940	956	978	1,045	956	978	1,045
	Sub		4,810	5,053	5,318	5,786	5,053	3,678	3,986
Andover District			**8,356**	**8,729**	**9,153**	**9,969**	**8,729**	**9,153**	**9,969**

Table 7-12 Construction Cost Details

(see following 2 pages)

Project Code	YR	Sub/Ckt	Project Description	Reason Code	@ Load (amps) [1]	Miles	Estimated Cost ($)
I. New Tie Lines							
							0
	Total New Tie Lines					0.00	0
II. Conversions and Line Changes							
313	2004	Webster / WB11	1 ph 2.4 kV to 7.2 kV conversion	WP	-	2.20	120,000
314	2004	Webster / WB11	1 ph 2.4 kV to 7.2 kV conversion	WP	-	1.00	40,000
315	2004	Webster / WB11	1 ph 2.4 kV to 7.2 kV conversion	WP	-	2.20	45,000
317	2005	Webster / WB11	1ph 4CU to 1ph 1/0 tree wire	WP	-	1.00	45,000
319	2005	Webster / WB12	3ph 4CU to 3ph 4/0 Hendrix	WP	-	3.00	250,000
321	2005	Webster / WB12	3ph 4CU to 3ph 4/0 Hendrix	WP	-	3.00	250,000
WB-2	2013	Webster / WB12	1ph 1/0 ACSR to 3ph 4/0 Hendrix	B,C,D,V	40	1.10	93,500
	Total Conversions and Line Changes					13.50	843,500
III. Projects that have Potential Reliability Improvement							
AX-R1	2023	Alexandria / AX12	1ph 1/0 ACSR			0.30	18,480
AX-R2	2023	Alexandria / AX12	1ph 1/0 ACSR			0.80	40,480
AX-R3	2023	Alexandria / AX12	1ph 1/0 ACSR			0.20	12,760
NF-R1	2013	Northfield / NF12	1ph 1/0 ACSR			0.60	33,000
WB-R1	2013	Webster / WB12	3ph 4/0 ACSR Hendrix			4.00	340,000
WB-R2	2023	Webster / WB11	1ph 1/0 ACSR			0.40	23,760
	Total Potential Reliability Improvements					6.30	468,480
	Total of all projects					19.80	1,311,980
	Total by year for first 4 years (includes reliability projects)						
	2004					5.40	205,000
	2005					7.00	545,000
	2006					0.00	0
	2007					0.00	0
	2008					0.00	0
	2013					5.70	466,500
	2023					1.70	95,480
			Total			19.80	1,311,980

Reason Code(s)

- A — To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life.
- B — To improve **B**ackup between circuits and substations.
- C — To provide additional **C**apacity.
- D — To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
- F — To accommodate **F**uture load.
- S — To accommodate new **S**ystem configuration as a result of other projects.
- U — To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
- V — To improve **V**oltage.
- WP — As per NHEC 2001-2005 Construction **W**ork **P**lan.

[1] @ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				
			None	
2009-2013 Time Period				
WL-1	2013	Wilmot Substation	New Substation, 5/7 MVA, 115 kV - 7.2/12.47 kV	600,000
			Total 2009-2013	600,000
WL-1	Project WL-1 is recommended when the circuit load reaches 200 amps/phase.			
2014-2023 Time Period				
			None	
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				
			None	
2009-2013 Time Period				
			None	
2014-2023 Time Period				
NF-1	2023	Northfield Substation	New 5/7 MVA 34.5 to 7.2/12.47 kV transformer	120,000
WB-1	2023	Webster Substation	New 5/7 MVA 34.5 to 7.2/12.47 kV transformer	120,000
			Total 2014-2023	240,000

Table 7-13 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
ANDOVER	AX11	2000	60	141	85		0.71	1.66	2.35
		2001	76	239	85		0.89	2.81	3.14
		2002	183	241	85		2.15	2.84	1.32
	Totals		319	621	255	Average	1.25	2.44	1.95
	AX12	2000	560	1,620	295		1.90	5.49	2.89
		2001	900	1,630	295		3.05	5.53	1.81
		2002	530	2,200	295		1.80	7.46	4.15
	Totals		1,990	5,450	885	Average	2.25	6.16	2.74
	NF12	2000	313	716	420		0.75	1.70	2.29
		2001	1,528	2,876	420		3.64	6.85	1.88
		2002	1,555	3,300	420		3.70	7.86	2.12
	Totals		3,396	6,892	1,260	Average	2.70	5.47	2.03
	NF13	2000	640	520	318		2.01	1.64	0.81
		2001	680	1,450	318		2.14	4.56	2.13
		2002	940	1,170	318		2.96	3.68	1.24
	Totals		2,260	3,140	954	Average	2.37	3.29	1.39
	WB11	2000	1,150	2,300	1,757		0.65	1.31	2.00
		2001	5,200	7,170	1,757		2.96	4.08	1.38
		2002	5,500	11,560	1,757		3.13	6.58	2.10
	Totals		11,850	21,030	5,271	Average	2.25	3.99	1.77
	WB12	2000	1,500	1,950	407		3.69	4.79	1.30
		2001	2,480	3,480	407		6.09	8.55	1.40
		2002	2,600	3,910	407		6.39	9.61	1.50
	Totals		6,580	9,340	1,221	Average	5.39	7.65	1.42
	District Total	2000	4,223	7,247	3,282		1.29	2.21	1.72
		2001	10,864	16,845	3,282		3.31	5.13	1.55
		2002	11,308	22,381	3,282		3.45	6.82	1.98
	Totals		26,395	46,473	9,846	Average	2.68	4.72	1.76

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side"Outages).*

8.0 Colebrook District

8.1 Load Analysis

The Colebrook District contains one delivery point, which accounted for about 1.5 percent of NHEC's load in 2002. The Colebrook delivery point had a 2002 peak demand of 2.7 MW. The delivery point is winter peaking.

The Colebrook delivery point has about 24 percent as many active consumers as population in the towns that it serves. The incremental share of population served is estimated at about 39% since many new accounts are second homes with residents that are not counted in the town populations. The CPR is expected to grow from .2374 to .2556 by 2023. As a result the number of active consumers served by this delivery point increases at an annual rate of 0.95% over the 2002 to 2023 period.

Demand per consumer was 2.17 kW in 2002, which is the 12th highest figure for the NHEC delivery points. This reflects some large loads such as the Tillotson Health Care Facility plus the household loads which average 1.2 kW per account. New loads will be mostly new second homes with an estimated average demand of 1.5 kW. The DPC is thus expected to decrease from 2.17 to 1.95 kW by 2023.

The net result of these changes is annual load growth through 2023 at a rate of 0.4% as shown in Table 8-1 and Figure 8-1.

Table 8-1 Colebrook DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	5,244				
2001	5,296				
2002	5,257	0.2374	1,248	2.169	2,707
2003	5,273	0.2379	1,254	2.117	2,655
2004	5,291	0.2384	1,261	2.148	2,709
2005	5,312	0.2390	1,269	2.139	2,716
2006	5,335	0.2396	1,278	2.131	2,724
2007	5,358	0.2403	1,287	2.122	2,731
2008	5,384	0.2410	1,297	2.112	2,740
2013	5,536	0.2451	1,357	2.060	2,795
2023	5,955	0.2556	1,522	1.945	2,960
Growth Rates					
2002 - 2003	0.31%	0.19%	0.50%	-2.39%	-1.90%
2002 - 2008	0.40%	0.25%	0.65%	-0.44%	0.20%
2002 - 2013	0.47%	0.29%	0.76%	-0.47%	0.29%
2002 - 2023	0.60%	0.35%	0.95%	-0.52%	0.43%

Table 8-2 Colebrook DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Colebrook	CB12	Car Care Center	50	-	-
	CB13	Balsam Resort Condo	50	120	50
		Wilderness Ski Area	30	30	40

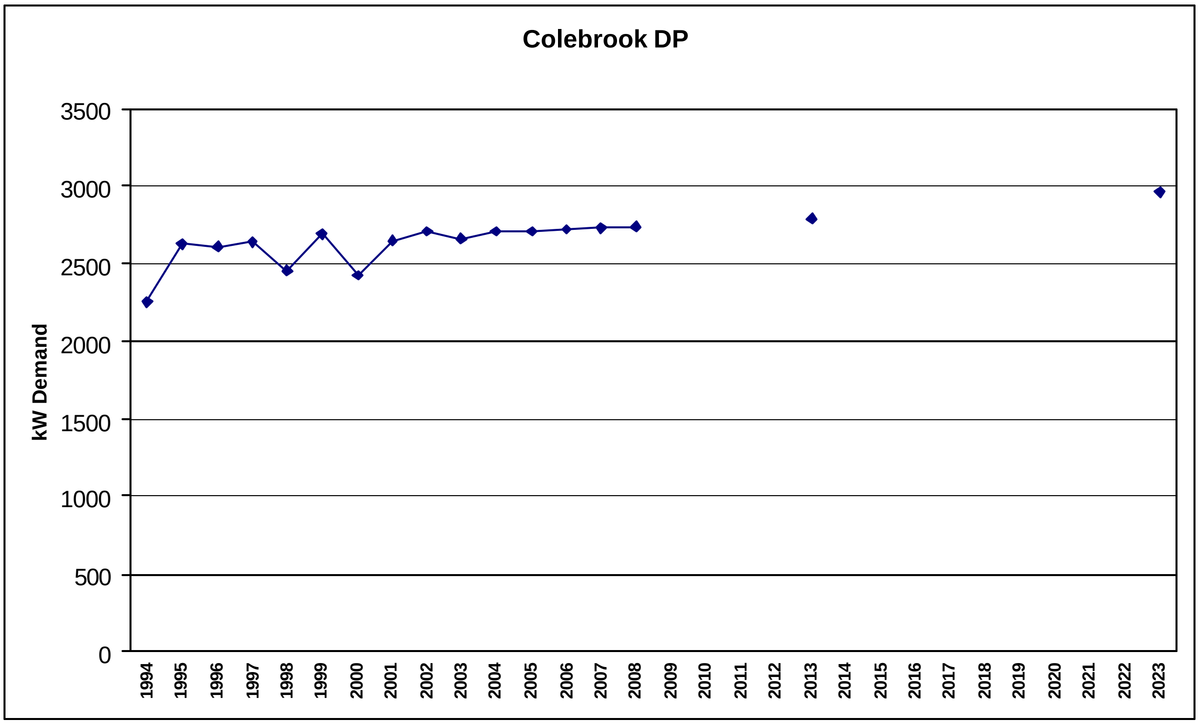

Figure 8-1 Historical and Forecasted Colebrook DP Demands

8.2 Transmission System

NHEC's Colebrook District is served at 34.5 kV from a radial line from PSNH's Lost Nation Substation at Groveton, NH. Lost Nation Substation is supplied from a looped 115 kV system originating at Whitefield Substation near Riverton, NH. The 115 kV loop extends from Whitefield to Lost Nation to Berlin to Whitefield. PSNH has a 18.3 MVA combustion turbine generator on the 34.5 kV bus at Lost Nation Substation.

8.2.1 34.5 kV Subtransmission System

Substation transformer capacity, and base case and forecasted coincident peak demands for transmission planning purposes are depicted in Table 8-3.

Table 8-3 Colebrook District 34.5 kV System and Load

PSNH Substation	115 – 34.5 kV Transformer Capacity: Summer Capacity	Winter Capacity	34.5 kV Feeders	Peak Loads – MVA: Summer 2003	Summer 2023	Winter 2002	Winter 2022
Lost Nation	1-33,1-64 MVA	1-37,1-38 MVA	3	17.1	20.4	13.9	20.9
	1 CT – 18.3 MVA						
Whitefield	1-52 MVA	1-61 MVA	3	25.6	30.0	33.2	31.7

PSNH Feeder 355 serves NHEC's Colebrook Substation and had a 2002 winter peak of 9.5 MVA and a projected 2003 summer peak of 10.8 MVA. PSNH has a 34.5 kV line voltage regulator station on the line side of PSNH's Colebrook Substation which provides adequate voltage to NHEC's Colebrook Substation. PSNH feeder 355 peaks at 12.9 MVA in the summer and 11.4 MVA in the winter in 2023. The forecasted area load growth rate is 0.74%. In 2013, PSNH will need to add a 34.5 kV 1.2 MVAR capacitor bank to PSNH Feeder 355 near Colebrook Substation to maintain adequate 34.5 kV voltage.

8.2.2 Historical Reliability

For the time period of 2000 to 2002, Colebrook Substation experienced an average of 1.33 power supplier outages per year which accounted for 20.7 percent of the consumer hours of outage. This performance is within the NHEC design criteria limits.

8.2.3 Contingency Performance

The outage of a single 115 kV transmission line or one 115-34.5 kV Lost Nation Substation transformer will not result in any unserved load, overloads or voltage deficiencies. An outage to PSNH Feeder 355 will result in an outage to NHEC's Colebrook Substation because of the radial configuration of this feeder and the location of Colebrook Substation. PSNH does employ feeder sectionalizing on Feeder 355 to limit permanent outage exposure and maintain reliability to NHEC's Colebrook Substation.

8.3 Distribution System

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 8.4, Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 8.0 shows the 2003, 2008, 2013 and 2023 peak load levels for each substation, DP and MP and circuit using the existing system configuration and the proposed system configuration.

8.3.1 New Substations, DP's and MP's

No new substations, delivery points or meter points are anticipated in the Colebrook District during this planning period.

8.3.2 Substation, DP and MP Changes

The following table shows the projected kW for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for the ordinary replacement of aged transformers are shown in **bold**. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 8-4 Substation Transformer and Regulator Data

	Transformer							Voltage Regulator		
	Rating (kVA)					Est.			Est.	
Name	OA 55°	FA 55°	OA 65°	FA 65°	Win Season	Load (kW)	Capacity (%)	Size (AMP)	Load (AMP)	Capacity (%)
Colebrook	3,750	---	---	---	4,125	2,982	74	150	155	103
Colebrook [1]	**3,750**	**4,312**	**4,200**	**4,830**	5,313	2,982	57	**219**	155	71

[1] Upgrade transformer and voltage regulators during 2014-2023 time period due to aged equipment. Project CB-1.

No conversion to a different distribution system operating voltage is recommended. The distribution operating voltage is to remain at 7.2/12.47 kV.

8.3.3 Colebrook Substation Service Area

8.3.3.1 Existing System Review

The Colebrook Substation is forecasted to serve 3.0 MW of peak load in 2023. It is the only substation in the Colebrook District and therefore has no ties to other substations for backup. The Colebrook area is served by two 7.2/12.47 kV circuits, CB12 and CB13. Circuit CB13 serves approximately 94 percent of the total load with CB12 serving the remaining 6 percent.

Circuit CB12 is approximately 0.1 miles long and serves one three-phase member. No three-phase main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

On Circuit CB13, the east-west three-phase feeder main is approximately 10.7 miles long. The northern part of the service area is 15 to 17 miles from the substation. The main three-phase line starts with 1 mile of 336 ACSR. The remaining three-phase and vee-phase lines are 1/0 ACSR. No three-phase, vee-phase or single-phase line capacity deficiencies were found at the forecasted 2023 load level. Line voltage regulators are installed in the main three-phase line approximately 4.9 miles east of the substation to maintain satisfactory voltage at the eastern edge of the service area. No areas with low voltage were found in the northern part of the service area.

8.3.3.2 Recommended Plan

Project 322 is the replacement of 2.0 miles of three-phase 1/0 ACSR with three-phase 336 ACSR and was included in year 2 of the 2001-2005 Construction Work Plan. This section of line has long spans and the poles are in bad condition. The project will provide additional capacity and will provide a 1.2 volt improvement to all members beyond the construction project.

Project CB-2 is the upgrading of the 3-75 amp voltage regulators to 3-150 amp voltage regulators. The existing 75 amp regulators are fully loaded at peak load times and need to be replaced with regulators with more capacity.

Consideration was given to the installation of a double circuit from the substation to where the three-phase line splits approximately 1 mile east of the substation. From that point, the three-phase going north is estimated to have 425 kW of peak load and the three-phase going east is estimated to have 2,270 kW of peak load. However, the existing three-phase 336 ACSR line has the capacity to serve both three-phase lines. Also, the double circuit would not provide a significant voltage improvement and the new circuit would not serve a significant amount of load. For these reasons, the double circuit is not being recommended at this time.

8.4 Distribution System Reliability

8.4.1 Historical Reliability

The Colebrook district has had lower than average distribution system reliability compared to the NHEC system averages during 2000-2002. This is primarily due to one long feeder and rural layout of the district. The following graph shows the resultant average indices for the two feeders as well as the entire Colebrook district.

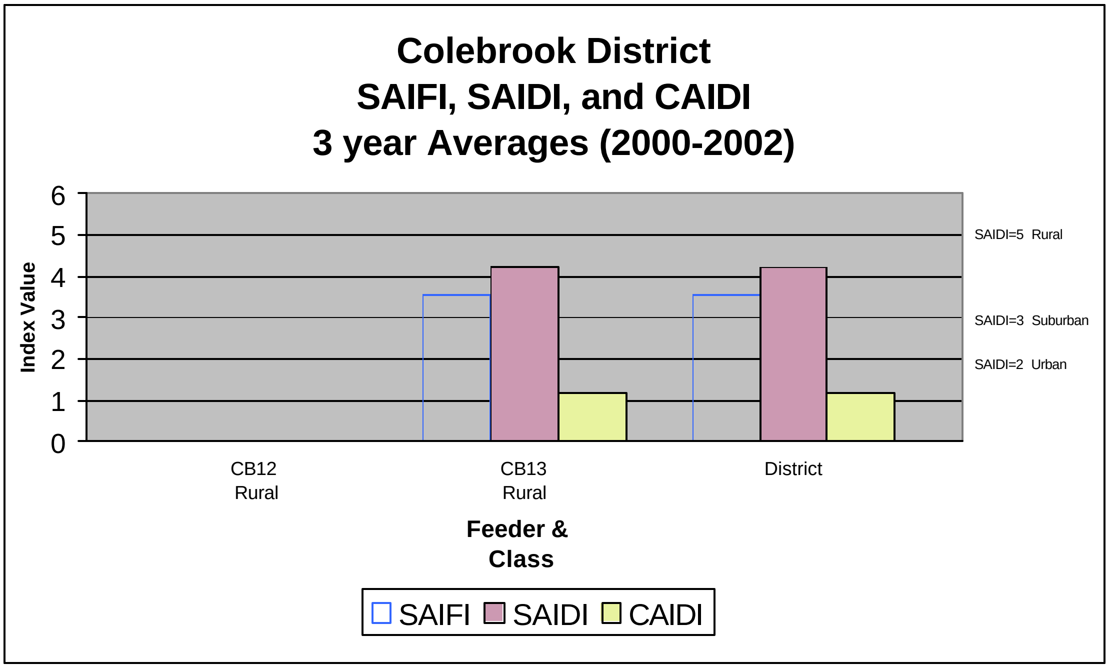

Figure 8-2 Colebrook District Average Reliability Indices

8.4.1.1 SAIFI & SAIDI

The graph indicates that Circuit CB12 has experienced no distribution system outages over the past three years. The IGA grocery store is the only member served by this very short circuit.

Circuit CB13 exceeded the reliability criteria for SAIFI, but met the SAIDI criteria of 5.0 for the rural feeder classification.

8.4.2 Circuits That Exceed Reliability Criteria

8.4.2.1 Colebrook Circuit CB13

The percentage of customer-minutes of outage duration due to each cause category can be seen in the following figure.

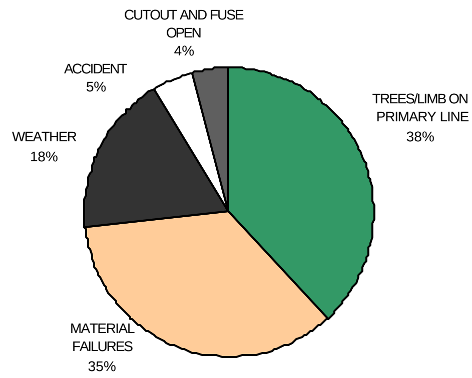

Figure 8-3 CB13 Percentage of Customer-Minutes Out by Outage Cause

More than 70% of customer-minutes were attributed to tree and material failure causes. The tree category cause makes sense due to dense forestry in the area. The high material failure rate was investigated, and outage details showed that over 90% of this cause code was due to failing insulators or arrestors. Therefore, focusing on O&M practices seems to be the only feasible solution to improve the SAIFI and SAIDI of this circuit.

Overall, though, due to the long, radial circuit configuration of the district, the outage indices prove better reliability than one would expect. Furthermore, faulted circuit indicators have been installed throughout much of the district in the past couple of years. As a result, these devices have dramatically helped fault location practices and therefore significantly reduced outage durations, which may possibly be one of the reasons for the improved outage indices every year throughout 2000-2002. The faulted circuit indicators should continue to be installed on long taps, lines that run through private right-of-way, and in areas that are prone to outages.

A geographical scan of the district shows that most of the longer single-phase tap lines have no looped capability. Therefore, for minimal investment, four single-phase tie-lines, designated as Projects CB-R1 through CB-R4, are recommended in the district. These proposals are along existing road right-of-way and will provide load balancing, overcurrent protection, and normal-open location options, in addition to the obvious backup capabilities.

8.5 Cost Estimates

A summary of the cost estimate for the proposed 5-Year, 10-Year and 20-Year Plans is provided in Table 8-5. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in Section 8.3 and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 8.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 8-5 Construction Cost Summary

	2004-2008 Cost ($)	2009-2013 Cost ($)	2014-2023 Cost ($)	2004-2023 Cost ($)
New Tie Lines	0	0	0	0
Conversions and Line Changes	176,000	0	0	176,000
New Substations, PD's and MP's	0	0	0	0
Substation, DP and MP Changes	0	0	109,000	109,000
Total	176,000	0	109,000	285,000
Projects for Improved Reliability	162,360	0	0	162,360

Table 8-6 Substation Load Data Projections

			Existing System Configuration				Proposed System Configuration		
			2003	2008	2013	2023	2008	2013	2023
Substation			Load level	Load level	Load level	Load level	Load level	Load level	Load level
Name	Ckt.	Season	kW	kW	kW	kW	kW	kW	kW
Colebrook	CB12	W	120	171	171	171	171	171	171
	CB13	W	2,566	2,559	2,634	2,811	2,559	2,634	2,811
	Sub	W	2,686	2,730	2,805	2,982	2,730	2,805	2,982
Colebrook District		W	**2,686**	**2,730**	**2,805**	**2,982**	**2,730**	**2,805**	**2,982**

Table 8-7 Construction Costs Detail

(see following 2 pages)

Project Code	YR	Sub/Ckt	Project Description	Reason Code	@ Load (amps) [1]	Miles	Estimated Cost ($)
I. New Tie Lines							
			None				
	Total New Tie Lines					0.00	0
II. Conversions and Line Changes							
322	2004	Colebrook / CB13	3ph 1/0 ACSR to 3ph 336 ACSR	WP	-	2.00	140,000
CB-2	2004	Colebrook / CB13	Upgrade voltage regulators from 3-75a to 3-150a	C	75	0.00	36,000
	Total Conversions and Line Changes					2.00	176,000
III. Projects that have Potential Reliability Improvement							
CB-R1	2005	Colebrook / CB13	1ph 1/0 ACSR			0.70	36,960
CB-R2	2006	Colebrook / CB13	1ph 1/0 ACSR			1.00	44,000
CB-R3	2007	Colebrook / CB13	1ph 1/0 ACSR			0.50	28,600
CB-R4	2008	Colebrook / CB13	1ph 1/0 ACSR			1.20	52,800
	Total Potential Reliability Improvements					3.40	162,360
	Total of all projects					5.40	338,360
Total by year for first 4 years (includes reliability projects)							
	2004					2.00	176,000
	2005					0.70	36,960
	2006					1.00	44,000
	2007					0.50	28,600
	2008					1.20	52,800
	2013					0.00	0
	2023					0.00	0
			Total			5.40	338,360

Reason Code(s)

A	To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life.
B	To improve **B**ackup between circuits and substations.
C	To provide additional **C**apacity.
D	To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
F	To accommodate **F**uture load.
S	To accommodate new **S**ystem configuration as a result of other projects.
U	To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
V	To improve **V**oltage.
WP	As per NHEC 2001-2005 Construction **W**ork **P**lan.

[1] @ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				
		None		
2009-2013 Time Period				0
		None		
2014-2023 Time Period				0
		None		
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				
			None	
2009-2013 Time Period				
			None	
2014-2023 Time Period				
CB-1	2023	Colebrook	Upgrade with new 3,750 kVA transformer, 34.5-7.2/12.5 l	86,000
CB-1	2023	Colebrook	Upgrade with 3 new 219 amp voltage regulators	23,000
			Total	109,000

Table 8-8 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
COLEBROOK	CB12	2000	0	0	1		0.00	0.00	0.00
		2001	0	0	1		0.00	0.00	0.00
		2002	0	0	1		0.00	0.00	0.00
	Totals		0	0	3	Average	0.00	0.00	0.00
	CB13	2000	4,502	7,085	1,110		4.06	6.38	1.57
		2001	4,017	3,938	1,110		3.62	3.55	0.98
		2002	4,098	3,904	1,110		3.69	3.52	0.95
	Totals		12,617	14,927	3,330	Average	3.79	4.48	1.18
	District Total	2000	4,502	7,085	1,111		4.05	6.38	1.57
		2001	4,017	3,938	1,111		3.62	3.54	0.98
		2002	4,098	3,904	1,111		3.69	3.51	0.95
	Totals		12,617	14,927	3,333	Average	3.79	4.48	1.18

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side"Outages).*

9.0 Conway District

9.1 Load Analysis

The Conway District contains two delivery points (Conway and Saco), which accounted for nearly twenty percent of NHEC's load in 2002. In 2002, the Conway delivery point experienced a peak demand of 16,400 kW while Saco recorded a peak of 18,800 kW[4]. Both delivery points are winter peaking.

The Conway delivery point has about one-third as many consumers as population in the towns that it serves. Consumer growth is expected to exceed population growth with an increase in the CPR from 0.3353 to 0.3414 by 2008. After that the CPR is expected to remain constant. As a result the number of active consumers served by this delivery point increases at an annual rate of 1.3% to 2008 and then at a rate of 0.4% over the 2008 to 2023 period.

Demand per consumer was 4.172 kW in 2002, which is the third highest figure for the NHEC delivery points. This reflects some very large loads, which do not represent the probable future additions. Without those loads, the demand per consumer is 2.7 kW. Using that figure for new connects lowers the DPC to 3.668 kW by 2023.

The net result of these changes is annual load growth through 2023 at a rate of 0.4% as shown in Table 9-1 and Figure 9-1.

[4] While interval data shows a peak of 24,336 kW for Saco occuring in December 2002, this was due to abnormal load switching to correct a problem at Conway. The Conway and Saco 2002 demands refered to above represent load under normal operations.

Table 9-1 Conway Non-Coincident Peak Demand Base Forecast

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	11,309				
2001	11,467				
2002	11,697	0.3353	3,922	4.172	16,361
2003	11,824	0.3364	3,977	4.131	16,430
2004	11,949	0.3374	4,032	4.093	16,500
2005	12,074	0.3385	4,087	4.055	16,573
2006	12,197	0.3395	4,140	4.020	16,646
2007	12,317	0.3404	4,193	3.987	16,720
2008	12,436	0.3414	4,245	3.956	16,795
2013	13,020	0.3414	4,445	3.846	17,094
2023	14,165	0.3414	4,836	3.668	17,738
Growth Rates					
2002 - 2003	1.08%	0.32%	1.40%	-0.97%	0.42%
2002 - 2008	1.03%	0.30%	1.33%	-0.88%	0.44%
2002 - 2013	0.98%	0.16%	1.14%	-0.74%	0.40%
2002 - 2023	0.92%	0.09%	1.00%	-0.61%	0.39%

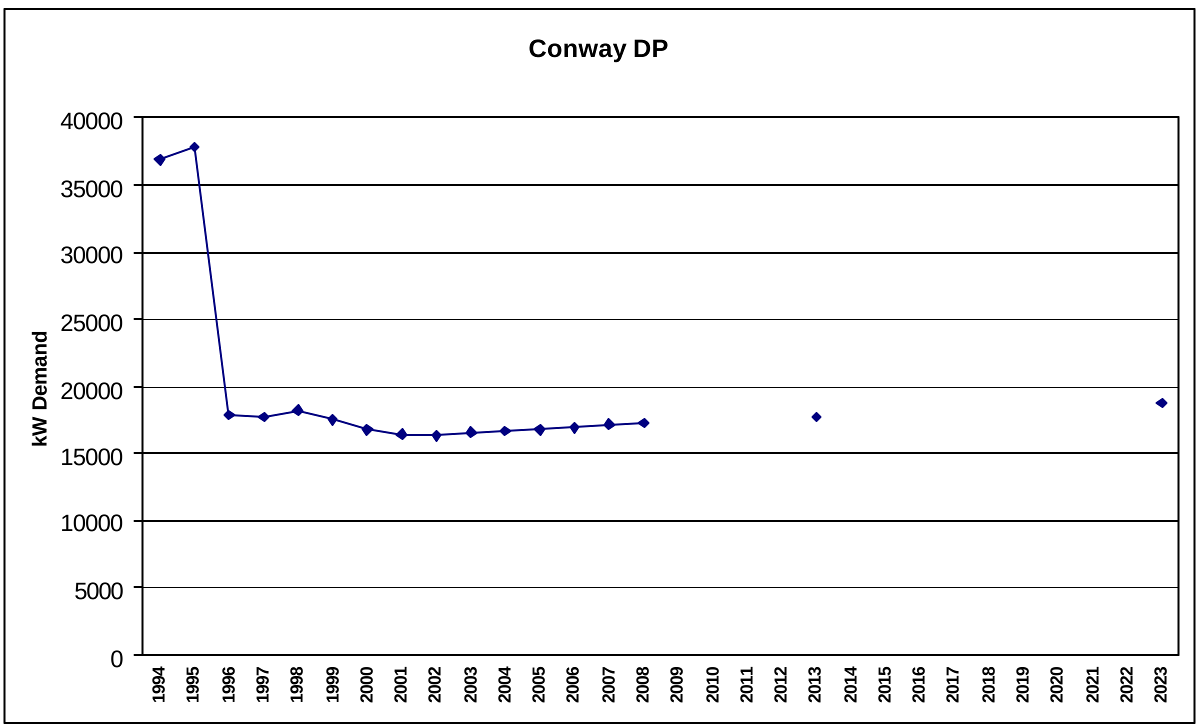

Figure 9-1 Historical and Forecasted Conway Demands

The Saco delivery point serves a high proportion of the service area population with a 2002 CPR of 43.3 percent. Growth in this area is expected to focus on the Saco service area which is expected to raise the CPR to 47.19 percent by the end of the planning period. Total active consumers are expected to increase by 1,820 with an average annual growth rate of 1.4% through 2023. Demand per consumer for this delivery point is high because of larger businesses and ski loads. Most of the growth is expected to be residential with an average demand of 2.5 kW per new consumer. This lowers the overall DPC to 3.0 kW compared to the current level of 3.5 kW by 2023. The result of these expected changes as shown in Table 9-2 and Figure 9-2 is an increase of 3.2 MW of load on this delivery point by 2023 under normal operating conditions.

Table 9-2 Saco Non-Coincident Peak Demand Base Forecast

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	12,144				
2001	12,319				
2002	12,574	0.4326	5,439	3.457	18,800
2003	12,717	0.4348	5,530	3.425	18,942
2004	12,859	0.4370	5,620	3.396	19,085
2005	13,002	0.4392	5,711	3.368	19,232
2006	13,141	0.4414	5,800	3.341	19,378
2007	13,277	0.4434	5,887	3.316	19,524
2008	13,413	0.4454	5,974	3.293	19,672
2013	14,078	0.4549	6,404	3.190	20,428
2023	15,384	0.4719	7,259	3.037	22,046
Growth Rates					
2002 - 2003	1.14%	0.52%	1.67%	-0.90%	0.75%
2002 - 2008	1.08%	0.49%	1.58%	-0.81%	0.76%
2002 - 2013	1.03%	0.46%	1.50%	-0.73%	0.76%
2002 - 2023	0.97%	0.41%	1.38%	-0.61%	0.76%

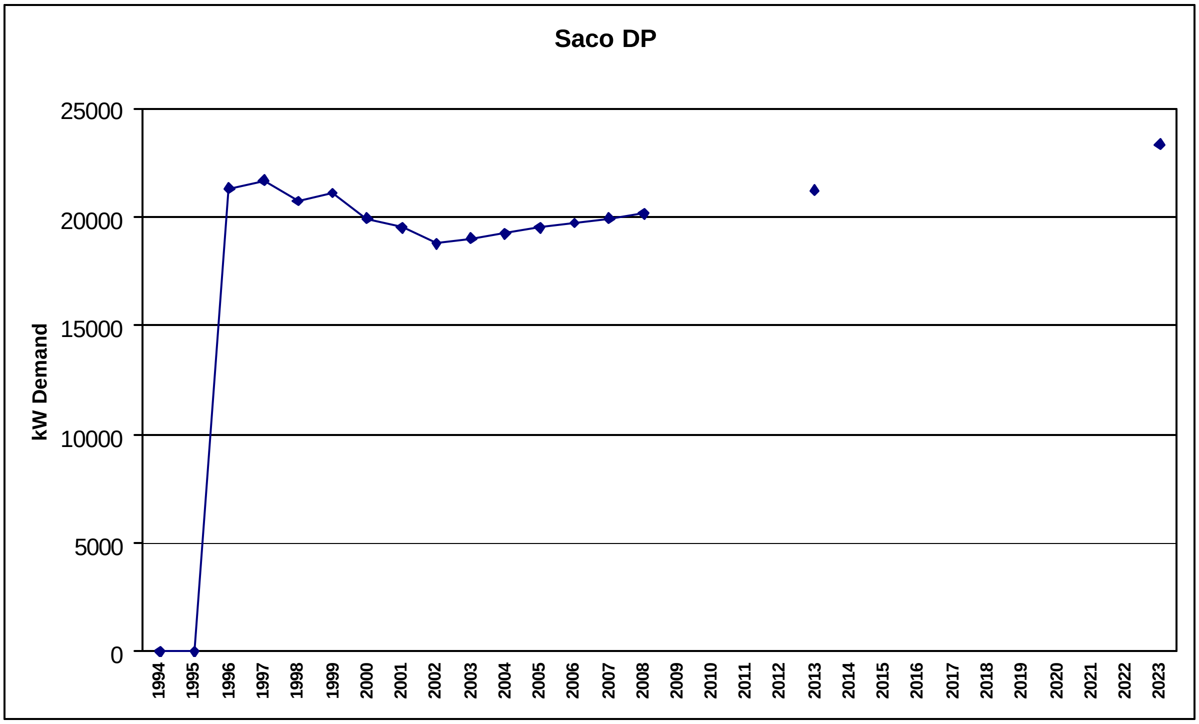

Figure 9-2 Historical and Forecasted Saco Demands

9.2 Transmission System

9.2.1 Bulk Transmission System

PSNH supplies bulk power to the Conway District at 115 kV and at 34.5 kV from PSNH's Saco Valley Substation. NHEC owns and operates a 115 kV radial transmission line from Saco Valley Substation to NHEC's Intervale Substation located adjacent to NHEC's Conway District Operating Center. NHEC's Saco Valley-Intervale 115 kV line is located on both private and railroad right-of-way and was constructed using 795 MCM ACSR conductor.

The 115 kV system is currently operated with the 115 kV loop open between Saco Valley and PSNH's White Lake Substation located to the west with Central Maine Power supplying Saco Valley and Intervale substations. The 115 kV loop is open to prevent contingent overloading of this 115 kV transmission tie between Maine and New Hampshire. In 2004, PSNH has plans to add a phase shifting transformer to Beebe River Substation and reactive support to the area's 115 kV system to enable the closing of the 115 kV loop and to increase the 115 kV interface power transfer capability by 70 megawatts. The estimated cost of this PSNH project is $7,000,000. Additional details of the project and need can be found in ISO-NE's RTE PO2 planning report.

NHEC will benefit from this project because the 115 kV source to Saco Valley Substation will be looped which will enhance the current reliability of the transmission supply to the Conway District.

9.2.2 34.5 kV Subtransmission System

The Conway District is supplied at two delivery points by PSNH. The Saco delivery point is at Intervale Substation. Intervale 115 - 34.5 kV Substation supplies Bartlett, Glen, and Jackson distribution substations. The Conway delivery point is located adjacent to Perkins Corner Substation on the PSNH 34.5 kV feeder 395. N. Conway Substation is also supplied via this delivery point through NHEC's 477 MCM ACSR 34.5 kV line, which ties to NHEC's Intervale IV32 34.5 kV feeder just outside the Intervale Substation.

NHEC's Intervale 115 – 34.5 kV Substation supplies the Glen and Bartlett distribution substations through Intervale 34.5 kV feeder IV33 and the Jackson distribution substation through Intervale Feeder IV31. Intervale feeders IV31 and IV33 can be tied at Glen Substation.

Substation transformer capacity and base case and coincident peak demands are:

Table 9-3 Conway District 34.5 kV System and Load

Substation	115-34.5 kV Transformers		34.5 kV	Coincident Peak Loads (MVA)			
				Summer		Winter	
	Summer Capacity	Winter Capacity	Feeders	2002	2023	2002	2023
PSNH Saco Valley	1-48 MVA	1-61 MVA*	4	25.7	36.5	30.9	32.9
NHEC Intervale	1-48 MVA	1-48 MVA*	3	13.7	16.6	16.2	18.8

9.2.3 Base System Performance

Base power flow studies for the summer and winter 2002 and 2023 peak conditions indicate there are no deficiencies. However, it should be noted that the Saco Valley and Intervale Substations are served radially at 115 kV; and until PSNH completes its 2004 planned transmission construction and closes the 115 kV tie to Central Maine Power, the Conway District is vulnerable to a single contingency 115 kV system outage.

9.2.4 Contingency Performance

Transmission reliability will improve in 2004 when the 115 kV system between Maine and New Hampshire is closed together, providing a dual 115 kV supply source to the area.

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* PSNH and NHEC transformers have the same transformer nameplate ratings. NHEC uses the top nameplate rating of the transformer to establish the maximum capacity rating. PSNH permits transformers to be loaded beyond nameplate rating based on pre-loading, ambient outdoor temperatures, and predicted post contingency loading cycle.

The contingency capability of the 34.5 kV system was tested in general using the PSNH power flow model. There were no deficiencies. However, the PSNH system model did not adequately represent the extensive NHEC 34.5 kV area system either on a system basis or on a coincident peak load basis. Therefore, a detailed peak load model of the combined PSHN-NHEC Conway District 34.5 kV system was utilized. Coincident peak load models and local delivery point peak load conditions were used to test the system performance in system normal and contingent conditions at 2002 and 2023 load conditions. There are no contingent deficiencies with the existing system at 2002 load levels.

The two most difficult contingencies at long range load levels are:

1. An outage of the NHEC Intervale Substation either by a substation equipment failure or loss of the radial Saco Valley - Intervale 115 kV transmission line.

2. An outage of the NHEC 34.5 kV Intervale IV33 feeder from Intervale to Glen.

At 2023 load levels, with maximum forecasted loads on the Saco delivery point supplying Bartlett, Glen, and Jackson substations and substation loads at 99 percent lagging power factor, 34.5 kV voltages are at 0.93 per unit for an Intervale Substation outage. The addition of capacitor banks at Jackson, 1.8 MVARs, Glen, 0.6 MVARs, and Bartlett; 0.6 MVARS, will correct these marginal voltage conditions to levels greater than 0.95 per unit without developing leading power factors. These capacitor banks would be used strictly for this contingency. For both cost and standardization reasons these banks should be installed at 12.5 kV in or just outside the substation fence at Bartlett, Glen, and Jackson substations and remotely controlled with NHEC's SCADA or load management control systems. These capacitor banks with remote control are estimated to cost $45,000 and will be needed in 2008 when voltages are projected to be below 0.95 per unit.

An outage of NHEC's 34.5 kV feeder Intervale IV31 and load transfer to NHEC's Intervale IV33 feeder results in IV33 feeder loads of 113 percent of normal rating in 2002 and 132 percent of normal rating in 2023. Both of these line loadings are within the winter emergency rating of this line; and, therefore, no upgrade is recommended.

9.2.5 Historical Reliability

A review of the 34.5 kV subtransmission outages for the period of 2000-2002 indicated the following average annual outage rates:

Table 9-4 Average Annual Outage Rates (Hrs./Customer/Yr.)

Delivery Points	NHEC Substations	PSNH Outages	NHEC Outages	Total Average Annual Outages
Conway	Conway	0.67	0.67	1.33
	Perkins Corner	0.67	0.67	1.33
Saco	Bartlett	1.33	0.67	2.0
	Glen	1.33	0.67	2.0
	Jackson	1.33	2.0	3.33

All annual outage rates are within the design criteria with the exception of Intervale 34.5 kV feeder IV31, which experienced four outages in 2002, all due to trees and all on the NHEC system. This suggests that NHEC should review tree clearance conditions on the IV31 feeder and continue to monitor the feeder's reliability performance. NHEC owns the 477 MCM ACSR 34.5 kV subtransmission line from the Perkins Corner metering point to N. Conway and on to Intervale Substation.

9.3 Distribution System

9.3.1 General

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 9.4, Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the approach fllowed in the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 9.0 shows the 2003, 2008, 2013 and 2023 peak load levels for each substation, DP and MP and circuit using the existing system configuration and the proposed system configuration.

9.3.2 New Substations, DP's and MP's

The Intervale Substation is a recently installed 115 kV to 34.5 kV substation and was designed to accommodate a 34.5-7.2/12.47 kV distribution substation. It is recommended that an Intervale 34.5-7.2/12.47 kV distribution substation designated as Project IN-1, be installed during the 2004-2008 period. This substation will serve the area that is presently served by Glen Substation, Circuit GL12, therefore allowing Circuit GL12 to provide load relief to the heavily loaded Jackson Circuit JS13.

Reliability improvement should be noticed in the immediate service area of the Intervale Substation. The new substation will serve the existing load on Glen Circuit GL-12, which has experienced significant outages over the last three years. Further reliability impact caused by the addition of Intervale is described in the Reliability Section 9.4.3.2, Glen Circuit GL-12, and 9.4.4.1, Jackson Circuit JS-13.

9.3.3 Substation, DP and MP Changes

The following table shows the projected demand for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for backup or for the ordinary replacement of aged transformers are shown in [**bold**]. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 9-5 Substation Transformer and Regulator Data

	Transformer							Voltage Regulator		
	Rating (kVA)					Est. Load (kW)	Capacity (%)	Size (AMP)	Est. Load (AMP)	Capacity (%)
Name	OA 55°	FA 55°	OA 65°	FA 65°	Win Season					
Bartlett	5,000	5,750	5,600	6,440	7,000	6,838	100	328	355	108
Bartlett [1]	**10,000**	**12,500**	**11,200**	**14,000**	15,400	6,838	45	**656**	355	54
Conway	12,000	16,000	13,400	17,900	26,400	13,200	51	LTC	686	---
Glen	5,000	5,750	5,600	6,440	7,000	3,916	57	328	203	62
Glen [2]	5,000	5,750	5,600	6,440	7,000	4,884	71	328	253	77
Glen [3]	**10,000**	**12,500**	**11,200**	**14,000**	15,400	4,884	32	**656**	253	39
Intervale [4]	5,000	5,750	5,600	6,440	7,000	2,685	39	328	140	43
Intervale [5]	**5,000**	**5,750**	**5,600**	**6,440**	7,000	2,685	39	**328**	140	43
Jackson	10,000	12,500	11,200	14,000	15,400	12,556	83	656	652	99
Jackson [6]	10,000	12,500	11,200	14,000	15,400	8,984	60	656	468	71
Perkins Corner	10,000	12,500	11,200	14,000	15,400	5,619	37	668	292	44

[1] Upgrade transformer and voltage regulators during 2004-2008 time period to increase capacity. Project 501 as per the Cooperative's 2001-2005 Construction Work Plan.

[2] Estimated peak load is after load transfer to Intervale and from Jackson.

[3] Upgrade transformer and voltage regulators during 2014-2023 time period to increase capacity for backup and to replace aged equipment. Project GL-1.

[4] The 3-1667 kVA transformers and 3-328 amp voltage regulators removed from Bartlett are to be installed at the new Intervale Substation.

[5] Upgrade transformer and voltage regulators during 2014-2023 time period due to aged equipment. Project IN-4.

[6] Estimated peak load is after load transfer to Glen.

No conversion to a different distribution system operating voltage is recommended at any of the substations. The distribution operating voltage is to remain at 7.2/12.47 kV.

9.3.4 Bartlett Substation Service Area

9.3.4.1 Existing System Review

The Bartlett Substation, which is forecasted to serve 6.8 MW of peak load in 2023, supplies two circuits, BL11 and BL13. Circuit BL13 serves approximately 58 percent of the total load with BL11 serving the remaining 42 percent.

Circuit BL11 is approximately 1.3 miles long and ties to Circuit GL11 of the Glen Substation. The main line conductor of BL11 is 336 ACSR and the circuit is operated at 7.2/12.47 kV. No three-phase main line capacity deficiencies or areas with low voltage are anticipated for Circuit BL11 during this planning period. The 2008 peak load on the main single-phase line near the end of the circuit that serves the Blueberry Hill Development area exceeds the maximum design limit of 50 amps per phase; and the line is therefore considered to have a capacity deficiency. The end of this line is approximately 2.4 miles from the substation and due to this close proximity, no low voltage was found.

Circuit BL13 is approximately 10.9 miles long and has no ties to other circuits. The main three-phase line is 2.5 miles long and consists of 2 miles of 336 ACSR and 0.5 miles of 2 ACSR. The remaining main line consists of 1.8 miles of vee-phase 336 ACSR and 6.6 miles of single-phase 1/0 AL underground and 1/0 ACSR. Most of BL13 is operated at 7.2/12.47 kV with two small areas operated at 2.4 kV line to ground. Capacity deficiencies were found on this circuit related to the three-phase 2 ACSR in the main line. Also, the 2023 peak load on the single-phase line that serves the Rolling Ridge Development area and at the beginning of the long single-phase line that serves the Harts Location area is close to or exceeds the maximum design limit of 50 amps per phase and the line is therefore considered to have a capacity deficiency. As a result, voltage is becoming marginal near the end of these single-phase lines.

9.3.4.2 Recommended Plan

On Circuit BL11, the existing single-phase line that serves the Blueberry Hill area is estimated to have 97 amps of peak load at the 2023 load level. Alternatives for providing additional capacity to improve serve to this area are:

A. Convert the existing single-phase 1/0 ACSR that presently serves the Blueberry Hill area to three-phase by adding 2-1/0 ACSR phase conductors.
B. Convert the existing single-phase 1/0 ACSR that comes from the west to three-phase by adding 2-1/0 ACSR phase conductors and extend the three-phase into the Blueberry Hill area thereby transferring the area to the more direct west line. The three-phase line is to be extended into the development so that single-phase taps can balance the load on the three-phase line.

C. Rebuild the existing single-phase 1/0 ACSR that presently serves the Blueberry Hill area to three-phase 4/0 ACSR.

D. Rebuild the existing single-phase 1/0 ACSR that comes from the west to three-phase 4/0 ACSR phase conductors and extend the three-phase into the Blueberry Hill area thereby transferring the area to the more direct west line.

Alternative B is projected to be the least cost alternative. In addition, this alternative provides the additional capacity and is the most direct route, thereby reducing exposure for overall improved service. For these reasons, Alternate B, identified as Project BL-1, is recommended. If converting the existing line from single-phase to three-phase is not possible, Alternative D, a new three-phase 4/0 ACSR line is recommended.

Project BL-2 on Circuit BL13, is the replacement of 0.5 miles of three-phase 2 ACSR with three-phase 336 ACSR. This section of line is in the main line and is the only remaining portion of small conductor. Replacement is recommended to provide additional capacity and improve voltage.

Project BL-3 is a three-phase extension to provide load relief to two heavily loaded single-phase lines, both with approximately 50 amps of peak load at the 2023 load level. The recommended conductor size is 1/0 ACSR.

Project BL-4 is a single-phase 1/0 AL underground tie line that will enable transferring load from one of the heavily loaded single-phase lines to the new three-phase line. This will provide a better balancing of load and reduce losses. The tie line will also provide a loop for improved reliability.

Project 324 is the replacement of 1.0 miles of single-phase 6 CU with three-phase 336 MCM, Hendrix spacer cable. At the same time, the operating voltage will be changed from 2.4 kV to 7.2/12.47 kV. The existing single-phase line is heavily loaded and there is potential for additional residential load growth. This project was recommended for construction in Year 1 of the Cooperative's 2001-2005 Construction Work Plan.

Project BL-5 is the conversion of the remaining 2.4 kV line to 7.2 kV. Along with having to replace distribution transformers, it is anticipated that some of the 4 ACSR, 6 CU and 4 CWC is aged and deteriorated and will need to be rebuilt instead of just reinsulated.

Projects BL-6 and BL-7 are related to providing additional capacity and improving voltage in the Harts Location area. Project BL-6 is the addition of the third phase to the existing vee-phase 336 ACSR line. Most of the load should be put on Phases B and C, thereby leaving Phase A for serving the Harts Location area. Project BL-7 is the conversion of 0.5 miles of single-phase 2 ACSR to vee-phase 2 ACSR by adding one 2 ACSR phase conductor. If converting the existing line from single-phase to vee-phase is not possible, a new vee-phase 1/0 ACSR line is recommended. None of the members along this vee-phase line should be on Phase A. This will leave Phase A for serving the Harts Location area and will help balance the three-phase line.

Project 325 is the conversion of a 2.4 kV line to 7.2 kV. Along with having to replace one distribution transformer, the existing underground cable needs to be replaced and installed in conduit because of being on forest service land. This project was recommended for construction in Year 1 of the Cooperative's 2001-2005 Construction Work Plan.

9.3.5 Conway Substation Service Area

9.3.5.1 Existing System Review

The Conway Substation is forecasted to serve 13.2 MW of peak load in 2023. The Conway area is served by four 7.2/12.47 kV circuits, CW11, CW12, CW13 and CW14. Circuit CW11 serves approximately 24 percent of the total load, CW12 serves 28 percent, CW13 serves 33 percent and CW14 the remaining 15 percent.

Circuit CW11 is approximately 2.4 miles long and ties to CW12, CW14 and Circuit PC13 of the Perkins Corner Substation. The main line conductor of CW11 is 336 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit CW12 is approximately 5 miles long and ties to CW11 about 0.9 miles from the substation and with CW13 about 1.2 miles from the substation. Therefore, most of CW12 is radial. The main line conductor of CW12 is 336 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit CW13 is approximately 3.3 miles long and ties to CW12 and Circuit GL12 of the Glen Substation. The main line conductor of CW13 is 336 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit CW14 is approximately 1.9 miles long and ties to CW11. The main line conductor of CW14 is 336 ACSR and 4 CU. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

9.3.5.2 Recommended Plan

On Circuit CW13, Project 330 is the replacement of three-phase 336 MCM tree wire with 336 MCM Hendrix spacer cable. The existing tree wire has radial cracks and inadequate phase-to-phase clearances may occur due to the poor insulation. This project was included in year 2 of the 2001-2005 Construction Work Plan.

On Circuit CW14, Project 326 is the replacement of the three-phase 4 CU line with 336 MCM, Hendrix cable. This project was included in year 3 of the 2001-2005 Construction Work Plan. The new line will follow road right-of-way and will enable the removal of line in private right-of-way. With this project, CW14 can become the main three-phase tie to the Perkins Corner Substation and to CW11.

9.3.6 Glen Substation Service Area

9.3.6.1 Existing System Review

The Glen Substation is forecasted to serve 3.9 MW of peak load in 2023. The Glen area is served by two 7.2/12.47 kV circuits, GL11 and GL12. Circuit GL12 serves approximately 69 percent of the total load with GL11 serving the remaining 31 percent.

Circuit GL11 is approximately 2.7 miles long and ties to Circuit BL11 of the Bartlett Substation. The main line conductor of GL11 is 336 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit GL12 is approximately 3.8 miles long and ties to Circuit CW13 of the Conway Substation. The main line conductor of GL12 begins with 1.9 miles of 336 ACSR and then has 0.9 miles of 4 CU and then ends with 2 CU. The 2023 peak load is approximately 50 percent of the rating of the 4 CU and since the line is a tie between circuits and substations the line is considered to have a capacity deficiency. No areas with low voltage are anticipated during this planning period.

9.3.6.2 Recommended Plan

On Circuit GL11, no new construction or existing line upgrades are needed to improve voltage or provide additional capacity during this planning period.

On Circuit GL12, Project GL-2 is the replacement of 0.9 miles of three-phase 4 CU and 0.9 miles of three-phase 2 CU with three-phase 336 ACSR. With the system configuration change resulting from the installation of a distribution substation and a north and south circuit at the Intervale Substation, these line sections are no longer part of the main three-phase line between substations. However, due to their estimated age, these line sections are expected to reach the end of their useful life during this planning period. These line sections provide a loop to the main three-phase line and the use of three-phase 4/0 ACSR is recommended.

9.3.7 Intervale Substation Service Area

9.3.7.1 Existing System Review

The Intervale Substation is a 115 kV to 34.5 kV substation that was designed to accommodate two 7.2/12.47 kV circuits. At the present time, neither circuit is being used.

9.3.7.2 Recommended Plan

It is recommended that both of the 7.2/12.47 kV circuits be put in service in the 2004-2008 time period. These circuits will serve the area that is presently served by Glen, Circuit GL12. By transferring the GL12 area to Intervale, Circuit GL12 can then be used to provide load relief to the heavily loaded Jackson Substation, Circuit JS13, which is forecasted to have approximately 6,500 kW of peak load in 2023. It is estimated that approximately, 3,500 kW of peak load would be transferred to GL12. By dividing this load over 2 circuits, voltage and service reliability will be improved. The 2003, 2008, 2013 and 2023 peak load levels by substation and circuit using the existing system configuration and the proposed system configuration, are seen in at the end of this district section.

Project IN-2 is the 2-500 MCM underground feeder exits that will extend three-phase from the Intervale Substation to connect with existing three-phase line to create the two new circuits. Project IN-3 is the conversion of the existing single-phase 336 ACSR line going south to three-phase by adding 2-336 ACSR phase conductors. This circuit will serve the area to the south and ties to Circuit CW13.

9.3.8 Jackson Substation Service Area

9.3.8.1 Existing System Review

The Jackson Substation is forecasted to serve 12.6 MW of peak load in 2023. The Jackson area is served by three circuits, JS11, JS12 and JS13. Circuit JS13 serves approximately 52 percent of the total load, JS12 serves 37 percent and JS11 the remaining 11 percent.

Circuit JS11 is approximately 5.3 miles long and is radial. The main line conductor of JS11 is 336 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period. All of JS11 is operated at 7.2/12.47 kV.

Circuit JS12 is approximately 2.3 miles long and is radial. The main line conductor of JS12 is 336 ACSR. No capacity deficiencies or low voltage is expected along the main line. Most of JS12 is operated at 7.2/12.47 kV. Three areas are operated at 2.4 kV line to ground. Capacity and low voltage problems are expected in areas that are served 2.4 kV single-phase.

Circuit JS13 is approximately 2.2 miles long and ties to Circuit GL12 of the Glen Substation. The main line conductor of JS13 is 336 ACSR. The 2013 peak load on the main three-phase line near the substation exceeds the maximum design limit of 280 amps per phase and the line is therefore considered to have a capacity deficiency. Also, the peak load on several single-phase lines is close to or exceeds the maximum design limit of 50 amps per phase and the line is therefore considered to have a capacity deficiency. The extremities of the circuit are relatively close to the substation and no areas of low voltage are expected. All of JS13 is operated at 7.2/12.47 kV.

9.3.8.2 Recommended Plan

On Circuit JS11, no new construction or existing line upgrades are needed to improve voltage or provide additional capacity during this planning period.

On Circuit JS12, Projects 327, JS-1, JS-2 and JS-3 are the conversion of 2.4 kV single-phase lines to 7.2 kV to provide additional capacity and improve voltage. Project 327 was included in year 1 of the 2001-2005 Construction Work Plan. It is recommended that Project JS-1 be done in the 2004-2008 time period and Projects JS-2 and JS-3 in the 2009-2013 time period. Along with having to replace distribution transformers, it is anticipated that some of the 4 ACSR, 4 CWC, 4 CU and 6 CU is aged and deteriorated and will need to be rebuilt instead of just reinsulated. Project JS-2 also includes 0.13 miles of vee-phase 1/0 ACSR construction to enable the single-phase lines beyond to be on different phases for improved load balance along the main line.

On Circuit JS13, it is recommended that part of the circuit be transferred to the Glen Substation to provide load relief to JS13. At the present time, JS13 ends just 0.2 miles from the Glen Substation. Most of the load on Glen, Circuit GL12, is to be transferred to the Intervale Substation as discussed in Section 9.3.7. The load transfer enables dividing the area between the Jackson and Glen Substations thereby providing the needed load relief to Circuit JS13.

Project JS-4 will provide additional capacity by converting the single-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 61 amps of peak load at the 2023 load level. The three-phase line is to be extended into the development so that single-phase taps can balance the load on the three-phase line.

Project JS-5 will provide additional capacity by converting the single-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 50 amps of peak load at the 2023 load level.

9.3.9 Perkins Corner Substation Service Area

9.3.9.1 Existing System Review

The Perkins Corner Substation is forecasted to serve 5.6 MW of peak load in 2023. The Perkins Corner area is served by two 7.2/12.47 kV circuits, PC13 and PC14. The total load on the substation is fairly equally divided over the two circuits.

Circuit PC13 is approximately 1.3 miles long and ties to PC14 and Circuit CW11 of the Conway Substation. The main line conductor of PC13 is 3/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit PC14 is approximately 0.6 miles long and ties to PC13. The main line conductor of PC14 is 336 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

9.3.9.2 Recommended Plan

No new construction or existing line upgrades are needed to improve voltage or provide additional capacity during this planning period.

Project 332 is the replacement of a three-phase 3/0 ACSR line due to a road widening project and was included in year 4 of the 2001-2005 Construction Work Plan. This three-phase line is a main tie between the Perkins Corner and Conway Substations and 336 ACSR is recommended to provide additional capacity during backup.

9.4 Distribution System Reliability

9.4.1 Historical Reliability

The Conway District has had much better distribution system reliability compared to the NHEC system averages over the last three years. In fact, the overall SAIDI index in this district ranked best of all districts. The following graph shows the resultant average indices for each feeder as well as the entire Conway district.

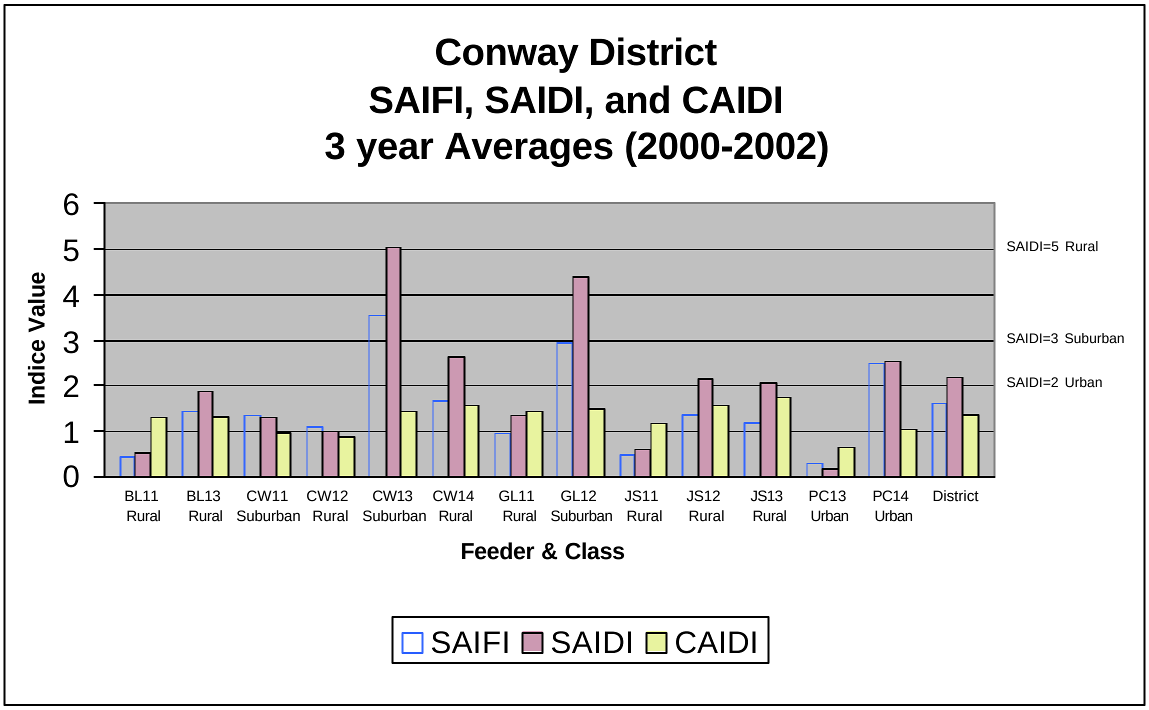


Figure 9-3 Conway District Historical Reliability Indices

9.4.1.1 SAIDI & SAIFI

The graph indicates that circuits CW13, GL12, and PC14 have experienced a higher SAIDI than the other circuits. All three of these feeders have exceeded the SAIDI reliability criteria set forth according to their corresponding feeder classification in the reliability planning approach portion of Section 5.0. The limits corresponding to each classification can be seen on the right-hand Y-axis.

The target SAIFI value of 2.0 for all feeders, regardless of feeder classification, was exceeded at feeders CW13, GL12, and PC14. Consequently, these are the same feeders that exceeded the SAIDI limits above.

9.4.2 Circuits That Exceed Reliability Criteria

9.4.2.1 Conway Circuit CW13

This circuit had the highest average SAIFI and SAIDI indices over the last three years. The percentage of customer-minutes of outage duration due to each cause category can be seen in the following figure.

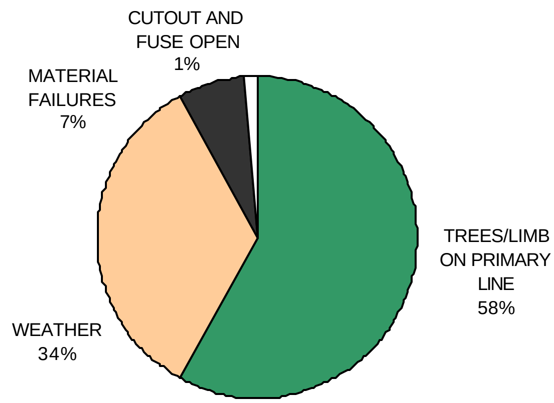


Figure 9-4 CW13 Percentage of Customer-Minutes Out by Outage Cause

More than half of the total customer-minutes out outages were due to tree problems. Therefore, from an operations and maintenance perspective, this circuit should receive a top priority when it comes to tree trimming and right-of-way clearing practices. If this is accomplished, along with proper overcurrent protection philosophy and coordination, potential of future reliability improvement should be promising.

From a voltage and capacity standpoint, this circuit meets criteria through the 2023 load levels. Furthermore, Circuit CW12 forms a three-phase tie with Circuit CW13, therefore providing backup for major three-phase feeder main outages. With the addition of the Intervale 34.5 - 7.2/12.47 kV distribution substation, further contingency capability will exist. Therefore, no capital improvement construction projects can be justified for this circuit for potential reliability improvement. As previously mentioned, sufficient O&M practices, along with proper sectionalizing, should provide reliability improvement.

9.4.2.2 Glen Circuit GL12

This suburban classified feeder had an average SAIDI of 4.4 over the last three years. As the following Figure 9-5 indicates, accidents, cutouts and fuses open, and tree problems were relatively equal in percentage of customer hours, and contributed overall to about 88% of the total consumer-hours.

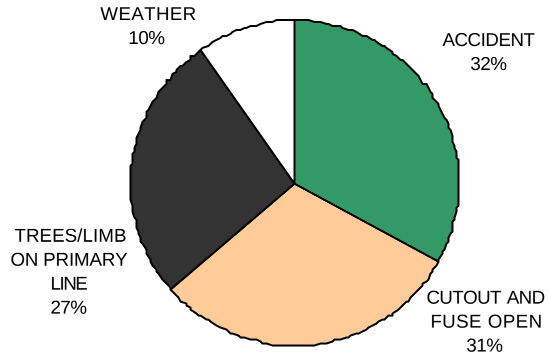


Figure 9-5 GL12 Percentage of Customer-Minutes Out by Outage Cause

Further review of individual outage details showed that most of the high consumer-hour outages were caused by entire GL12 feeder outages. Six outages affected all consumers on GL12, and caused over 80% of the consumer-minutes. At least one event for each of the top four cause categories in Figure 9.5 caused an entire feeder outage. This indicates that O&M practices are generally adequate for the entire feeder, except within the first zone of protection where the majority of the outages contributing customer-minutes have occurred. There should be more focus within the first zone of protection for Circuit GL12, particularly in the first five years of the plan, or until the new Intervale Substation and proposed circuit configuration change gets implemented as described in the next two paragraphs.

Presently, the main three-phase line of Circuit GL12 is approximately four miles in length, with the vast majority of the load and consumers located near the last half of the feeder. Therefore, problems occurring closer to the substation have been causing all members on this circuit to experience outages. As indicated in Section 9.3.2, New Substations, DP's and MP's, the Intervale distribution substation is proposed in the first five years of the plan to indirectly provide load relief to the Jackson Substation. The Intervale Substation will also provide greater contingency capability between the Glen and Jackson Substations.

In addition to voltage and capacity improvements due to the addition of the Intervale Substation, substantial reliability improvements could potentially be noticed. Intervale Substation will initially be constructed with two feeders. This will divide the members on Circuit GL-12 into two feeders, causing a reduced number of circuit-miles of primary line exposure to each member. Furthermore, since the two Intervale Circuits will be serving the existing members of GL-12, the current first zone of protection of GL-12 will become the "last" zone of protection of the Intervale Circuit. Due to the small number of members and load within this zone, any outages in the area will not affect the load center of the Intervale Substation if properly sectionalized into a second or third zone of protection.

9.4.2.3 Perkins Corner Circuit PC14

This urban classified feeder had an average SAIDI of 2.54 over the last three years. Even though this does not appear to be too excessive, the urban classification caused this feeder to be further assessed for reliability improvements. The following figure indicates that more than half the consumer-hours were attributed to material failure causes. In fact, the 57% of consumer-hours was due to one transformer failure. Investigation into the cause of the transformer failure is beyond the scope of this study, and it is assumed that all required steps have been taken to reduce the possibility of this reoccurring.

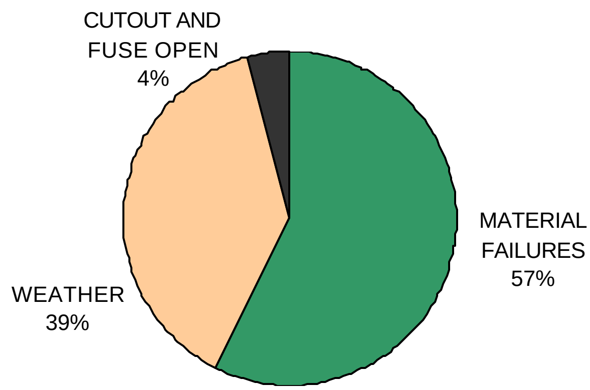


Figure 9-6 PC14 Percentage of Customer-Minutes Out by Outage Cause

It appears there are no obvious O&M practice improvements that will significantly improve the overall reliability on Circuit PC14. There have only been approximately six outages on this feeder in the past three years, with one of them being somewhat of an uncommon occurrence.

There is one construction project that may have a positive effect on the reliability of this circuit, Project CW-R1. This new three-phase tie-line, is discussed in the Conway Circuit CW12 reliability section.

The proposed tie-line construction project CW-R1 will provide another option for contingencies between PC-14 and CW-12.

9.4.3 Circuits That Meet Reliability Criteria

9.4.3.1 Jackson Circuit JS13

Even though Circuit JS-13 met the reliability criteria set forth previously, there are definite reliability impacts due to proposed circuit configuration changes, as well as proposed tie-lines.

As a result of the proposed Intervale 34.5 – 7.2/12.47 kV distribution substation, the circuit configurations for Glen Circuit GL12 and Jackson Circuit JS13 should be changed. With these changes, Circuit JS13 will be divided into two circuits, with one being served from Jackson and the other from Glen. Therefore, the feeder lengths and exposure to outages will be cut in half, and as a result, reliability will be improved. Furthermore, the number of members per feeder will be less than the existing configuration, therefore further enhancing the reliability.

Projects JS-R1, JS-R2, and GL-R1 are recommended based on engineering judgment. All three projects will improve the backup potential between the two taps of Circuits JS-13 and GL-11. Along with each project, comes a certain amount of potential reliability improvement. For the minimal investment of Project JS-R1, backup to the members on only one phase of the two tap lines can be accomplished, but will still provide significant improvements. Complete backup for all the members on both these tap lines can be accomplished with Projects JS-R2 and GL-R1. Furthermore, the three-phase loop will provide better reliability due to load balancing, overcurrent protection, and normal-open location options.

9.4.3.2 Bartlett Substation

There are three projects located within the Bartlett Substation service area that will provide potential reliability improvements.

Project BL-R1 is the recommended upgrade of the existing single-phase 1/0 ACSR line. This line presently serves the Blueberry Hill area and should be converted to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors, thereby creating a three-phase loop to the Blueberry Hill area. If converting the existing line from single-phase to three-phase is not possible, a new three-phase 4/0 ACSR line is recommended.

Project BL-R2 is the upgrade of a vee-phase and single-phase underground line through a concentrated area with 1,500 kW of peak load at the 2023 load level. The area is presently served by two radial three-phase and vee-phase lines, which are tied together with single-phase. It is recommended that the vee-phase and single-phase lines be replaced with three-phase 1/0 AL underground to provide a three-phase loop for improved load balance and reliability.

Project BL-R3 is a single-phase 1/0 ACSR tie line that will provide a loop for potential improvement in reliability.

9.4.3.3 Conway Circuit CW12

This circuit has a projected 2023 load level of approximately 3,700 kW. About 78% of the load, or 2,900 kW, is located on the long three-phase tap that serves Hales Location Country Club area along West Side Road. Due to the radial configuration of this line, there exists no contingency capability for any three-phase outages along the main line. Therefore, a new three-phase tie-line designated as Project CW-R1 is recommended.

Project CW-R1 will provide contingency capability between Circuits CW-12 and PC-14. Due to the radial configuration of CW-12, along with the lower than desired outage history on Circuit PC-14, this project will benefit both circuits.

The Saco River is located between these circuits PC-14 and CW-12, therefore making this construction extremely difficult and costly. For the purposes of this study, the project is projected to be about $126,000 for 0.9 miles of three-phase 336 ACSR line. If this project is at all possible, it should be considered due to the potential reliability improvements and contingency capabilities.

9.5 Cost Estimates

A summary of the cost estimate for the proposed 5-Year, 10-Year and 20-Year Plans is provided in Table 9-7. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in Section 9.3 and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 9.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 9-6 Construction Cost Summary

	2004-2008 Cost ($)	**2009-2013 Cost ($)**	**2014-2023 Cost ($)**	**2004-2023 Cost ($)**
New Tie Lines	40,000	0	7,350	47,350
Conversions and Line Changes	671,935	372,710	245,510	1,290,155
New Substations, PD's and MP's	250,000	0	0	250,000
Substation, DP and MP Changes	66,000	0	362,000	428,000
Total	1,027,935	372,710	614,860	2,015,505
Projects for Improved Reliability	0	0	319,260	319,260

Table 9-7 District Substation Load Data Projections

Substation Name	Ckt.	Season	Existing System Configuration				Proposed System Configuration		
			2003 Load kW	2008 Load kW	2013 Load kW	2023 Load kW	2008 Load kW	2013 Load kW	2023 Load kW
Bartlett	BL11	W	1,991	2,224	2,448	2,888	2,224	2,448	2,888
	BL12	W	2,696	3,018	3,331	3,950	3,018	3,331	3,950
	Sub	W	4,687	5,242	5,779	6,838	5,242	5,779	6,838
Conway	CW11	W	2,656	2,854	2,975	3,216	1,875	1,961	2,133
	CW12	W	3,138	3,347	3,475	3,729	3,347	3,475	3,729
	CW13	W	3,668	3,905	4,050	4,338	3,905	4,050	4,338
	CW14	W	1,699	1,777	1,824	1,917	2,756	2,838	3,000
	Sub	W	11,161	11,883	12,324	13,200	11,883	12,324	13,200
Glen	GL11	W	988	1,046	1,101	1,213	1,046	1,101	1,213
	GL12	W	2,211	2,338	2,461	2,703	3,357	3,463	3,671
	Sub	W	3,199	3,384	3,562	3,916	4,403	4,564	4,884
Intervale	IN11	W					1,227	1,292	1,419
	IN12	W					1,095	1,153	1,266
	Sub	W					2,322	2,445	2,685
Jackson	JS11	W	1,279	1,320	1,362	1,443	1,320	1,362	1,443
	JS12	W	4,065	4,199	4,329	4,590	4,199	4,329	4,590
	JS13	W	5,783	5,975	6,162	6,533	2,699	2,783	2,951
	Sub	W	11,127	11,494	11,853	12,566	8,218	8,474	8,984
Perkins Corner	PC13	W	2,609	2,609	2,658	2,744	2,609	2,658	2,744
	PC14	W	2,733	2,733	2,785	2,875	2,733	2,785	2,875
	Sub	W	5342	5342	5443	5619	5342	5443	5,619
Conway District		W	**35,516**	**37,345**	**38,961**	**42,139**	**37,410**	**39,029**	**42,210**

Table 9-8 Construction Cost Details

(see following 2 pages)

Project Code	YR	Sub/Ckt	Project Description	Reason Code	@ Load (amps) [1]	Miles	Estimated Cost ($)
I. New Tie Lines							
BL-4	2023	Bartlett / BL13	1ph 1/0 AL UG	D,S	-	0.10	7,350
IN-2	2005	Intervale	2-3ph 500 MCM underground feeder exits	S	-	0.10	40,000
	Total New Tie Lines					0.20	47,350
II. Conversions and Line Changes							
BL-1	2004	Bartlett / BL11	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D	45	0.60	21,750
BL-2	2013	Bartlett / BL13	3ph 2 ACSR to 3ph 336 ACSR	A,C,V	150	0.50	64,350
324	2004	Bartlett / BL13	1ph 6 CU to 3ph 336 ACSR Hendrix, Convert voltage	WP	-	1.00	80,000
BL-3	2023	Bartlett / BL13	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D	45	0.40	15,660
BL-5	2013	Bartlett / BL13	1ph 6 & 4 to 1ph 1/0 ACSR, Convert 2.4 kV to 7.2 kV	A,C,V	25	1.25	80,000
BL-6	2023	Bartlett / BL13	2ph 336 ACSR to 3ph 336 ACSR (add 1)	D,V	40	1.80	43,200
BL-7	2023	Bartlett / BL13	1ph 2 ACSR to 2ph 2 ACSR (add 1)	C,D,V	35	0.50	8,450
325	2004	Bartlett / BL13	Convert 2.4 kV to 7.2 kV	WP	-	2.00	60,000
330	2004	Conway / CW13	3ph 336 ACSR Tree to 3ph 336 ACSR Hendrix	WP	-	0.60	50,000
326	2004	Conway / CW14	3ph 4 CU to 3ph 336 ACSR Hendrix	WP	-	0.80	70,000
GL-2	2023	Glen / GL12	3ph 4 & 2 CU to 3ph 336 ACSR	A	-	1.80	178,200
IN-3	2005	Intervale / South	1ph 336 ACSR to 3ph 336 ACSR (add 2)	S	-	0.70	34,440
327	2004	Jackson / JS12	1ph 6 CU to 1ph 1/0 ACSR, Convert 2.4 kV to 7.2 kV	WP	-	2.00	100,000
JS-1	2004	Jackson / JS12	Convert 2.4 kV to 7.2 kV	A,C,V	25	1.60	114,000
JS-2	2013	Jackson / JS12	Convert 2.4 kV to 7.2 kV	A,C,V	25	1.80	116,000
JS-3	2013	Jackson / JS12	Convert 2.4 kV to 7.2 kV	A,C,V	25	1.60	88,000
JS-4	2006	Jackson / JS13	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D	45	0.30	11,745
JS-5	2013	Jackson / JS13	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D	45	0.70	24,360
332	2004	Perkins C. / PC14	3ph 3/0 ACSR to 3ph 336 ACSR	WP	-	1.50	130,000
	Total Conversions and Line Changes					21.45	1,290,155
III. Projects that have Potential Reliability Improvement							
BL-R1	2023	Bartlett / BL11	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)			0.80	26,680
BL-R2	2023	Bartlett / BL11	1ph & 2ph 1/0 AL UG to 3ph 1/0 AL UG			0.40	47,320
BL-R3	2023	Bartlett / BL13	1ph 1/0 ACSR			0.20	12,760
JS-R1	2023	Jackson / JS13	1ph 1/0 ACSR			0.10	6,600
CW-R1	2023	Conway / CW12	3ph 336 ACSR			0.90	126,000
GL-R1	2023	Glen / GL11	1ph 2ACSR to 3ph 1/0 ACSR			1.00	68,000
JS-R2	2023	Jackson / JS13	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)			1.10	31,900
	Total Potential Reliability Improvements					4.50	319,260
	Total of all projects					26.15	1,656,765
Total by year for first 4 years (includes reliability projects)							
	2004					10.10	625,750
	2005					0.80	74,440
	2006					0.30	11,745
	2007					0.00	0
	2008					0.00	0
	2013					5.85	372,710
	2023					9.10	572,120
			Total			26.15	1,656,765

Reason Code(s)

- A — To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life.
- B — To improve **B**ackup between circuits and substations.
- C — To provide additional **C**apacity.
- D — To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
- F — To accommodate **F**uture load.
- S — To accommodate new **S**ystem configuration as a result of other projects.
- U — To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
- V — To improve **V**oltage.
- WP — As per NHEC 2001-2005 Construction **W**ork **P**lan.

[1] @ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				
IN-1	2005	Intervale Substation	34.5-7.2/12.47 kV; 5,000/5,600/7,000 kVA Structure, fence, ground grid, etc. $250,000 5,000/5,600/7,000 kVA transformer and 3-328 amp voltage regulators are to come from Bartlett Substation.	250,000
2009-2013 Time Period				0
2014-2023 Time Period				0
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				
501	2004	Bartlett	Install 3-3333 kVA transformers from stock	20,000
501	2004	Bartlett	Upgrade with 3-656 amp voltage regulators	46,000
			Total 2004-2008	66,000
2009-2013 Time Period				
2014-2023 Time Period				
GL-1	2023	Glen	Upgrade with new 10,000 kVA transformer, 34.5-7.2/12.5	170,000
GL-1	2023	Glen	Upgrade with 3 new 656 amp voltage regulators	46,000
			Total	216,000
IN-4	2023	Intervale	Upgrade with new 5,000 kVA transformer, 34.5-7.2/12.5 l	120,000
IN-4	2023	Intervale	Upgrade with 3 new 328 amp voltage regulators	26,000
			Total	146,000

Table 9-9 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
CONWAY	BL11	2000	511	676	444		1.15	1.52	1.32
		2001	0	0	444		0.00	0.00	0.00
		2002	54	45	444		0.12	0.10	0.83
	Totals		565	721	1,332	Average	0.42	0.54	1.28
	BL13	2000	2,113	2,751	595		3.55	4.62	1.30
		2001	105	140	595		0.18	0.24	1.33
		2002	317	465	595		0.53	0.78	1.47
	Totals		2,535	3,356	1,785	Average	1.42	1.88	1.32
	CW11	2000	36	43	755		0.05	0.06	1.19
		2001	64	72	755		0.08	0.10	1.13
		2002	2,941	2,834	755		3.90	3.75	0.96
	Totals		3,041	2,949	2,265	Average	1.34	1.30	0.97
	CW12	2000	81	148	1,127		0.07	0.13	1.83
		2001	1,428	1,145	1,127		1.27	1.02	0.80
		2002	2,225	2,027	1,127		1.97	1.80	0.91
	Totals		3,734	3,320	3,381	Average	1.10	0.98	0.89
	CW13	2000	2,308	1,630	1,025		2.25	1.59	0.71
		2001	6,184	8,243	1,025		6.03	8.04	1.33
		2002	2,425	5,604	1,025		2.37	5.47	2.31
	Totals		10,917	15,477	3,075	Average	3.55	5.03	1.42
	CW14	2000	290	378	248		1.17	1.52	1.30
		2001	602	820	248		2.43	3.31	1.36
		2002	355	760	248		1.43	3.06	2.14
	Totals		1,247	1,958	744	Average	1.68	2.63	1.57
	GL11	2000	342	581	887		0.39	0.66	1.70
		2001	1,461	1,762	887		1.65	1.99	1.21
		2002	676	1,200	887		0.76	1.35	1.78
	Totals		2,479	3,543	2,661	Average	0.93	1.33	1.43
	GL12	2000	2,807	5,055	1,084		2.59	4.66	1.80
		2001	3,297	4,033	1,084		3.04	3.72	1.22
		2002	3,441	5,211	1,084		3.17	4.81	1.51
	Totals		9,545	14,299	3,252	Average	2.94	4.40	1.50
	JS11	2000	791	969	1,059		0.75	0.92	1.23
		2001	46	136	1,059		0.04	0.13	2.96
		2002	713	710	1,059		0.67	0.67	1.00
	Totals		1,550	1,815	3,177	Average	0.49	0.57	1.17
	JS12	2000	526	697	743		0.71	0.94	1.33
		2001	246	374	743		0.33	0.50	1.52
		2002	2,258	3,697	743		3.04	4.98	1.64
	Totals		3,030	4,768	2,229	Average	1.36	2.14	1.57
	JS13	2000	1,211	2,760	1,029		1.18	2.68	2.28
		2001	256	280	1,029		0.25	0.27	1.09
		2002	2,228	3,377	1,029		2.17	3.28	1.52
	Totals		3,695	6,417	3,087	Average	1.20	2.08	1.74
	PC13	2000	0	0	247		0.00	0.00	0.00
		2001	8	14	247		0.03	0.06	1.75
		2002	200	117	247		0.81	0.47	0.59
	Totals		208	131	741	Average	0.28	0.18	0.63
	PC14	2000	585	708	160		3.66	4.43	1.21
		2001	574	478	160		3.59	2.99	0.83
		2002	30	35	160		0.19	0.22	1.17
	Totals		1,189	1,221	480	Average	2.48	2.54	1.03
	District Total	2000	11,601	16,396	9,403		1.23	1.74	1.41
		2001	14,271	17,497	9,403		1.52	1.86	1.23
		2002	17,863	26,082	9,403		1.90	2.77	1.46
	Totals		43,735	59,975	28,209	Average	1.55	2.13	1.37

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side"Outages).*

10.0 Lisbon District

10.1 Load Analysis

The Lisbon District contains 3 delivery points, which accounted for about 1.2 percent of NHEC's load in 2002. The delivery points of Haverhill, Lisbon, and Monroe had respective 2002 peak demands of 708, 939, and 524 kW. All of these delivery points are winter peaking.

The Haverhill delivery point has about 10 percent as many active consumers as population in the towns that it serves. No change in this ratio is expected. Both service area population and consumers are expected to increase slowly from 2002 to 2023 at an average annual rate of 0.6%.

Haverhill demand per consumer was 1.24 kW in 2002, which is the lowest figure of all the 34 NHEC delivery points. This is a very rural area with very stable loads. With no significant change anticipated in the DPC, loads are also expected to grow at an annual rate of 0.6%. Included in this growth is one subdivision on the HA11 circuit.

The forecasts of consumers and loads are shown in Table 10-1 and Figure 10-1.

Table 10-1 Haverhill DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	5,623				
2001	5,686				
2002	5,677	0.1006	571	1.240	708
2003	5,710	0.1006	574	1.240	712
2004	5,744	0.1006	578	1.240	717
2005	5,779	0.1006	581	1.240	721
2006	5,814	0.1006	585	1.240	725
2007	5,848	0.1006	588	1.241	730
2008	5,883	0.1006	592	1.241	734
2013	6,066	0.1006	610	1.241	757
2023	6,463	0.1006	650	1.242	808
Growth Rates					
2002 - 2003	0.59%	0.00%	0.59%	0.01%	0.60%
2002 - 2008	0.60%	0.00%	0.60%	0.01%	0.61%
2002 - 2013	0.60%	0.00%	0.60%	0.01%	0.61%
2002 - 2023	0.62%	0.00%	0.62%	0.01%	0.63%

Table 10-2 Haverhill DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Haverhill	HA11	Subdivision	10	10	10

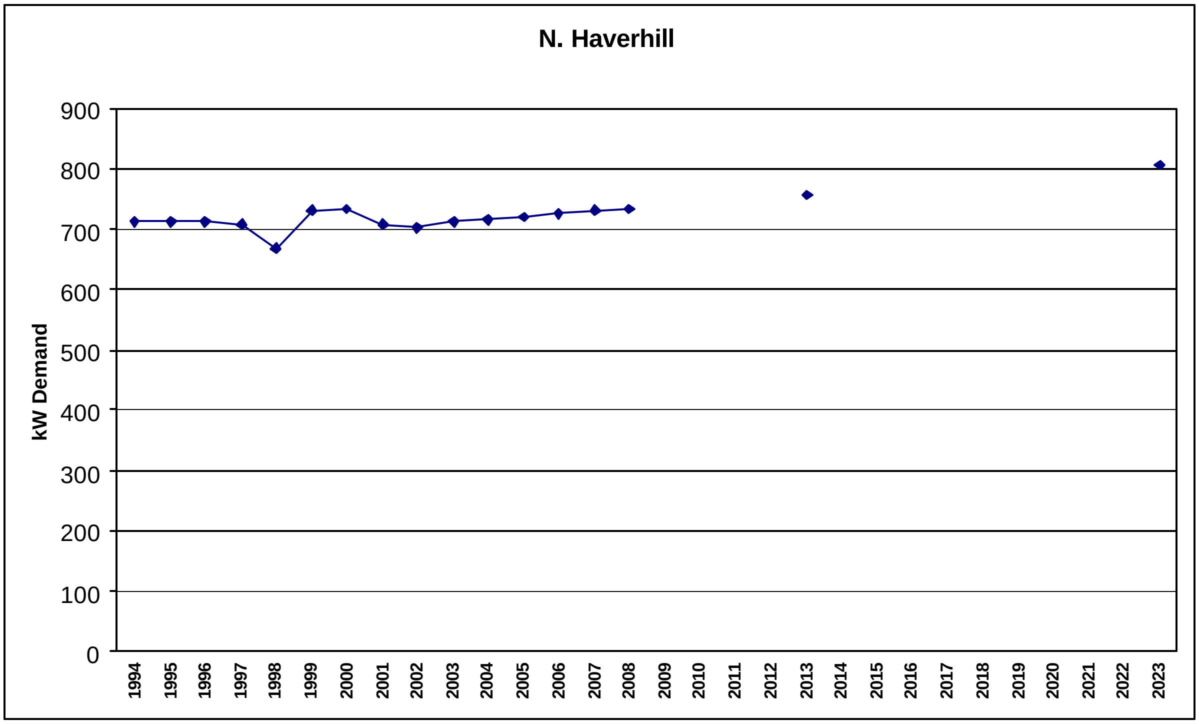


Figure 10-1 Historical and Forecasted Haverhill DP Demands

The Lisbon delivery point serves a low proportion of the service area population with a 2002 CPR of 7.0 percent. Consumer and population growth in this area are expected to mirror each other, with an overall annual growth rate of 0.23 percent from 2002 to 2023. The DPC is the eighth lowest compared to the other 34 delivery points and is expected to remain constant at 1.55 kW. The CPR is also expected to remain steady at 7.0 percent.

This area is also very rural with stable loads. With no significant change anticipated in the DPC, loads are expected to grow at an annual rate of 0.23%. Included in this growth is a subdivision on the LS11 circuit, and a commercial/industrial development on Circuit LS12. The forecasts of consumers and loads are shown in Table 10-3 and Figure 10-2.

Table 10-3 Lisbon DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	8,629				
2001	8,747				
2002	8,696	0.0697	606	1.550	939
2003	8,710	0.0697	607	1.550	941
2004	8,726	0.0697	608	1.550	942
2005	8,743	0.0697	609	1.550	944
2006	8,759	0.0697	610	1.550	946
2007	8,776	0.0697	612	1.550	948
2008	8,793	0.0697	613	1.550	950
2013	8,890	0.0697	620	1.550	960
2023	9,129	0.0697	636	1.550	986
Growth Rates					
2002 - 2003	0.17%	0.00%	0.17%	0.00%	0.17%
2002 - 2008	0.19%	0.00%	0.19%	0.00%	0.19%
2002 - 2013	0.20%	0.00%	0.20%	0.00%	0.20%
2002 - 2023	0.23%	0.00%	0.23%	0.00%	0.23%

Table 10-4 Lisbon DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Lisbon	LS11	Pepperbrook Subdivision	10	10	10
	LS12	C&I Development	25	25	25

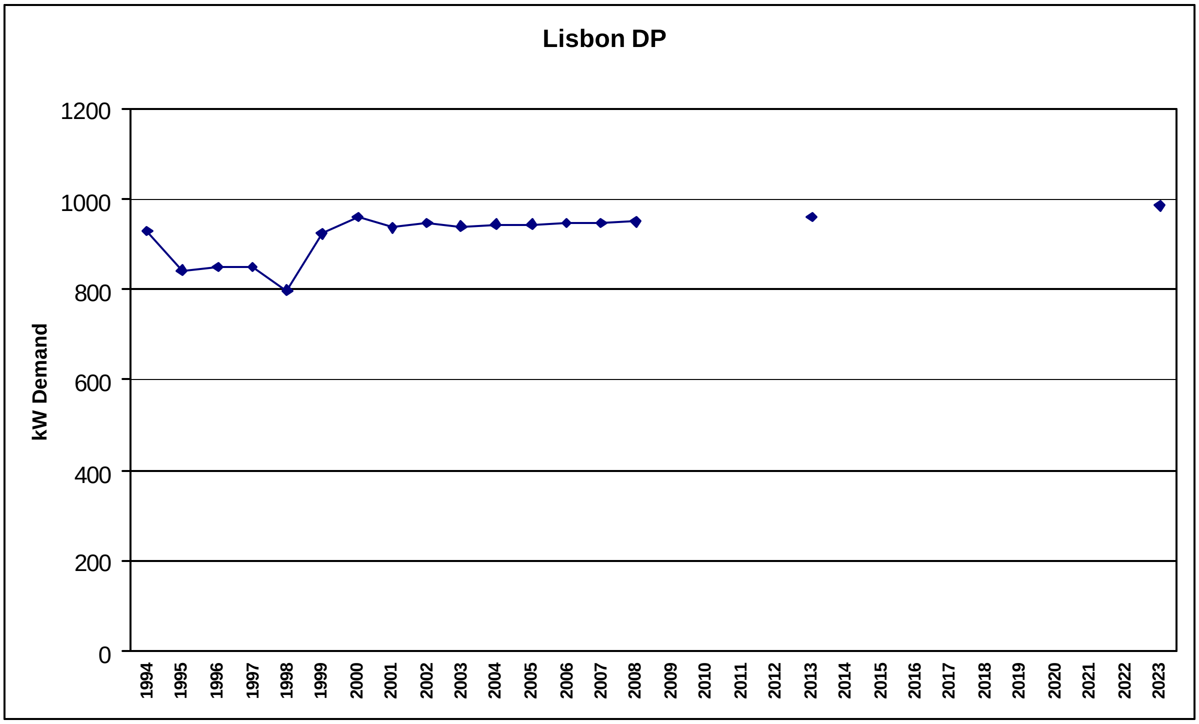


Figure 10-2 Historical and Forecasted Lisbon DP Demands

The Monroe delivery point has about 3.8 percent as many consumers as population in the towns that it serves. Slow consumer growth is expected to match slow population growth, at an average annual rate of 0.3% from 2002 to 2023. The CPR is expected to remain static at 0.04.

Demand per consumer was 1.91 kW in 2002, which is below the average for all the 34 NHEC delivery points. This is a very rural area with very stable loads. With no significant change anticipated in the DPC, loads are expected to grow at an annual rate of 0.3%.

The forecasts of consumers and loads are shown in Table 10-5 and Figure 10-3.

Table 10-5 Monroe DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	7,091				
2001	7,193				
2002	7,156	0.0384	275	1.905	524
2003	7,172	0.0384	276	1.905	525
2004	7,190	0.0384	276	1.905	527
2005	7,209	0.0384	277	1.906	528
2006	7,226	0.0384	278	1.906	529
2007	7,245	0.0384	278	1.906	531
2008	7,264	0.0384	279	1.906	532
2013	7,367	0.0384	283	1.906	540
2023	7,611	0.0384	292	1.906	557
Growth Rates					
2002 - 2003	0.23%	0.00%	0.23%	0.00%	0.23%
2002 - 2008	0.25%	0.00%	0.25%	0.00%	0.25%
2002 - 2013	0.26%	0.00%	0.26%	0.00%	0.27%
2002 - 2023	0.29%	0.00%	0.29%	0.00%	0.30%

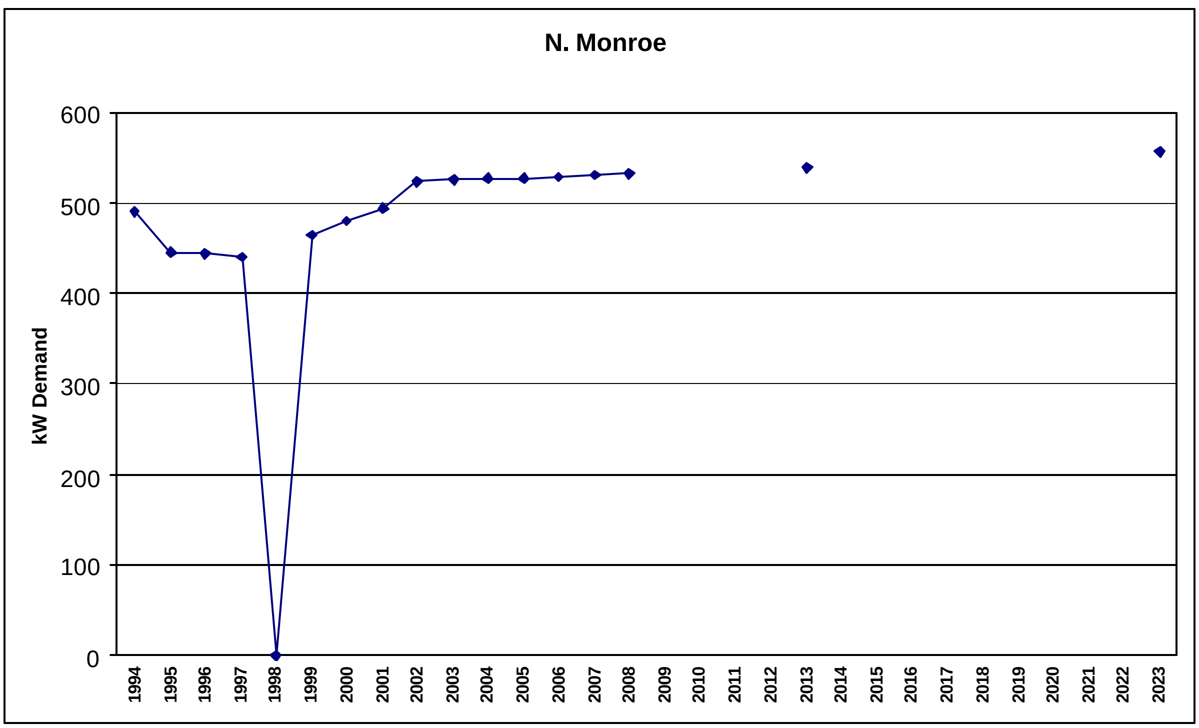


Figure 10-3 Historical and Forecasted Monroe DP Demands

10.2 Transmission System

10.2.1 Bulk Transmission System

NHEC's Lisbon District has three delivery points at Lisbon Substation and Haverhill and Monroe distribution voltage level delivery points. Haverhill and Monroe are supplied by the Central Vermont Power System and are discussed in the distribution section summary. Lisbon Substation is supplied from PSNH's Whitefield Substation. Whitefield is a major 115-34.5 kV substation with four 115 kV transmission lines.

10.2.2 34.5 Kv Subtransmission System

Substation capacity and base case and forecasted load levels are depicted in Table 10-6. Future coincident peak loads are based on an annual area growth rate of 0.74% for both the summer and winter peaks.

Table 10-6 Lisbon District 34.5 kV System and Loads

PSNH Substation	115 – 34.5 kV Transformers		34.5 kV Feeders	Peak Loads – MVA			
				Summer		Winter	
	Summer Capacity	Winter Capacity		2003	2023	2002	2022
Whitefield	1-52 MVA	1-61 MVA	3	25.6	30.0	33.2	31.7
Berlin	1-20, 1-28 MVA	1-25, 1-33 MVA	3	19.5	22.3	19.4	26.8
Lost Nation	1-33, 1-34 MVA 1 CT-21 MVA	1-37, 1-38 MVA	3	17.1	20.4	13.9	20.8

Lisbon Substation is supplied from PSNH 34.5 kV feeder 348 from PSNH's Whitefield Substation. PSNH feeder 348 is a radial feeder, but does have a major small power producer at Bethlehem with 12.6 MW of generating capacity. PSNH Whitefield 34.5 kV feeders 351 and 376 are operated in a network configuration tied to Berlin feeder 352 and Lost Nation feeder 376, respectively. Whitefield feeder 351 also has a major small power producer at Whitefield with 14.0 MW of generating capacity.

There are no capacity or voltage deficiencies in the 2002-2003 cases. In 2012, without generation at Bethlehem, PSNH 34.5 kV feeder 348 experiences line side voltages below .95 per unit on the Sugar Hill voltage regulator station and the voltage regulators are at the 12.0 MVA normal full operating range capacity limit. PSNH will need to add a 1.2 MVAR capacitor bank on the load side of these regulators to address this deficiency in 2012.

10.2.3 Historical Reliability

Lisbon Substation has experienced an average of 1 power supplier outage per year for the 2000-2002 time period. This is within the reliability criteria limits established by NHEC.

10.2.4 Contingency Performance

The outage of a single 115 kV transmission line or the 115-34.5 kV Whitefield transformer will not result in any unserved load, capacity deficiencies, or voltage deficiencies as long as the Bethlehem generation is operating. Bethlehem has a contract with PSNH to supply power through 2006 at avoided cost based rates which are above the current market rates for wholesale power. For the purposes of this study, it is assumed that this small power producer will remain viable through the planning period. Without the Bethlehem generation, PSNH would need to add another 115-34.5 kV transformer to Whitefield Substation in 2006, when the Bethlehem contract ends, to maintain comparable service and reliability because peak load conditions would result in line voltages on the Whitefield feeder 348 of 0.80 per unit and would require PSNH to shed load including the Lisbon Substation for a Whitefield 115-34.5 kV transformer outage. Alternatively, without Bethlehem generation, the PSNH design criteria would permit an outage of up to 24 hours at peak load to move a mobile substation into position to restore service.

10.3 Distribution System

10.3.1 General

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 10.4, Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 10.0 shows the 2003, 2008, 2013 and 2023 peak load levels for each substation, DP, MP and circuit using the existing system configuration and proposed system configuration.

10.3.2 New Substations, DP's and MP's

No new substations, delivery points or meter points are required in the Raymond District during this 20-year planning period.

10.3.3 Substation, DP and MP Changes

The following table shows the projected kW for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for backup or for the ordinary replacement of aged transformers are shown in [**bold**]. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 10-7 Substation Transformer and Regulator Data

	Transformer							Voltage Regulator		
	Rating (kVA)					Est.			Est.	
Name	OA 55°	FA 55°	OA 65°	FA 65°	Win Season	Load (kW)	Capacity (%)	Size (AMP)	Load (AMP)	Capacity (%)
Haverhill MP	--	--	--	--	--	858	--	50	45	89
Lisbon Sub	1,000	--	--	--	1,100	1,074	100	75	56	74
Lisbon Sub [1]	**2,500**	**3,125**	**2,800**	**3,500**	**3,080**	1,074	36	75	56	74
Monroe MP	--	--	--	--	--	532	--	--	--	--
Monroe DP	**2,500**	--	**2,800**	--	**3,080**	532	18	**50**	28	55

[1] Fans are not installed.

No conversion to a different distribution system operating voltage is recommended at any of the substations, meter points or delivery points. The distribution operating voltage is to remain at 7.2/12.47 kV.

10.3.4 Haverhill Meter Point Service Area

10.3.4.1 Existing System Review

The Haverhill MP takes service from Central Vermont PSC at 7.2/12.47 kV. The MP consists of one circuit, which is forecasted to serve 0.9 MW of peak load in 2023. Voltage regulators are installed just beyond the MP.

Circuit HA11 is approximately 9.0 miles long and has no ties to other circuits. The main three-phase line is 5.3 miles long and is 1/0 ACSR. The remaining vee-phase and single-phase lines are mostly 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

10.3.4.2 Recommended Plan

Project HA-1 is the installation of a 150 kVAR fixed capacitor bank to improve the power factor. The recommended location is shown on the circuit diagram map.

10.3.5 Lisbon Substation Service Area

10.3.5.1 Existing System Review

The Lisbon Substation is forecasted to serve 1.1 MW of peak load in 2023. The Lisbon area is served by two 7.2/12.47 kV circuits: LS11 and LS12. Circuit LS11 serves approximately 54 percent of the total load and LS12 serves the remaining 46 percent.

Circuit LS11 is approximately 16.0 miles long and has no ties to other circuits. The main three-phase line is 5.4 miles long and is 1/0 ACSR. The remaining vee-phase and single-phase lines are mostly 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit LS12 is approximately 8.0 miles long and has no ties to other circuits. The main three-phase line is 5.4 miles long and is 1/0 ACSR. The remaining vee-phase and single-phase lines are mostly 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

10.3.5.2 Recommended Plan

Project LS-1 is the installation of a 150 kVAR fixed capacitor bank to improve the power factor on circuit LS11. The recommended location is at the end of the three-phase main feeder as shown on the circuit diagram map.

10.3.6 Monroe Meter Point Service Area

10.3.6.1 Existing System Review

The Monroe MP takes service from Central Vermont PSC at 7.2 kV. The MP consists of one circuit, which is forecasted to serve 0.5 MW of peak load in 2023. No voltage regulators are installed near the MP.

The single-phase feeder main of Circuit MR11 splits into two single-phase lines approximately 0.25 miles from the MP. These two single-phase lines are for the purpose of dividing the load over additional sectionalizing devices for improved reliability. The two single-phase lines are on the same poles and continue for 3.5 miles.

The Monroe MP has no ties to other circuits. The main single-phase lines are mostly 1/0 ACSR with some parts being 8SCG, 8A CWC, 4 ACSR and 2 ACSR. One line voltage regulator is installed about 3.8 miles from the substation. No line capacity deficiencies or areas with low voltage, when using the existing voltage regulator, are anticipated during this planning period. However, this amount of single-phase load may be causing considerable load unbalance on the supplier's system.

10.3.6.2 Recommended Plan

Projects 202, 337, 338, and 401 are from NHEC's current construction work plan and are needed to introduce a new 19.9/34.5 kV to 7.2/12.47 kV delivery point into the area. The addition of a three-phase source compared to the existing single-phase metering point will improve service potential and reliability in the area.

10.4 Distribution System Reliability

10.4.1 Historical Reliability

The Lisbon district has had slightly better than average distribution system reliability compared to the NHEC system averages over the last three years, and ranked fourth best of all districts. The following figure shows the resultant average indices for each feeder as well as the entire Lisbon district.

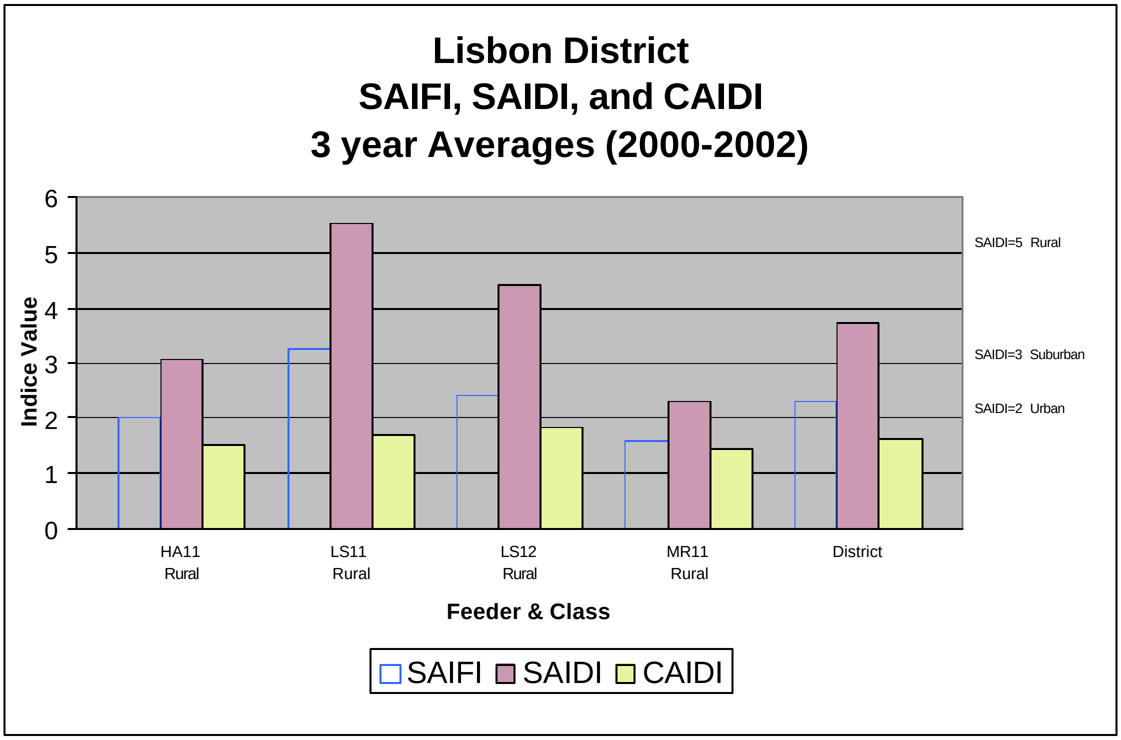


Figure 10-4 Lisbon District Historical Reliability Indices

10.4.2 SAIDI & SAIFI

Only circuit LS11 exceeded the SAIDI reliability criteria for the rural feeder classification. All circuits except for MR11 exceeded the SAIFI criteria.

10.4.3 Circuits That Exceed Reliability Criteria

10.4.3.1 Circuit HA11

This circuit had an average SAIFI of 2.0 over the 2000-2002 period, which coincidentally matches the SAIFI reliability criteria. Outages by cause can be seen in the following figure.

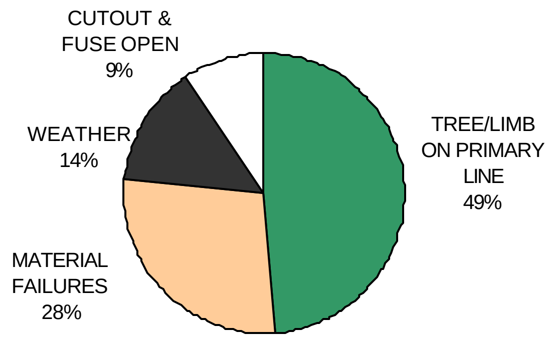


Figure 10-5 Circuit HA11 Percentage of Customer-Minutes Out by Outage Cause

Basically, this circuit consists of one long three-phase first zone of protection, and three second zones of protection consisting of one single-phase tap and two vee-phase taps. About 68% of the consumer-hours of outages were caused by outages in the first zone of protection. There were two feeder outages that accounted for about 43% of the total consumer-hours on this circuit. Overall, this circuit has experienced adequate distribution reliability, and therefore there are no proposed projects strictly for reliability purposes.

10.4.3.2 Circuit LS11

This circuit exceeded both the SAIFI and SAIDI reliability criteria and was the worst performing feeder in the Lisbon district with a SAIDI of 5.53. The following figure reflects outages by customer-minutes of outage.

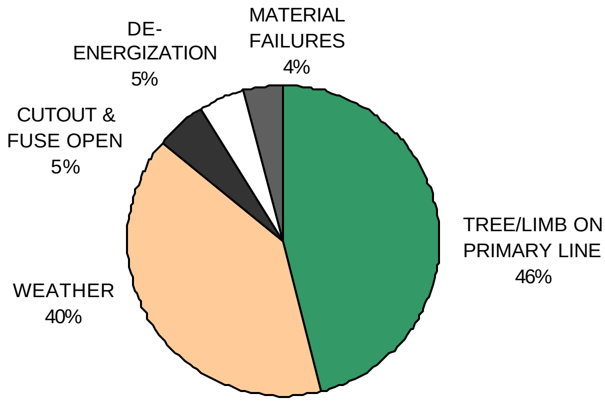


Figure 10-6Circuit LS11 Percentage of Customer-Minutes Out by Outage Cause

The configuration of circuit LS11 is similar to circuit HA11. About 42% of the consumer-hours were caused by outages occurring in the first zone of protection. Furthermore, two feeder outages caused approximately 22% of the total customer-minutes.

There are no recommended distribution construction projects for reliability purposes on circuit LS11. According to the above figure, increased O&M, particularly right-of-way clearing, may prove to be a feasible low cost option to improve reliability on this circuit. Furthermore, a few projects for conversion to tree-wire and new underground line in NHEC's current construction work plan should reduce outages caused by tree contact.

10.4.3.3 Circuit LS12

Circuit LS12 was the second worst performing feeder in the Lisbon district, but still met the SAIDI criteria for rural classified feeders. The figure below indicates the consumer-hours of outages due to various causes.

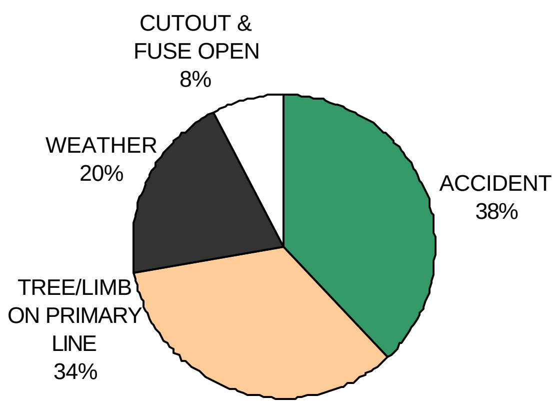


Figure 10-7 Circuit LS12 Percentage of Customer-Minutes Out by Outage Cause

The accident cause category ranked the highest in contribution to customer-minutes of outage, although there was only one accident caused outage. This outage affected all members on the feeder and lasted about 4.5 hours. Therefore, after excluding this atypical outage, the following figure indicates the revised customer-minutes of outages.

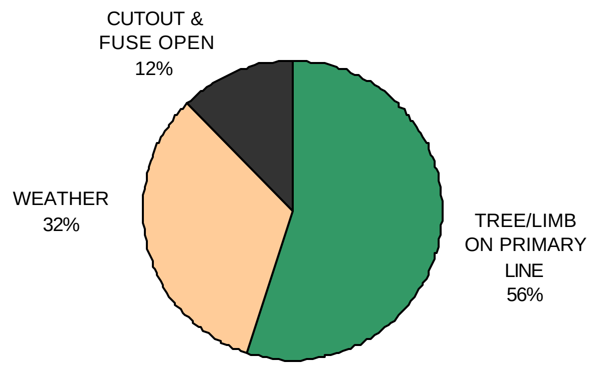


Figure 10-8 Circuit LS12 Percentage of Customer-Minutes Out by Outage Cause w/o Accident

Excluding the accident, the resulting outage indices decrease to a SAIFI of 2.05 and a SAIDI of 2.77. There are no proposed distribution system reliability construction projects for this feeder.

10.4.4 Circuits that Meet Reliability Criteria

10.4.4.1 Circuit MR11

This circuit has experienced very good reliability over the past three years with a SAIDI index of 2.29. There are no proposed distribution system reliability projects for this feeder.

10.5 Cost Estimates

A summary of the cost estimates for the proposed 5-Year, 10-Year and 20-Year Plans is provided in Table 10-8. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in Section 10.3 and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 10.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 10-8 Construction Cost Summary

	2004-2008 Cost ($)	2009-2013 Cost ($)	2014-2023 Cost ($)	2004-2023 Cost ($)
New Tie Lines	102,000	0	0	102,000
Conversions and Line Changes	162,700	0	0	162,700
New Substations, DP's and MP's	120,000	0	0	120,000
Substation, DP and MP Changes	0	0	0	0
Total	384,700	0	0	384,700
Projects for Improved Reliability	0	0	0	0

Table 10-9 Substation Load Data Projections

Substation Delivery Point or Meter Point Name	Ckt.	Season	Existing System Configuration 2003 Load kW	2008 Load kW	2013 Load kW	2023 Load kW	Proposed System Configuration 2008 Load kW	2013 Load kW	2023 Load kW
Haverhill	HA11	W	770	790	811	858	790	811	858
55 deg. w/o fans	Sub	W	770	790	811	858	790	811	858
Lisbon	LS11	W	583	578	573	577	578	573	577
3750/4200 kVA	LS12	W	449	462	476	497	462	476	497
65 deg. w/o fans	Sub		1,032	1,040	1,049	1,074	1,040	1,049	1,074
Monroe	MR11	W	530	537	544	532	537	544	532
55 deg. w/o fans	Sub	W	530	537	544	532	537	544	532
Lisbon District			**2,332**	**2,367**	**2,404**	**2,464**	**2,367**	**2,404**	**2,464**

Table 10-10 Construction Cost Details

(see following 2 pages)

Project Code	YR	Sub/Ckt	Project Description	Reason Code	@ Load (amps) [1]	Miles	Estimated Cost ($)
I. New Tie Lines							
202	2005	New Monroe / South	3ph 1/0 ACSR	WP	-	1.50	102,000
	Total New Tie Lines					1.50	102,000
II. Conversions and Line Changes							
337	2005	New Monroe / South	1ph 6 CU to 3ph 1/0 ACSR	WP	-	1.00	68,000
338	2005	New Monroe / South	Vph 6 CU to 3ph 1/0 ACSR	WP	-	1.50	90,000
HA-1	2005	Haverhill / HA11	Add 3-50 kVAR Capacitors, Fixed	C,V	25	-	2,350
LS-1	2005	Lisbon / LS11	Add 3-50 kVAR Capacitors, Fixed	C,V	25	-	2,350
	Total Conversions and Line Changes					2.50	162,700
III. Projects that have Potential Reliability Improvement							
							0
	Total Potential Reliablilty Improvements					0.00	0
	Total of all projects					4.00	264,700
	Total by year for first 4 years (includes reliability projects)						
	2004					0.00	0
	2005					4.00	264,700
	2006					0.00	0
	2007					0.00	0
	2008					0.00	0
	2013					0.00	0
	2023					0.00	0
			Total			4.00	264,700

Reason Code(s)

A	To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life.
B	To improve **B**ackup between circuits and substations.
C	To provide additional **C**apacity.
D	To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
F	To accommodate **F**uture load.
S	To accommodate new **S**ystem configuration as a result of other projects.
U	To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
V	To improve **V**oltage.
WP	As per NHEC 2001-2005 Construction **W**ork **P**lan.

[1] @ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				
401	2005	New Monroe	New 19.9/34.5 kV to 7.2/12.47 kV Delivery Point	120,000
2009-2013 Time Period				
			None	
2014-2023 Time Period				
			None	
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				
			None	
2009-2013 Time Period				
			None	
2014-2023 Time Period				
			None	

Table 10-11 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
LISBON	HA11	2000	490	895	496		0.99	1.80	1.83
		2001	2,142	3,060	496		4.32	6.17	1.43
		2002	350	580	496		0.71	1.17	1.66
	Totals		2,982	4,535	1,488	Average	2.00	3.05	1.52
	LS11	2000	630	1,100	287		2.20	3.83	1.75
		2001	1,050	2,050	287		3.66	7.14	1.95
		2002	1,120	1,610	287		3.90	5.61	1.44
	Totals		2,800	4,760	861	Average	3.25	5.53	1.70
	LS12	2000	280	220	230		1.22	0.96	0.79
		2001	860	2,130	230		3.74	9.26	2.48
		2002	530	690	230		2.30	3.00	1.30
	Totals		1,670	3,040	690	Average	2.42	4.41	1.82
	MR11	2000	63	145	231		0.27	0.63	2.30
		2001	280	390	231		1.21	1.69	1.39
		2002	750	1,050	231		3.25	4.55	1.40
	Totals		1,093	1,585	693	Average	1.58	2.29	1.45
	District Total	2000	1,463	2,360	1,244		1.18	1.90	1.61
		2001	4,332	7,630	1,244		3.48	6.13	1.76
		2002	2,750	3,930	1,244		2.21	3.16	1.43
	Totals		8,545	13,920	3,732	Average	2.29	3.73	1.63

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side"Outages).*

11.0 Meredith District

11.1 Load Analysis

The Meredith District contains four delivery points (DP), which accounted for about 15% percent of NHEC's load in 2002. The delivery points of Center Harbor, Meredith 1, Meredith 2 (Corliss Hill), and Melvin Village, had respective 2002 peak demands of 10,613, 6,682, 5,273, and 3,732 kW. Unlike most other NHEC districts, all of Meredith's delivery points have been summer peaking in the past four years with the single exception of Meredith 1 which peaked the winter in 2000.

The Center Harbor delivery point has about 38.7 percent as many consumers as population in the townships that it serves. Consumer growth is expected to match population growth at annualized rates of 2.1% through 2008 and 1.8% through 2023.

The Center Harbor demand per consumer was 1.88 kW in 2002, which is about average for NHEC delivery points. Demand per consumer is expected to increase at an annualized rate of 1.2% through 2008 , and then to level off at an annualized 0.5% through 2023. This reflects the district manager's perception that over the next five years there will be service upgrades to existing homes and new connections will accommodate larger homes. Combined consumer and demand consumer growth results in relatively rapid load growth at annual rates of 3.3% through 2008 The total average annual load growth is expected to be 3.3% through 2008, leveling off to an annual average of 2.3% through 2023.

The forecasts of consumers and loads are shown in Table 11-1 and Figure 11-1. Included in this load growth forecast is a spot commercial load on circuit CH13 as described in Table 11-2.

Table 11-1 Center Harbor DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	13,861				
2001	14,132				
2002	14,576	0.3869	5,640	1.882	10,613
2003	14,904	0.3869	5,767	1.909	11,007
2004	15,231	0.3869	5,894	1.934	11,398
2005	15,560	0.3869	6,021	1.957	11,785
2006	15,883	0.3869	6,146	1.979	12,165
2007	16,206	0.3869	6,271	2.000	12,541
2008	16,528	0.3869	6,395	2.019	12,914
2013	18,132	0.3869	7,016	2.020	14,175
2023	21,343	0.3869	8,259	2.070	17,098
Growth Rates					
2002 - 2003	2.25%	0.00%	2.25%	1.43%	3.71%
2002 - 2008	2.12%	0.00%	2.12%	1.18%	3.32%
2002 - 2013	2.00%	0.00%	2.00%	0.65%	2.67%
2002 - 2023	1.83%	0.00%	1.83%	0.46%	2.30%

Table 11-2 Center Harbor DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Center Harbor	CH13	Commercial	50	50	100

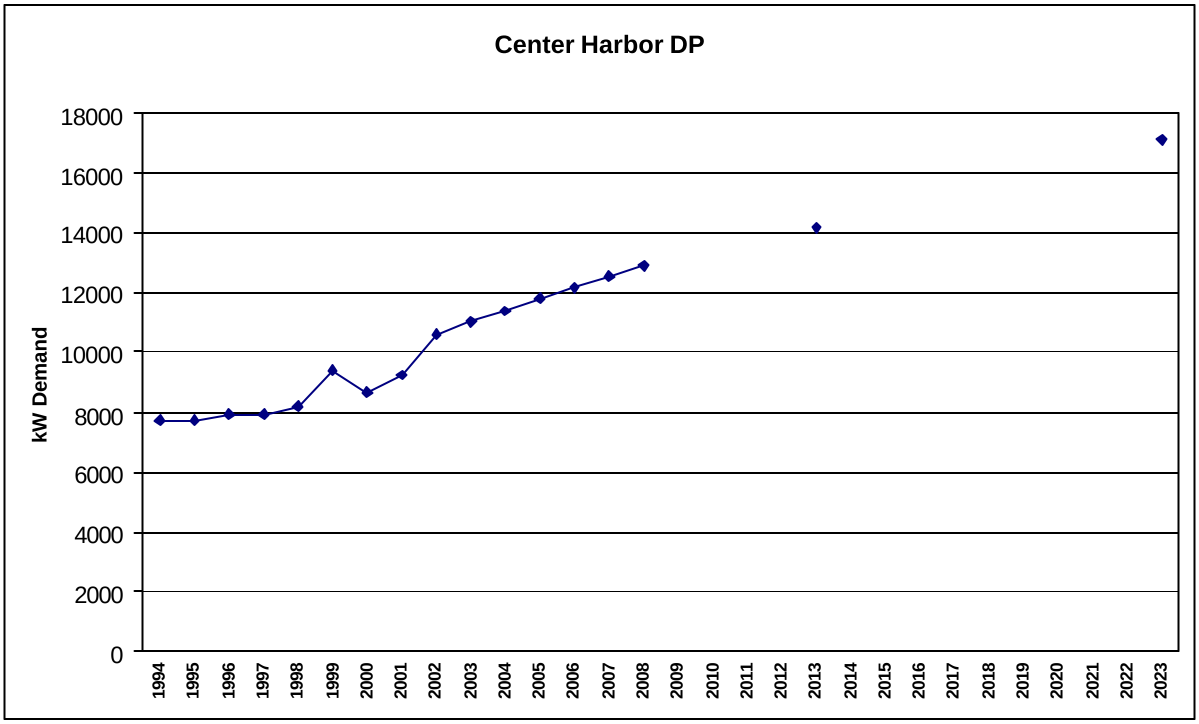


Figure 11-1 Historical and Forecasted Center Harbor DP Demands

The Meredith 1 delivery point consumers represent 21 percent of the service area population. Consumer growth is expected to match population growth at an annual rate of 1.4% over the next two decades.

The 2002 demand per consumer was 1.85 kW in 2002, slightly below average for NHEC delivery points. Demand per consumer is expected to increase slightly due to larger home sizes over the 20-year horizon. The resultant change in peak demands is forecasted to be about 1.6% annually over the two decades.

The forecasts of consumers and loads are shown in Table 11-3 and Figure 11-2. In addition to the base load growth forecasted is a spot load on circuit ME11 as shown in Table 11-4.

Table 11-3 Meredith 1 DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	16,626				
2001	16,965				
2002	17,336	0.2089	3,621	1.845	6,682
2003	17,615	0.2089	3,679	1.850	6,807
2004	17,896	0.2089	3,738	1.855	6,933
2005	18,175	0.2089	3,796	1.859	7,059
2006	18,450	0.2089	3,854	1.863	7,181
2007	18,727	0.2089	3,911	1.867	7,305
2008	19,004	0.2089	3,969	1.871	7,428
2013	20,392	0.2089	4,259	1.888	8,043
2023	23,228	0.2089	4,852	1.914	9,286
Growth Rates					
2002 - 2003	1.61%	0.00%	1.61%	0.26%	1.88%
2002 - 2008	1.54%	0.00%	1.54%	0.23%	1.78%
2002 - 2013	1.49%	0.00%	1.49%	0.21%	1.70%
2002 - 2023	1.40%	0.00%	1.40%	0.17%	1.58%

Table 11-4 Meredith 1 DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR 2004-2008 Load (kW)	YEAR 2009-2013 Load (kW)	YEAR 2014-2023 Load (kW)
Meredith	ME11	Church**	300	100	-
** In addition to base forecast					

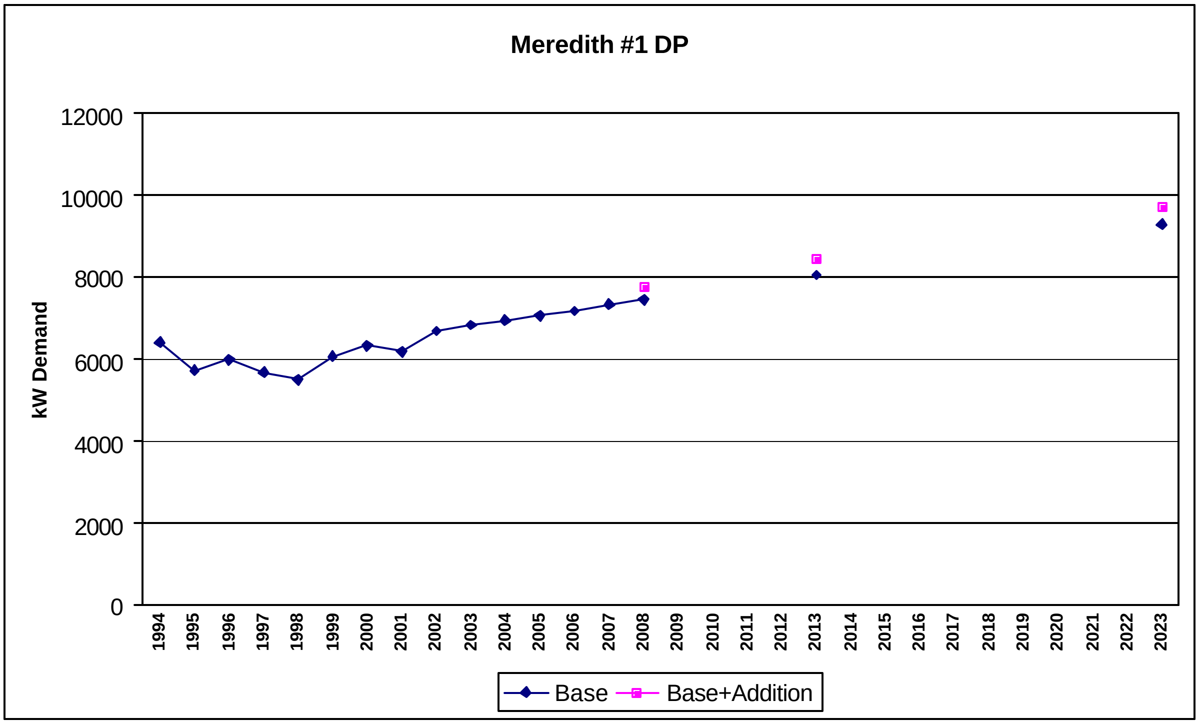


Figure 11-2 Historical and Forecasted Meredith 1 DP Demands

The Meredith 2 delivery point has about eight percent as many consumers as population in the townships that it serves. Consumer growth is expected to match population growth. Growth is expected at an average annualized rate of about 1.0% over the 20 year study period.

The Meredith 2 demand per consumer was 2.3 kW in 2002, which was in the top ten for NHEC delivery points. Demand per consumer is expected to decrease at an annualized rate of -0.2% through 2023, as new connections should be below the 2.3 kW average. The total average annual load growth is expected to be about 0.8% annually over the 20-year period.

The forecasts of consumers and loads are shown in Table 11-5 and Figure 11-3. Included in the load growth forecast are spot loads on circuit CL12 as shown in Table 11-6.

Table 11-5 Meredith 2 DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	26,885				
2001	27,375				
2002	27,867	0.0832	2,318	2.275	5,273
2003	28,163	0.0832	2,343	2.269	5,316
2004	28,462	0.0832	2,368	2.263	5,359
2005	28,759	0.0832	2,392	2.258	5,402
2006	29,046	0.0832	2,416	2.253	5,443
2007	29,337	0.0832	2,440	2.248	5,486
2008	29,628	0.0832	2,465	2.243	5,528
2013	31,085	0.0832	2,586	2.221	5,742
2023	34,067	0.0832	2,834	2.184	6,189
Growth Rates					
2002 - 2003	1.06%	0.00%	1.06%	-0.25%	0.81%
2002 - 2008	1.03%	0.00%	1.03%	-0.23%	0.79%
2002 - 2013	1.00%	0.00%	1.00%	-0.22%	0.78%
2002 - 2023	0.96%	0.00%	0.96%	-0.19%	0.77%

Table 11-6 Meredith 2 DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR 2004-2008	YEAR 2009-2013	YEAR 2014-2023
			Load (kW)		
Corliss Hill	CL11	-			
	CL12	Residential	10	10	15
		Residential	10	10	15
	CL13	-			
	CL14	-			

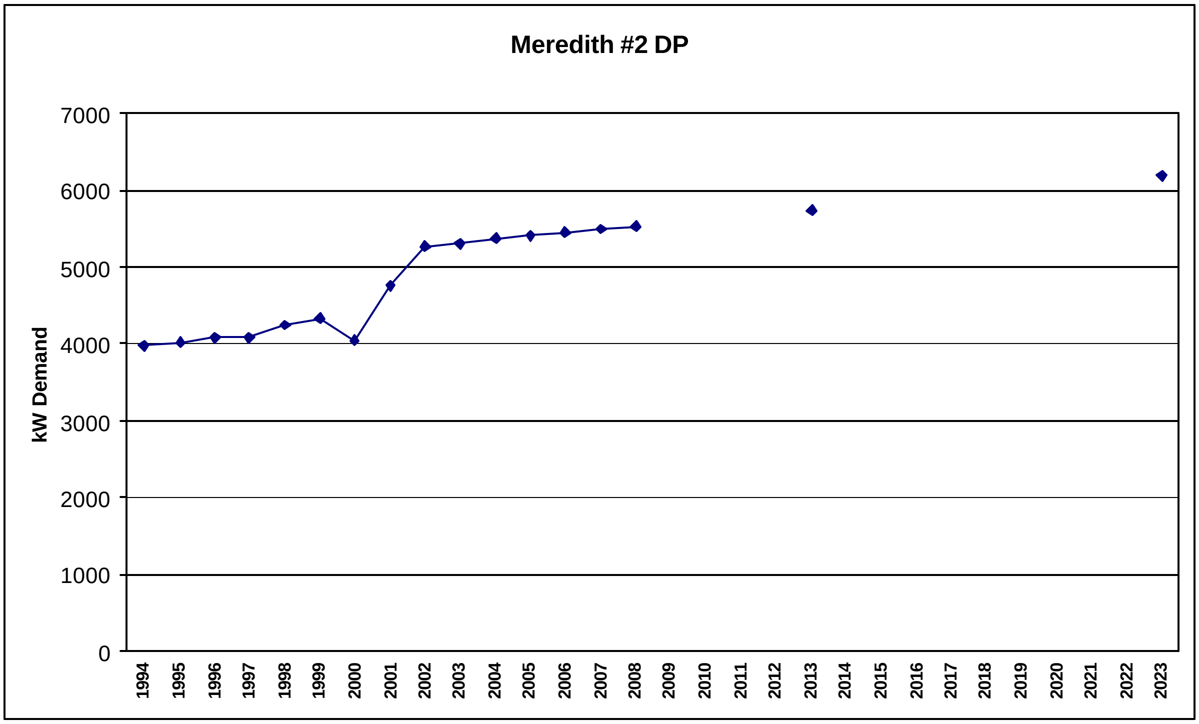


Figure 11-3 Historical and Forecasted Meredith 2 DP Demands

The Melvin Village delivery point serves about 21 percent of the service area population. Consumer growth is expected to match population growth. Growth is expected at an average annualized rate of 2.2% through 2008 compared to 1.9% over the entire the 20-year horizon.

The 1.7 kW demand per consumer in 2002 is below average for NHEC delivery points. Demand per consumer is expected to increase slightly at an average annual rate of 0.2% through 2023. Total average annual load growth is then expected to be 2.4% through 2008 compared to an annual average of 2.0% through 2023.

The forecasts of consumers and loads are shown in Table 11-7 and Figure 11-4. Spot loads on circuit MV13 are as shown in Table 11-8.

Table 11-7 Melvin Village DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	10,066				
2001	10,261				
2002	10,600	0.2072	2,196	1.699	3,732
2003	10,846	0.2072	2,247	1.704	3,829
2004	11,092	0.2072	2,298	1.708	3,925
2005	11,338	0.2072	2,349	1.712	4,022
2006	11,581	0.2072	2,399	1.716	4,117
2007	11,823	0.2072	2,449	1.719	4,211
2008	12,063	0.2072	2,499	1.722	4,304
2013	13,255	0.2072	2,746	1.736	4,767
2023	15,618	0.2072	3,236	1.754	5,674
Growth Rates					
2002 - 2003	2.33%	0.00%	2.33%	0.27%	2.60%
2002 - 2008	2.18%	0.00%	2.18%	0.22%	2.41%
2002 - 2013	2.05%	0.00%	2.05%	0.19%	2.25%
2002 - 2023	1.86%	0.00%	1.86%	0.15%	2.02%

Table 11-8 Melvin Village DP Spot Loads Identified

	Circuit	Load Type	YEAR 2004-2008 Load (kW)	YEAR 2009-2013 Load (kW)	YEAR 2014-2023 Load (kW)
Melvin Village	MV13	Commercial	40	40	30
		Suissevale Subdivision	150	150	200
		Suissevale Subdivision	150	150	200
		Castle Springs Bottling Plant**	400	400	200

** In addition to base forecast

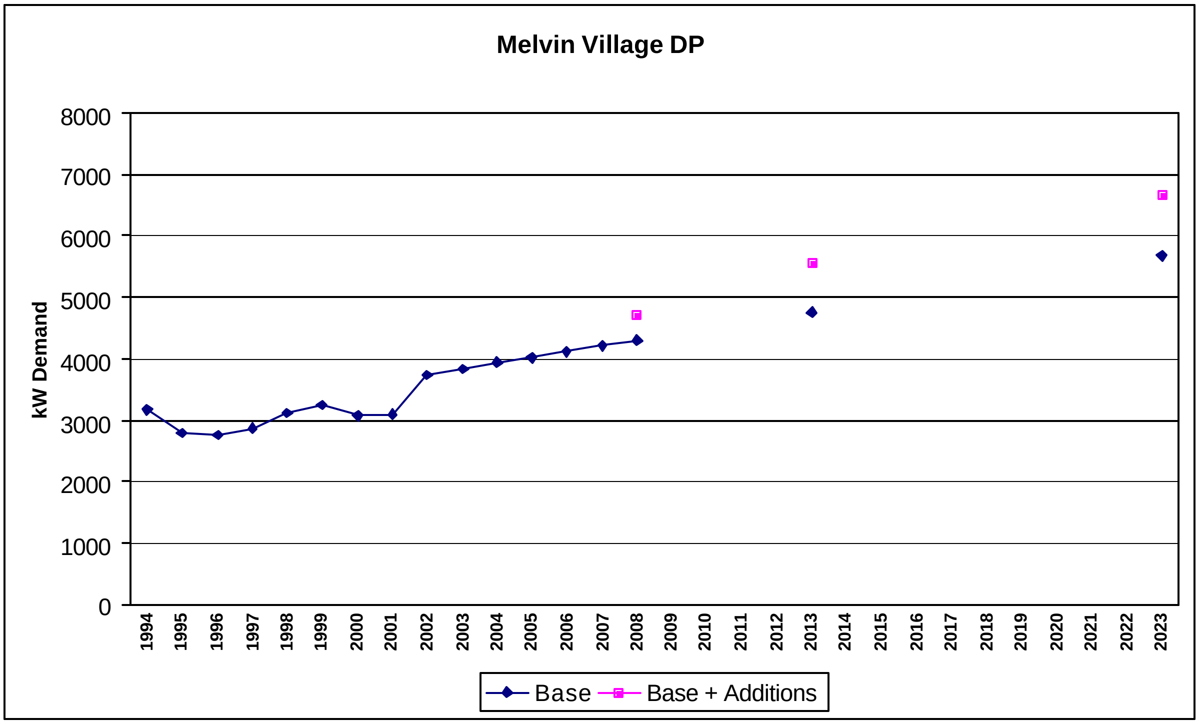


Figure 11-4 Historical and Forecasted Melvin Village DP Demands

11.2 Transmission System

11.2.1 Bulk Transmission System

PSNH supplies bulk power to the Meredith District at 34.5 kV. The 115 kV system supplies power to PSNH's 115 – 34.5 kV Ashland and Pemigewasett Substations which are the source of the 34.5 kV system serving the District's substations.

Ashland and Pemigewasett Substations are tapped from the Webster-Beebe River 115 kV line and thus are looped with two transmission lines. The Webster-Beebe River 115 kV line also has a 115 kV breaker, for fault isolation, located electrically mid-way between Ashland and Pemigewasett Substations. This 115 kV system design leaves either substation vulnerable to a 115 kV line outage between breakers and is not as reliable as a design which has line breakers or two-way auto-sectionalizers on the 115 kV at Ashland and Pemigewasett Substations.

The 115 kV system serving this district will benefit marginally when PSNH and Central Maine Power complete work at Beebe River Substation, in Maine, and with increasing the area's reactive power supply in 2004. This work will permit the Beebe River–White Lake–Saco 115 kV line to be tied to Central Maine Power's 115 kV system.

11.2.2 34.5 kV Subtransmission System

The Meredith District is supplied by PSNH at Meredith I, Meredith 2, Center Harbor and Melvin Village substations located around the central and western shores of Lake Winnipesauke. Currently Ashland Substation supplies the entire Meredith District. Pemigewasett Substation is available for contingency support. At the easterly end of the District there is a voltage and capacity limited 34.5 kV tie to the White Lake Substation.

Substation transformer capacity and base case and long-range coincident peak demands are shown in Table 11-9. The long-range load levels represent an annual area load growth rate of 1.76 percent in the summer demand and an annual rate of .93 percent in the winter demand.

Table 11-9 Meredith District 34.5 kV System and Load

	115 – 34.5 kV Transformers			Coincident Peak Loads (MVA)			
			34.5 kV	Summer		Winter	
Substation	Summer Capacity	Winter Capacity	Feeders	2002	2023	2002	2023
Ashland	1-31 MVA	1-41 MVA	2	32.0	44.4	22.2	27.0
Pemigewasett	1-28 MVA	1-32 MVA	3	13.4	18.9	13.8	16.8
White Lake	1-27, 1-31 MVA, 1-20 MW CT	1-34, 1-39 MVA	3	33.8	49.8	31.6	34.0

11.2.3 Base System Performance

Base power flow studies for the 2003 winter peak, 2003 summer peak and 2023 winter peak indicate there are no deficiencies. The 2023 summer peak case indicates Ashland feeder 338 is at 38.4 MVA. Feeder 338 exceeds the 30 MVA per feeder design criteria in 2008. The Ashland transformer also overloads in 2010. In 2003, it was necessary to add 2.4 megavars of capacitors at Center Harbor in order to maintain acceptable voltages.

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. This work needs to be completed by 2008 when Ashland 338 feeder exceeds 30 MVA of load. NHEC should request that this be done in conjunction with the Ashland and Pemigewasett transformer upgrades in 2005. Currently all four district substations are served from the Ashland 338 feeder.

NHEC should also strive to maintain unity power factor at the PSNH delivery points during the summer peak demand periods. PSNH’s Ashland 338 feeder lacks a neutral for connecting ground wye capacitor banks over a significant length of the feeder which precludes the use of line-to-ground rated equipment. For planning purposes NHEC should install 3.6 megavars of distribution primary voltage rated capacitors; 1.8 megavars at Meredith 1, 1.2 megavars at Center Harbor and 600 kilovars at Melvin Village. Thence, NHEC should strive to maintain unity power factor during the summer peak at each substation over the planning period. These capacitor banks should be switched with multi-function controls and equipped for remote switching via SCADA as contingency capacitor banks. The estimated cost of these capacitor banks is $75,000.

11.2.4 Contingency Performance

Meredith I, Meredith II, Center Harbor and Melvin Village are all currently served by a single 34.5 kV feeder; Ashland 338, from a single transformer substation. For reliability and contingency purposes, Meredith II should be transferred to the Pemigewasett 345 feeder. This is assumed to have been done in conjunction with the transformer upgrades at Ashland and Pemigewasett in 2005.

Until these upgrades are completed, outages to:

- Ashland 115 –3 4.5 kV transformer
- Straights 344 line to Meredith I, and
- Straights 338 line to Meredith II

will result in a outage to Center Harbor Substation and Meredith I Substation because of inadequate capacity.

Subsequent to these upgrades only an outage to the Straights 344 line to Meredith I will result in an outage to Meredith I and Center Harbor. This is simply because the Ashland 338 tie to White Lake 346/3116 has inadequate capacity to support transfer of load at Meredith I, Center Harbor and Melvin Village Substations.

In order to support this load transfer and provide full backup capability to the Meredith I and Center Harbor Substations, an additional 115-34.5 kV source is necessary in the NHEC Tuftonboro-Melvin Village vicinity. Developing that source would require:

PROJECT ELEMENT	
• Redeveloping White Lake into a breakered 115 kV substation	$2,000,000
• Extending a 13.0 mile 115 kV line from White Lake Substation to the new 115–34.5 kV substation at Tuftonboro	4,550,000
• Develop a new 115–34.5 kV substation at Tuftonboro with 1 – 24 MVA transformer, three 34.5 kV feeders (The site should be adequate for two transformers, two 115 kV lines and five 34.5 kV feeders)	1,500,000
• Engineering, Environmental, ROW & Regulatory Support	1,600,000
TOTAL	$9,650,000

This plan would also need to acquire significant new right-of-way for the 115 kV transmission line, land at White Lake Substation and land at the new Tuftonboro Substation site. This plan is not likely to receive support from PSNH because the contingent backup capability this project provides exceeds the PSNH 34.5 kV design criteria. It will also require an interconnection agreement with PSNH for a White Lake Substation interconnection and will likely need study review and approvals by the ISO-NE. It is unlikely that this project could be in-service in 2006.

Because of the cost and these major hurdles, this plan alternative was not included in the District's planning portfolio.

The following table summarizes the PSNH 34.5 kV plan for the Meredith District.

Table 11-10 Plymouth District 34.5 kV Subtransmission Plan

Year	Plan Element	Estimated Cost ($)
2004	NHEC Distribution Voltage Capacitor Banks – 3.6 MVARS	75,000
2005	Increase Ashland 115 - 34.5 kV Transformer Capacity	PSNH
2005	Increase Pemigewasett 115 – 34.5 kV Transformer Capacity	PSNH
2005	Rebuild Straights Road Switching Station (to serve Meredith II from Pemigewasett Substation feeder 345)	PSNH
2005-2023	1. NHEC Maintain Unity Power Factor at 34.5 kV Delivery Points – Meredith I, Center Harbor and Melvin Village	100,000
	2. PSNH Maintain Unity Power Factor at PSNH 34.5 kV Delivery Points	PSNH

11.2.5 Historical Reliability

A review of the 34.5 kV subtransmission outages for the period of 2000-2002 indicated the following average annual outage rates:

Table 11-11 Average Annual Outage Rates 2000-2002

Delivery Points/Substations	PSNH Outages	Average Annual Outages
Center Harbor	3	1.00
Meredith I (Meredith)	2	0.67
Meredith II (Corliss Hill)	2	0.67
Melvin Village	3	1.00

These outage rates are within NHEC's design criteria.

11.2.6 Reliability Improvement (of Plan)

The subtransmission plan proposed for the Plymouth District will improve the reliability of service largely by removing capacity constraints at the Straights Road Switching Station and transformer capacity constraints at Ashland and Pemigewasett Substations.

The plan was not able to provide sufficient capacity for the first contingency backup under all outage possibilities for Center Harbor and Melvin Village Substations. However, an alternative is developed and presented which could provide that capability. That alternative should be reviewed again during the next long-range plan development.

The circumstances surrounding the Center Harbor and Melvin Village Substations lack of full first contingency backup at the subtransmission level are very similar to those of being supplied by a radial transmission line at peak. A situation very similar to these circumstances exists in the Alton District and providing first contingency capability for Alton and New Durham Substations.

11.3 Distribution System

11.3.1 General

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 11.4. Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 11.0 shows the 2003, 2008, 2013 and 2023 peak load levels by substation, DP, MP and circuit using the existing system configuration and proposed system configuration.

11.3.2 New Substations, DP's and MP's

One new substation is recommended in the Meredith District during this 20-year planning period to provide voltage, capacity, and reliability support. This new substation, tentatively named Moultonborough Substation, should be located in the Township of Moultonborough along Moultonborough Road. The new source will provide load relief to the heavily loaded Circuit CH14 of the Center Harbor substation.

The existing transmission line that serves the Melvin Village, Center Harbor, and Meredith Substations is PSNH's 34.5 kV 346 line. This line is looped between the White Lake and Pemigewasett 115 kV to 34.5 kV transmission substations, therefore providing more reliable service to these three distribution substations in Meredith District. The new Moultonborough Substation is to be installed at a location near both the transmission and distribution line as shown on the proposed system Circuit Diagram.

11.3.3 Substation, DP and MP Changes

The following table shows the projected kW for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for backup or for the ordinary replacement of aged transformers are shown in [**bold**]. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 11-12 Substation Transformer and Regulator Data

Name	Transformer							Voltage Regulator		
	Rating (kVA)					Est. Load (kW)	Capacity (%)	Size (AMP)	Est. Load (AMP)	Capacity (%)
	OA 55°	FA 55°	OA 65°	FA 65°	Win Season					
Center Harbor	10,000	12,500	11,200	14,000	15,400	11,684	77	437	607	139
Corliss Hill [1]	5,000	5,750	5,600	6,440	5,500	6,239	116	219	324	148
Corliss Hill [2]	**10,000**	**12,500**	**11,200**	**14,000**	**15,400**	6,239	41	**656**	324	49
Melvin Village	10,000	12,500	11,200	14,000	15,400	6,703	44	656	348	53
Meredith	10,000	12,500	11,200	14,000	15,400	9,621	64	656	500	76
Moultonborough	7,500	9,375	8,400	10,500	11,550	5,290	47	437	275	63

[1] Fans are not installed.

[2] Scheduled to be changed in 2004 to provide additional capacity. Project CL-1.

No conversion to a different distribution system operating voltage is recommended at any of the substations. The distribution operating voltage is to remain at 7.2/12.47 kV throughout the district.

11.3.4 Center Harbor Substation Service Area

11.3.4.1 Existing System Review

The Center Harbor Substation is forecasted to serve 17.1 MW of peak load in 2023 compared to 11.0 MW at the existing system level. The Center Harbor area is served by four 7.2/12.47 kV circuits: CH11, CH12, CH13 and CH14. Circuit CH11 serves approximately 8 percent of the total load, CH12 serves 18 percent, CH13 serves 43 percent and CH14 serves the remaining 31 percent.

Circuit CH11 serves to the north-northwest approximately 10 miles and will have low voltage at the node CH10070-36 extremity, which is a 2.4 kV segment. There were no other deficiencies noted.

Circuit CH12 serves to the south approximately 4 miles with a single-phase interconnection to Meredith Circuit ME11. There are no deficiencies noted in the load flow calculations.

Circuit CH13 serves to the north-northeast approximately 14 miles and it will have a substantial amount of load (7.4 MW) at the 2023 load level which will cause capacity deficiencies and will likely contribute to poor performance and reliability. This heavily loaded circuit only has a couple of small remote single-phase ties to other circuits which do not contribute much redundant capacity for contingencies.

Circuit CH14 serves to the southeast approximately 14 miles and has no interconnections to other circuits because it serves a peninsula extending into Lake Winnipesaukee. The primary system voltages and service reliability are expected to become marginal during the long range planning period. This circuit is operated at 7.2/12.5 kV on the main lines and 2.4 kV on several small single-phase taps.

11.3.4.2 Recommended Plan

On Circuit CH11, Project CH-1 is recommended to enable a circuit configuration change between Circuits CH11 and CH13. Currently, the long single-phase taps in this area are connected to Circuit CH13 which is very heavily loaded with a projected load of 7.4 MW, partially due to commercial members along Highway 25. Project CH-1 will enable the transfer of approximately 1,475 kW of load and 330 members from Circuit CH13 to CH11. Furthermore, the system change will improve reliability to these 330 members on the single-phase taps due to the poor reliability within the second zone of Circuit CH13. This is further explained in the distribution system reliability section for Circuit CH13.

Projects CH-2 and CH-3 will extend three-phase and vee-phase to enable the load to be divided over additional phases. These projects and will improve load balance along the three-phase line.

Project CH-4 is the installation of 3-100 amp voltage regulators to provide additional voltage support on this long feeder.

Project 342 is the replacement of single-phase 1/0 bare concentric with new jacketed 1/0 AL URD. The existing line is non-jacketed with 1/3 neutral and has a history of outages. This project was included in year 2 of the 2001-2005 Construction Work Plan.

Project 343 is the conversion to three-phase 336 Hendrix spacer cable. This project is needed so than an underground section of line routed under a highway may be eliminated. This project was included in year 3 of the 2001-2005 Construction Work Plan.

Project 345 on Circuit CH12 is the replacement of a three-phase 3/0 ACSR line with a double-circuit three-phase 336 ACSR near the substation feeder exit. Portions of the existing line are inaccessible, which increases restoration times during major feeder outages in the area. This project was included in year 4 of the 2001-2005 Construction Work Plan.

On Circuit CH12, Project 344 is the replacement and conversion of single-phase, 2.4 kV, 6 CU line with three-phase, 7.2/12.5 kV, 336 Hendrix cable. The 2001-2005 Construction Work Plan suggested the new conductor be single-phase 1/0 ACSR operated at 7.2 kV. Due to the reliability project designated as ME-R1, it is recommended that Project 344 be modified to three-phase 336 Hendrix cable to complete the three-phase loop between Circuit CH12 and Circuit ME11 of the Meredith Substation.

On circuit CH13, Project CH-5 is a single-phase 1/0 ACSR tie-line that will help reduce the length of the line currently serving these members, therefore providing voltage and reliability improvement. Likewise, Project CH-6 is proposed for capacity support and to help divide the members over two taps instead of one.

Project 339 will provide a three-phase tie between Circuit CH13 and Circuit MV13 of the Melvin Village Substation. The existing line is old single-phase 6 CU operated at 2.4 kV. This project was included in year 2 of the 2001-2005 Construction Work Plan.

On Circuit CH14, a three-phase 336 ACSR double-circuit line is needed from the new Moultonborough Substation to the existing three-phase feeder main of Circuit CH14. The double-circuit, identified as Project CH-7, will provide additional capacity and reliability compared to a single-circuit. Construction Project 341, the upgrade to three-phase 336 Hendrix cable, will provide the third circuit out of the new Moultonborough Substation. This new substation is discussed in more detail in the Section 11.3.2, New Substations, DP's and MP's section. Project 341 was included in year 1 of the 2001-2005 Construction Work Plan.

With the installation of the Moultonborough Substation, all of the load is taken off Circuit CH14. This enables the transfer of load from Circuit CH13 to CH14. Where the two circuits split with one going to the northeast and one to the southeast, the northeast feeder should be switched over to Circuit CH14. This will provide capacity relief to Circuit CH13.

Project 346 is the replacement of three-phase 2 CU with three-phase 336 Hendrix cable. This project is an upgrade to an existing bridge crossing. Project 346 was included in year 4 of the 2001-2005 Construction Work Plan.

Project 347 is the replacement of single-phase 1/0 bare concentric with new jacketed 1/0 AL URD. The existing line is non-jacketed with 1/3 neutral and has a history of outages. This project was included in year 4 of the 2001-2005 Construction Work Plan.

11.3.5 Corliss Hill Substation Service Area

11.3.5.1 Existing System Review

The Corliss Hill Substation is forecasted to serve 6.2 MW of peak load in 2023. The Corliss Hill area is served by four 7.2/12.47 kV circuits: CL11, CL12, CL13 and CL14. Circuit CL11 serves approximately 7 percent of the total load, CL12 serves 59 percent, CL13 serves 11 percent and CL14 serves the remaining 23 percent. Circuits CL11, CL12, and CL13 are shorter in length compared to the majority of the circuits on NHEC's system while Circuit CL14 extends approximately 17 miles from the substation.

Circuit CL11 is approximately 3.5 miles long and has no ties to other circuits. The main three-phase line is entirely 336 ACSR and is routed along Highway 104. There are no anticipated voltage or capacity deficiencies on this feeder at the 20-year load level.

Circuit CL12 extends about 5 miles and has a three-phase tie with the Meredith Substation. Similar to Circuit CL11, Circuit CL12 also serves members along Highway 104 and then continues south along Interstate 3. The main three-phase line is 336 ACSR and the three-phase tap along Interstate 3 is a mixture of 336 ACSR, 2 ACSR and 4 CWC. The first 750 feet of conductor on Circuit CL12 is 3/0 ACSR and should be replaced with 336 ACSR. Only one deficiency was encountered on this circuit at the 20-year load level. The 2023 peak load on the vee-phase tap along Winona and Lakes Road exceeds the maximum design limit of 50 amps per phase.

The main three-phase feeder of Circuit CL13 heads south out of the substation for about 2 miles. At this point, long single-phase taps continue south and one of them serves members along the eastern side of Lake Winnisquam. The main three-phase line is 336 ACSR and the single-phase taps are mainly 1/0 ACSR. Similar to Circuit CL12, the first section of conductor out of the substation is 3/0 ACSR and should be replaced with 336 ACSR. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit CL14 is the longest feeder in the district and also has a significant amount of load. The configuration of the main line is three-phase for about 5 miles, vee-phase for 8 miles, and then two single-phase taps that extend about 5 miles. The main three-phase lime as it leaves the substation is 4 CWC, 1/0 ACSR and 4/0 ACSR. The vee-phase section is mainly 1/0 ACSR with a few sections of 4/0 ACSR near the start of the vee-phase. Primarily all of the single-phase taps are 1/0 ACSR. Currently, two line voltage regulators are installed near the beginning of the vee-phase section. Even with voltage regulation, the voltage drop at the end of the line is approaching design criteria voltage limits at the 20-year level.

11.3.5.2 Recommended Plan

Projects CL-2 and CL-3 on Circuit CL12 will provide additional capacity by rebuilding the single-phase and vee-phase 1/0 ACSR line to three-phase 4/0 ACSR. The existing single-phase line is estimated to have 54 amps of peak load at the 2023 load level. The three-phase extension will improve voltage at the end of the line by dividing the load over additional phases and will also improve load balance along the three-phase main line. It is also anticipated that the three-phase line will become a three-phase tie to Circuit BW11 of the Bridgewater Substation in the Plymouth District.

Project CL-4 will provide a three-phase tie-line between Circuits CL12 and CL13. At the present time, there is no backup to the radial three-phase lines on Circuit CL12. Therefore, Project CL-4, in conjunction with reliability Project CL-R1, will improve voltage, capacity and reliability in this area.

On Circuit CL14, Project 349 will replace 1.5 miles of old three-phase 4 CU and 1/0 ACSR lines with 336 Hendrix cable. These lines have reached the end of their useful life. This project was included in year 1 of the <u>2001-2005 Construction Work Plan</u>.

Due to the long, radial configuration of Circuit CL14, conversion to three-phase along the main feeder is recommended to provide voltage improvement. Projects CL-5 and CL-6 are the addition of the third phase conductor along the existing vee-phase lines. The conversion will enable dividing the load over an additional phase and will load balance and voltage.

11.3.6 Melvin Village Substation Service Area

11.3.6.1 Existing System Review

The Melvin Village Substation is forecasted to serve 6.8 MW of peak load in 2023 compared to 3.8 MW at the existing system level. The Melvin Village area is served by two 7.2/12.47 kV circuits (MV11 and MV13) and one 2.4/4.16 kV circuit (MV12). Circuit MV11 serves approximately 17 percent of the total load, MV12 serves 6 percent and MV13 serves the remaining 77 percent.

Circuit MV11 is approximately 5 miles long and ties to Circuit TF12 of the Tuftonboro Substation. The first half of the circuit is operated at 7.2/12.47 kV and the second half at 2.4/4.16 kV. The main line consists of 1/0 ACSR and 2 CU. The estimated peak load is 53 amps per phase at the 2023 load level. Because of the lower operating voltage, the tie to TF12 is not effective. Otherwise, no main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit MV12 serves a small area southwest of the substation. The circuit is approximately 2 miles long and has no ties to other circuits. The main three-phase line is approximately 1.2 miles long and is mostly 4 CU. Most of the single-phase lines are 2 ACSR or smaller. This circuit is operated at 2.4/4.16 kV and will have voltage and capacity deficiencies during this planning period.

Circuit MV13 is approximately 18 miles long and has no ties to other circuits. The main three-phase line is approximately 8 miles long. The first 3 miles are 336 ACSR and the next 5 miles are 1/0 ACSR. Most of the other vee-phase and single-phase lines are 1/0 ACSR. Most of the load on this circuit is within the first 4 miles. The peak load at the 2023 load level is approximately 240 amps per phase, which includes a considerable amount of new load, and is therefore approaching the maximum design load limit of 280 amps per phase which is considered to be capacity deficient. At this load level, low voltage is anticipated at the end of the circuit.

11.3.6.2 Recommended Plan

On Circuit MV11, Project 351 is the conversion of a three-phase line operated at 2.4/4.16 kV to the 7.2/12.47 kV operating voltage. This voltage conversion will provide the additional capacity and voltage improvement needed. Upon completion, the project will create a three-phase tie to Circuit TF12 of the Tuftonboro Substation in the Ossipee District. This project was included in year 3 of the 2001-2005 Construction Work .

On Circuit MV12, Project MV-1 is the conversion from 2.4/4.16 kV to 7.2/12.47 kV. This conversion will provide the capacity to serve the area. Most of the main line is 4 CU and will need to be rebuilt.

Project MV-2, MV-3 and MV-4 are recommended to create a new three-phase 336 ACSR feeder main to divide the load on the heavily loaded Circuit MV13. This circuit is forecasted to have 5.2 MW of load in 2023 which results in capacity and voltage deficiencies. These projects will provide a three-phase loop to much of the 5.2 MW of load for improved reliability.

Project MV-5 will provide additional capacity by converting the vee-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 1-1/0 ACSR phase conductor. The existing vee-phase line is estimated to have 53 amps of peak load on Phase A and 27 amps on Phase C at the 2023 load level. The three-phase line is to be extended 2.0 miles so that single-phase taps can balance the load on the three-phase line.

Project MV-6 will also provide additional capacity by converting the single-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 34 amps of peak load at the 2023 load level. The three-phase line is to be extended 1.2 miles so that single-phase taps can balance the load on the three-phase line.

Project MV-7 is the installation of 3-100 amp voltage regulators to provide additional voltage support on this long feeder. The voltage regulators will also be useful during backup to this area from the Center Harbor Substation.

Project MV-8 is a single-phase 1/0 aluminum underground tie line that will divide the load. The existing single-phase line is estimated to have 47 amps of peak load in 2023. The tie line will enable dividing the members over two taps instead of one.

11.3.7 Meredith Substation Service Area

11.3.7.1 Existing System Review

The Meredith Substation is forecasted to serve 9.7 MW of peak load in 2023. The Meredith area is served by four 7.2/12.47 kV circuits: ME11, ME12, ME13 and ME14. Circuit ME11 serves approximately 34 percent of the total load, ME12 serves 23 percent, ME13 serves 28 percent and ME14 serves the remaining 15 percent.

Circuit ME11 is approximately 9 miles long and is mostly radial. The main three-phase line is approximately 4.5 miles long and is 336 ACSR. Most of the other vee-phase and single-phase lines are 1/0 ACSR. The peak load at the 2023 load level is approximately 150 amps per phase. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit ME12 is approximately 3 miles long and has two ties to Circuit CL12. The first 1.0 miles are 3/0 ACSR, the next 0.6 miles are 336 ACSR and then 1.2 miles of 4 CU. Most of the other three-phase, vee-phase and single-phase lines are either 2 ACSR or 1/0 ACSR. The peak load at the 2023 load level is approximately 100 amps per phase. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit ME13 is approximately 1.5 miles long and has two ties to Circuits ME11 and ME12. Most of the main line is 336 ACSR. The peak load at the 2023 load level is approximately 125 amps per phase. Except for a small area that is operated at 2.4 kV, no line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit ME14 is approximately 6 miles long and has no ties to other circuits. Most of the first 1.8 miles are 6 CU, the next 0.6 miles are 336 ACSR and then 1.2 miles of 4 CU. Most of the remaining three-phase, vee-phase and single-phase lines are either 2 ACSR or 1/0 ACSR. The peak load at the 2023 load level is approximately 62 amps per phase. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

11.3.7.2 Recommended Plan

Project 352 is a 3.5 mile line relocation project due to a NHDOT highway improvement and widening project. The new line will be three-phase 336 Hendrix cable and will provide a loop to Circuit CH12 of the Center Harbor Substation. This project was included in year 2 of the 2001-2005 Construction Work Plan.

On Circuit ME13, Project 353 is the conversion of old, small conductor, single-phase lines operated at 2.4 kV to single-phase 1/0 tree wire to be operated at 7.2 kV. The conversion is needed to provide additional capacity. This project was included in year 4 of the 2001-2005 Construction Work Plan.

Project ME-3 is the replacement of 1.5 miles of three-phase 4A CWC with three-phase 336 ACSR This portion of the main line is expected to reach the end of its useful life during this planning period. The upgrading of the old, small conductor three-phase line will provide a more reliable line.

Project ME-4 is the replacement of 1.5 miles of three-phase 6 CU with three-phase 336 ACSR This portion of the main line is expected to reach the end of its useful life during this planning period. This line is part of the main feeder and effects the reliability of the entire circuit. The upgrading of the old, small conductor three-phase line will provide a more reliable line.

11.4 Distribution System Reliability

11.4.1 Historical Reliability

The Meredith district reliability has been better than average compared to the NHEC system wide reliability indices. Of the ten districts, Meredith ranked third best overall in terms of the SAIDI index. Historical three-year outage indices by circuit can be seen in the following figure.

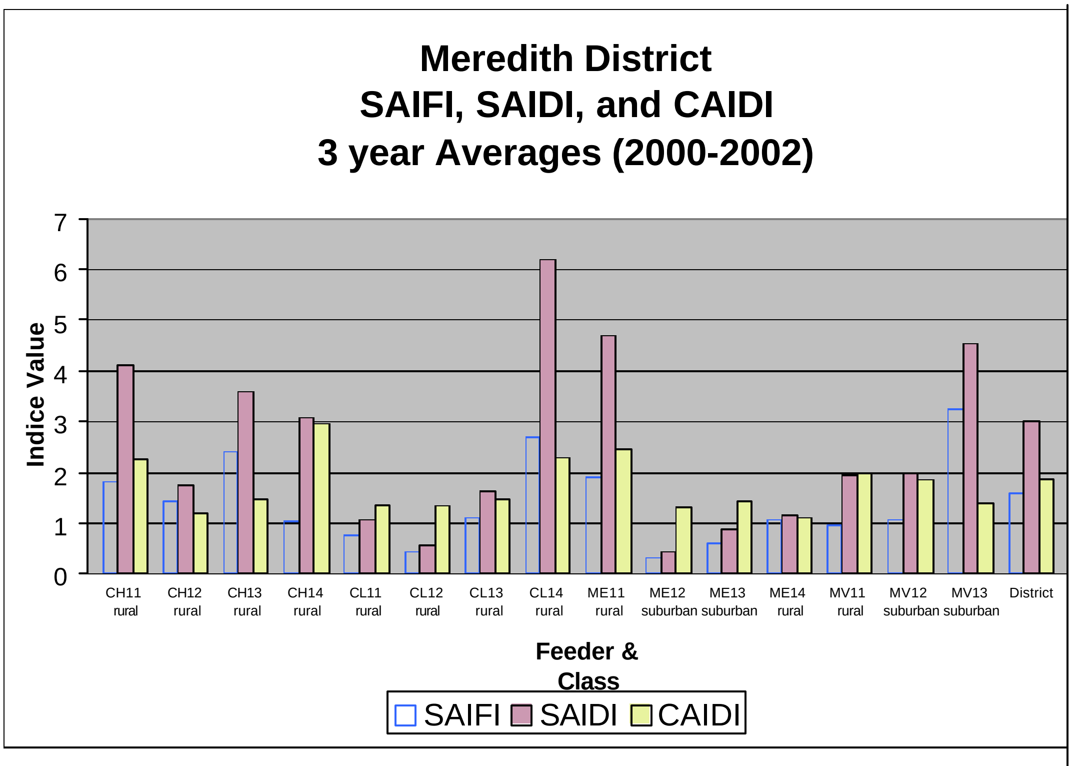


Figure 11-5 Meredith District Average Reliability Indices

11.4.1.1 SAIFI & SAIDI

Out of the fifteen total circuits in the Meredith district, only three exceeded the SAIFI criteria of 2.0, which were circuits CH13, CL14, and MV13. Furthermore, only two circuits, CL14 and MV13, exceeded their SAIDI reliability limits of 5.0 and 3.0, respectively.

11.4.2 Circuits That Exceed Reliability Criteria

11.4.2.1 Circuit CH13

This feeder experienced a SAIFI slightly higher than the 2.0 criteria, but the SAIDI index of 3.59 was within the limits. Outages by cause for the three-year period can be seen in the following figure.

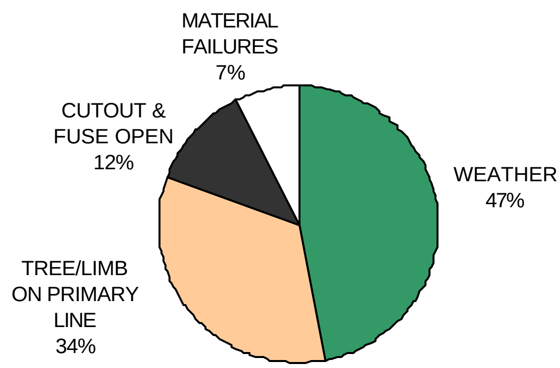


Figure 11-6 Circuit CH13 Percentage of Customer-Minutes Out by Outage Cause

Weather was the major contributor of customer-minutes of outages. Three feeder outages caused about 36% of the total customer-minutes. Two of the three outages were due to weather.

Portions of this circuit will be transferred to other circuits to accompany system configuration changes. For instance, the single-phase taps at the northern extremities of the circuit should be transferred to circuit CH11. This is justified for both load serving, as was discussed in the distribution section 11.3, and reliability reasons. Regarding reliability, the approximate 500 members served in the main second zone of protection on circuit CH13 experienced very poor reliability. There were four outages that caused the main line three-phase recloser to operate at the beginning of the second zone. Investigation into the reliability of circuit CH11 to support the configuration change showed that only one outage occurred within the second zone of protection on circuit CH11. Therefore, projects CH-1, CH-2, CH-3, and the configuration change should improve reliability.

A three-phase tie-line between circuits CH13 and MV13 is scheduled in the 2005 time period as indicated in NHEC's current construction work plan. This tie should improve reliability for major transmission, substation, or main feeder outages on circuit CH13.

11.4.2.2 Circuit CL14

The worst reliability within the Meredith district occurred on this feeder. In 2000 and 2001, reliability was very good with SAIDI indices of 1.2 and 3.1, respectively. Although, the SAIDI index in 2002 was 14.25, which obviously significantly affected the average. Review of 2002 outages indicated that one feeder outage lasting longer than six hours contributed about 4,100 consumer-hours, or about 40% of the outage-minutes in 2002. Furthermore, of the 36 outages in 2002, about five outages of longer duration affected around 200 members per outage event.

Outages by cause are shown in the following figure.

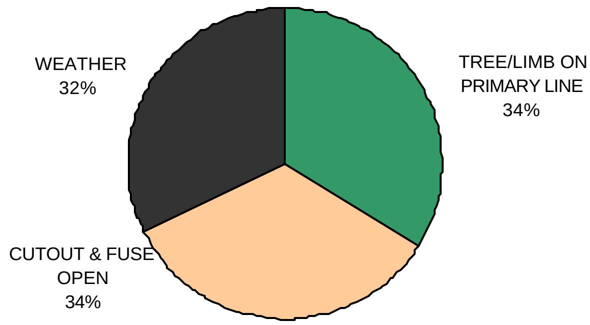


Figure 11-7 Circuit CL14 Percentage of Customer-Minutes Out by Outage Cause

The cutout and fuse open category included the one extreme outage previously discussed. After excluding this outage, the tree and weather cause categories were each responsible for about half of the customer-minutes.

This circuit basically has one large three-phase first and second zone of protection, and another long vee-phase third zone of protection. Each zone contains a few longer single-phase taps off the main lines. The following table shows outage information by zone.

Table 11-13 Circuit CL14 Outage Information by Protection Zone

Protection Zone	Recloser Number	Phase	Outages	%	Customer-Hours	%
1[1]	CL14R	ABC	11	18	6,018	48
2	CL14R11	ABC	10	16	1,571	13
2	CL14R12	AC	10	16	636	5
3[2]	CL14R13	AC	30	50	4,205	34

[1] Figures include extreme feeder outage responsible for 4,100 customer-hours

[2] Figures include two recloser protected taps off the third zone, CL14R14 & CL14R15

The above table indicates that outages within the third zone of protection were a major contributor to the customer-hours of outages. The addition of the third phase as shown in projects CL-5 and CL-6, in addition to proper right-of-way tree clearing, should improve the reliability for the 230 members within this zone.

11.4.2.3 Circuit MV13

Due to the suburban feeder classification for circuit MV13, the SAIDI of 4.54 exceeded the reliability criteria. The SAIFI index of 3.26 greatly exceeded the SAIFI criteria of 2.0. Outage information by cause category is reflected in the following figure.

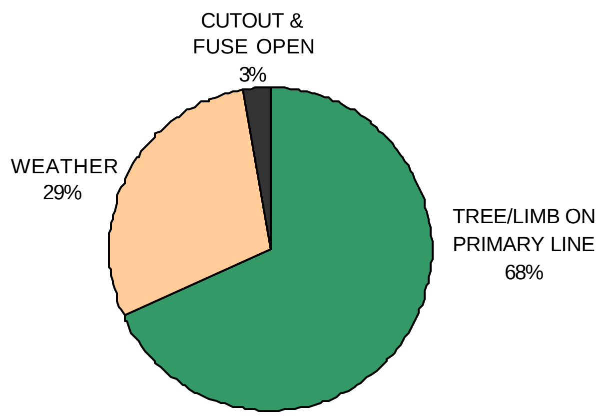


Figure 11-8 Circuit MV13 Percentage of Customer-Minutes Out by Outage Cause

Overwhelmingly, the tree/limb category ranked the highest in percentage of customer-hours of outages. A total of six feeder outages contributed about 53% of the total customer-minutes. Four of these feeder outages were caused by tree contact.

There are major system configuration changes recommended on this circuit. As previously discussed in the Melvin Village substation service area of the distribution Section 11.3, a new fourth circuit, MV14, is proposed. This circuit will serve the Castle Springs bottling plant and the northern portions of the existing circuit MV13, while the Suissevale area continues to be served by circuit MV13. As previously discussed, outages due to trees within the first zone of protection caused major reliability impacts. Therefore, increased right-of-way clearing and tree trimming, or the conversion to tree-wire in persistent trouble areas should be considered. Otherwise, reliability to the Suissevale members will remain poor. The main three-phase feeder of circuit MV14 will be new construction, therefore increasing reliability to Castle Springs bottling plant and existing members at the circuit extremities.

Project MV-R1 is recommended to improve the looped capability to the members served in the Suissevale area. Currently, taps into this area are radial, and the new project will provide a three-phase loop. There have been about 23 outages causing 1,200 customer-hours in the Suissevale area over the last three years.

11.4.3 Circuits That Meet Reliability Criteria

11.4.3.1 Circuit CL12

A three-phase tie-line project CL-R1 is recommended between circuits CL12 and CL13 of the Corliss Hill Substation. Currently, the three-phase taps heading south on circuit CL12 are radial, and the proposed construction will provide looped capability between the two feeders. This area can also be served from the Meredith substation during Corliss Hill substation outages.

11.4.3.2 Circuit ME11

With a SAIDI index of 4.70, the historical reliability on this feeder was very close to exceeding the criterion. This circuit is radial and serves members along the lakeshores of Lake Winnipesaukee. Projects ME-R1 and ME-R2 will provide potential reliability improvement. Project ME-R1, in addition to NHEC's current construction work plan project 344 which should be modified to three-phase construction, will provide a three-phase tie with circuit CH12 which has experienced above average reliability over the last three years. Due to the high number of consumer-hours of outages within the first zone of protection on circuit ME11, future configuration changes to this area should be considered, such as the transfer of members along the lakeshore from circuit ME11 to CH12. Project ME-R2 is simply a single-phase tie-line to provide backup potential to the 230 members in this area.

11.4.3.3 Meredith ME13

Project ME-R3 is a short single-phase tie-line between two long taps off circuits CL12 and ME13. There are also configuration changes recommended in this area as discussed in the Corliss Hill Substation area of Section 11.3. These changes should better balance the load and improve reliability in the area.

11.5 Cost Estimates

A summary of the cost estimates for the proposed 5-Year, 10-Year and 20-Year Plans is provided in Table 11-14. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in Section 11.3 and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 11.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 11-14 Construction Cost Summary

	2004-2008 Cost ($)	2009-2013 Cost ($)	2014-2023 Cost ($)	2004-2023 Cost ($)
New Tie Lines	0	25,000	36,000	61,000
Conversions and Line Changes	1,982,000	653,900	963,825	3,599,725
New Substations, PD's and MP's	0	700,000	0	700,000
Substation, DP and MP Changes	216,000	0	0	216,000
Total	2,198,000	1,378,900	999,825	4,576,725
Projects for Improved Reliability	0	149,000	395,000	544,000

Table 11-15 Substation Load Data Projections

Substation Delivery Point or Meter Point Name	Ckt.	Season	Existing System Configuration 2003 Load kW	2008 Load kW	2013 Load kW	2023 Load kW	Proposed System Configuration 2008 Load kW	2013 Load kW	2023 Load kW
	CH11	W	896	1,001	1,094	1,314	1,001	1,094	2,870
Center Harbor	CH12	W	2,103	2,301	2,519	3,024	2,301	2,519	3,024
	CH13	W	4,500	5,521	6,089	7,391	5,521	3,200	2,330
	CH14	W	3,516	4,099	4,484	5,387	4,099	2,882	3,460
	Sub		11,015	12,922	14,186	17,116	12,922	9,695	11,684
	CL11	W	392	406	420	449	406	420	449
Corliss Hill	CL12	W	3,103	3,237	3,369	3,640	3,237	2,050	2,220
	CL13	W	577	597	618	662	597	1,980	2,140
	CL14	W	1,245	1,291	1,336	1,436	1,291	1,336	1,430
	Sub		5,317	5,531	5,743	6,187	5,531	5,786	6,239
Melvin Village	MV11	W	964	1,050	1,033	1,160	1,050	1,033	1,160
	MV12	W	336	346	356	393	346	356	393
	MV13	W	2,526	3,381	4,241	5,226	3,381	2,340	2,880
	MV14	W	---	---	---	---	---	1,850	2,270
	Sub		3,826	4,777	5,630	6,779	4,777	5,579	6,703
	ME11	W	2,094	2,602	2,904	3,305	2,602	2,904	3,305
Meredith	ME12	W	1,733	1,872	2,007	2,283	1,872	2,007	2,283
	ME13	W	1,990	2,164	2,336	2,683	2,164	2,336	2,683
	ME14	W	989	1,098	1,208	1,428	1,098	1,208	1,350
	Sub		6,806	7,736	8,455	9,699	7,736	8,455	9,621
Moultonborough	MB11	W	---	---	---	---	---	730	880
	MB12	W	---	---	---	---	---	590	710
	MB13	W	---	---	---	---	---	3,080	3,700
	Sub		---	---	---	---	---	4,400	5,290
Meredith District			**26,964**	**30,966**	**34,014**	**39,781**	**30,966**	**33,915**	**39,537**

Table 11-16 Construction Cost Details

(see following 2 pages)

Project Code	YR	Sub/Ckt	Project Description	Reason Code	@ Load (amps) [1]	Miles	Estimated Cost ($)
I. New Tie Lines							
CH-5	2023	C. Harbor / CH13	1ph 1/0 ACSR	D	20	0.5	22,000
CH-6	2013	C. Harbor / CH13	1ph 1/0 AL,UG	D	20	0.5	25,000
MV-8	2023	Melvin V. / MV13	1ph 1/0 AL,UG	D	40	0.2	14,000
	Total New Tie Lines					1.2	61,000
II. Conversions and Line Changes							
343	2004	C. Harbor / CH11	3ph 4 CU to 3ph 336 ACSR Hendrix	WP	-	1.5	180,000
345	2004	C. Harbor / CH11	3ph 3/0 ACSR to 3ph 336 ACSR Hendrix dbl ckt	WP	-	0.5	75,000
342	2005	C. Harbor / CH11	1ph 1/0 AL, UG to 1ph 1/0 AL, UG	WP	-	0.8	100,000
CH-1	2023	C. Harbor / CH11	2ph 1/0 ACSR to 3ph 336 ACSR	B,D	50	2.8	277,200
CH-2	2023	C. Harbor / CH13	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)	C,D,V	40	0.5	7,000
CH-3	2023	C. Harbor / CH13	1ph 1/0 ACSR to 2ph 1/0 ACSR (add 1)	C,D,V	40	0.7	20,125
CH-4	2023	C. Harbor / CH13	3-100 amp voltage regulators	S	-		27,300
339	2004	C. Harbor / CH13	1ph 6 CU to 3ph 336 ACSR Hendrix	WP	-	2.2	210,000
344	2004	C. Harbor / CH12	1ph 6 CU to 1ph 1/0 ACSR Hendrix	WP	-	2.5	250,000
341	2004	C. Harbor / CH14	1ph 4 CU to 3ph 336 ACSR Hendrix	WP	-	2.5	170,000
CH-7	2013	C. Harbor / CH14	Add 2nd circuit 3ph 336 ACSR Hendrix	S	[1]	0.5	50,000
346	2005	C. Harbor / CH14	3ph 2 ACSR to 3ph 336 ACSR Hendrix	WP	-	0.5	100,000
347	2005	C .Harbor / CH14	1ph 1/0 AL, UG to 1ph 1/0 AL, UG	WP	-	1.0	180,000
CL-2	2023	Corliss Hill / CL12	1ph 1/0 ACSR to 3ph 4/0 ACSR	B,C,D	45	1.8	153,000
CL-3	2023	Corliss Hill / CL12	1ph 1/0 ACSR to 3ph 4/0 ACSR	B,C,D	30	0.6	51,000
CL-4	2013	Corliss Hill / CL13	1ph 1/0 ACSR to 3ph 336 ACSR	B,C	[2]	1.5	148,500
349	2006	Corliss Hill / CL14	3ph 1/0 ACSR to 3ph 336 ACSR Hendrix	WP	-	1.5	150,000
CL-5	2023	Corliss Hill / CL14	2ph 4/0 ACSR to 3ph 4/0 ACSR (add 1)	C,D,V	45	1.5	33,000
CL-6	2023	Corliss Hill / CL14	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)	C,D,V	40	3.6	46,800
351	2004	Melvin V. / MV11	3ph 2 CU, 4.2 kV to 3ph 2 CU. 12.5 kV	WP	-	2.5	75,000
MV-1	2008	Melvin V. / MV12	3 ph 4 CU, 4.2 kV to 3ph 1/0 ACSR, 12.5 kV	A,C,V		2.0	142,000
MV-2	2013	Melvin V. / MV14	Add 2nd circuit 3ph 336 ACSR	C,D,V	200	1.2	118,800
MV-3	2013	Melvin V. / MV14	1ph 6A CU to 3ph 336 ACSR	B,C,D,V	200	1.8	178,200
MV-4	2013	Melvin V. / MV14	3ph 1/0 ACSR to 3ph 336 ACSR	B,C,V	200	1.6	158,400
MV-5	2023	Melvin V. / MV14	2 ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)	C,D,V	45	2.0	26,000
MV-6	2023	Melvin V. / MV14	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D,V	30	1.3	37,700
MV-7	2023	Melvin V. / MV14	3-100 amp voltage regulators	S	-		27,300
352	2004	Meredith / ME11	3ph 2 CU to 3ph 336 ACSR	WP	-	3.5	280,000
353	2005	Meredith / ME13	1ph 6 CU,2.4 kV to 1ph 1/0 ACSR,7.2 kV	WP	-	2.0	70,000
ME-3	2023	Meredith / ME12	3ph 4A CU to 3ph 336 ACSR	A	-	1.2	118,800
ME-4	2023	Meredith / ME14	3ph 6A CU to 3ph 336 ACSR	A,C	60	1.4	138,600
	Total Conversions and Line Changes					47.0	3,599,725
III. Projects That Have Potential Reliability Improvement							
CL-R1	2023	Corliss Hill / CL12	3ph 336 ACSR			2.0	192,000
MV-R1	2023	Melvin V. / MV13	2ph 1/0 ACSR to 3ph 336 ACSR			1.7	169,000
ME-R1	2013	Meredith / ME11	2ph 1/0 ACSR to 3ph 336 ACSR			1.5	149,000
ME-R2	2023	Meredith / ME11	1ph 1/0 ACSR			0.5	22,000
ME-R3	2023	Meredith / ME14	1ph 1/0 ACSR			0.2	12,000
	Total Potential Reliability Improvements					5.9	544,000
	TOTAL ALL PROJECTS					54.1	4,204,725
	Total by year for first 4 years (includes reliability projects)						
	2004					15.2	1,240,000
	2005					4.3	450,000
	2006					1.5	150,000
	2007					0.0	0
	2008					2.0	142,000
	2013					8.6	827,900
	2023					22.5	1,394,825
			Total			54.1	4,204,725

Reason Code(s)

A	To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life.
B	To improve **B**ackup between circuits and substations.
C	To provide additional **C**apacity.
D	To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
F	To accommodate **F**uture load.
S	To accommodate new **S**ystem configuration as a result of other projects.
U	To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
V	To improve **V**oltage.
WP	As per NHEC 2001-2005 Construction **W**ork **P**lan.
[1]	Recommended when Moultonborough Substation is installed.
[2]	Recommended when peak load on CL12 reaches 150 amps/phase.

[1] @ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				0.00
2009-2013 Time Period				
MB-1		Moultonborough	34.5-7.2/12.47 kV; 7,500/10,500 kVA Substation	700,000
MB-1	Project MB-1 is recommended when the load on Circuit CH13 reaches 250 amps/phase or when the load on Circuit CH14 reaches 200 amps/phase, whichever comes first.			
2014-2023 Time Period				0.00
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				
CL-1	2004	Corliss Hill	Replace with new 10/14 MVA transformer, 34.5-7.2/12.5	170,000
		Corliss Hill	3-656 amp voltage regulators	46,000
			Total 2002-2008	216,000
2009-2013 Time Period				
2014-2023 Time Period				

Table 11-17 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
MEREDITH	CH11	2000	354	642	531		0.67	1.21	1.81
		2001	1,058	2,054	531		1.99	3.87	1.94
		2002	1,474	3,848	531		2.78	7.25	2.61
	Totals		2,886	6,544	1,593	Average	1.81	4.11	2.27
	CH12	2000	625	1,750	722		0.87	2.42	2.80
		2001	1,259	1,405	722		1.74	1.95	1.12
		2002	1,231	644	722		1.70	0.89	0.52
	Totals		3,115	3,799	2,166	Average	1.44	1.75	1.22
	CH13	2000	2,160	3,406	1,663		1.30	2.05	1.58
		2001	5,182	7,443	1,663		3.12	4.48	1.44
		2002	4,679	7,044	1,663		2.81	4.24	1.51
	Totals		12,021	17,893	4,989	Average	2.41	3.59	1.49
	CH14	2000	1,802	4,030	2,208		0.82	1.83	2.24
		2001	2,300	6,500	2,208		1.04	2.94	2.83
		2002	2,800	9,832	2,208		1.27	4.45	3.51
	Totals		6,902	20,362	6,624	Average	1.04	3.07	2.95
	CL11	2000	76	91	231		0.33	0.39	1.20
		2001	144	193	231		0.62	0.84	1.34
		2002	316	450	231		1.37	1.95	1.42
	Totals		536	734	693	Average	0.77	1.06	1.37
	CL12	2000	230	280	774		0.30	0.36	1.22
		2001	209	211	774		0.27	0.27	1.01
		2002	560	860	774		0.72	1.11	1.54
	Totals		999	1,351	2,322	Average	0.43	0.58	1.35
	CL13	2000	240	330	348		0.69	0.95	1.38
		2001	790	1,230	348		2.27	3.53	1.56
		2002	130	160	348		0.37	0.46	1.23
	Totals		1,160	1,720	1,044	Average	1.11	1.65	1.48
	CL14	2000	420	800	669		0.63	1.20	1.90
		2001	1,630	2,090	669		2.44	3.12	1.28
		2002	3,380	9,535	669		5.05	14.25	2.82
	Totals		5,430	12,425	2,007	Average	2.71	6.19	2.29
	ME11	2000	1,730	5,500	1,662		1.04	3.31	3.18
		2001	3,128	7,834	1,662		1.88	4.71	2.50
		2002	4,685	10,111	1,662		2.82	6.08	2.16
	Totals		9,543	23,445	4,986	Average	1.91	4.70	2.46
	ME12	2000	110	77	565		0.19	0.14	0.70
		2001	190	186	565		0.34	0.33	0.98
		2002	248	453	565		0.44	0.80	1.83
	Totals		548	716	1,695	Average	0.32	0.42	1.31
	ME13	2000	135	152	575		0.23	0.26	1.13
		2001	808	1,032	575		1.41	1.79	1.28
		2002	122	342	575		0.21	0.59	2.80
	Totals		1,065	1,526	1,725	Average	0.62	0.88	1.43
	ME14	2000	276	265	660		0.42	0.40	0.96
		2001	486	557	660		0.74	0.84	1.15
		2002	1,334	1,487	660		2.02	2.25	1.11
	Totals		2,096	2,309	1,980	Average	1.06	1.17	1.10
	MV11	2000	320	450	624		0.51	0.72	1.41
		2001	570	1,090	624		0.91	1.75	1.91
		2002	940	2,100	624		1.51	3.37	2.23
	Totals		1,830	3,640	1,872	Average	0.98	1.94	1.99
	MV12	2000	40	80	78		0.51	1.03	2.00
		2001	120	198	78		1.54	2.54	1.65
		2002	90	187	78		1.15	2.40	2.08
	Totals		250	465	234	Average	1.07	1.99	1.86
	MV13	2000	3,420	4,750	1,242		2.75	3.82	1.39
		2001	5,660	7,220	1,242		4.56	5.81	1.28
		2002	3,050	4,950	1,242		2.46	3.99	1.62
	Totals		12,130	16,920	3,726	Average	3.26	4.54	1.39
	District Total	2000	11,938	22,603	12,552		0.95	1.80	1.89
		2001	23,534	39,243	12,552		1.87	3.13	1.67
		2002	25,039	52,003	12,552		1.99	4.14	2.08
	Totals		60,511	113,849	37,656	Average	1.61	3.02	1.88

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side"Outages).*

12.0 Ossipee District

12.1 Load Analysis

The Ossipee District contains 2 delivery points, which accounted for about 2.8 percent of NHEC's load in 2002. The delivery points of Tamworth and Tuftonboro had respective 2002 peak demands of 1,223 and 3,677 kW. In recent years, Tamworth has been winter peaking, and Tuftonboro summer peaking other than in 2000 when it peaked in winter.

The Tamworth delivery point has about 9.3 percent as many consumers as population in the towns that it serves. Consumer growth is expected to outpace town population growth with an average annual CPR growth rate of 1.7% for the first 10 years, leveling off in the later years for an average annual growth rate of 0.9% over the planning horizon.

Tamworth demand per consumer was 1.60 kW in 2002, which is near the bottom quartile for the 34 NHEC delivery points. The DPC is expected to decrease to about 1.47 kW by 2023, since the new connections will reduce the effect of a large ski area load (King Pine) which is now served. The resultant average annual growth rates over the next two decades are -0.4% for DPC, and 2.1% for peak demands. This reflects rapid consumer growth mitigated by slight decreases in demand per consumer The forecasts of consumers and loads are shown in Table 12-1 and Figure 12-1. Included in the load growth forecast are several loads on Circuit TW11 as shown in Table 12-2.

Table 12-1 Tamworth DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	7,873				
2001	8,018				
2002	8,256	0.0925	764	1.601	1,223
2003	8,422	0.0945	796	1.585	1,262
2004	8,587	0.0964	828	1.571	1,301
2005	8,753	0.0983	861	1.558	1,341
2006	8,917	0.1002	893	1.547	1,382
2007	9,079	0.1019	925	1.537	1,422
2008	9,240	0.1037	958	1.528	1,464
2013	10,038	0.1116	1,121	1.493	1,673
2023	11,618	0.1116	1,297	1.470	1,906
Growth Rates					
2002 - 2003	2.01%	2.13%	4.19%	-0.99%	3.16%
2002 - 2008	1.89%	1.91%	3.84%	-0.78%	3.04%
2002 - 2013	1.79%	1.72%	3.54%	-0.63%	2.89%
2002 - 2023	1.64%	0.90%	2.55%	-0.41%	2.14%

Table 12-2 Tamworth DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Tamworth	TW11	Winsock Village Subdivision	30	30	50
		Winsock Village Subdivision	30	30	50
		27 lot subdivision	15	15	20
		Connor Pond	10	10	10
		Residential	15	15	10
		Residential	100	100	100

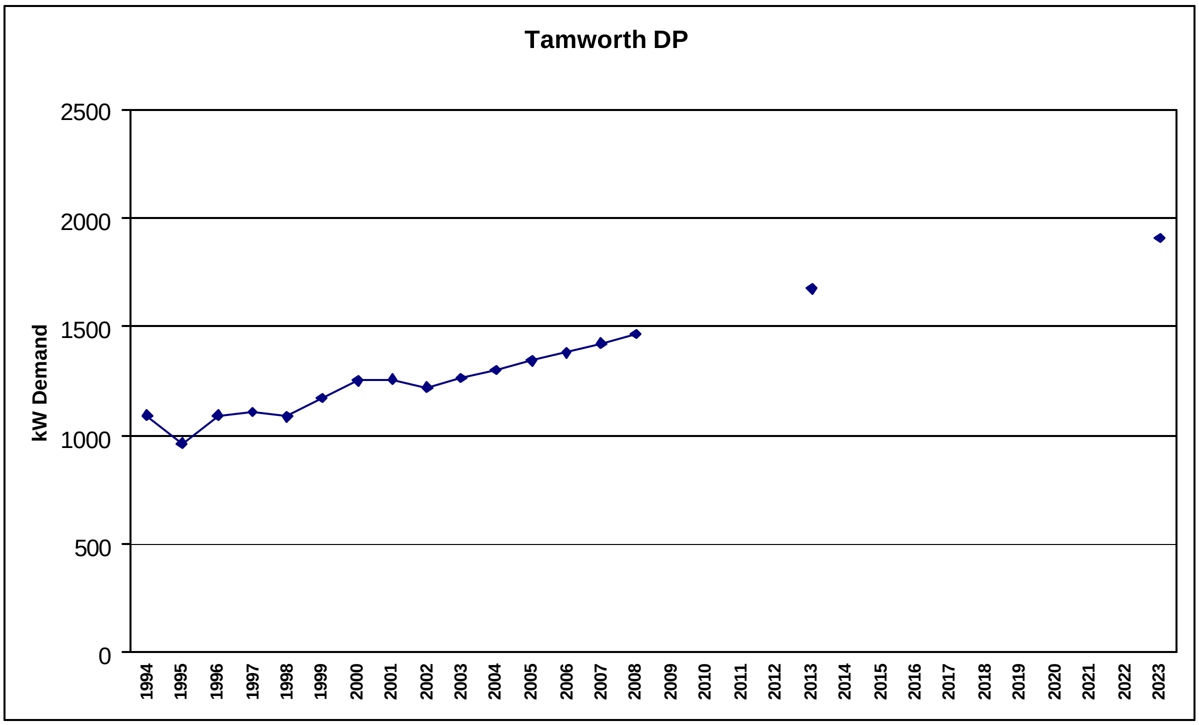


Figure 12-1 Historical and Forecasted Tamworth DP Demands

The Tuftonboro delivery point serves consumers equaling about 12.5 percent of the service area population in 2002. Consumer growth in this service area is expected to slightly outpace town population growth raising the CPR to .13 by 2023. Average annual CPR growth rates of 0.29% over the first ten years, leveling off to an annual average of 0.15% over the twenty year time horizon are predicted. Combined with relatively rapid population growth of 1.8 percent per year, this implies an annual growth rate of 1.9% for consumers served by this delivery point over the next two decades.

Demand per consumer for this delivery point in 2002 was in the lower quartile at about 1.51 kW. The DPC is expected to grow rapidly from 2002-2013, leveling off somewhat in later years. This growth pattern reflects district manager's perception that initially new homes will be larger and existing homes will be adding air-conditioning loads. The 20 year annual average load growth rate is forecasted to be about 2.0% The result of these expected changes is shown in Table 12-3 and Figure 12-2. Included in the load growth forecast are loads on Circuit TF12 and TF13 as shown in Table 12-4.

Table 12-3 Tuftonboro DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	18,571				
2001	18,869				
2002	19,464	0.1252	2,436	1.509	3,677
2003	19,889	0.1256	2,498	1.524	3,806
2004	20,313	0.1260	2,559	1.537	3,933
2005	20,738	0.1264	2,621	1.549	4,061
2006	21,157	0.1268	2,683	1.560	4,186
2007	21,573	0.1272	2,744	1.571	4,311
2008	21,986	0.1276	2,805	1.581	4,434
2013	24,039	0.1293	3,108	1.621	5,039
2023	28,103	0.1293	3,633	1.541	5,600
Growth Rates					
2002 - 2003	2.19%	0.34%	2.53%	0.94%	3.50%
2002 - 2008	2.05%	0.32%	2.38%	0.77%	3.17%
2002 - 2013	1.94%	0.29%	2.24%	0.65%	2.91%
2002 - 2023	1.76%	0.15%	1.92%	0.10%	2.02%

Table 12-4 Tuftonboro DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR 2004-2008	2009-2013	2014-2023
			Load (kW)		
Tuftonboro	TF12	Medium Density Residential	50	50	100
		Neighborhood Business	10	10	10
	TF13	YMCA Camp	50	50	100

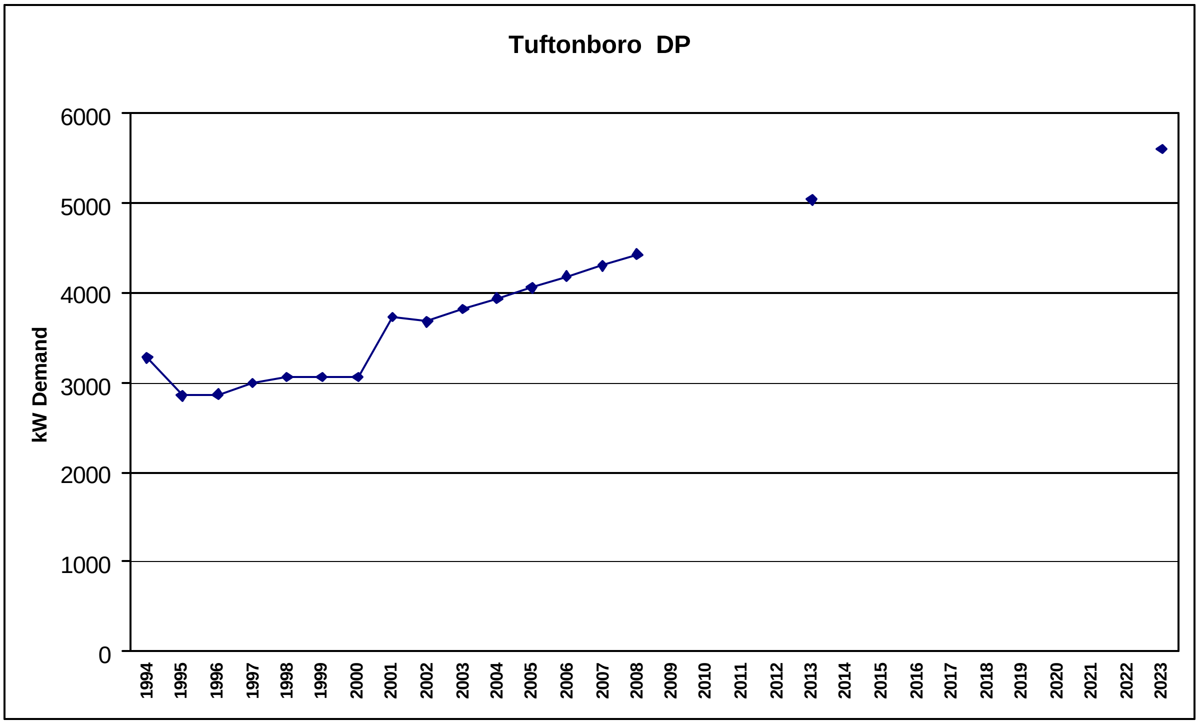


Figure 12-2 Historical and Forecasted Tuftonboro DP Demands

12.2 Transmission System

12.2.1 Bulk Transmission System

PSNH supplies bulk power to the Ossippee District at 34.5 kV from the White Lake Substation. White Lake Substation is supplied by the PSNH 115 kV system with lines from Beebe River Substation and Saco Substation. Currently, the Saco to Central Maine Power (CMP) 115 kV transmission line is operated open because of 115 kV system limitations in both Maine and New Hampshire. In 2004, this line will be closed after CMP upgrades limiting terminal equipment and PSNH completes upgrades at Beebe River Substation and installs reactive power additions to the area's 115 kV system. Although the 115 kV system is now operated radial in this area, closing the SACO-CMP 115 kV interconnection will loop the system and provide two separate 115 kV supply sources to the White Lake Substation in 2004.

12.2.2 34.5 kV Subtransmission System

The Ossippee District is supplied at two delivery points by the PSNH 34.5 kV system from White Lake Substation. White Lake 34.5 kV feeders 346 and 3116X extend southerly from the substation to serve NHEC's Tamworth and Tuftonboro Substations. Area backup support is supplied by PSNH Ashland and Saco Valley Substations.

Substation transformer capacity and base case and future coincident peak load forecasts are shown in Table 12-5 below. For planning purposes, the assumed annual load growth rate for the planning period was 1.48 percent for the summer coincident peak and 0.37 percent in the winter coincident peak loads.

Table 12-5 Ossipee District 34.5 kV System and Load

PSNH Substation	115 – 34.5 kV Transformers Summer Capacity	Winter Capacity	34.5 kV Feeders	Coincident Peak Loads (MVA) Summer 2002	Summer 2023	Winter 2002	Winter 2023
White Lake	1-27, 1-31MVA, 1-21 MW CT	1-34, 1-39 MVA	3	33.8	49.8	32.0	34.1
Saco Valley	1-48	1-54 MVA	3	24.7	36.9	27.6	30.0
Ashland	1-31 MVA	1-41 MVA	2	31.7	34.3	22.4	2.68

12.2.3 Base System Performance

PSNH is forecasting that the larger service area surrounding and including the Ossippee District is and will remain summer peaking. NHEC is projecting that all NHEC loads will remain winter peaking over the planning period.

Base power flow studies for the 2002 and 2023 winter peak indicate there are no deficiencies. For the 2003 summer peak there are low voltages at Wolfboro (0.945). For the 2023 summer peak there are low voltages on the White Lake 346 feeder beginning at Center Ossippee and continuing southerly to the end of the feeder and the 346 feeder is severely overloaded. Summer feeder overloading is expected to begin in 2007 although low feeder voltages begin in 2003.

PSNH plans to reconductor White Lake feeder 346 from Ossippee to Tuftonboro by the 2005 summer. This will solve the summer peak overloading and voltage deficiencies until 2006 when PSNH will first add capacitors 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 need to increase the capacity of the Tuftonboro regulators on feeder 346. In 2119, PSNH will need to extend an additional 34.5 kV line from Tuftonboro to Wolfboro to not exceed the 30 MVA system normal feeder load limit on the White Lake 346 feeder.

12.2.4 Contingency Performance

Transmission reliability will improve in 2004 when the 115 kV system between Maine and New Hampshire is tied together, providing a dual 115 kV supply source to the area and White Lake Substation.

The most serious subtransmission system single contingency outages for the Ossippee District are the outage of the White Lake 346 feeder. The outage of one 115 – 34.5 kV White Lake transformer or 115 kV transmission line after the 115 kV tie to Central Maine Power is re-established will not result in any unserved load. For the 2002 winter and 2003 summer, there are no deficiencies for a first contingency outage.

For 2023 summer and winter peaks, both with and without PSNH upgrades to White Lake feeders 346 and 3116, it is necessary to leave Wolfboro unserved to avoid overloads and low line voltages for a 34.5 kV feeder outage to either 346 or 3116 feeder.

12.2.5 Historical Reliability

A review of the 34.5 kV subtransmission outages for the period of 2000-2002 indicates that NHEC's Tamworth and Tuftonboro Substations have experienced an average of 1.33 and 1.67 outages annually. This is within the NHEC design criteria limits.

12.2.6 Reliability Improvement

Tamworth and Tuftonboro substations are at the extremities of the 34.5 kV subtransmission system from the White Lake Substation to the north and the Ashland/Pemigewasett system from the west. Because of the areas geography and development, there are no other 34.5 kV or 115 kV sources readily available.

PSNH's plan to extend a second 34.5 kV circuit, White Lake feeder 3116, south and roughly parallel to the existing 346 feeder will provide backup to Tuftonboro. Tamworth Substation is already looped.

However, first contingency deficiencies exist in the adjacent Meredith District, which cannot be easily addressed. A need for first contingency capability is not in the PSNH 34.5 kV design criteria although it is implicit in NHEC's design criteria where reasonable. An alternate reliability improvement plan is presented for the Meredith District which includes extending a radial 115 kV transmission line southerly from White Lake Substation to a new 115–34.5 kV substation at Tuftonboro. This alternative would provide for full first contingency capability for the Meredith District and the Ossippee District substations. Please refer to the Meredith District section for a discussion of this alternative.

12.3 Distribution System

12.3.1 General

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 12.4, Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 12.0 shows the 2003, 2008, 2013 and 2023 peak load levels for each substation, DP, MP and circuit using the existing system configuration and proposed system configuration.

12.3.2 New Substations, DP's and MP's

No new substations, delivery points or meter points are required in the Ossipee District during this 20-year planning period.

12.3.3 Substation, DP and MP Changes

The following table shows the projected kW for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for backup or for the ordinary replacement of aged transformers are shown in [**bold**]. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 12-6 Substation Transformer and Regulator Data

Name	Transformer							Voltage Regulator		
	Rating (kVA)					Est. Load (kW)	Capacity (%)	Size (AMP)	Est. Load (AMP)	Capacity (%)
	OA 55°	FA 55°	OA 65°	FA 65°	Win Season					
Tamworth DP [1]	2,500	3,125	2,800	3,500	3,080	1,915	63	--	100	--
Tuftonboro Sub	5,000	--	--	--	5,500	5,613	104	328	292	89
Tuftonboro Sub [2]	**5,000**	**6,250**	**5,600**	**7,000**	**7,700**	5,613	74	328	292	89

[1] Fans are not installed.

[2] Upgrade to replace aged equipment. Project TF-1.

Project TF-1 is the replacement of the existing 3-1,667 kVA transformers with a new 5/7 MVA transformer. The existing transformers were purchased in 1968 and replacement due to age is expected.

No conversion to a different distribution system operating voltage is recommended at any of the substations or delivery points. The distribution operating voltage is to remain at 7.2/12.47 kV.

12.3.4 Tamworth Delivery Point Service Area

12.3.4.1 Existing System Review

The Tamworth Delivery Point is forecasted to serve 1.9 MW of peak load in 2023. The Tamworth area is served by one 7.2/12.47 kV three-phase circuit (TW11). No voltage regulators are installed at the DP.

Circuit TX11 splits into northeast and south feeders approximately 0.9 miles from the DP. The northeast feeder continues with three-phase for another 9 miles and then vee-phase for 0.5 miles and then single-phase for about another 6 miles. The south feeder continues with three-phase for another 0.5 miles and then vee-phase for 1.5 miles and then single-phase for about another 6 miles. Neither of the feeders have a tie to another circuit.

The first 0.9 miles of Circuit TX11 are mostly 2A CWC. The northeast three-phase is 3/0 ACSR and the main vee-phase and single-phase lines are 1/0 ACSR. Voltage regulators are installed in the three-phase line approximately 5 miles from the DP. On the south feeder, the three-phase, vee-phase and most of the single-phase lines are 1/0 ACSR.

No major line capacity deficiencies or areas with low voltage are anticipated during this planning period provided the voltage at the DP is 122 volts or higher.

12.3.4.2 Recommended Plan

Project 354 is the replacement of 0.5 miles of an old single-phase line with single-phase 1/0 tree wire. The existing poles are in poor condition and the line is difficult to access. The new line will be constructed along road right-of-way. This project was included in year 1 of the 2001-2005 Construction Work Plan.

Project 355 is the replacement of 1.4 miles of old vee-phase bare concentric neutral 1/0 aluminum underground cable with new vee-phase 1/0 aluminum jacketed cable. The existing cable is in poor physical condition. The new line will be more accessible and will improve reliability. This project was included in year 1 of the 2001-2005 Construction Work Plan.

Project 356 is the replacement of 1.7 miles of old single-phase bare concentric neutral 1/0 aluminum underground cable with new single-phase 1/0 aluminum jacketed cable. The existing cable is in poor physical condition. The new lines will be looped to improve reliability. This project was included in year 1 of the 2001-2005 Construction Work Plan.

Project 357 is the replacement of 0.9 miles of an old three-phase 2A CWC line with a three-phase 336 Hendrix cable line. The existing line has reached the end of its useful life. This project was included in year 4 of the 2001-2005 Construction Work Plan.

Project TW-1 is the conversion of a vee-phase and single-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding phase conductors to the existing line. This 1.1 mile three-phase extension will improve voltage at the end of the line by improving load balance along the three-phase main line and will improve reliability by dividing the load over additional phases. Also, several phase changes on single-phase taps are recommended to further improve load balance and voltage at the end of the circuit.

Project TW-2 is the addition of a 100-amp line voltage regulator.

12.3.5 Tuftonboro Substation Service Area

12.3.5.1 Existing System Review

The Tuftonboro Substation is forecasted to serve 5.6 MW of peak load in 2023. The Tuftonboro area is served by two circuits: TF12 and TF13. Circuit TF12 serves approximately 48 percent of the total load with TF13 serving the remaining 52 percent.

Circuit TF12 is approximately 8 miles long and has a tie to Circuit MV11 of the Melvin Village Substation in the Meredith District. At the present time, however, this tie is not effective due to part of Circuit MV11 being operated at 2.4/4.16 kV. Converting this line to 7.2/12.24 kV is included in the 2001-2005 Construction Work Plan. The main three-phase line is approximately 6.7 miles long. The first 5 miles are 336 ACSR and the last 1.7 miles are 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

On Circuit TF13, the three-phase feeder main is about 13 miles long and then splits into northeast and southeast feeders. The northeast three-phase feeder continues for another 0.9 miles, then vee-phase for 2.5 miles and then single-phase for about 3 miles. The southeast three-phase feeder continues for 2.6 miles and then single-phase for another 5.6 miles. The 13 mile feeder main consist of 6 miles of 336 ACSR and 7 miles of 1/0 ACSR. The northeast and southeast feeders are mostly 1/0 ACSR. Two sets of voltage regulators are installed in the main line. The first set is approximately 6 miles from the substation and the second set is approximately 12 miles from the substation. No three-phase line capacity problems are anticipated during this planning period. The 2023 peak load on several single-phase lines is approaching or exceeds the maximum design limit of 50 amps and the line is therefore considered to have a capacity deficiency.

12.3.5.2 Recommended Plan

On Circuit TF12, Projects 358 and 360 are related to the conversion of old single-phase 6 CU lines operated at 2.4 kV to single-phase 1/0 lines to be operated at 7.2 kV. The existing lines are in poor physical condition. Project 358 was included in year 1 of the 2001-2005 Construction Work Plan and Project 360 was in year 4.

On Circuit TF13, Project 359 is the relocation of the existing three-phase 336 ACSR line. A road improvement project has made the existing line difficult to access. The new line will be located along road right-of-way. This 0.6-mile project was included in year 1 of the 2001-2005 Construction Work Plan.

Project TF-2 will provide additional capacity by converting the single-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 44 amps of peak load at the 2023 load level. The three-phase line is to be extended 0.9 miles so that single-phase taps can balance the load on the three-phase line.

Project TF-3 will provide additional capacity by converting the single-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 50 amps of peak load at the 2023 load level. The three-phase line is to be extended 1.8 miles so that single-phase taps can balance the load on the three-phase line.

12.4 Distribution System Reliability

12.4.1 Historical Reliability

The overall reliability in the Ossipee district throughout 2000-2002 has been much better than the NHEC system average, ranking the second best of all NHEC districts. The following figure shows the reliability for each of the Ossipee district feeders, as well as the district total.

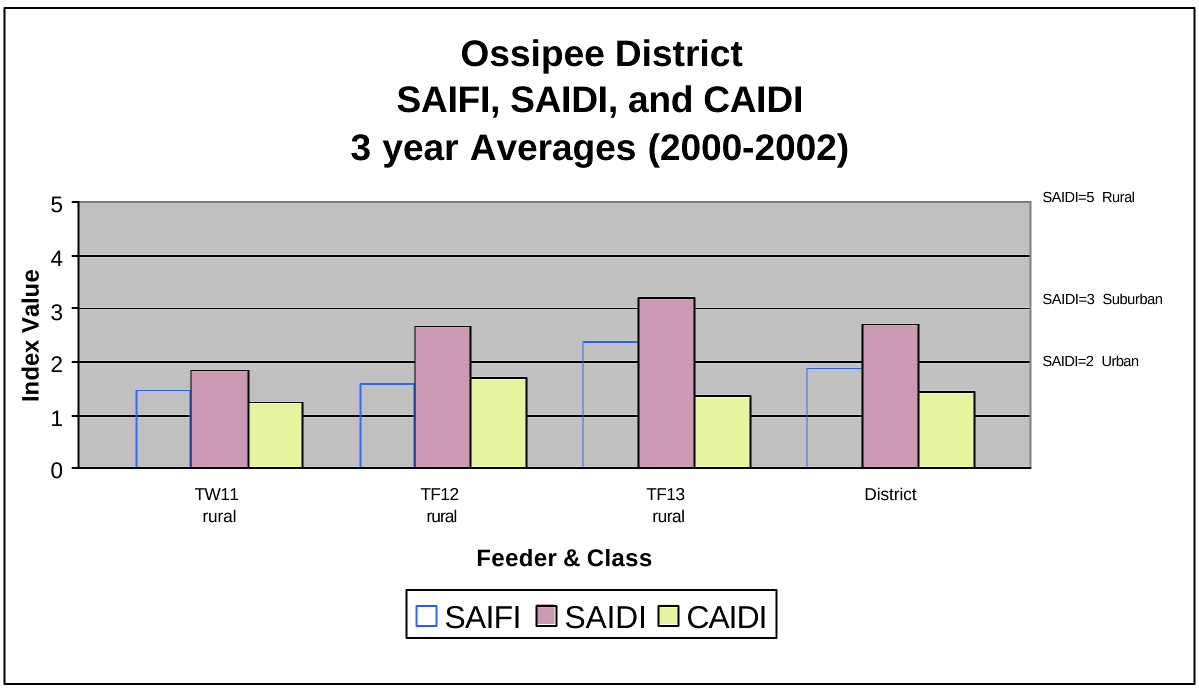


Figure 12-3 Ossipee District Average Reliability Indices

12.4.2 SAIFI & SAIDI

All feeders were within the SAIDI reliability criteria of 5.0 for rural classified feeders. The only feeder that exceeded the SAIFI criteria of 2.0 was TF13, which had a SAIFI value of 2.38.

12.4.3 Circuits That Exceed Reliability Criteria

12.4.3.1 Circuit TF13

This is the longest circuit in the Ossipee District, but still was well within the SAIDI reliability criteria with a value of 3.23. Outages by cause category can be seen in the following figure.

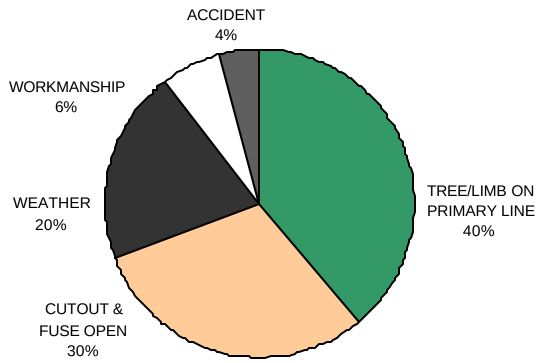


Figure 12-4 Circuit TF13 Percentage of Customer-Minutes Out by Outage Cause

The majority of customer-minutes of outage were due to tree contact and the operating of fuse links in cutouts.

Due to the length of this circuit, a breakdown of outage information by major three-phase overcurrent protection zone is illustrated in the following table.

Table 12-7 Circuit TF13 Outage Information by Protection Zone

Protection Zone[1]	Recloser Number	Phase	Outages	%	Consumer-Hours	%
1	TF13R	ABC	13	22	2,554	31
2	TF13R11	ABC	3	5	941	11
3	TF13R15	ABC	13	22	901	10
4	TF13R16	ABC	17	28	2,885	35
4	TF13R17	ABC	14	23	1,050	13

[1] Recloser-to-recloser, excluding fuses.

Note: Figures do not include outages on recloser protected single-phase taps off the main three-phase zones.

There were only two feeder outages that occurred in the first zone of protection affecting all members on the circuit. The above figures do not indicate any excessive outage rates within the first three zones of protection, although recloser number TF13R16 in the fourth protection zone accumulated almost 3,000 consumer-hours of outages over the 2000-2002 period. On average, each outage in this zone affected more than 100 members, and averaged almost 1.5 hours.

Therefore, it is recommended that an overcurrent protection update and detailed outage analysis be performed for this area to determine potential reliability improvements.

Projects TF-R1, TF-R2, and TF-R3 are proposed to enable backup for the existing long single-phase taps on circuit TF13. A new normal-open switch location should be considered once project TF-R1 is implemented to improve voltage in this area.

12.4.4 Circuits That Meet Reliability Criteria

12.4.4.1 Circuit TF12

This circuit has been well within the reliability criteria over the 2000-2002 period. The top two outages that affected the most members were entire feeder outages affecting 1,066 and 1,017 members, while the third highest member-count outage only affected 115 members. This indicates that the feeder overcurrent protection configuration is adequate, and the main three-phase lines have satisfactory clearances. Furthermore, circuit TF12 forms a tie with circuit MV11 of the Melvin Village Substation in the Meredith District, which will provide contingency capability during major outages on circuit TF12 once the voltage conversion project, 4160 V to 12.5 kV, is completed on circuit MV11.

There are no proposed distribution construction projects for reliability purposes on circuit TF12.

12.4.4.2 Circuit TW11

Circuit TW11 had the best reliability in the Ossipee District. This circuit splits into northeast and south feeders approximately 0.9 miles from the delivery point. The northeast feeder has had great reliability, while the south feeder has contributed to over 67% of the consumer-hours of outage on circuit TW11. Furthermore, the northeast feeder is almost three times the length of the south feeder. A review of the outages also indicates that there were four events that affected the majority of the 310 members served on the south feeder. This indicates that either the outages are occurring within the first zone of protection on this south feeder, or the overcurrent devices are not properly coordinated.

There are no proposed distribution construction projects for reliability purposes on circuit TW11.

12.5 Cost Estimates

A summary of the cost estimates for the proposed 5-Year, 10-Year and 20-Year Plans is provided in Table 12-8. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in Section 12.3 and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 12.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 12-8 Construction Cost Summary

	2004-2008 Cost ($)	2009-2013 Cost ($)	2014-2023 Cost ($)	2004-2023 Cost ($)
New Tie Lines	0	0	0	0
Conversions and Line Changes	566,100	0	110,000	676,100
New Substations, DP's and MP's	0	0	120,000	120,000
Substation, DP and MP Changes	0	0	0	0
Total	566,100	0	230,000	796,100
Projects for Improved Reliability	44,000	80,000	33,000	157,000

Table 12-9 Substation Load Data Projections

Substation			Existing System Configuration				Proposed System Configuration		
Delivery Point			2003	2008	2013	2023	2008	2013	2023
or Meter Point			Load	Load	Load	Load	Load	Load	Load
Name	Ckt.	Season	kW	kW	kW	kW	kW	kW	kW
Tamworth	TW11	W	1,236	1,446	1,659	1,915	1,446	1,659	1,915
55 deg. w/o fans	Sub	W	1,236	1,446	1,659	1,915	1,446	1,659	1,915
Tuftonboro	TF12	W	1,826	2,122	2,407	2,678	2,122	2,407	2,678
2500/3500 kVA	TF13	W	1,983	2,266	2,640	2,935	2,266	2,640	2,935
65 deg. w/fans	Sub		3,809	4,388	5,047	5,613	4,388	5,047	5,613
Ossipee District			**5,045**	**5,834**	**6,706**	**7,528**	**5,834**	**6,706**	**7,528**

Table 12-10 Construction Cost Details

(see following 2 pages)

I. New Tie Lines							
			NONE				
	Total New Tie Lines					0.00	0
II. Conversions and Line Changes							
354	2004	Tamworth/TW11	1ph 1/0 ACSR, 2.4 kV to 1ph 1/0 tree wire, 7.2 kV	WP	-	0.50	30,000
355	2004	Tamworth/TW11	2ph 1/0 AL, UG to 2ph 1/0 AL, UG	WP	-	1.40	100,000
356	2004	Tamworth/TW11	1ph 1/0 AL, UG to 1ph 1/0 AL, UG	WP	-	1.70	240,000
357	2005	Tamworth/TW11	3ph 2A CU to 3ph 336 ACSR Hendrix	WP	-	0.90	72,000
TW-1	2023	Tamworth/TW11	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,V	30	1.10	32,000
TW-2	2008	Tamworth/TW11	1-100 amp voltage regulator	V	30	-	9,100
358	2004	Tuftonboro/TF12	1ph 6 CU, 2.4 kV to 1ph 1/0 tree wire, 7.2 kV	WP	-	0.40	25,000
360	2005	Tuftonboro/TF12	1ph 6, 2.4 kV to 1ph 1/0 tree wire, 7.2 kV	WP	-	0.50	30,000
359	2004	Tuftonboro/TF13	3 ph 336 ACSR to 3ph 336 ACSR	WP	-	0.60	60,000
TF-2	2023	Tuftonboro/TF13	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,V	45	0.90	26,000
TF-3	2023	Tuftonboro/TF13	1ph 1/0 ACSR tp 3ph 1/0 ACSR (add 2)	C,V	45	1.80	52,000
	Total Conversions and Line Changes					9.80	676,100
III. Projects that have Potential Reliability Improvement							
TF-R1	2008	Tuftonboro/TF13	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)			1.00	44,000
TF-R2	2023	Tuftonboro/TF13	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)			0.60	33,000
TF-R3	2013	Tuftonboro/TF13	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)			1.80	80,000
	Total Potential Reliablilty Improvements					3.40	157,000
	Total of all projects					13.20	833,100
	Total by year for first 4 years (includes reliability projects)						
	2004					4.60	455,000
	2005					1.40	102,000
	2006					0.00	0
	2007					0.00	0
	2008					1.00	53,100
	2013					1.80	80,000
	2023					4.40	143,000
			Total			13.20	833,100

Reason Code(s)

A	To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life.
B	To improve **B**ackup between circuits and substations.
C	To provide additional **C**apacity.
D	To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
F	To accommodate **F**uture load.
S	To accommodate new **S**ystem configuration as a result of other projects.
U	To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
V	To improve **V**oltage.
WP	As per NHEC 2001-2005 Construction **W**ork **P**lan.
1	@ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				
			None	
2009-2013 Time Period				
			None	
2014-2023 Time Period				
			None	
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				
			None	
2009-2013 Time Period				
			None	
2014-2023 Time Period				
TF-1	2023	Tuftonboro	Replace with new 5/7 MVA transformer, 34.5-7.2/12.5 kV	120,000

Table 12-11 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
OSSIPEE	TW11	2000	1,380	1,550	671		2.06	2.31	1.12
		2001	560	1,012	671		0.83	1.51	1.81
		2002	1,000	1,100	671		1.49	1.64	1.10
	Totals		2,940	3,662	2,013	Average	1.46	1.82	1.25
	TF12	2000	560	1,250	946		0.59	1.32	2.23
		2001	2,015	2,500	946		2.13	2.64	1.24
		2002	1,900	3,870	946		2.01	4.09	2.04
	Totals		4,475	7,620	2,838	Average	1.58	2.68	1.70
	TF13	2000	1,500	1,770	1,073		1.40	1.65	1.18
		2001	3,420	5,030	1,073		3.19	4.69	1.47
		2002	2,730	3,610	1,073		2.54	3.36	1.32
	Totals		7,650	10,410	3,219	Average	2.38	3.23	1.36
	District Total	2000	3,440	4,570	2,690		1.28	1.70	1.33
		2001	5,995	8,542	2,690		2.23	3.18	1.42
		2002	5,630	8,580	2,690		2.09	3.19	1.52
	Totals		15,065	21,692	8,070	Average	1.87	2.69	1.44

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side"Outages).*

13.0 Plymouth District

13.1 Load Analysis

The Plymouth District contains 7 delivery points, which accounted for nearly one-third of NHEC's load in 2002. The delivery points of Bridgewater, Plymouth 1, Plymouth 2, Woodstock, Lyme, Rumney, and Thorton, had respective 2002 peak demands of 4,442, 2,086, 6,741, 21,958, 1,052, 5,692, and 16,157 kW. All of these delivery points have been winter peaking in the last four years with the exceptions of Plymouth 1 that peaked in the fall of 2002 and 2001, and Rumney which peaked in summer during 2001.

The Bridgewater delivery point has about 15 percent as many consumers as population in the towns that it serves. Consumer growth is expected to match population growth, at an average annual rate of 0.9% over the 20 year forecast period. Demand per consumer was 1.6 kW in 2002 which is below average for NHEC delivery points. With new connections expected to be slightly higher than the 2002 average, the DPC is forecasted to grow at an annualized rate of about 0.1% over the forecast horizon. The corresponding annual peak load growth would then be about 1.0% over the 20 period.

The forecasts of consumers and loads are shown in Table 13-1 and Figure 13-1. Included in the load growth forecast is a spot load on the BW11 Circuit as shown in Table 13-2.

Table 13-1 Bridgewater DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	18,016				
2001	18,466				
2002	18,573	0.1460	2,711	1.639	4,442
2003	18,754	0.1460	2,737	1.640	4,488
2004	18,935	0.1460	2,764	1.641	4,535
2005	19,120	0.1460	2,791	1.642	4,582
2006	19,301	0.1460	2,817	1.643	4,629
2007	19,482	0.1460	2,844	1.644	4,675
2008	19,666	0.1460	2,871	1.645	4,722
2013	20,597	0.1460	3,006	1.650	4,961
2023	22,549	0.1460	3,291	1.658	5,458
Growth Rates					
2002 - 2003	0.97%	0.00%	0.97%	0.07%	1.04%
2002 - 2008	0.96%	0.00%	0.96%	0.07%	1.03%
2002 - 2013	0.94%	0.00%	0.94%	0.06%	1.01%
2002 - 2023	0.93%	0.00%	0.93%	0.06%	0.99%

Table 13-2 Bridgewater DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Bridgewater	BW11	Housing (30 lots)	15	15	30

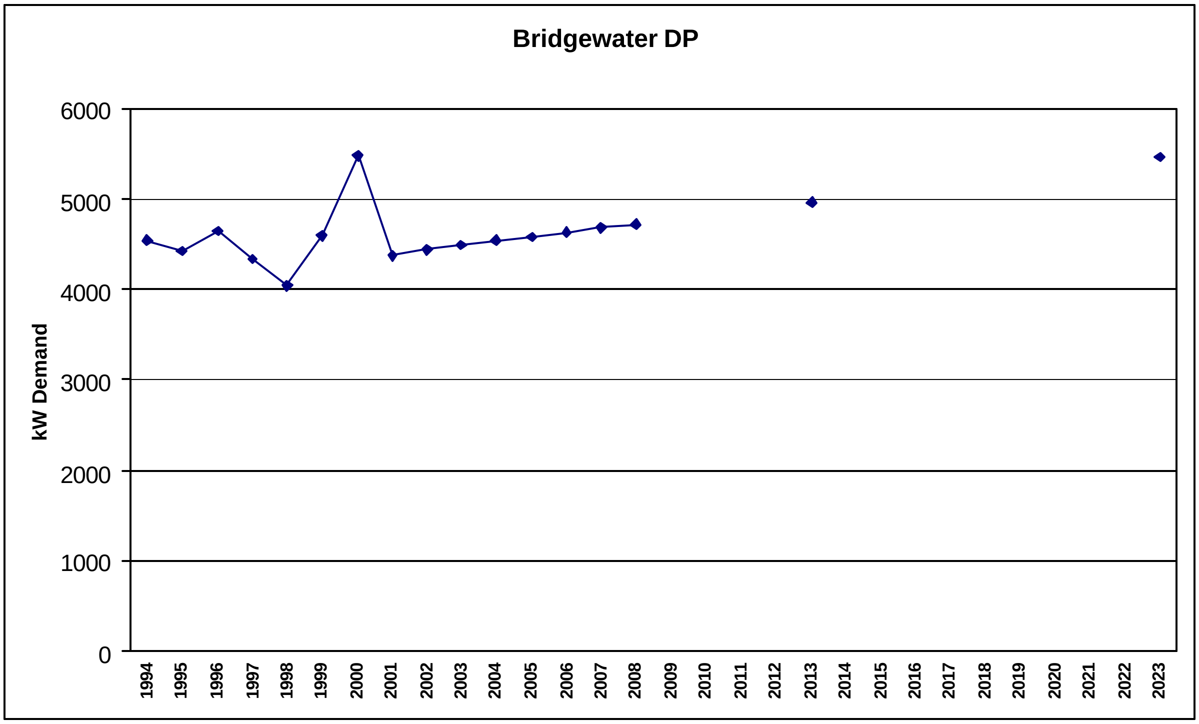


Figure 13-1 Historical and Forecasted Bridgewater DP Demands

The Plymouth 1 delivery point serves 14 percent as many consumers as population in the towns that it serves. Consumer growth is expected to match population growth, at an annualized rate of about 0.6 % over the 20 year time period. Demand per consumer was about 1.8 kW in 2002, which is below average for the NHEC delivery points. Over the 20 year forecast horizon, with a nearly static DPC, load growth is forecasted to match population at about 0.6%.

The forecasts of consumers and loads are shown in Table 13-3 and Figure 13-2. In addition to the base load growth forecast a spot load on the GS44 Circuit has been added as described in Table 13-4.

Table 13-3 Plymouth 1 DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	7,822				
2001	8,112				
2002	8,101	0.1423	1,153	1.809	2,086
2003	8,151	0.1423	1,160	1.809	2,099
2004	8,202	0.1423	1,167	1.809	2,112
2005	8,254	0.1423	1,175	1.809	2,125
2006	8,305	0.1423	1,182	1.809	2,138
2007	8,357	0.1423	1,189	1.809	2,151
2008	8,409	0.1423	1,197	1.809	2,165
2022	8,681	0.1423	1,235	1.808	2,234
2023	9,269	0.1423	1,319	1.807	2,384
Growth Rates					
2002 - 2003	0.62%	0.00%	0.62%	-0.01%	0.61%
2002 - 2008	0.62%	0.00%	0.62%	-0.01%	0.62%
2002 - 2013	0.63%	0.00%	0.63%	-0.01%	0.62%
2002 - 2023	0.64%	0.00%	0.64%	-0.01%	0.64%

Table 13-4 Plymouth 1 DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Green Street	GS44	Plymouth College**	100	100	150
** In addition to base forecast					

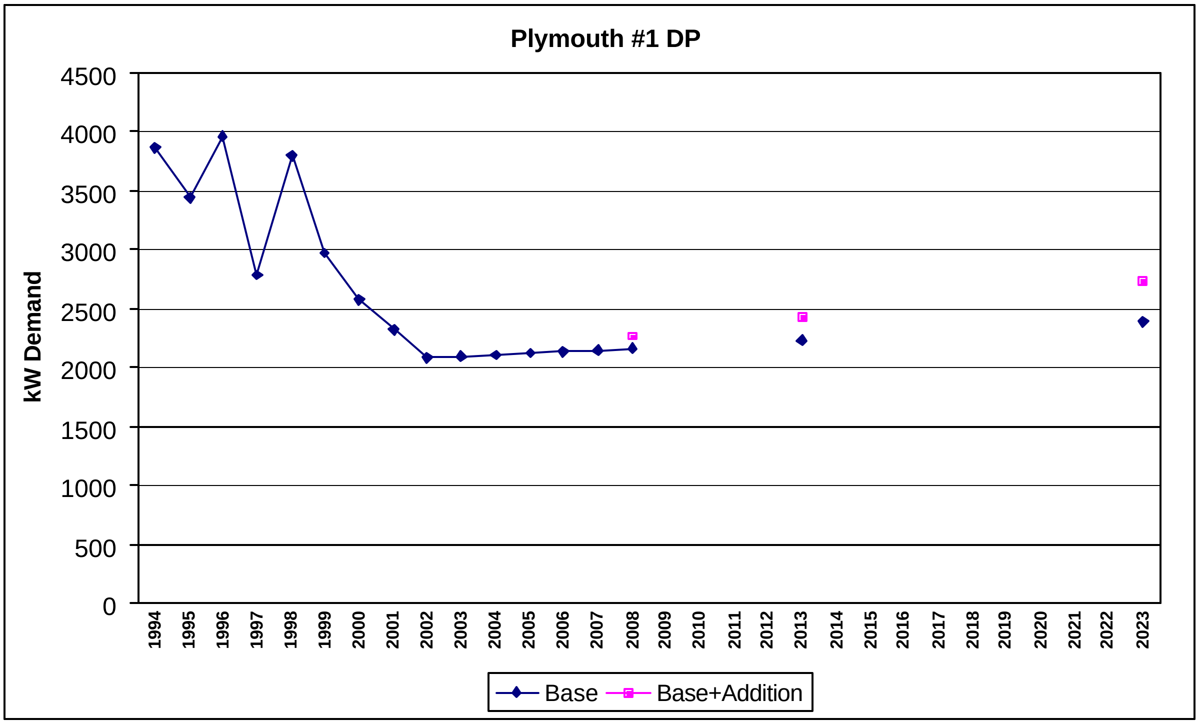


Figure 13-2 Historical and Forecasted Plymouth 1 DP Demands

The Plymouth 2 delivery point has about 18 percent as many consumers as population in the towns that it serves. Consumer growth is expected to exceed population growth, particularly during the first five years. The corresponding annualized CPR growth rate through 2008 is expected to be about 0.5% compared to a rate of 0.3% over the 20 year forecast horizon.

With many large commercial businesses, demand per consumer was about 3.0 kW in 2002, the seventh highest of all NHEC delivery points. During the first 10 year period, little change in the DPC is expected. As more loads are added with lower per consumer demands, however, the average DPC declines. The average rate of change over the next two decades is -0.2%. Annualized load growth of about 1.3% is forecasted through 2008 compared to a growth rate of about 0.9% over the 20 year period.

The forecasts of consumers and loads are shown in Table 13-5 and Figure 13-3. A number of spot loads are expected on the FG14 Circuit as shown in Table 13-6.

Table 13-5 Plymouth 2 DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	12,480				
2001	12,871				
2002	12,871	0.1771	2,280	2.957	6,741
2003	12,968	0.1781	2,310	2.958	6,831
2004	13,066	0.1791	2,340	2.959	6,923
2005	13,166	0.1801	2,371	2.960	7,018
2006	13,265	0.1810	2,402	2.961	7,111
2007	13,364	0.1820	2,432	2.962	7,204
2008	13,465	0.1830	2,464	2.963	7,300
2022	13,983	0.1848	2,584	2.966	7,666
2023	15,093	0.1885	2,845	2.836	8,069
Growth Rates					
2002 - 2003	0.75%	0.55%	1.30%	0.04%	1.34%
2002 - 2008	0.75%	0.54%	1.30%	0.04%	1.34%
2002 - 2013	0.76%	0.39%	1.15%	0.03%	1.18%
2002 - 2023	0.76%	0.30%	1.06%	-0.20%	0.86%

Table 13-6 Plymouth 2 DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Fairgrounds	FG14	Walmart	600		
		Burger King	150		
		Tenney Mtn Ski	500		
		Tenney Mtn Ski**	1000		
		Townhouses	40		
		Residential (9 homes)	20		10
		Residential (9 homes)	20		10
		Residential (9 homes)	20		10
** In addition to base forecast					

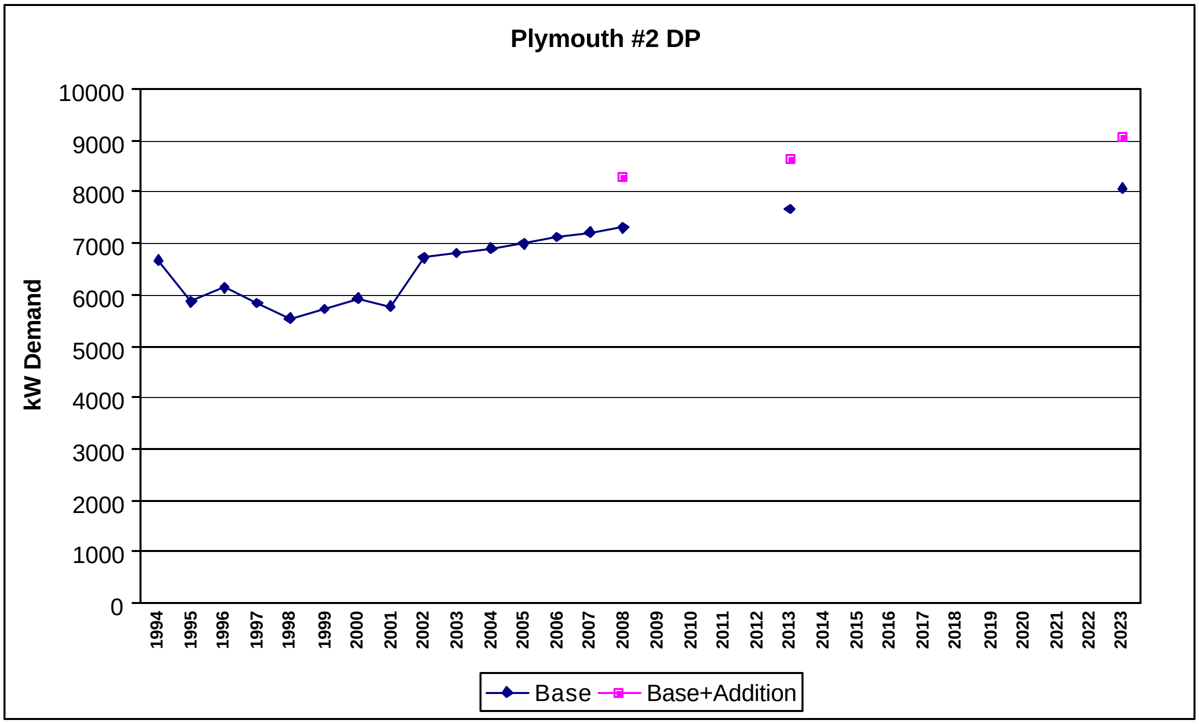


Figure 13-3 Historical and Forecasted Plymouth 2 DP Demands

The Woodstock delivery point has about 152% as many consumers as population in the towns that it serves. This extraordinary figure comes from the fact that many of the homes in the area are secondary residences and therefore not included in the population count. Consumer growth is expected to exceed population growth, particularly through 2013. The corresponding annualized CPR growth rate through 2013 is expected to be about 0.14% compared to an annualized rate of 0.10% over the 20 year time period.

With the Loon Mountain ski area included, demand per consumer for this delivery point was about 5.4 kW in 2002, the second highest of all NHEC delivery points. The DPC is expected to grow at an average annual rate of about 0.6% through 2008 compared to an annual average of about 0.2% over the 20 year period. During the same time periods, peak loads are expected to grow at annual rates of 1.2% and 0.8% respectively. This reflects the expectation of continued growth at the ski resort and the surrounding residences.

The forecasts of consumers and loads are shown in Table 13-7 and Figure 13-4. Spot loads on a new circuit are as shown in Table 13-8.

Table 13-7 Woodstock DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	2,667				
2001	2,695				
2002	2,687	1.5206	4,085	5.375	21,958
2003	2,698	1.5227	4,109	5.406	22,210
2004	2,710	1.5250	4,133	5.436	22,468
2005	2,723	1.5273	4,159	5.467	22,736
2006	2,735	1.5295	4,183	5.497	22,995
2007	2,747	1.5317	4,208	5.527	23,256
2008	2,760	1.5340	4,234	5.557	23,527
2022	2,826	1.5434	4,362	5.607	24,454
2023	2,973	1.5532	4,618	5.593	25,824
Growth Rates					
2002 - 2003	0.44%	0.14%	0.58%	0.56%	1.15%
2002 - 2008	0.45%	0.15%	0.60%	0.55%	1.16%
2002 - 2013	0.46%	0.14%	0.60%	0.38%	0.98%
2002 - 2023	0.48%	0.10%	0.59%	0.19%	0.78%

Table 13-8 Woodstock DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Lincoln	*	Loon Mtn. South **	1300	500	200
* This load will need to be served from a new circuit ** In addition to base forecast					

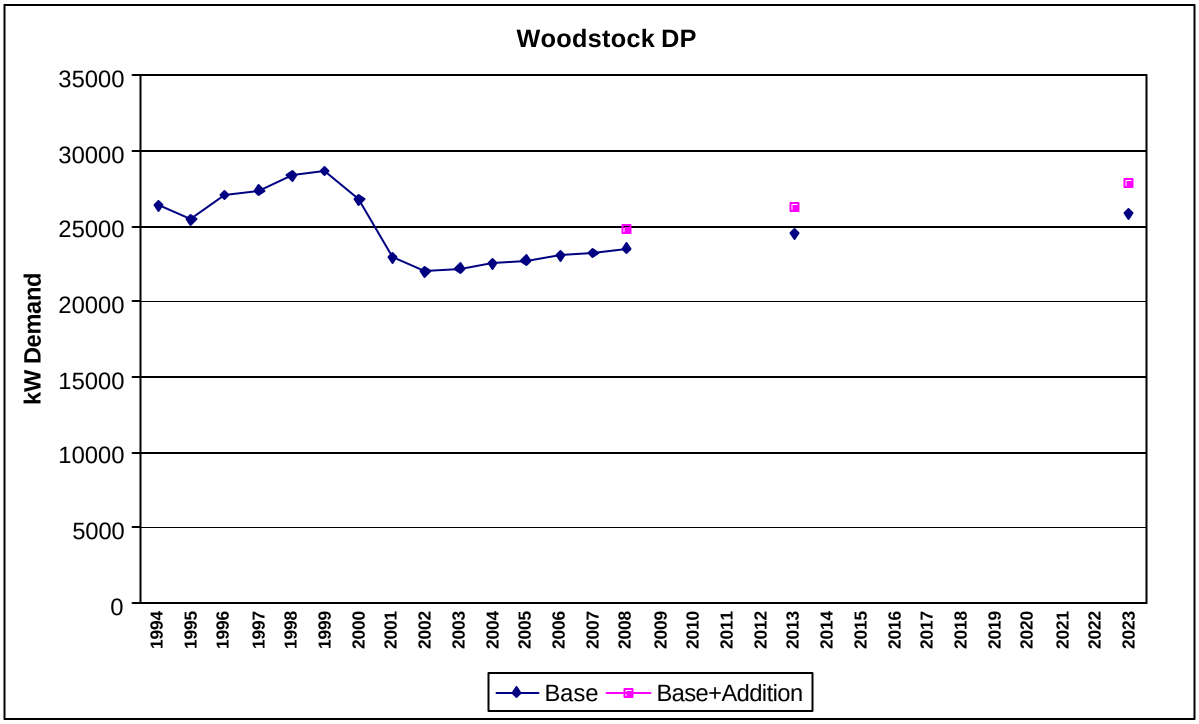


Figure 13-4 Historical and Forecasted Woodstock DP Demands

The Lyme delivery point serves a low proportion of the service area population with a 2002 CPR of just 4.0 percent. Consumer growth is expected to match population growth, at an annualized rate of about 1.1% over the 20 year time period. Demand per consumer was about 1.6 kW in 2002, below average for the NHEC delivery points. The DPC is expected to increase at an annual average of about 0.5% through 2008, then slow to an annualized 0.1% over the 20 year forecast horizon. This corresponds to the expectation that larger homes are expected over the first several years of the study. Peak loads are forecasted to grow at about 1.7% annually through 2008 and 1.3% per year over the 20 year period.

The forecasts of consumers and loads are shown in Table 13-9 and Figure 13-5.

Table 13-9 LymeDP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	15,848				
2001	16,011				
2002	16,085	0.0400	643	1.635	1,051
2003	16,279	0.0400	651	1.643	1,069
2004	16,474	0.0400	659	1.652	1,088
2005	16,673	0.0400	667	1.660	1,106
2006	16,869	0.0400	674	1.668	1,125
2007	17,066	0.0400	682	1.675	1,143
2008	17,265	0.0400	690	1.683	1,161
2022	18,277	0.0400	731	1.666	1,218
2023	20,402	0.0400	816	1.673	1,364
Growth Rates					
2002 - 2003	1.21%	0.00%	1.21%	0.53%	1.74%
2002 - 2008	1.19%	0.00%	1.19%	0.49%	1.68%
2002 - 2013	1.17%	0.00%	1.17%	0.18%	1.35%
2002 - 2023	1.14%	0.00%	1.14%	0.11%	1.25%

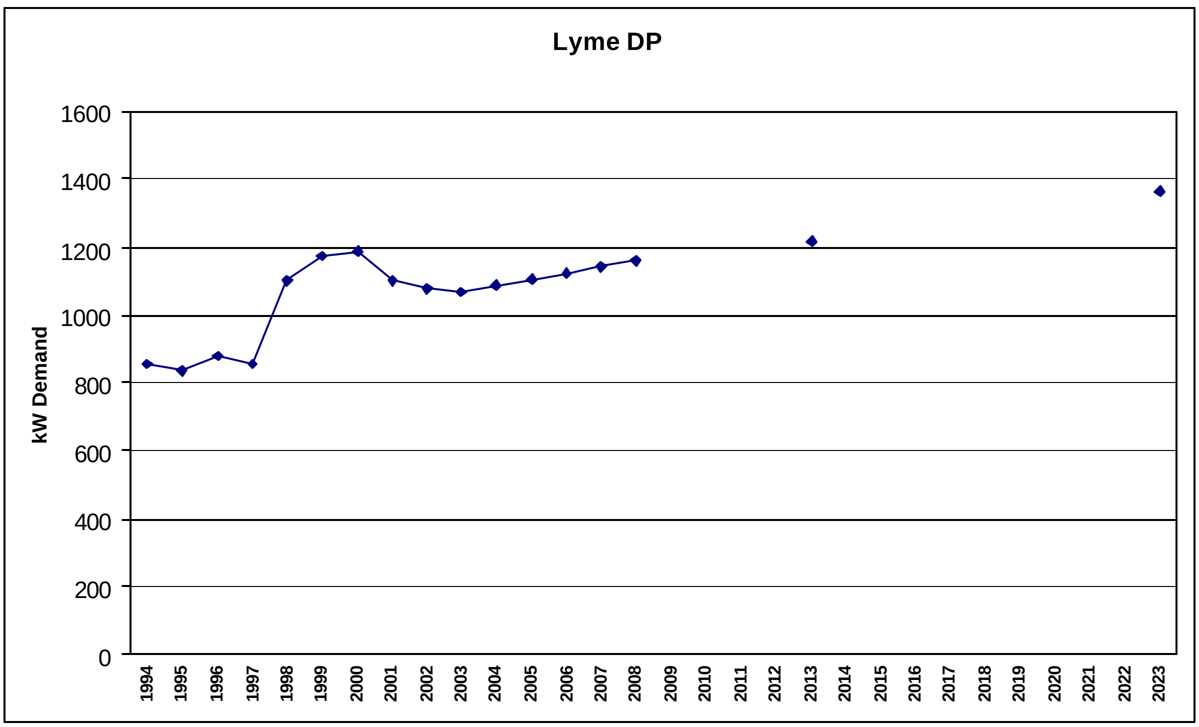


Figure 13-5 Historical and Forecasted Lyme DP Demands

The Rumney delivery point has about one-third as many consumers as population in the towns that it serves. Consumer growth is expected to match population growth with an average annual increase of about 1.0% over the 20 year horizon. Demand per consumer was about 1.5 kW in 2002, below average for the NHEC delivery points. With a nearly stable DPC expected, peak load growth of about 1.0% annually is forecasted though 2023.

The forecasts of consumers and loads are shown in Table 13-10 and Figure 13-6. Spot loads on RU12 are as shown in Table 13-11.

Table 13-10 Rumney DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	11,062				
2001	11,228				
2002	11,256	0.3396	3,823	1.489	5,692
2003	11,369	0.3396	3,861	1.489	5,750
2004	11,483	0.3396	3,900	1.489	5,808
2005	11,599	0.3396	3,939	1.490	5,868
2006	11,714	0.3396	3,978	1.490	5,927
2007	11,828	0.3396	4,017	1.490	5,985
2008	11,945	0.3396	4,057	1.490	6,045
2022	12,538	0.3396	4,258	1.491	6,349
2023	13,794	0.3396	4,685	1.493	6,992
Growth Rates					
2002 - 2003	1.00%	0.00%	1.00%	0.01%	1.02%
2002 - 2008	0.99%	0.00%	0.99%	0.01%	1.01%
2002 - 2013	0.99%	0.00%	0.99%	0.01%	1.00%
2002 - 2023	0.97%	0.00%	0.97%	0.01%	0.98%

Table 13-11 Rumney DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Rumney	RU12	Commercial		100	100

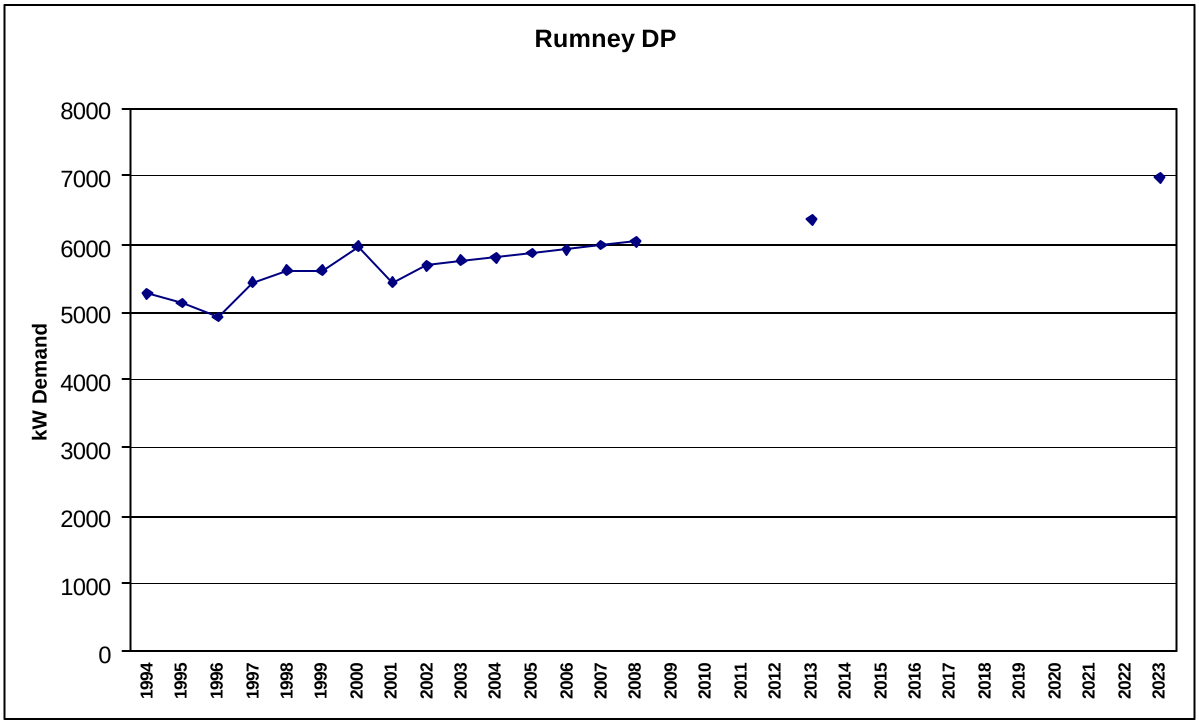


Figure 13-6 Historical and Forecasted Rumney DP Demands

The Thornton delivery point serves about 37 percent as many consumers as population in its service area population. Consumer growth is expected to match population growth, at an annualized rate of about 1.2 % over the 20 year time period. Including the Water Valley Ski Area, demand per consumer was about 7.1 kW in 2002, the highest of all NHEC delivery points. The above average DPC is expected to remain, due to ski area growth and growth in surrounding large residences. Over the 20 year forecast horizon, the peak load is forecasted to grow at about 1.2% annually, from about 16 MW to about 21 MW.

The forecasts of consumers and loads are shown in Table 13-12 and Figure 13-7. Spot loads on TH12 are as shown in Table 13-13.

Table 13-12 Thornton DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	6,045				
2001	6,154				
2002	6,183	0.3707	2,292	7.049	16,157
2003	6,259	0.3707	2,320	7.053	16,363
2004	6,335	0.3707	2,348	7.056	16,571
2005	6,413	0.3707	2,377	7.060	16,781
2006	6,489	0.3707	2,405	7.063	16,990
2007	6,566	0.3707	2,434	7.066	17,198
2008	6,644	0.3707	2,463	7.069	17,409
2022	7,038	0.3707	2,609	7.084	18,480
2023	7,866	0.3707	2,916	7.107	20,721
Growth Rates					
2002 - 2003	1.22%	0.00%	1.22%	0.05%	1.28%
2002 - 2008	1.20%	0.00%	1.20%	0.05%	1.25%
2002 - 2013	1.18%	0.00%	1.18%	0.04%	1.23%
2002 - 2023	1.15%	0.00%	1.15%	0.04%	1.19%

Table 13-13 Thornton DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR 2004-2008	YEAR 2009-2013	YEAR 2014-2023
			Load (kW)		
Thornton	TH12	School**	300	200	
		residential	40	40	20
		residential	30	30	20
** In addition to base forecast					

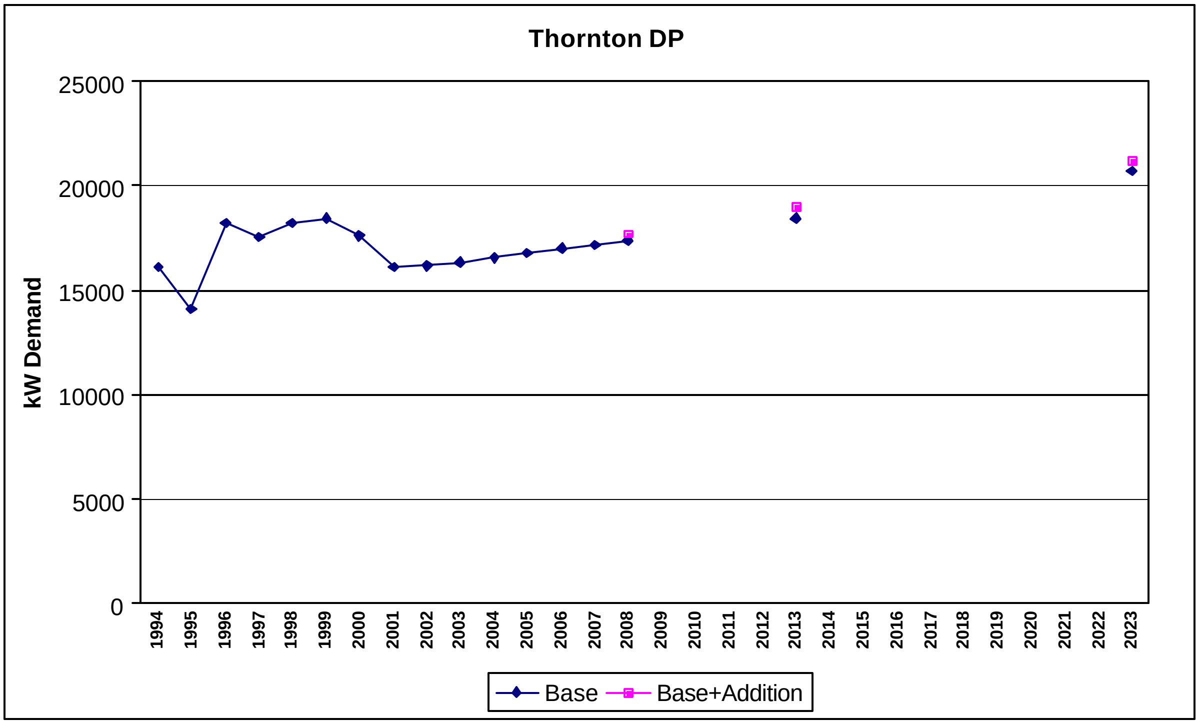


Figure 13-7 Historical and Forecasted Thornton DP Demands

13.2 Transmission System

PSNH supplies bulk power to the Plymouth District at 115 kV. PSNH 115–34.5 kV substations at N. Woodstock and Beebe River supply Plymouth District substations at 34.5 kV. PSNH's 115-34.5 kV substation at Ashland also provides support during contingent conditions.

The 115 kV system is looped to all PSNH substations serving this district. Each 115–34.5 kV substation has at least two 115 kV lines to it. PSNH's Beebe River Substation has three 115 kV lines including a 115 kV transmission tie line to White Lake–Saco–CMP. This 115 kV tie line is currently operated open between White Lake and Saco Substations. In 2004, when CMP finishes upgrades in Maine, when PSNH completes a phase shifting transformer upgrade at Beebe River Substation and adds additional reactive support to the area's 115 kV system, this transmission line will operate with the 115 kV tie at Saco Substation closed. This will provide a third 115 kV supply to the Plymouth area and improve transmission reliability and increase transmission transfer capability by 70 megawatts. The estimated cost of this PSNH project is $7,000,000. Additional details can be found in ISO-NE's RTE PO2 planning report.

13.2.1 34.5 kV Subtransmission System

The Plymouth District is supplied from the 34.5 kV system from PSNH's N. Woodstock and Beebe River Substations. NHEC's Bridgewater, Fairgrounds, Green Street and Rumney Substations are served from the PSNH Beebe River 342A feeder. The Thornton delivery point supplies NHEC's Thornton and Waterville Valley Substations from PSNH's Beebe River 342B feeder. PSNH's N. Woodstock 3126 feeder supplies NHEC's Woodstock delivery point serving NHEC's Woodstock and Lincoln Substations.

NHEC owns the 34.5 kV subtransmission lines from Thornton to Waterville Valley, Thornton to N. Woodstock and Woodstock to Lincoln Substations. PSNH owns and operates the areas other 34.5 kV subtransmission feeders. PSNH's Ashland Substation provides contingent support for the Plymouth District load.

Substation transformer capacity and base case and coincident peak demands for planning purposes are reflected in Table 13-14 below. The coincident peak demands reflect NHEC's coincident peak demands in 2002/03 and 2022/23 and a forecasted load growth rate of 0.30 percent annually. The Plymouth District is winter peaking and is projected to remain winter peaking.

Table 13-14 Plymouth district 34.5 kV System and Load

	115 – 34.5 kV Transformers			Coincident Peak Loads (MVA)			
	Summer	Winter	34.5 kV	Summer		Winter	
Substation	Capacity	Capacity	Feeders	2002	2023	2002	2023
Ashland	1-31 MVA	1-41 MVA	2	27.9	28.8	16.4	29.9
Beebe River	1-44 MVA	1-54 MVA	2	22.9	32.6	37.8	45.9
N. Woodstock	1-46 MVA	1-59 MVA	1	12.5	17.9	21.8	22.8

PSNH's 34.5 kV subtransmission system serving this area utilizes single 115–34.5 kV transformer substations which puts added importance on a well developed feeder network to provide contingent capability.

A small power producer, the Bridgewater Power and Light Company, has a moderately sized 15 megawatt small power production (SPP) facility at Bridgewater. This facility provides significant local area generation and system support during the winter peak periods. PSNH's contract with this SPP runs through 2006. PSNH does not expect this SPP to continue operating after 2006 because of the availability of much lower cost power supplies.

PSNH has existing plans to upgrade the capacity of the Ashland 115–34.5 kV transformer in 2005 for additional area support in contingencies. NHEC had a previous Work Plan project to extend a new 34.5 kV feeder from N. Woodstock Substation to Lincoln Substation in 1998.

13.2.2 Base System Performance

Base power flow studies for the summer and winter of 2002/03 2023 peak load conditions indicate there are no deficiencies when measured against PSNH planning criteria. However, the load served in this area is almost exclusively NHEC's and NHEC has a significant 34.5 kV subtransmission system presence. NHEC's design criteria is also at a higher standard in the contingency capability area. For contingency evaluation and design, the following section should be referred to.

13.2.3 Contingency Performance

Transmission reliability will improve in 2004 when the 115 kV system between Maine and New Hampshire is closed together at Saco Valley Substation, providing a third 115 kV supply source to the area.

The contingency capability of the 34.5 kV system was tested using the PSNH power flow model with a complete representation of the 34.5 kV system which includes all NHEC 34.5 kV facilities.

There are contingent deficiencies with the existing system at 2002 winter peak load levels. The outage of the PSNH transformer at N. Woodstock or N. Woodstock feeder 3126 will result in a 15 percent overload, based on the emergency rating, of the Beebe River 342B feeder between the Beebe River and PSNH's Campton delivery point and low voltage, 0.929, at the Waterville Valley 34.5 kV bus. With the addition of 10.4 megavars of capacitors in four banks at Campton, Waterville Valley, Woodstock and the NHEC voltage regulator station, the low voltage at Waterville Valley can be corrected to 0.962 per unit but the Beebe River – Campton overload remains. The operating solution would be to leave the Waterville Valley or other load unserved for this contingency.

For the loss of the Beebe River Substation transformer or Beebe River 342B feeder, 6.3 megavars of capacitors in four banks at Campton, Waterville Valley, Woodstock and the NHEC voltage regulator station are needed to avoid a low voltage deficiency when picking up Beebe River feeder 342B load from N. Woodstock Substation.

At 2023 winter peak load levels, these deficiencies are repeated and intensify. The Beebe River – Campton 34.5 kV line emergency rating overload increases to 132 percent and the only option to relieving low voltages and line overloads is to leave the Waterville Valley load unserved. A Beebe River transformer outage or 342B feeder outage also results in low voltage which can be corrected with the installation of 8.4 megavars of line capacitors. However, the N. Woodstock 3126 feeder is loaded to its 49 MVA PSNH emergency rating.

Concern also exists about the contingency backup of Lincoln Substation, which is currently 18 megawatts of coincident peak load, and Waterville Valley Substation, which is currently 11 megawatts of coincident peak load, as both are served by radial 34.5 kV lines.

The final concern is with the number of substations and load served from PSNH Beebe River feeder 342A. Currently the 342A feeder supplies Rumney, Fairgrounds, Green Street and

Bridgewater substations. An outage to either the Beebe River transformer or 342A feeder results in an outage to the entire southern portion of the Plymouth District. From a subtransmission system contingent performance basis this entire feeder can be picked up by the Ashland 342A feeder throughout the planning period. However, when all the distribution substations are outaged at once by a single transmission outage, it is impossible to exercise distribution feeder level ties for contingent backup purposes. Therefore, this problem will be addressed in this section of the report and not in the reliability section for the Plymouth District.

13.2.4 Contingency Plan

13.2.4.1 Beebe River 342A Contingent Performance – NHEC Rumney, Fairgrounds, Green Street, and Bridgewater Substations Simultaneous Outage.

PSNH currently operates the Beebe River–Ashland Substations 342A feeder loop open just beyond the Bridgewater small power generation facility. This was done to isolate the Bridgewater generation facility on one feeder. PSNH indicates that it would not be a problem to move this normally open point to the Holderness Switching Station. At Holderness are the 34.5 kV taps to Green Street (Plymouth 1), Fairgrounds (Plymouth 2) and Rumney Substations. It is proposed to rebuild the common 34.5 kV line tap for Fairgrounds and Rumney with separate 34.5 kV taps for each back to the Holderness Switching Station. It is also proposed to rebuild Holderness Switching Station into two distinct load buses with one bus served by Ashland feeder 342A and the other served by Beebe River feeder 342A. There should be disconnects on the line side of each bus and tie disconnects between buses. The Green Street, Fairgrounds and Rumney tap lines each should be capable of being tied to either bus in the Holderness Switching Station. The suggested final configuration of the switching would have Rumney and Green Street fed from Beebe River feeder 342A, and Bridgewater and Fairgrounds fed from the Ashland 342A feeder. The cost of this plan is estimated to be between $150,000 and $300,000, depending on the level of site development needed and level of recloser protection on the tap lines desired by NHEC.

This solution splits the southern Plymouth District's load between Ashland and Beebe River 34.5 kV Substations and feeders. It also facilitates the ability to transfer load at the distribution substation feeder level for subtransmission system outages.

13.2.4.2 Waterville Valley – Thornton Contingent Backup

Waterville Valley Substation is supplied from a radial 34.5 kV NHEC feeder. Loss of this radial line would generally mean a prolonged outage for this substation. However, a high capacity regulated 24.9 kV 10.3 mile long feeder still exists between Thornton Substation and Waterville Valley. Each substation is thus capable of backing up the other. However, other contingent outages result in deficient voltage levels at the Waterville Valley 34.5 kV bus. In its current configuration and load levels, two 1200 KVAR contingent switched capacitor banks are recommended for the Waterville Valley 24.9kV system. An additional 1200 kVAR contingent switched capacitor bank is recommended for the Thornton 24.9 kV system. All three contingent banks should have multifunction automatic controls and be remotely operable by SCADA. They are recommended for installation in 2004 and are estimated to cost $75,000. The early installation is to address contingent voltage deficiencies for a N. Woodstock or Ashland Substation transformer or 34.5 kV feeder outage.

13.2.4.3 Lincoln Substation – Contingent Backup

Lincoln Substation currently has a peak coincident load of 18.2 megawatts. It is supplied by a single radial 34.5 kV feeder from NHEC's Woodstock Substation. NHEC formerly had a 1998 Work Plan project to develop a second feeder bay with protection at PSNH's N. Woodstock Substation and extend a feeder directly to Lincoln Substation. This feeder would loop Lincoln and thus improves reliability to this substation.

From a capacity and voltage criteria perspective, this improvement is needed to avoid overloading the N. Woodstock 3126 feeder with a contingent outage of the Beebe River Substation transformer in 2022 by PSNH design criteria. By the more conservative NHEC line rating of 43.5 MVA, this upgrade is needed in 2008 as the N. Woodstock 3126 feeder is carrying 41.5 MVA in a contingent backup for a Beebe River Substation or Beebe River 342B feeder outage during a 2002 winter peak load event.

Lincoln and Woodstock Substations also need to maintain unity load power factor or a slightly leading power factor to compensate for substation transformer reactive losses at winter peak and to maintain voltage during contingent N. Woodstock Substation transformer or feeder outages. Lincoln should have a 1200 kVAR capacitor bank and Woodstock should have a 600 kVAR capacitor bank. Both banks should be switched using local multifunction controllers with remote SCADA control. Both banks are recommended for installation in 2004.

The estimated cost of these projects are:

• Lincoln and Woodstock Switched Capacitor Banks	2004	$ 50,000
• Second N. Woodstock 34.5 kV Feeder to Lincoln	2008	960,000

13.2.4.4 N. Woodstock Substation Contingent Backup

The most serious capacity deficiency in the 34.5 kV subtransmission system supplying the Plymouth district is the absence of a full capacity backup capability at winter peak load for the outage of the PSNH N. Woodstock Substation transformer or N. Woodstock 34.5 kV feeder 3126. At 2003 winter peak loads, the Beebe River–Thornton 34.5 kV 342B feeder exceeds its emergency rating by 15%. In 2023, the overloads intensify and the emergency rating of the Beebe River–Thornton 34.5 kV line is exceeded by 32% and acceptable voltage levels cannot be maintained. In both years, it was necessary to leave Waterville Valley Substation load unserved for these outages to eliminate overloads and low voltages.

Three alternative plans were tested to correct this deficiency. Each plan resolved the deficiency. The plans are:

Alternative Plan 1

Develop a new Beebe River 34.5 kV feeder and extend this express 477 MCM ACSR feeder from Beebe River Substation to Thornton Substation. At Thornton, develop a switching station with two buses, one for each Beebe River 34.5 kV feeder. Develop the station so that the lines to Thornton Substation, Waterville Valley Substation and to N. Woodstock Substation could each be fed by either Beebe River 34.5 kV feeder. For normal operation, Thornton and Waterville Valley lines would be on different Beebe River 34.5 kV feeders which would facilitate utilizing distribution level feeders ties between these two substations for backup as required. For the outage of N. Woodstock Substation, all load can be transferred from the express feeder, as necessary. The express feeder from Beebe River to N. Woodstock would then be used to restore service to NHEC's Lincoln and Woodstock Substations.

The estimated cost of this development in 2004 is:

• Beebe River Substation Feeder Bay and Protection	$130,000
• Beebe River – Thornton 477 MCM 34.35 kV Feeder 3.5 miles	440,000
• Thornton Switching Station	50,000
Total:	$620,000

Alternative Plan 2

At N. Woodstock, add a second 115–34.5 kV 24 MVA transformer, high and low voltage structures and bus, 115 kV transmission line breakers, SF6 circuit switches, 115 kV line terminals, foundations and site expansion and modifications, and protection modifications at adjacent substations

The PSNH estimated cost of this development in 2004 is $3,000,000.

This estimate is for planning purposes only. The actual estimated cost may be more or less, depending on actual site conditions and design requirements. This estimated cost has been reviewed by PSNH and found to be reasonable.

This option is perhaps the most straightforward of the three alternatives as it requires little 34.5 kV line modifications or feeder reconfigurations. This project may require additional right-of-way and regulatory approvals. It is unlikely that this development, if selected, could be in service in 2004.

Alternative Plan 3

This alternative would develop a new 115–34.5 kV substation at Thornton. The substation would have a single 115 – 34.5 kV transformer rated 24 MVA, base rating, with LTC. The substation would initially have three 34.5 kV feeders to NHEC's Thornton and Waterville Valley Substations, and PSNH's N. Woodstock Substation. The ultimate design would permit expansion to two transformers. The 115 kV would have line breakers for each transmission line and utilize circuit switchers for transformer protection. This alternative assumes that PSNH would grant an interconnection to the existing 115 kV Beebe River–N. Woodstock transmission line.

The estimated cost of this development in 2004 is:

• 115 substation development – land, structure and fence		$530,000
• 115 kV line breakers and terminations		800,000
• 115 – 34.5 kV, 24 MVA transformer @ LTC		350,000
• Three 34.5 kV line terminations		390,000
• Two miles of 34.5 kV, 477 MCM feeder line		250,000
	Total	$2,320,000

This project will require additional right-of-way, site acquisition and other regulatory approvals. This cost estimate also assumes a double circuit overhead 34.5 kV line can be accomplished. With land acquisition, negotiations, design efforts, and permitting and regulatory approvals required the earliest the alternative could be in service is 2005/6.

Plan Selection

Alternative Plan 1 is the recommended alternative for cost, flexibility, and the speed with which this alternative can be developed. It is unlikely that PSNH would participate in Plan Alternatives 1 or 3. Alternative Plan 2 would require PSNH to be a partner but since no PSNH design criteria have been exceeded, PSNH's participation would need to be negotiated.

The recommended construction plan for the 34.5 kV subtransmission system serving the Plymouth district is summarized in Table 13-15 below.

Table 13-15 Recommended Construction Plan for 34.5 kV Subtransmission System

Year	Plan Element	Estimated Cost - $
2004	New Beebe River – Thornton 34.5 kV feeder	620,000
2008	New N. Woodstock 34.5 kV feeder to NHEC's Lincoln Substation	960,000
2004	Rebuild PSNH's Holderness 34.5 kV Switching Station	150,000
2004	Waterville Valley and Thornton Substations 3.6 MVARs line capacitors	75,000
2004	Lincoln and Woodstock – 1.8 MVARs line capacitors	50,000

13.2.5 Historical Reliability

A review of the 34.5 kV subtransmission outages for the period of 2000-2002 indicated the following average annual outage rates:

Table 13-16 Average Annual Outage Rates

Delivery Points	NHEC Substations	PSNH Outages	Total Average Annual Outages
Bridgewater	Bridgewater	1	0.33
Plymouth 2	Fairgrounds	0	0
Plymouth 1	Green Street	1	0.33
Woodstock	Lincoln (3 subs) Woodstock	0 0	0 0
Rumney	Rumney	1	0.33
Thornton	Thornton (2 subs)	0	0

These outage rates are within NHEC's design criteria.

13.2.6 Reliability Improvement (of Plan)

The principle reliability related 34.5 kV design characteristic of the current system is the reliance on just two substations, two transformers and three feeders to supply the eleven NHEC substations in Plymouth District. An outage of a PSNH substation or 115–34.5 kV transformer puts the lights out at seven NHEC substations for a Beebe River Substation outage and four NHEC substations if N. Woodstock Substation is outaged. The impact of a 34.5 kV feeder outage is nearly as severe as there are only three 34.5 kV feeders which normally serve the district's eleven distribution substations.

An additional factor which can have a large impact on the ability to minimize outage durations is the availability of alternate supply paths at the distribution primary voltage level. With the current arrangement of a single 34.5 kV feeder supplying multiple adjacent substations, it is not possible to utilize distribution switching to restore service for a single 34.5 kV feeder outage.

The existing system also has capacity and voltage limitations that result in the necessity of not returning all loads to service from a backup 34.5 kV feeder following an outage.

The plan for the 34.5 kV subtransmission system addresses each of these shortcomings and in doing so will result in a much more reliable transmission and distribution system. The plan:

- Provides adequate capacity for first contingency 34.5 kV system backup.
- Distributes the district's eleven distribution substations over:
  - Three 34.5 kV substations instead of two, and
  - Six 34.5 kV feeders instead of just three.
- Provides every NHEC substation a looped system and alternate supply path(s).
- Facilitates the ability to transfer loads at the distribution substation feeder level to adjacent substations and feeders for a single 34.5 kV subtransmission feeder outage.

The annual power supplier caused outage rates for this district have been quite low. The concern in this district should be on outage duration and the geographic extent of an outage. This plan provides a system which addresses those shortcomings.

13.3 Distribution System

13.3.1 General

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 13.4, Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 13.0 shows the 2003, 2008, 2013 and 2023 peak load levels for each substation, DP, MP and circuit using the existing system configuration and proposed system configuration.

13.3.2 New Substations, DP's and MP's

No new substations, delivery points or meter points are anticipated in the Plymouth District during this 20-year planning period to provide additional capacity or to improve voltage.

13.3.3 Substation, DP and MP Changes

The following table shows the projected kW for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for backup or for the ordinary replacement of aged transformers are shown in [**bold**]. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 13-17 Substation Transformer and Regulator Data

Name	Transformer							Voltage Regulator		
	Rating (kVA)					Est. Load (kW)	Capacity (%)	Size (AMP)	Est. Load (AMP)	Capacity (%)
	OA 55°	FA 55°	OA 65°	FA 65°	Win Season					
Bridgewater	5,000	5,750	5,600	6,440	7,085	4,670	67	328	243	74
Bridgewater [1]	**7,500**	**9,375**	**8,400**	**10,500**	**11,500**	4,670	41	**438**	243	55
Fairgrounds	10,000	12,500	11,200	14,000	15,400	7,776	52	656	404	62
Green Street, 2.4 [2]	5,000	5,750	5,600	6,440	6,160	5,344	89	668	833	125
Green Street, 7.2 [3]	**10,000**	**12,500**	**11,200**	**14,000**	**15,400**	5,344	35	**656**	278	42
Lincoln-T1, 7.2	12,000	16,000	13,500	18,000	24,640	6,021	25	LTC	313	--
Lincoln-T2, 14.4	15,000	20,000	16,800	22,400	30,800	9,315	31	LTC	242	--
Lincoln-T3, 14.4	15,000	20,000	16,800	22,400	30,800	5,709	19	LTC	148	--
Lyme MP	--	--	--	--	--	1,471	--	--	76	--
Rumney	10,000	12,500	11,200	14,000	15,400	7,190	48	656	374	57
Thornton-T1, 7.2	3,750	4,312	4,200	4,830	5,313	5,694	109	328	296	90
Thornton-T1, 7.2 [1]	**7,500**	**9,375**	**8,400**	**10,500**	**11,550**	5,694	50	**438**	296	68
Thornton-T2, 14.4	10,000	12,500	11,200	14,000	15,400	1,785	12	347	46	7
Thornton-T2,14.4 [1]	**10,000**	**12,500**	**11,200**	**14,000**	**15,400**	1,785	12	**347**	46	7
Waterville V.	15,000	20,000	16,800	22,400	30,800	13,598	45	LTC	707	--
Woodstock	10,000	--	11,200	--	12,320	4,618	38	656	240	37

[1] Upgrade to replace aged equipment. Projects BW-1 and TN-1.

[2] Fans are not installed

[3] To accommodate conversion from 2.4/4.16 kV to 7.2/12.47 kV. Project GS-5.

The secondary voltage at the Green Street Substation is 2.4/4.16 kV. The nearby Fairgrounds and Bridgewater Substations have a secondary voltage of 7.2/12.47 kV. Due to the different secondary voltage, the Green Street Substation service area cannot receive backup from Fairgrounds or Bridgewater. Equally important, the Green Street Substation can not provide backup to either Fairgrounds or Bridgewater. The Fairgrounds Substation is forecasted to serve 9.4 MW of load in 2023 and Bridgewater is forecasted to serve 5.7 MW of load.

It is recommended that the Green Street Substation be upgraded to 7.2/12.47 kV and that its distribution line be reinsulated or rebuilt to operate at 7.2/12.47 kV. This will enable Green Street, Fairgrounds and Bridgewater to provide backup service to each other. The combined load of Fairgrounds and Green Street is over 12 MW at the 2023 load level and without the Green Street Substation, the Bridgewater, Rumney and Thornton Substations are to far away to provide worthwhile backup to the entire Fairgrounds and Green Street service area. Also, the added system capacity provided by the Green Street Substation will significantly improve overall system operation and flexibility during maintenance and emergency situations.

Project BW-1 is the replacement of the existing 3-1,667 kVA transformers with a new 7.5/10.5 MVA transformer. The existing transformers were purchased in 1971 and replacement due to age is expected. Larger sized voltage regulators will also be needed.

Project TN-1 is the replacement of the 7.2/12.47 kV rated transformers and the 14.4/24.94 kV rated transformers due to age and deterioration. It is recommended that the 3-1,250 kVA, 7.2/12.47 kV rated transformers that were purchased in 1961 be replaced with a new 7.5/10.5 MVA transformer. It is recommended that the 3-3,333 kVA, 14.4/24.94 kV rated transformers that were purchased in 1969 be replaced with a new 10/14 MVA transformer. Larger sized voltage regulators will also be needed.

13.3.4 Bridgewater Substation Service Area

13.3.4.1 Existing System Review

The Bridgewater Substation is forecasted to serve 5.7 MW of peak load in 2023. The Bridgewater area is served by three 7.2/12.47 kV circuits: BW11, BW12 and BW13. Circuit BW11 serves approximately 24 percent of the total load, BW12 serves 8 percent and BW13 serves the remaining 68 percent.

Circuit BW11 is approximately 15 miles long and has no ties to other circuits. The main three-phase line is approximately 8 miles long. The first 6 miles are 336 ACSR and the next 2 miles are 1/0 ACSR. A portion of the three-phase feeder going east is 6A CWC. Most of the remaining three-phase, vee-phase and single-phase lines are 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit BW12 is approximately 10 miles long and has no ties to other circuits. The main three-phase line is approximately 3 miles long. Most of the three-phase, vee-phase and single-phase lines are 1/0 ACSR. A portion of line near the end of the circuit is 8X SCG. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit BW13 is approximately 16 miles long and has a tie to Circuit **??** of the Fairground Substation. The main three-phase line is approximately 14 miles long. The first 6 miles are mostly 336 ACSR, the next 2 miles are 4 CU and then 6 miles of 1/0 ACSR. A portion of the three-phase feeder going north that ties to the Fairground Substation consists of 4 CU, 2A CWC, 2 ACSR, 1/0 ACSR and 336 ACSR. Most of the remaining three-phase, vee-phase and single-phase lines are 1/0 ACSR. Voltage regulators are installed in the main three-phase line about 6.6 miles from the substation. The estimated peak load on Circuit BW13 is 171 amps per phase at the 2023 load level. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

13.3.4.2 Recommended Plan

Project BW-2 is a 0.3 mile single-phase 1/0 ACSR to vee-phase 1/0 ACSR conversion by adding 1-1/0 ACSR phase conductor. The single-phase line has 36 amps of peak load at the 2023 load level. The vee-phase line will enable the load beyond to be divided over two phases and will improve load balance along the three-phase line.

On Circuit BW13, Project BW-3 is a 356 foot single-phase 1/0 ACSR to vee-phase 1/0 ACSR conversion by adding 1-1/0 ACSR phase conductor. The single-phase line has 31 amps of peak load at the 2023 load level. The vee-phase line will enable the load beyond to be divided over two phases and will improve load balance along the three-phase line.

Project BW-4 is the replacement of 2.2 miles of three-phase 4 CU with three-phase 336 ACSR. This portion of the main line is expected to reach the end of its useful life during this planning period.

Project BW-5 is the replacement of 0.3 miles of three-phase 4 CU and 0.6 miles of three-phase 2A CWC with three-phase 336 ACSR and a 0.4 mile three-phase 336 ACSR tie line that will connect the east circuit of the Green Street Substation to Circuit BW13. With the conversion of the Green Street Substation from 2.4/4.16 kV to 7.2/12.47 kV, as discussed in Section 13.3.3, ties between Green Street and other substation are now possible. This tie line and the upgrading of the old, small conductor three-phase line will then provide a worthwhile tie line to the area northeast of the Bridgewater Substation. Also, the tie line will enable the transfer of approximately 1000 kW (47 amps per phase) of load at the 2023 load level from the heavily loaded Circuit BW-13 to the closer Green Street Substation.

13.3.5 Fairgrounds Substation Service Area

13.3.5.1 Existing System Review

The Fairgrounds Substation is forecasted to serve 9.4 MW of peak load in 2023. The Fairgrounds area is served by three 7.2/12.47 kV circuits: FG13, FG14 and FG15. Circuit FG13 serves approximately 23 percent of the total load, FG14 serves 51 percent and FG15 serves the remaining 26 percent.

Circuit FG13 is approximately 5 miles long and has no ties to other circuits. The main three-phase line is approximately 3 miles long and is 336 ACSR. Most of the single-phase lines are 1/0 ACSR. The peak load at the 2023 load level is approximately 100 amps per phase. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit FG14 is approximately 8 miles long and has no ties to other circuits. The main three-phase line is approximately 4.5 miles long. The first 1.7 miles are 336 ACSR, the next 1.2 miles are 3/0 ACSR and then 1.6 miles of 336 ACSR. This circuit serves the Tenney Mountain Ski area and other commercial and retail loads. The peak load at the 2023 load level is approximately 230 amps per phase which is approaching the maximum design load limit of 280 amps per phase and being capacity deficient. No areas with low voltage are anticipated during this planning period.

Circuit FG15 exits the substation and splits into east and west feeders. The east feeder is about 11 miles in length and has no ties to other circuits. The main three-phase line is approximately 4.7 miles long. The first 2.6 miles are 3/0 ACSR and the next 2.1 miles are 1/0 ACSR. The remaining vee-phase and most of the single-phase lines are 1/0 ACSR. The west feeder about 8 miles in length and has no ties to other circuits. The main line has 4.1 miles of 1/0 ACSR vee-phase. The remaining single-phase lines are mostly 1/0 ACSR. The peak load at the 2023 load level is approximately 115 amps per phase. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

13.3.5.2 Recommended Plan

With the conversion of the Green Street Substation to 7.2/12.47 kV, it is recommended that approximately 1,600 kW of load be transferred from Circuit FG13 to Green Street Circuit GS11. The proposed normal open between these two circuits is shown on the Long Range Plan Circuit Diagram. This load transfer will then enable FG13 to be extended to the west to provide a three-phase loop to the heavily loaded FG14. Project FG-1 is the replacement of 3 miles of single-phase and three-phase 1/0 ACSR with three-phase 336 ACSR to provide the loop to FG14. This will enable the Mt. Tenney Ski area to be transferred to FG13. This transfer will more equally divide the load in the area over Circuits FG13, FG14 and GS11 for overall improved system performance and reliability. The peak load on Circuit FG14 will be reduced from approximately 230 amps per phase to 125 amps and will therefore have more capacity to provide backup to the Rumney Substation.

13.3.6 Green Street Substation Service Area

13.3.6.1 Existing System Review

The Green Street Substation is forecasted to serve 2.7 MW of peak load in 2023. The Green Street area is served by four 2.4/4.16 kV circuits: GS41, GS42, GS43 and GS44. Circuit GS41 serves approximately 38 percent of the total load, GS43 serves 36 percent and GS44 serves the remaining 26 percent. None of the circuits tie to other substations because of the difference in operating voltages.

Circuit GS41 is approximately 3 miles long and has a tie to Circuit GS43. The main three-phase line is approximately 0.6 miles long. The first 0.2 miles are 1/0 ACSR and the next 0.4 miles are 336 ACSR. The single-phase continuing to the south is mostly 2 CU. The estimated peak load on GS41 is 147 amps per phase at the 2023 load level which exceeds 50 percent of the summer season emergency current rating of 1/0 ACSR. This could be a limiting factor during backup to GS43 at peak load times. No areas with low voltage are anticipated during this planning period.

Circuit GS42 is a dedicated express circuit that provides backup to the Plymouth State College. The three-phase feeder is approximately 0.5 miles long and is 336 Hendrix, 15 kV rated cable.

On Circuit GS43, the 336 ACSR three-phase feeder main splits into north and west feeders approximately 0.25 miles from the substation. The north feeder continues with 336 ACSR for 0.2 miles, then 4 CU for 0.3 miles and then 1/0 ACSR for 0.3 miles. The west feeder continues with 336 ACSR for another 0.25 miles and then 1/0 ACSR for about 0.5 miles. The estimated peak load on Circuit GS43 is 132 amps per phase at the 2023 load level. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit GS43 is approximately 0.4 miles long and does not tie to any of the other Green Street circuits. The main three-phase line is 336 ACSR. The estimated peak load is 98 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

13.3.6.2 Recommended Plan

As discussed in Section 13.3.3, it is recommended that the entire Green Street Substation service area be converted from 2.4/4.16 kV to 7.2/12.47 kV. Accordingly, Projects GS-1, GS-2, GS-3 and GS-4 are for the conversion of Circuits GS41, GS42, GS43 and GS44, respectively. The circuits of this substation can then be tied to the Bridgewater and Fairgrounds Substations which will provide a significant improvement in reliability to the area.

On Circuit GS41, Project GS-1 also includes the replacement of 620 feet of three-phase 1/0 ACSR with three-phase 336 ACSR. This section of line is at the beginning of the circuit and the upgrade will provide a high capacity line for emergency and maintenance situations when serving other circuits.

On Circuit GS43, Project GS-3 also includes the replacement of 0.3 miles of three-phase 4 CU and 0.3 miles of three-phase 1/0 ACSR with three-phase 336 ACSR. This line upgrade will provide a worthwhile tie line to Circuit FG15.

13.3.7 Lincoln Substation Service Area

13.3.7.1 Existing System Review

The Lincoln Substation is forecasted to serve 21 MW of peak load in 2023. The Lincoln area is served by two 7.2/12.47 kV circuits (LN11 and LN12) and two 14.4/24.94 kV circuits (LN23 and LN24). Circuit LN11 serves approximately 11 percent of the total load, LN12 serves 18 percent, LN23 serves 44 percent and LN24 serves the remaining 27 percent.

Circuit LN11 is approximately 2.4 miles long and is close to Circuits LN23 and LN24 but is not tied to these circuits because of the different operating voltages. The main three-phase line starts with 303 feet of 350 MCM aluminum underground and then has 2.1 miles of 336 ACSR. The estimated peak load is 100 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

The main line of Circuit LN12 is approximately 1.1 miles long and is tied to Circuit WD13 of the Woodstock Substation. The main three-phase line starts with 470 feet of 350 MCM aluminum underground and is then 336 ACSR. The estimated peak load is 167 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit LN23 is approximately 1.7 miles long and is tied to Circuit LN24. The circuit is dedicated to serve the Loon Mountain Ski area. The main three-phase line starts with 540 feet of 350 MCM aluminum underground and is then 336 ACSR. The three-phase taps serving Loon

Mountain are 350 aluminum underground. The estimated peak load is 209 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit LN24 is approximately 3.0 miles long and is tied to Circuit LN23. The main three-phase line starts with 423 feet of 350 MCM aluminum underground and is then 336 ACSR. The estimated peak load is 127 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

13.3.7.2 Recommended Plan

There are no distribution system primary line construction projects anticipated as necessary for voltage and/or capacity reasons within the Lincoln Substation service area. Projects based on improving reliability are discussed in Section 13.4.

13.3.8 Lyme Meter Point Service Area

13.3.8.1 Existing System Review

The Lyme Meter Point is forecasted to serve 1.5 MW of peak load in 2023. The Lyme area is served by three 7.2/12.47 kV circuits: LY11, LY12 and LY13. Circuit LY11 serves approximately 35 percent of the total load, LY12 serves 41 percent and LY13 serves the remaining 24 percent. No voltage regulators are installed at the MP or out on the line.

Circuit LY11 is approximately 8 miles long and has no ties to other circuits. The main three-phase line is approximately 3 miles long and is mostly 4/0 ACSR. Most of the single-phase lines are 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period provided the voltage at the MP is 122 volts or higher.

Circuit LY12 is approximately 12 miles long and has no ties to other circuits. The main three-phase line is approximately 7 miles long and is 1/0 ACSR. Most of the vee-phase and single-phase lines are 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period provided the voltage at the MP is 122 volts or higher.

Circuit LY13 is approximately 3 miles long and has no ties to other circuits. The main three-phase line is approximately 1 mile long and is 336 ACSR. Most of the single-phase lines are 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period provided the voltage at the MP is 122 volts or higher.

13.3.8.2 Recommended Plan

There are no distribution system primary line construction projects anticipated as necessary for voltage and/or capacity reasons within the Lyme Substation service area. Projects based on improving reliability are discussed in Section 13.4.

13.3.9 Rumney Substation Service Area

13.3.9.1 Existing System Review

The Rumney Substation is forecasted to serve 7.2 MW of peak load in 2023. The Rumney area is served by three 7.2/12.47 kV circuits: RU12, RU13 and RU14. Circuit RU12 serves approximately 35 percent of the total load, RU13 serves 49 percent and RU14 serves the remaining 16 percent.

Circuit RU12 is approximately 29 miles long and has a tie to Circuit RU13 approximately 3.6 miles from the substation. The remaining portion of Circuit RU12 has no ties to other circuits except for a relatively in-effective single-phase tie with Circuit LY12 of the Lyme Meter Point. The main three-phase line is approximately 18 miles long. The first 3 miles are 336 ACSR, the next 0.75 miles are 350 MCM aluminum underground and then 14 miles of 1/0 ACSR. Most of the other three-phase, vee-phase and single-phase lines are 1/0 ACSR. Two sets of voltage regulators are installed in the main line. The first set is approximately 4.8 miles from the substation and the second set is approximately 13.3 miles from the substation. This circuit is considered to have a voltage deficiency since multiple sets of voltage regulators are needed to provide the required voltage on this long circuit. At the 2023 load level, the circuit has low voltage on the source side of the second set of voltage regulators. The 336 ACSR main line conductor has adequate capacity to serve the 2023 load level. The 1/0 ACSR main line conductor is undersized given the amount of load and length of the circuit.

On Circuit RU13, the 336 ACSR three-phase feeder main splits into west and north feeders approximately 7.4 miles from the substation. The west three-phase feeder continues with 336 for another 2.8 miles and then 1/0 ACSR for another 13 miles. The ends of the west feeder are about 25 miles from the substation. The north three-phase feeder continues with 336 for another 2.8 miles and then mostly 4 CU for another 1.8 miles. The ends of the north feeder are about 18 miles from the substation. Voltage regulators are installed in the main three-phase about 6 miles from the substation and also on the west and north three-phase feeders. Voltage regulators are also installed on two of the single-phase lines. This circuit is considered to have a voltage deficiency since multiple sets of voltage regulators are needed to provide the required voltage on this long circuit. At the 2023 load level, the circuit has low voltage on the source side of the first set of voltage regulators. The 336 ACSR and 1/0 ACSR main line conductor has adequate capacity to serve the 2023 load level.

Circuit RU14 is approximately 9 miles long and has no ties to other circuits. The main three-phase line is approximately 6 miles long. The first 3 miles are 336 ACSR and the next 3 miles are 2A CWC. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

13.3.9.2 Recommended Plan

It is recommended that the three-phase feeder mains of Circuits RU12 and RU13 be converted from 7.2/12.47 kV to 14.4/24.94 kV. The Rumney Substation transformer has a dual voltage secondary (7.2/12.47 and 14.4/24.94 kV) to facilitate the conversion to the higher distribution voltage. Due to a combination of load, length and conductor size, the possibility of low voltage is increasing. No transmission lines or other potential power sources appear to be in the area to enable dividing the load to improve voltage.

Project 368 is the replacement of 1.8 miles of an old vee-phase 6A CWC line with single-phase 1/0 tree wire. The existing poles and conductor are in poor condition and the line is difficult to access. The new line will be located along road right-of-way. This project was included in year 3 of the <u>2001-2005 Construction Work Plan</u>.

Project 369 is the replacement of 2.0 miles of an old single-phase 6A CWC line with single-phase 1/0 tree wire. The existing poles and conductor are in poor condition. The new line should be extended to provide a loop with the nearby single-phase line. This project was included in year 3 of the <u>2001-2005 Construction Work Plan</u>.

13.3.10 Thornton Substation Service Area

13.3.10.1 Existing System Review

The Thornton Substation is forecasted to serve 7.5 MW of peak load in 2023. The Thornton area is served by two 7.2/12.47 kV circuits (TN11 and TN12) and one 14.4/24.94 kV circuit (TN23). Circuit TN11 serves approximately 21 percent of the total load, TN12 serves 55 percent and TN23 serves the remaining 24 percent.

Circuit TN11 is approximately 8 miles long and has no ties to other circuits. The main three-phase line is approximately 4.4 miles long. The first 0.6 miles are 350 MCM aluminum underground, the next 1.2 miles are 4 CU and the next 2.6 miles are 1/0 ACSR. No major line capacity deficiencies or areas with low voltage are anticipated during this planning period. The 4 CU main line conductor is undersized given the amount of load.

On Circuit TN12, the 336 ACSR three-phase feeder main splits into north and northeast feeders approximately 0.3 miles from the substation. The north three-phase feeder continues with 336 for another 3.3 miles, then 4 CU for 1.4 miles, then 336 ACSR for 1.0 mile, then 1/0 aluminum underground for 0.5 miles and then 336 ACSR for another 1.2 miles. The ends of the north feeder are about 10 miles from the substation. The northeast three-phase feeder continues with 2 ACSR for 0.5 miles and then 1/0 ACSR for 3.8 miles. The ends of the northeast feeder are about 7 miles from the substation. No major line capacity deficiencies or areas with low voltage are anticipated during this planning period. The 2 ACSR main line conductor is undersized given the amount of load.

Circuit TN23 is approximately 6 miles long and is tied to Circuit WV24 of the Waterville Valley Substation. The main three-phase line is approximately 6 miles long and is 336 ACSR. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period. One single-phase line that serves a residential area is becoming heavily loaded.

13.3.10.2 Recommended Plan

Project TN-2 is the replacement of 1.2 miles of three-phase 4 CU with three-phase 336 ACSR This portion of the main line is expected to reach the end of its useful life during this planning period. The upgrading of the old, small conductor three-phase line along with the reliability project that ties the two radial Circuits TN11 and FG15 together will provide a worthwhile tie line between these two circuits.

Project TN-3 is the replacement of 1.4 miles of three-phase 4 CU with three-phase 336 ACSR This portion of the main line is expected to reach the end of its useful life during this planning period. The upgrading of the old, small conductor three-phase line along with the reliability project that ties the two radial Circuits TN12 and WD11 together will provide a worthwhile tie line between these two circuits.

On Circuit TN23, Project TN-4 will provide additional capacity by converting the single-phase 1/0 aluminum underground line to three-phase 1/0. The existing single-phase line is estimated to have 40 amps of peak load at the 2023 load level. The three-phase line is to be extended into the development so that single-phase taps can balance the load on the three-phase line. Also included in Project TN-4 is a single-phase tie line to provide a loop feed to radial single-phase lines for improved reliability.

13.3.11 Waterville Valley Substation Service Area

13.3.11.1 Existing System Review

The Waterville Valley Substation is forecasted to serve 13.6 MW of peak load in 2023. The Waterville Valley area is served by four 14.4/24.94 kV circuits: WV21, WV22, WV23 and WV24. Circuit WV21 serves approximately 10 percent of the total load, WV22 serves 28 percent and WV23 serves the remaining 62 percent.

Circuit WV21 is approximately 1.5 miles long and is tied to Circuits WV22 and WV23 at several different locations. The main three-phase line is 500 MCM aluminum underground. The estimated peak load is 32 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit WV22 is approximately 1.7 miles long and is tied to Circuits WV21 and WV23 at several different locations. The main three-phase line starts with 0.8 miles of 350 MCM aluminum underground and then has 0.8 miles of 500 MCM aluminum underground and then 0.1 miles of 1/0 aluminum underground. The estimated peak load is 92 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit WV23 is approximately 3.2 miles long and is tied to Circuits WV21 and WV22 at several different locations. The main three-phase line starts with 260 feet of 350 MCM aluminum underground and then has 1.9 miles of 336 ACSR and then 1.2 miles of 1/0 aluminum underground. This circuit serves the Mt. Tecumseh resort and ski area and the estimated peak load on the circuit is 193 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit WV24 is an express feeder that provides a tie between the Waterville Valley Substation and Circuit TN23 of the Thornton Substation. The circuit serves no load except during backup situations. The main three-phase line is 4 miles long and is 336 ACSR.

13.3.11.2 Recommended Plan

Project 387 is a new 2.7 mile 34.5 kV line 336 ACSR (with 14.4/24.94 kV underbuild) from the Waterville Valley Substation to the Mt. Tecumseh resort. This project is contingent upon the load increasing at the resort. It is expected that the consumer will provide a contribution in aid of construction that will cover most of the cost of the project. This project was included in year 4 of the 2001-2005 Construction Work Plan.

13.3.12 Woodstock Substation Service Area

13.3.12.1 Existing System Review

The Woodstock Substation is forecasted to serve 4.6 MW of peak load in 2023. The Woodstock area is served by four 7.2/12.47 kV circuits: WD11, WD12, WD13 and WD14. Circuit WD11 serves approximately 15 percent of the total load, WD12 serves 29 percent, WD13 serves 23 percent and WD14 serves the remaining 33 percent.

Circuit WD11 exits the substation and splits into south and west feeders. The south feeder is about 3.3 miles in length and has no ties to other circuits. The main three-phase line is approximately 2.5 miles long and is 336 ACSR. The west feeder about 6 miles in length and has no ties to other circuits. The main line has 1.6 miles of three-phase 1/0 ACSR. The remaining single-phase lines are mostly 2 ACSR and 1/0 ACSR. The estimated peak load is 31 amps per phase at the 2023 load level. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit WD12 is approximately 1.4 miles long and is tied to Circuit WD14. The first 0.9 miles are 336 ACSR and the next 0.5 miles are 350 MCM aluminum underground. The estimated peak load is 59 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit WD13 is approximately 1.2 miles long and is tied to Circuit LN12 of the Lincoln Substation. The main line consists of 336 ACSR, 350 MCM aluminum underground, 2 ACSR and 1/0 aluminum underground. The estimated peak load is 48 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit WD14 is approximately 6.2 miles long and is tied to Circuit WD12. The main line consists of 336 ACSR and 350 MCM aluminum underground. The estimated peak load is 72 amps per phase at the 2023 load level. No main line capacity deficiencies or areas with low voltage are anticipated during this planning period.

13.3.12.2 Recommended Plan

There are no distribution system primary line construction projects anticipated as necessary for voltage and/or capacity reasons within the Woodstock Substation service area. Projects based on improving reliability are discussed in Section 13.4.

13.4 Distribution System Reliability

13.4.1 Historical Reliability

Overall, the Plymouth District has experienced lower than average distribution system reliability compared to the NHEC system averages over the last three years, ranking fifth of all districts. This is the largest district within the NHEC system, and several larger feeders with significant amounts of load and members have drastically exceeded the reliability design criteria. For example, six of the top ten worst performing feeders on the NHEC system were in the Plymouth District. The following two figures show the average indices for each feeder as well as the entire Plymouth district.

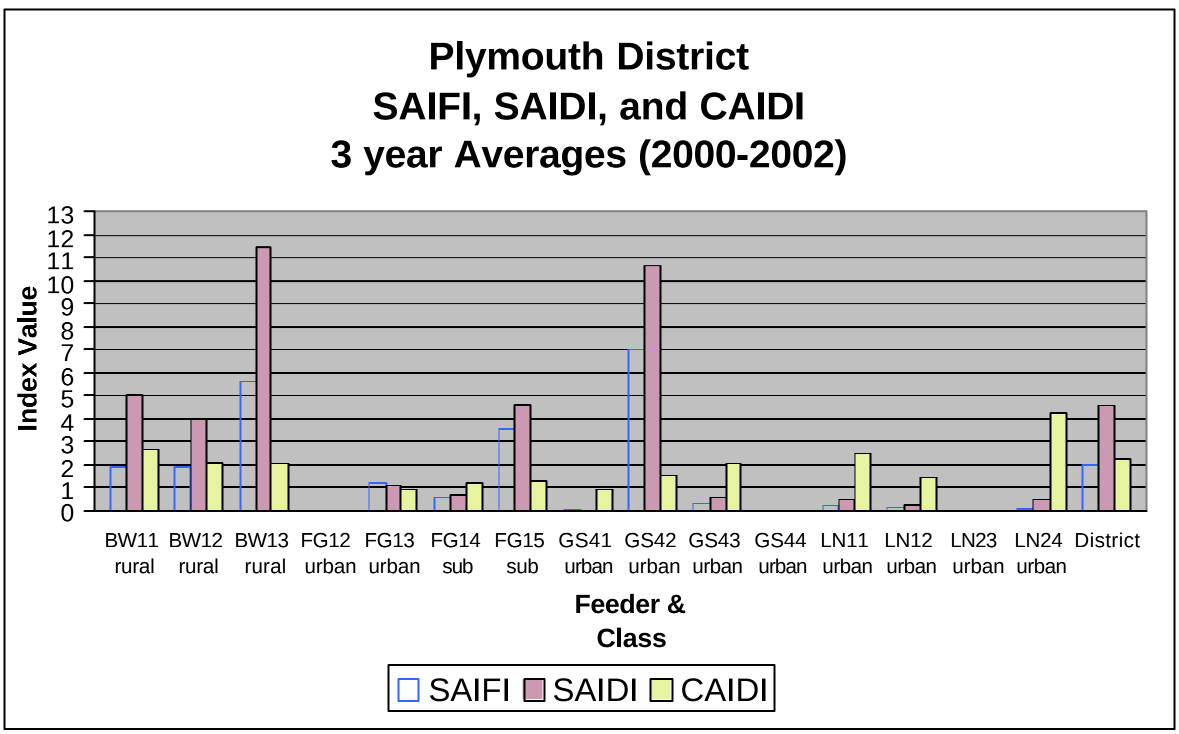


Figure 13-8 Plymouth District Average Reliability Indices

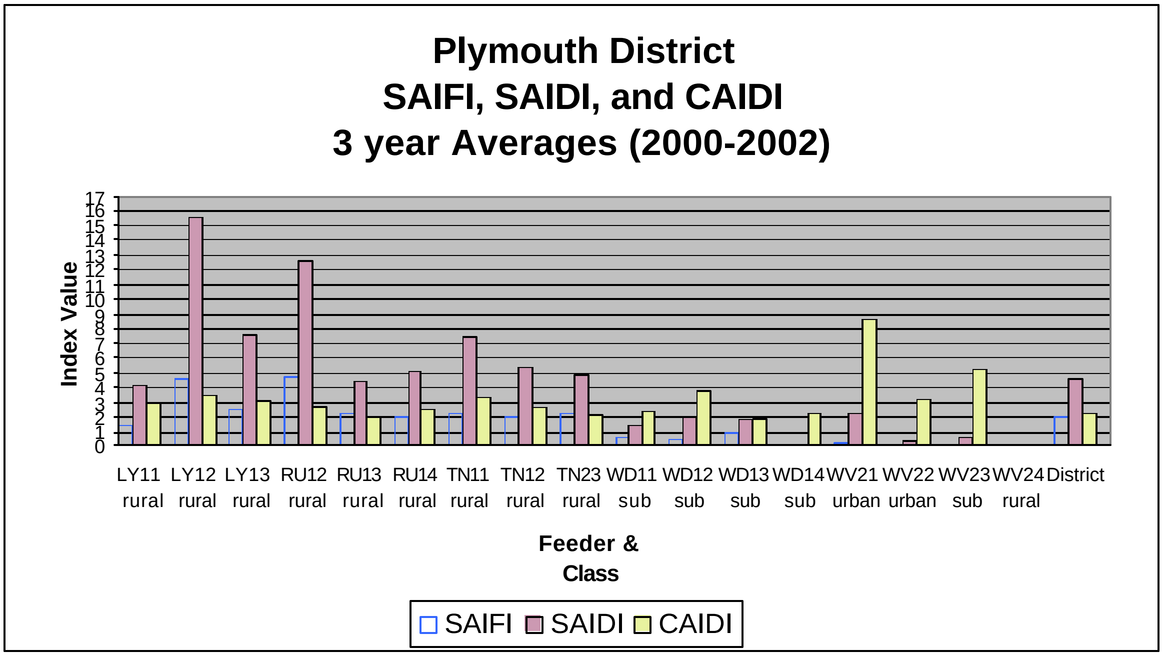


Figure 13-9 Plymouth District Average Reliability Indices

13.4.1.1 SAIDI

The overall SAIDI for the district was 4.56. The two figures above indicate that 11 of the 32 circuits in this district exceeded their SAIDI criteria. The 11 feeders are as follows: BW11, BW13, FG15, GS42, LY12, LY13, RU12, RU14, TN11, TN12, and WV21. Even though this is only about 35% of the feeders, many of these indices were drastically high causing the district average index to significantly increase.

13.4.1.2 SAIFI

Coincidentally, the Plymouth SAIFI index was 2.0, which closely matches the NHEC system index. The target SAIFI value of 2.0 for all feeders, regardless of feeder classification, was exceeded at 10 of the 32 circuits. These circuits are listed as follows: BW13, FG15, GS42, LY12, LY13, RU12, RU13, RU14, TN11, TN23.

13.4.2 Circuits That Exceed Reliability Criteria

13.4.2.1 Circuit BW11

This longer south circuit of the Bridgewater Substation had a SAIDI of 5.05, which just barely exceeds the rural feeder classification limit of 5.0. Outages by cause are reflected in the following figure.

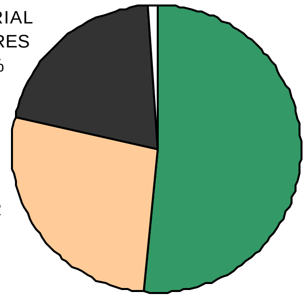


Figure 13-10 Circuit BW11 Percentage of Customer-Minutes Out by Outage Cause

Trees and weather were accountable for the majority of the customer-minutes of outages. An outage analysis by overcurrent protection zone was created to help find the any particular problematic areas. The table is shown below.

Table 13-18 Circuit BW11 Outage Information By Overcurrent Protection Zone

Protection Zone[1]	Recloser Number	Phase	Outages	%	Consumer-Hours	%
1	BW11R	ABC	10	30	3,740	38
2[2]	BW11R13	ABC	10	30	2,407	24
2[3]	BW11R11	ABC	11[4]	32	3,673[4]	37
3	BW11R19	A	3	8	137	1
		Totals	34	100	9,957	100

[1] Recloser-to-recloser, excluding fuses.
[2] Three-phase feeder main to the south
[3] Three-phase tap to the east
[4] Includes one extreme outage affecting 260 members and lasting 9.2 hours (2,380 customer-hours)

The table indicates that outages occurring within the first zone of protection were responsible for more customer-minutes than any other zone. Of the ten outages, two were entire feeder outages lasting about 1.5 hours, and an additional four affected up to 250 members and lasted between two and three hours. These four were caused by recloser failures occurring on the same day.

Currently, circuit BW11 has no ties with any other feeders. Therefore, due to the poor historical reliability, project BW-R1 is recommended to provide backup from circuit CL12 of the Corliss Hill Substation in the Meredith District. Project CL-2 and CL-3 in the Meredith District are needed for voltage and capacity support, therefore making reliability project BW-R1 shorter and less costly. Projects BW-R1, in conjunction with CL-2 and CL-3, will create contingency capability between circuits BW11 and CL12, therefore improving reliability during extreme outages.

Another option to improve reliability is to add a delivery point at the southern tip of circuit BW11. PSNH owns many facilities in this area, in particular the double-circuit 34.5 kV transmission lines 345A and 345B. NHEC's BW11 feeder is less than a mile from these lines, therefore providing incentive to add a new 2,500 kVA, 34.5-7.2/12.47 kV, delivery point for reliability reasons. Although, crossing the Pemigewasett River may complicate this alternative. This project is designated as BW-R1alt on the proposed system diagram.

13.4.2.2 Circuit BW13

With a SAIDI of 11.48, this feeder was the thirst worst performing circuit in the NHEC system. Furthermore, the SAIFI of 5.59 was one of the highest. Outages by customer-minute for the top five causes can be seen in the following figure.

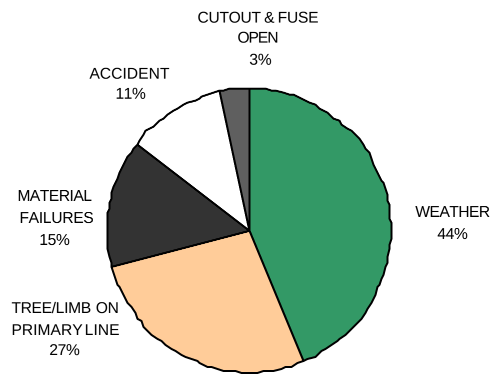


Figure 13-11 Circuit BW13 Percentage of Customer-Minutes Out by Outage Cause

Weather accounted for almost half the customer-minutes of outage. This may be due to the fact that the majority of members on this circuit are located along the north side of Squam Lake. Therefore, extreme weather and strong winds off the lake may be causing these major outages.

Basically, circuit BW13 leaves the substation and then splits into north and east three-phase lines. The northern portion consists of one zone, while the eastern portion along Squam Lake is divided into two three-phase zones. In order to determine where the outages have been occurring during 2000-2002, the following table was created to show outage information by overcurrent protection zone.

Table 13-19 Circuit BW13 Outage Information By Overcurrent Protection Zone

Protection Zone[1]	Recloser Number	Phase	Outages	%	Consumer-Hours	%
1	BW13R	ABC	15	11	16,340	34
2[2]	BW13R12	ABC	20[3]	15	12,680[3]	27
2[4]	BW13R11	ABC	40	30	5,446	11
3	BW13R15	ABC	55	41	12,821	27
3	BW13R16	A	4	3	447	1
		Totals	134	100	47,734	100

[1] Recloser-to-recloser, excluding fuses.
[2] Three-phase feeder main heading east
[3] Does not include outages on tap reclosers BW13R13 or BW13R14 within this zone
[4] Three-phase feeder main heading north

The table shows that the main three-phase first, second, and third zones are very much responsible for the poor reliability on this feeder. The first zone is only about three miles long, and experienced six feeder outages affecting all 1,500 members on the circuit. Only one of these six outages was not weather related. The main three-phase second zone heading to the east also experienced six outages causing reclosers BW13R12 to operate. One of these outages was due to a car vs. pole accident, which lasted almost six hours, accounting for about 5,600 of the 12,680 total consumer-hours. Interestingly, each of these six outages affected 972 members and was responsible for approximately 12,393 of the consumer-hours, or 98% of the total, within this zone. The third zone, starting with recloser BW13R15, experienced 13 outages that caused all 311 members within the zone to be affected. All but three of these outages were tree related. Sixty-four percent of the customer-hours within this third zone were caused by the 13 outages.

Reliability improvements by zone should be considered due to the historical outage diversity within each zone. The six outages within the first zone were weather related, and therefore research into the details of these causes may yield reliability improvement ideas. Outages within the second zone heading east were due to many different outage causes, and therefore, there are no recommendations at this time. The main three-phase third zone of protection along Squam Lake should be given more consideration for increased tree trimming. If standard maintenance practices do not produce better reliability, a fourth or even fifth zone of protection could be considered depending upon the location of faults within the zone. As mentioned, if these do not prove to be successful, the conversion of the single-phase 1/0 ACSR to 1/0 or 4/0 ACSR tree-wire should be considered. For purposes of this plan, reliability project BW-R2 is the conversion to 1/0 ACSR tree-wire for about 5.6 miles. When this project is considered, the option of converting to 4/0 or 336 ACSR should be examined.

Currently, circuits BW13 and ME14, of the Meredith district, are long, radial three-phase feeders. The distance between the three-phase extremities of both circuits is only about one-mile. Therefore, project BW-R3, the partial conversion and addition of 1.0 miles of three-phase 4/0 ACSR, will provide contingency capability between circuits BW13 and ME14.

Project BW-R4 is a very short single-phase tie-line to provide backup capability between circuits BW11 and BW13. The project has the potential to improve reliability for about 200 members.

As explained in the Circuit FG15 reliability portion that follows, project FG-R1 will provide a tie between the two radial circuits FG15 and BW13.

13.4.2.3 Circuit FG15

This Fairgrounds Substation circuit exceeded the SAIDI criteria due to its' classification as a suburban feeder. The SAIDI index for the three-year period was 4.6, while the corresponding SAIFI index was 3.55. The higher SAIFI and somewhat common SAIDI values indicates that there were many members affected on this circuit, but overall the restoration times were not particularly long. The following figure indicates the consumer-hours of outage by the top causes for circuit FG15.

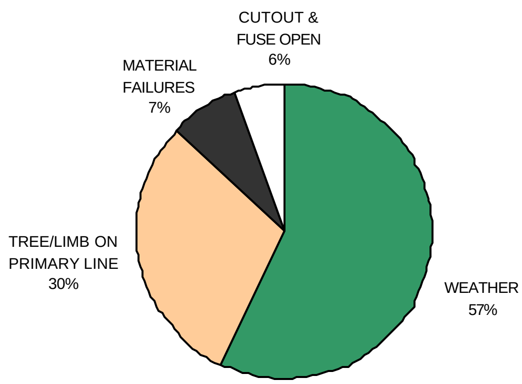


Figure 13-12 Circuit FG15 Percentage of Customer-Minutes Out by Outage Cause

Similar to circuit BW13, weather was primarily responsible for the customer-minutes of outages, followed by tree contact. Four feeder outages were responsible for approximately 30% of the total consumer-hours on this circuit, two of them caused by weather. As previously explained, more specific information should be logged for all future outages due to weather, and all outages in general, to assist in the reliability review and recommendations. Data examples include type of weather, what actually occurred as a result, and the type of equipment failure.

Circuit FG15 currently has a three-phase tie with circuit GS43 of the Green Street Substation, but cannot be used because of the different operating voltages between the two. Although, project GS-3 is the voltage conversion of circuit GS43 from 2.4/416 kV to 7.2/12.47 kV, therefore allowing backup capability.

There are two tie-lines recommended near extremities of circuit FG15, which will provide backup to various portions of circuit FG15. Project FG-R1 is the addition of a very short three-phase tie between circuits FG15 and BW13. The new line should cross the Pemigewasett River near the existing single-phase river crossing if possible.

Project FG-R2 is needed to provide backup between circuits FG15 and TN11 of the Thornton Substation. Since both circuits are radial, the new tie-line will provide significant contingency capability for improved service. Highway 3 is the recommended route for the new line. In addition, this project will become even more beneficial due to project TN-2.

Project FG-R3 and FG-R4 are short single-phase tie-lines to improve reliability for the members on these long, heavily loaded single-phase lines. Potential service improvement can be expected for the 240 members in this area. These projects will also provide more flexibility in normal-open switch locations if needed for voltage or capacity reasons.

13.4.2.4 Circuit GS42

This circuit serves the Plymouth State College, which is primary metered from NHEC's 2.4/4.16 kV line. There were only two distribution outages recorded on this feeder over the 2000-2002 period. Due to the small amount of members on this circuit, the reliability indices were significantly affected causing a higher SAIDI and SAIFI index. Both outages were caused by tree contact and lasted between one and two hours.

Project GS-2, the conversion to 7.2/12.47 kV, may improve reliability as well due to additional tree trimming to accommodate the higher operating voltage line configuration.

13.4.2.5 Circuit LY12

From a reliability index perspective, circuit LY12 was the most unreliable circuit on the entire NHEC system with a SAIDI index of 15.6. The SAIDI indices by year were 17.9, 5.85, and 23.0 for 2000, 2001, and 2002, respectively, which significantly affected the three-year average.

The top three causes contributing to the customer-minutes of outages are shown in the figure below.

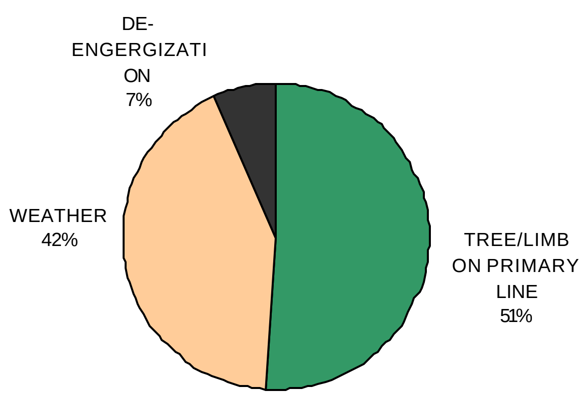


Figure 13-13 Circuit LY12 Percentage of Customer-Minutes Out by Outage Cause

More than 50% of the outage-minutes were due to tree contact, with the remaining caused by weather. Four feeder outages, each lasting between two and three hours, caused about 20% of the total customer-minutes. Furthermore, 21 outages affected more than 100 members. The average duration of these outages was nearly four hours. Considering all outages on this feeder, the average outage duration was 3.8 hours. Therefore, obviously, there is a deficiency in outage restoration times on this circuit. Cooperative personnel indicated that the travel time to this area is in excess of one hour. Furthermore, during major outages throughout the, the Lyme metering point is the last area to be restored because of its location. Therefore, fault indicators, additional reclosing devices, or an overcurrent protection review in conjunction with a more detailed outage and reliability analysis may prove to be beneficial. In aid of this, the following table was created to help locate problematic areas.

Table 13-20 Circuit LY12 Outage Information By Overcurrent Protection Zone

Protection Zone[1]	Recloser Number	Phase	Outages	%	Consumer-Hours	%
1	LY12R11	ABC	28	54	13,596	73
2	LY12R13	AC	10	19	3,942	22
2	LY12R12	B	14	27	980	5
		Totals	52	100	18,518	100
[1] Recloser-to-recloser, excluding fuses.						

Almost three-quarters of the consumer-hours occurred within the first three-phase protection zone. The main line on this feeder is 1/0 ACSR and therefore meets criteria from a voltage and capacity standpoint. Therefore, it is difficult to justify any capital improvement that may only provide reliability incentive to the 400 members on this feeder. First, steps should be taken to help resolve the excessive outage durations. After the outage duration reduction project is implemented, steps can be taken to reduce the occurrence of outages within the first zone of protection on circuit LY12. Possibilities include more frequent tree trimming, or the conversion to tree wire or underground cable.

There are no proposed projects on this feeder for reliability reasons.

13.4.2.6 Circuit LY13

From 2000-2002, the SAIDI reliability index gradually increased from 4.4 to 10.0. There are only about 18 members are served by this short feeder, therefore the smallest outages drastically affect the outage indices. Furthermore, this circuit only contains one zone of protection, besides a few short, fused single-phase taps, that causes an outage on the entire circuit during any main line outage. This is most likely due to the fact that most of the members are served on the one long single-phase tap at the end of the line, therefore making additional zones unnecessary. The following figure indicates consumer-hour of outages by cause.

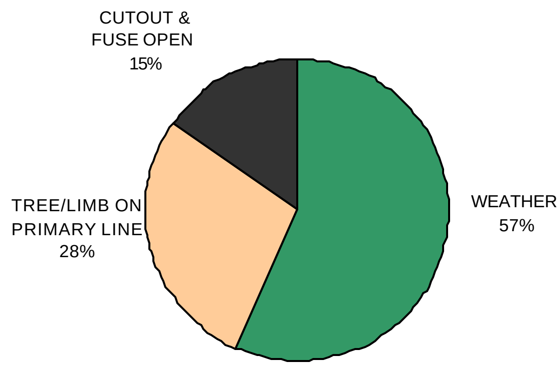


Figure 13-14 Circuit LY13 Percentage of Customer-Minutes Out by Outage Cause

There were only six outages on this circuit over the three-year period, although four of them were of significantly long duration therefore increasing the reliability statistics.

There are no proposed projects on this feeder for reliability reasons. Steps should be taken to help resolve the excessive outage durations, followed by a listing a potential solutions.

13.4.2.7 Circuit RU12

Outages in 2002 caused the three-year average SAIDI index on circuit RU12 to become the second worst in the entire NHEC system due to a SAIDI of almost 30. This was obviously due to many high consumer-hour outages. For example, the average outage for the three-year period affected about 105 members and lasted approximately 2.8 hours.

Cause categories for the three highest consumer-minutes of outages can be seen below.

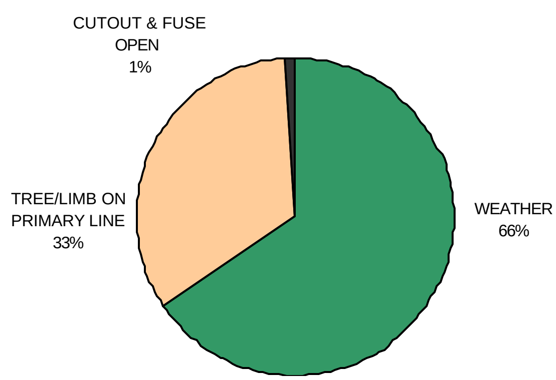


Figure 13-15 Circuit RU12 Percentage of Customer-Minutes Out by Outage Cause

The figure indicates that weather and tree contact contributed almost all the consumer-hours of outages.

Circuit RU12 is one of the longest feeders in the Plymouth District and contains five zones of protection. The following table indicates number of outages and consumer-hours of outages by zone.

Table 13-21 Circuit RU12 Outage Information By Overcurrent Protection Zone

Protection Zone[1]	Recloser Number	Phase	Outages	%	Consumer-Hours	%
1[2]	RU12RA	ABC	16	14	6,550	15
2[3]	RU12AR11	ABC	9	8	1,270	3
2	RU12AR14	ABC	29	25	12,400	28
3[4]	RU12AR15	ABC	12	10	1,506	3
3	RU12AR17	ABC	13	11	9,150	20
3[4]	RU12AR18	AC	12	10	1,600	4
4	RU12AR19	AC	7	6	9,500	21
5	RU12AR22	AC	18	16	2,800	6
		Totals	116	100	44,776	100

[1] Recloser-to-recloser, excluding fuses.
[2] Includes one feeder outage of 5,585 consumer-hours
[3] Three-phase tap heading north near substation
[4] Three-phase tap off second zone protected by RU12AR14

One feeder outage occurred in the first three-phase zone that lasted over four hours and was responsible for 5,584 customer-hours of outages. The main three-phase second zone is the longest zone on the feeder, and accumulated the highest number of outages and consumer-hours of outages. Of the 29 outages within this zone, seven caused the protecting reclosers to operate and affect all 1,200 members downline.

The possibility of adding another delivery point near the southern half of circuit RU12 was researched, but PSNH transmission facilities did not appear to be located within a reasonable distance.

Project RU-2, the conversion from 7.2/12.47 kV to 14.4/24.9 kV as discussed in the preceding Distribution System report section, may help reduce future outages if proper O&M on this portion of line is completed in conjunction with the project.

Reliability project RU-R1 is a single-phase tie that will provide contingency capability to the members in the area.

13.4.2.8 Circuit RU13

This circuit had a three-year average SAIFI of 2.2 and SAIDI of 4.4. The SAIFI just exceeded the SAIFI criteria of 2.0, while the SAIDI criterion was slightly worse than the NHEC system and district averages. This feeder is another one of the longest in the Plymouth District, and therefore performed rather reliably when considering the configuration.

The following figure indicates the consumer-hours of outage by the top causes for circuit RU13.

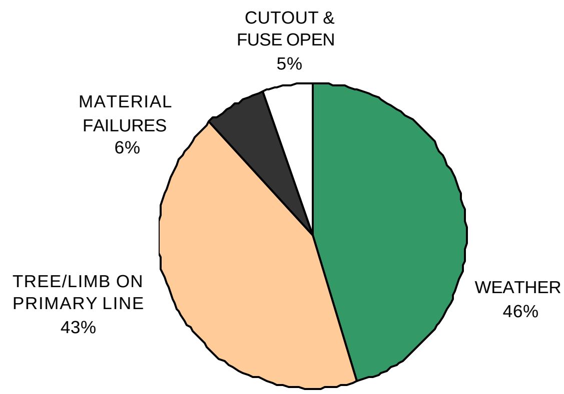


Figure 13-16 Circuit RU13 Percentage of Customer-Minutes Out by Outage Cause

Similar to circuit RU12, weather and trees contributed the vast majority of the consumer-hours of outages. Only one outage, which lasted less than 0.5 hours, caused all members on this circuit to be affected. More than 90% of the consumer-hours of outage were due to outages occurring within the second through last zone of protection. In particular, six outages within the second zone caused the reclosers to operate, which caused all 700 members within the zone to be affected. Therefore, proper O&M practices should prove to yield satisfactory reliability in the future.

The possibility of adding another delivery point near the northern portion of circuit RU12 was researched, but PSNH transmission facilities did not appear to be located within a reasonable distance. Furthermore, NHEC facilities are not located within a reasonable distance to justify any interconnections with circuit RU13.

Projects RU-R2 and RU-R3 are recommended to improve looped capability on the existing longer single-phase lines. These proposed tie-lines will allow greater flexibility in selecting future normal-open switch locations as well.

13.4.2.9 Circuit RU14

This radial circuit heads to the east from the substation and then the major three-phase line turns to the north. Both the SAIFI and SAIDI index values barely exceeded the reliability criteria. The following figure indicates the consumer-hours by cause.

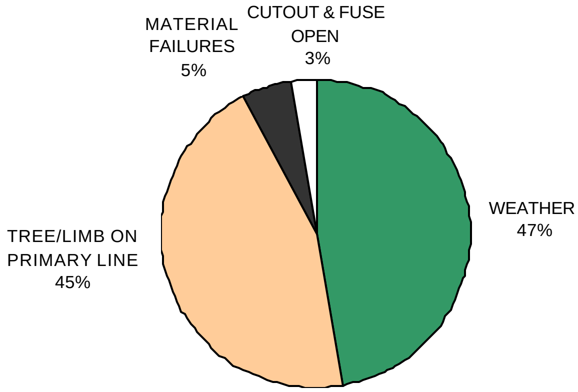


Figure 13-17 Circuit RU14 Percentage of Customer-Minutes Out by Outage Cause

Once again, this figure indicates weather and trees were responsible for almost all the consumer-hours. In fact, these two causes were responsible for more than 90% of the outages that occurred within the entire Rumney Substation service area.

Since this circuit's reliability was generally adequate for the three-year sample period, and did not experience too many extreme outages, it is believed that general O&M practices should yield improved reliability in the future.

Project RU-4 is the addition of 2.2 miles of three-phase 336 ACSR to be operated at 14.4/24.9 kV. Also included in this project are the conversion of the feeder main between Rumney and Fairgrounds Substations, and the addition of two 14.4/24.9 kV – 7.2/12.47 kV step-down transformers. One is needed to serve the members on the north three-phase line of circuit RU14, and the other needs to be located between circuits RU14 and FG14 due to the different operating voltages. This transformer should be sized for contingencies between the Rumney and Fairgrounds substations service areas.

13.4.2.10 Circuit TN11

Circuit TN11 is a shorter feeder that heads south from the Thornton Substation. The following figure indicates the consumer-hours of outage by the top causes for circuit TN11.

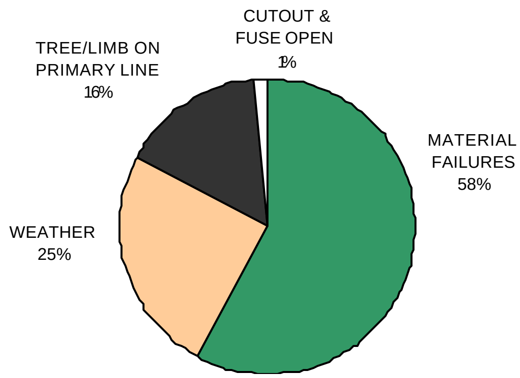


Figure 13-18 Circuit TN11 Percentage of Customer-Minutes Out by Outage Cause

There were three feeder outages on this circuit over the three-year period. Two of these outages had durations of 8.2 and 2.9 hours, which dramatically affected the SAIDI index of 7.46. In fact, these two outages were responsible for over 50% of the total customer-minutes on the feeder. In addition, these two large outages were caused by material failure causing the above figure to be somewhat misleading.

Currently, circuit TN11 is radial. Project FG-R2, as discussed in the FG15 reliability section, will complete a three-phase tie between the Thornton and Fairgrounds Substations. When complete, circuit FG15 will be able to serve circuit TN11 during major outages, such as the two major feeder outages that occurred due to material failures.

13.4.2.11 Circuit TN12

The following figure indicates the consumer-hours of outage by the top causes for circuit TN12.

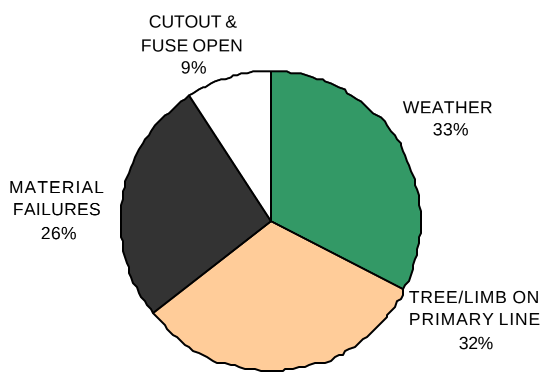


Figure 13-19 Circuit TN12 Percentage of Customer-Minutes Out by Outage Cause

The top three causes were fairly equal in contribution of customer-minutes of outages. Individual outage evaluation indicates that there were no feeder outages over the 2000-2002 period, which is rather surprising since the main three-phase zone of protection extends almost to the end of the main line. The majority of members on this feeder are located along two three-phase taps that head to the east off the main feeder. In fact, over 70% of the consumer-hours of outages occurred on the two taps. The two taps are radial, but run parallel to the main three-phase feeder with nearby tie points. Therefore, project TN-R1 is the addition of a three-phase tie-line to provide looped capability for the 600 members on the first major tap, and will also provide incentive to a portion of the second major three-phase tap. Project TN-R2 is a short, single-phase tie-line to improve reliability for the members on the single-phase radial line.

Project TN-R3, the addition of three-phase 336 ACSR, is recommended to improve backup between the Thornton and Woodstock Substations. This will be effective during any major transmission, substation, or major feeder outages.

13.4.2.12 Circuit TN23

The following figure indicates the consumer-hours of outage by the top causes for circuit TN23.

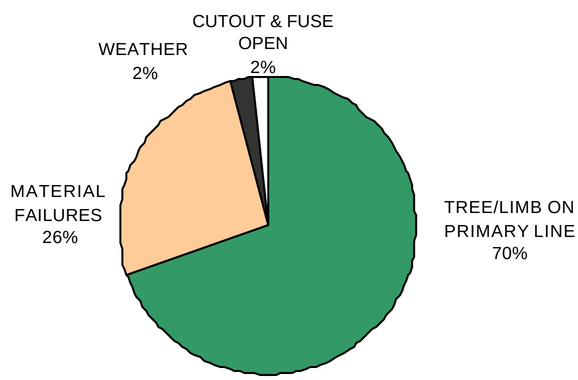


Figure 13-20 Circuit TN23 Percentage of Customer-Minutes Out by Outage Cause

The figure indicates that tree contact was responsible for the majority of customer-minutes of outages. Increased tree trimming and/or tree wire may provide the reduction in outages.

There were only 17 outages on the entire circuit during the sample period, but six of them were feeder outages affecting all members on the circuit. Currently, only one zone of protection exists on the feeder since there are no significant taps off the main line. Therefore, any faults along the six-miles of three-phase will affect all members on the circuit since there is a three-phase recloser at the substation. Another option of replacing the three-phase recloser with a one that has various trip/open capabilities, such as a Cooper Triple-Single recloser, or the Schweitzer SEL-651, may prove to be effective. This will allow single-phase lockout to be used during normal system configuration, and three-phase lockout during contingencies with the Waterville Valley Substation.

Depending upon the location of the outages along the main line, an additional zone of protection could be established to minimize the number of members affected. In this case, the overcurrent protection device would have to be sized and configured for contingency situations with the Waterville Valley Substation.

There are no projects recommended for reliability reasons on circuit TN23.

13.4.2.13 Circuit WV21

For the most part, the Waterville Valley Substation experienced very high reliability during the 2000-2002 time period, with a SAIDI index near 0.25. Although, circuit WV21 had an average SAIDI index of 2.29, which exceeded the urban feeder classification. This was due to a very unreliable year in 2002 due to a single outage that lasted 11.6 hours and affected 150 members. There was only one outage in 2000 and no outages in 2001 on this circuit.

The following figure indicates the consumer-hours of outage by the top causes for circuit WV21.

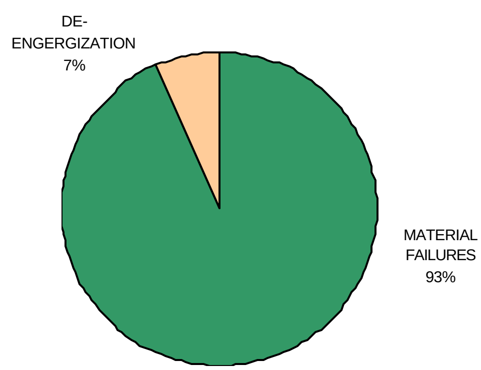


Figure 13-21 Circuit WV21 Percentage of Customer-Minutes Out by Outage Cause

As previously explained, there were two outages on this feeder, each due to a different cause as shown above.

Circuit WV21 is very short in length, and entirely underground, which helps the overall circuit reliability.

There are no projects recommended for reliability reasons on circuit WV21.

13.4.3 Circuits That Meet Reliability Criteria

13.4.3.1 Circuit BW12

Project BW-R5 is recommended to form a three-phase tie-line between circuits BW11 and GS41 of the Green Street Substation. Currently, the Green Street substation and service area are operated at 2.4/4.16 kV, so there exists no contingency capability between Green Street and any other surrounding sources. Although, since it is recommended that Green Street be upgraded to 7.2/12.47 kV, the tie-line project BW-R5 will be useful. During an outage at the Bridgewater Substation, the tie-line will allow Green Street circuit GS41 or Fairgrounds circuit FG13 to backup circuit BW12, therefore providing load relief for any other circuits such as GS44, ME14, or CL12 to serve the remaining Bridgewater circuits.

13.4.3.2 Circuit FG13

This circuit has experienced great reliability during 2000-2002. The only reliability-based project on this circuit is a single-phase tie-line between two single-phase taps along New Hebron Road. The project is designated as FG-R5.

13.4.3.3 Circuit FG14

A three-phase tie-line between circuits FG14 and RU13 is discussed in the Rumney Substation Circuit RU13 reliability report section. A portion of the circuit FG14 service territory will be transferred to circuit RU13.

13.4.3.4 Circuits LN11 and LN24

To provide contingency capability between circuits LN11 and LN24, it is recommended that a 14.4/24.9 kV – 7.2/12.47 kV step-down transformer be installed between both circuits. The location of the transformer should be near the end of circuit LN11, which will provide additional potential during contingencies. This project is designated as LN-R1.

13.5 Cost Estimates

A summary of the cost estimate for the proposed 5-Year, 10-Year and 20-Year Plans is provided in the following table. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in the previous sections and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 13.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 13-22 Construction Cost Summary

	2004-2008 Cost ($)	2009-2013 Cost ($)	2014-2023 Cost ($)	2004-2023 Cost ($)
New Tie Lines	0	0	0	0
Conversions and Line Changes	245,000	1,671,600	541,760	2,458,360
New Substations, DP's and MP's	0	0	0	0
Substation, DP and MP Changes	0	446,000	569,000	1,015,000
Total	245,000	2,117,600	1,110,760	3,473,360
Projects for Improved Reliability	60,000	898,300	1,260,530	2,218,830

Table 13-23 Substation Load Data Projections

Substation Delivery Point or Meter Point Name	Ckt.	Season	Existing System Configuration 2003 Load kW	2008 Load kW	2013 Load kW	2023 Load kW	Proposed System Configuration 2008 Load kW	2013 Load kW	2023 Load kW
Bridgewater	BW11	W	1,081	1,144	1,207	1,340	1,144	1,207	1,340
	BW12	W	404	422	440	477	422	440	477
	BW13	W	3,256	3,399	3,544	3,853	3,399	2,624	2,853
	Sub		4,741	4,965	5,191	5,670	4,965	4,271	4,670
Fairgrounds	FG12	W	1	2	2	2	2	2	2
	FG13	W	1,912	1,975	2,086	2,194	1,975	2,600	2,712
	FG14	W	3,160	4,534	4,653	4,802	4,534	2,530	2,635
	FG15	W	2,113	2,182	2,306	2,427	2,182	2,306	2,427
	Sub		7,186	8,693	9,047	9,425	8,693	7,438	7,776
Green Street	GS41	W	919	947	978	1,043	947	2,550	2,654
	GS42	W	0	0	0	0	0	0	0
	GS43	W	853	880	908	970	880	908	970
	GS44	W	325	435	547	720	435	1,447	1,720
	Sub		2,097	2,262	2,433	2,733	2,262	4,905	5,344
Lincoln	LN11	W	1,930	2,052	2,134	2,256	2,052	2,134	2,256
	LN12	W	3,222	3,425	3,562	3,765	3,425	3,562	3,765
	LN23	W	7,974	8,475	8,814	9,315	8,475	8,814	9,315
	LN24	W	7,886	5,194	5,400	5,709	5,194	5,400	5,709
	Sub		21,012	19,146	19,910	21,045	19,146	19,910	21,045
Lyme	LY11	W	390	426	449	507	426	449	507
	LY12	W	467	512	538	607	512	538	607
	LY13	W	344	349	351	357	349	351	357
	Sub		1,201	1,287	1,338	1,471	1,287	1,338	1,471
Rumney	RU11	W	2,153	2,263	2,337	2,538	2,263	2,337	2,538
	RU12	W	2,838	2,967	3,155	3,490	2,967	3,155	3,490
	RU13	W	994	1,043	1,075	1,162	1,043	1,075	1,162
	Sub		5,985	6,273	6,567	7,190	6,273	6,567	7,190
Thornton	TH11	W	953	1,116	1,284	1,604	1,116	1,284	1,604
	TH12	W	2,179	2,829	3,387	4,090	2,829	3,387	4,090
	TH23	W	1,116	1,275	1,434	1,785	1,275	1,434	1,785
	Sub		4,248	5,220	6,105	7,479	5,220	6,105	7,479
Waterville Valley	WV21	W	1,063	1,131	1,201	1,353	1,131	1,201	1,353
	WV22	W	2,704	2,961	3,222	3,797	2,961	3,222	3,797
	WV23	W	8,140	8,212	8,287	8,448	8,212	8,287	8,448
	WV24	W	0	0	0	0	0	0	0
	Sub		11,907	12,304	12,710	13,598	12,304	12,710	13,598
Woodstock	WD11	W	592	629	655	691	629	655	691
	WD12	W	1,138	1,209	1,257	1,328	1,209	1,257	1,328
	WD13	W	906	965	1,002	1,059	965	1,002	1,059
	WD14	W	1,317	1,401	1,457	1,540	1,401	1,457	1,540
	Sub		3,953	4,204	4,371	4,618	4,204	4,371	4,618
Plymouth District			**62,330**	**64,354**	**67,672**	**73,229**	**64,354**	**67,615**	**73,191**

Table 13-24 Construction Cost Details

(see following 2 pages)

Project Code	YR	Sub/Ckt	Project Description	Reason Code	@ Load (amps) [1]	Miles	Estimated Cost ($)
I. New Tie Lines							
		Total New Tie Lines				0.00	0
II. Conversions and Line Changes							
BW-2	2023	Bridgewater / BW11	1ph 1/0 ACSR to 2ph 1/0 ACSR (add 1)	D	30	0.30	5,460
BW-3	2013	Bridgewater / BW13	1ph 1/0 ACSR to 2ph 1/0 ACSR (add 1)	D	25	0.10	1,950
BW-4	2023	Bridgewater / BW13	3ph 4 CU to 3ph 336 ACSR	A,C,V	50	2.20	217,800
BW-5	2013	Bridgewater / BW13	3ph 4 CU & 2A CWC to 3ph 336 ACSR	A,B,S	[1]	1.30	128,700
FG-1	2013	Fairgrounds / FG-13	1ph & 3ph 1/0 ACSR to 3ph 336 ACSR	B,C,V	[1],[2]	3.00	400,950
GS-1	2013	Green Street / GS41	2.4/4.16 kV to 7.2/12.47 kV 3ph 336 ACSR	A,B,C,V	[3]		65,000
GS-2	2013	Green Street / GS42	2.4/4.16 kV to 7.2/12.47 kV 3ph 336 ACSR	A,B,C,V	[3]		10,000
GS-3	2013	Green Street / GS43	2.4/4.16 kV to 7.2/12.47 kV 3ph 336 ACSR	A,B,C,V	[3]		150,000
GS-4	2013	Green Street / GS44	2.4/4.16 kV to 7.2/12.47 kV 3ph 336 ACSR	A,B,C,V	[3]		50,000
RU-2	2013	Rumney / RU12	Convert 7.2/12.47 kV to 14.4/24.94 kV	C,V	[4]		530,000
RU-3	2013	Rumney / RU13	Convert 7.2/12.47 kV to 14.4/24.94 kV	C,V	[4]		335,000
368	2004	Rumney / RU13	2ph 6A CWC to 1ph 1/0 tree wire	WP	-	1.80	45,000
369	2004	Rumney / RU13	1ph 6A CWC to 1ph 1/0 tree wire	WP	-	2.00	100,000
TN-2	2023	Thornton / TN11	3ph 4 CU to 3ph 336 ACSR	A,B,C,V	50	1.20	118,800
TN-3	2023	Thornton / TN12	3ph 4 CU to 3ph 336 ACSR	A,B,C,V	50	1.40	138,600
TN-4	2023	Thornton / TN13	1ph 1/0 AL UG to 3ph 1/0 AL UG	D	30	0.50	61,100
387	2004	Waterville /	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	WP	-	2.70	100,000
		Total Conversions and Line Changes				16.50	2,458,360
III. Projects that have Potential Reliability Improvement							
BW-R1	2023	Bridgewater / BW11	1ph 1/0 ACSR to 3ph 4/0 ACSR			4.00	340,000
BW-R1 Alt	2023	Bridgewater / BW11	New Delivery Point			-	150,000
BW-R2	2013	Bridgewater / BW13	3ph 1/0 ACSR to 3ph 1/0 tree wire			5.60	280,000
BW-R3	2023	Bridgewater / BW13	3ph 1/0 ACSR to 3ph 336 ACSR			2.80	277,200
BW-R4	2023	Bridgewater / BW13	1ph 1/0 ACSR			0.10	6,600
BW-R5	2013	Bridgewater / BW12	1ph 2 CU to 3ph 336 ACSR			2.30	227,700
FG-R1	2023	Fairgrounds / FG-15	3ph 4/0 ACSR			0.40	45,900
FG-R2	2023	Fairgrounds / FG-15	1ph & 2ph various to 3ph 336 ACSR			2.80	277,200
FG-R3	2023	Fairgrounds / FG-15	1ph 1/0 ACSR			0.30	18,480
FG-R4	2023	Fairgrounds / FG-15	1ph 1/0 ACSR			0.30	18,480
FG-R5	2023	Fairgrounds / FG-13	1ph 1/0 ACSR			0.30	18,480
LN-R1	2008	Lincoln / LN11	2:1 Stepdown tie transformer, 5,000 kVA			-	60,000
RU-R1	2023	Rumney / RU12	1ph 1/0 ACSR			0.10	6,600
RU-R2	2023	Rumney / RU13	1ph 1/0 ACSR			0.20	12,760
RU-R3	2023	Rumney / RU13	1ph 1/0 ACSR			0.10	6,600
RU-R4	2013	Rumney / RU14	Convert 7.2/12.47 kV to 14.4/24.94 kV			-	325,000
TN-R1	2023	Thornton /TN12	1ph 1/0 ACSR to 3ph 4/0 ACSR			0.60	63,750
TN-R2	2023	Thornton /TN12	1ph 1/0 ACSR			0.30	18,480
TN-R3	2013	Thornton /TN12	1ph 336 ACSR to 3ph 336 ACSR (add 2)			1.60	65,600
		Total Potential Reliability Improvements				21.80	2,218,830
		Total of all projects				38.30	4,677,190
		Total by year for first 4 years (includes reliability projects)					
	2004					6.50	245,000
	2005					0.00	0
	2006					0.00	0
	2007					0.00	0
	2008					0.00	60,000
	2013					13.90	2,569,900
	2023					17.90	1,802,290
			Total			38.30	4,677,190

Reason Code(s)

- A To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life
- B To improve **B**ackup between circuits and substations.
- C To provide additional **C**apacity.
- D To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
- F To accommodate **F**uture load.
- S To accommodate new **S**ystem configuration as a result of other projects.
- U To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
- V To improve **V**oltage.
- WP As per NHEC 2001-2005 Construction **W**ork **P**lan.
- [1] Recommended soon after the Green Street Substation is converted to 7.2/12.47 kV.
- [2] Recommended when the peak load on FG14 reaches 200 amps/per phase.
- [3] Recommended when the Green Street 2.4/4.16 kV facilities need replacement due to age and deterioration and/or when improved backup service to the Fairgrounds Substation service area is desired.
- [4] Recommended when the peak load on RU12 reaches 100 amps/per phase or when the peak load on RU13 reaches 150 amps/per phase.

[1] @ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				0
2009-2013 Time Period				0
2014-2023 Time Period				0
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				0
2009-2013 Time Period				
GS-5	2013	Green Street	Upgrade with new 10,000 kVA transformer, 34.5-7.2/12.5 kV	170,000
GS-5	2013	Green Street	Upgrade with 3 new 656 amp voltage regulators, 7.2 kV units	46,000
GS-5	2013	Green Street	Structure and bus modifications	200,000
GS-5			Total	416,000
GS-5	Project JS-5 is recommended when the Green Street 2.4/4.16 kV facilities need replacement due to age and deterioration and/or when improved backup service to the Fairgrounds Substation service area is desired.			
2014-2023 Time Period				
BW-1	2023	Bridgewater	Upgrade with new 7,500 kVA transformer, 34.5-7.2/12.5 kV	140,000
BW-1	2023	Bridgewater	Upgrade with 3 new 438 amp voltage regulators	32,000
BW-1			Total	172,000
RU-3	2013	Rumney	Replace 7.2 kV regulators with 3 new 347 amp, 14.4 kV units	30,000
TN-1	2023	Thornton-T1	Upgrade with new 7,500 kVA transformer, 34.5-7.2/12.5 kV	140,000
TN-1	2023	Thornton-T1	Upgrade with 3 new 438 amp voltage regulators, 7.2 kV units	32,000
TN-1	2023	Thornton-T2	Upgrade with new 10,000 kVA transformer, 34.5-14.4/24.9 kV	195,000
TN-1	2023	Thornton-T2	Upgrade with 3 new 347 amp voltage regulators, 14.4 kV units	30,000
TN-1			Total	397,000
			Total 2014-2023	599,000
			Total 2004-2023	1,015,000

Table 13-25 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
PLYMOUTH	BW11	2000	1,512	2,977	636		2.38	4.68	1.97
		2001	1,280	1,927	636		2.01	3.03	1.51
		2002	888	4,730	636		1.40	7.44	5.33
	Totals		3,680	9,634	1,908	Average	1.93	5.05	2.62
	BW12	2000	202	407	261		0.77	1.56	2.01
		2001	962	2,310	261		3.69	8.85	2.40
		2002	316	398	261		1.21	1.52	1.26
	Totals		1,480	3,115	783	Average	1.89	3.98	2.10
	BW13	2000	4,580	7,235	1,438		3.18	5.03	1.58
		2001	11,437	23,845	1,438		7.95	16.58	2.08
		2002	8,105	18,450	1,438		5.64	12.83	2.28
	Totals		24,122	49,530	4,314	Average	5.59	11.48	2.05
	FG12	2000	0	0	1		0.00	0.00	0.00
		2001	0	0	1		0.00	0.00	0.00
		2002	0	0	1		0.00	0.00	0.00
	Totals		0	0	3	Average	0.00	0.00	0.00
	FG13	2000	1,019	775	662		1.54	1.17	0.76
		2001	1,152	886	662		1.74	1.34	0.77
		2002	220	418	662		0.33	0.63	1.90
	Totals		2,391	2,079	1,986	Average	1.20	1.05	0.87
	FG14	2000	303	97	591		0.51	0.16	0.32
		2001	341	548	591		0.58	0.93	1.61
		2002	304	500	591		0.51	0.85	1.64
	Totals		948	1,145	1,773	Average	0.53	0.65	1.21
	FG15	2000	2,222	2,929	1,118		1.99	2.62	1.32
		2001	5,146	6,788	1,118		4.60	6.07	1.32
		2002	4,534	5,727	1,118		4.06	5.12	1.26
	Totals		11,902	15,444	3,354	Average	3.55	4.60	1.30
	GS41	2000	0	0	302		0.00	0.00	0.00
		2001	0	0	302		0.00	0.00	0.00
		2002	23	20	302		0.08	0.07	0.87
	Totals		23	20	906	Average	0.03	0.02	0.87
	GS42	2000	10	14	1		10.00	14.00	1.40
		2001	11	18	1		11.00	18.00	0.00
		2002	0	0	1		0.00	0.00	0.00
	Totals		21	32	3	Average	7.00	10.67	1.52
	GS43	2000	20	33	223		0.09	0.15	1.65
		2001	112	287	223		0.50	1.29	2.56
		2002	37	27	223		0.17	0.12	0.73
	Totals		169	347	669	Average	0.25	0.52	2.05
	GS44	2000	0	0	55		0.00	0.00	0.00
		2001	0	0	55		0.00	0.00	0.00
		2002	0	0	55		0.00	0.00	0.00
	Totals		0	0	165	Average	0.00	0.00	0.00
	LN11	2000	15	60	458		0.03	0.13	4.00
		2001	166	407	458		0.36	0.89	2.45
		2002	75	168	458		0.16	0.37	2.24
	Totals		256	635	1,374	Average	0.19	0.46	2.48
	LN12	2000	146	161	1,012		0.14	0.16	1.10
		2001	279	313	1,012		0.28	0.31	1.12
		2002	43	181	1,012		0.04	0.18	4.21
	Totals		468	655	3,036	Average	0.15	0.22	1.40
	LN23	2000	0	0	1		0.00	0.00	0.00
		2001	0	0	1		0.00	0.00	0.00
		2002	0	0	1		0.00	0.00	0.00
	Totals		0	0	3	Average	0.00	0.00	0.00
	LN24	2000	13	18	1,105		0.01	0.02	1.38
		2001	38	129	1,105		0.03	0.12	3.39
		2002	302	1,362	1,105		0.27	1.23	4.51
	Totals		353	1,509	3,315	Average	0.11	0.46	4.27
	LY11	2000	242	899	192		1.26	4.68	3.71
		2001	291	695	192		1.52	3.62	2.39
		2002	263	795	192		1.37	4.14	3.02
	Totals		796	2,389	576	Average	1.38	4.15	3.00
	LY12	2000	1,969	7,094	396		4.97	17.91	3.60
		2001	657	2,315	396		1.66	5.85	3.52
		2002	2,821	9,110	396		7.12	23.01	3.23
	Totals		5,447	18,519	1,188	Average	4.59	15.59	3.40
	LY13	2000	30	80	18		1.67	4.44	2.67
		2001	58	150	18		3.22	8.33	2.59
		2002	47	180	18		2.61	10.00	3.83
	Totals		135	410	54	Average	2.50	7.59	3.04

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side"Outages).*

14.0 Raymond District

14.1 Load Analysis

The Raymond District contains six delivery points, which accounted for 10.2 percent of NHEC's load in 2002. The delivery points of Brentwood, Chester, Deerfield, Derry, Lee, and Raymond, had 2002 peak demands ranging from 1,550 kW to 4,910 kW. All of these delivery points except Chester peaked in July or August in 2002 which reflects the rapid growth of air conditioning in this area. Chester has also peaked in the summer in two of the last four years.

The Brentwood delivery point serves a relatively small share of the population in the towns that comprise its service area with a consumer-population ratio of about 3.1%. Consumer growth is expected to exceed population growth with an increase in the CPR from .0306 to .0368 by 2023. As a result the number of active consumers served by this delivery point increases at an annual rate of 2.9% over the 2008 to 2023 period.

Demand per consumer was 2.865 kW in 2002, which is the eighth highest figure for the 35 NHEC delivery points. This reflects expected development of new subdivisions with average use of 3.7 kwh per consumer in the next decade. After that, demands of 3.0 kW per consumer have been assumed. Aggregate demand per consumer increases at 1.0% per year for the next decade. The net result of these changes is annual load growth through 2023 at a rate of 3.1 % as shown in Table 14-1 and Figure 14-1.

Table 14-1 Brentwood DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	16,592				
2001	17,265				
2002	17,665	0.0306	541	2.865	1,550
2003	18,093	0.0311	563	2.913	1,639
2004	18,520	0.0316	584	2.956	1,728
2005	18,950	0.0320	607	2.995	1,817
2006	19,375	0.0325	629	3.030	1,905
2007	19,800	0.0329	651	3.062	1,993
2008	20,224	0.0333	673	3.090	2,081
2013	22,344	0.0352	786	3.200	2,516
2023	26,605	0.0368	979	3.028	2,965
Growth Rates					
2002 - 2003	2.42%	1.54%	4.00%	1.67%	5.75%
2002 - 2008	2.28%	1.41%	3.72%	1.27%	5.03%
2002 - 2013	2.16%	1.27%	3.46%	1.01%	4.50%
2002 - 2023	1.97%	0.88%	2.86%	0.26%	3.14%

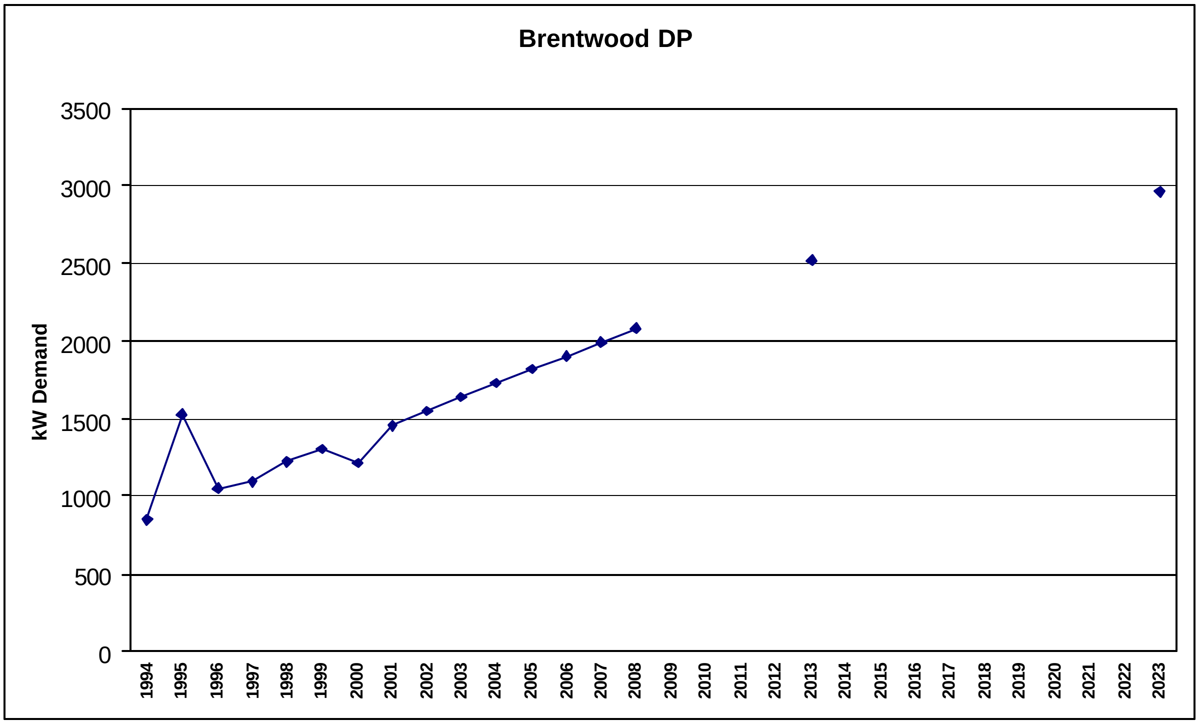


Figure 14-1 Historical and Forecasted Brentwood DP Demands

The Chester delivery point serves a significant proportion of the service area population with a 2002 CPR of 14.8 percent. The marginal share of population growth served by this delivery point is expected to increase to 17.8% for the next decade and then return to 14.8% for the following ten years. The CPR will then grow to 15.4 percent by 2023. A total of 1,146 new consumers is anticipated which represents an annual growth rate of 2.2% over the planning horizon.

Demand per consumer for this delivery point was 2.4 kW in 2002. Over the next decade, new consumers in this area are expected to be 3.0 kW before returning to 2.5 kW in the second ten years of the planning period. The aggregate DPC will increase from 2.4 to 2.7 by 2013 but will then decrease to 2.5 kW by 2023. The result of these expected changes is shown in Table 14-2 and Figure 14-2. Table 14-3 identifies two major subdivisions plus and elementary school addition as key spot loads included in the expected increases to a total 2023 load of 8.0 MW.

Table 14-2 Chester DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	12,846				
2001	13,338				
2002	13,643	0.1475	2,013	2.439	4,910
2003	13,970	0.1482	2,071	2.470	5,116
2004	14,297	0.1489	2,129	2.499	5,320
2005	14,625	0.1496	2,188	2.525	5,525
2006	14,950	0.1503	2,246	2.550	5,727
2007	15,274	0.1509	2,305	2.572	5,928
2008	15,598	0.1515	2,363	2.593	6,128
2013	17,216	0.1543	2,657	2.678	7,116
2023	20,469	0.1543	3,159	2.540	8,025
Growth Rates					
2002 - 2003	2.40%	0.48%	2.88%	1.27%	4.19%
2002 - 2008	2.26%	0.44%	2.71%	1.03%	3.76%
2002 - 2013	2.14%	0.41%	2.56%	0.85%	3.43%
2002 - 2023	1.95%	0.21%	2.17%	0.19%	2.37%

Table 14-3 Chester DP Spot Load Increments

Substation	Circuit	Load Type	YEAR 2004-2008 Load (kW)	YEAR 2009-2013 Load (kW)	YEAR 2014-2023 Load (kW)
Chester	CS11	180 lot development	250	100	50
	CS14	Elem. School Addition	300	200	100
		150 lot development	200	100	50
		Potential Development	100	50	50

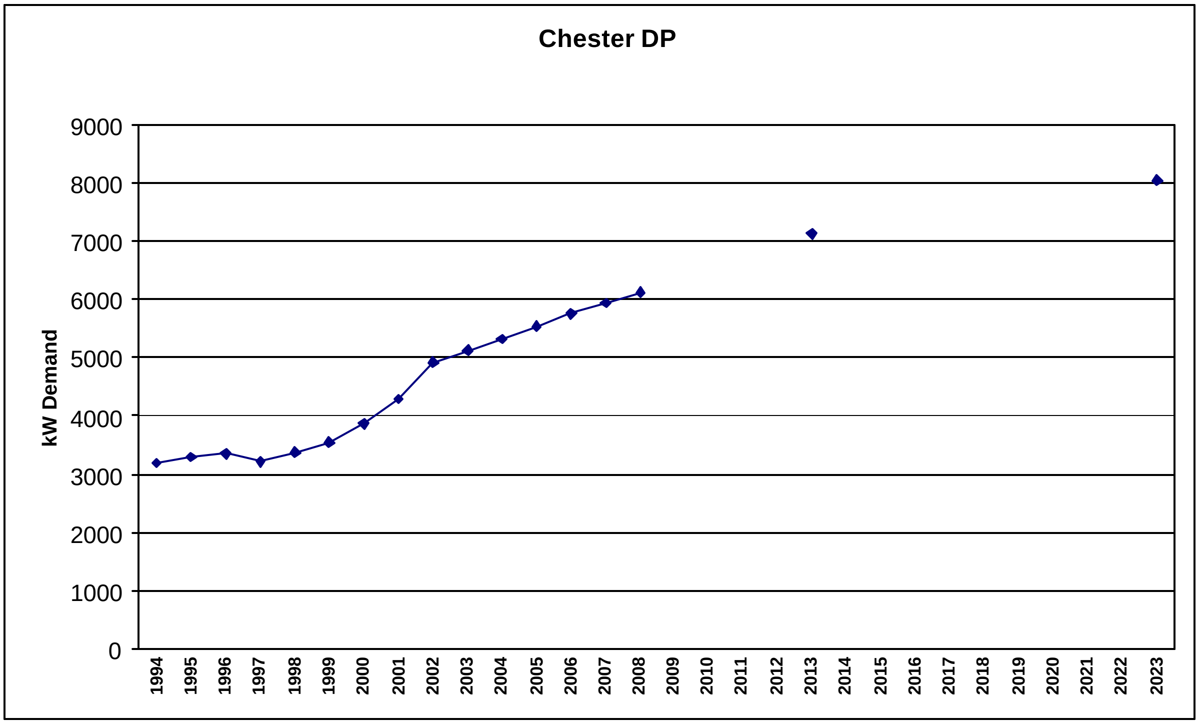


Figure 14-2 Historical and Forecasted Chester DP Demands

The Deerfield delivery point currently has about 4.0% as many consumers as population in the towns that it serves. That ratio is expected to remain fixed which translates to consumer growth at an annual rate of 1.2% from 2002 to 2023.

Demand per consumer was 2.083 kW in 2002, which is above average for NHEC delivery points. New connects are expected have average demands of 3.0 kW for the next five years but that figure is expected to then gradually decrease to 2.0 kW over the remainder of the planning horizon.

The net result of these changes is annual load growth through 2023 at a rate of 1.3 % as shown in Table 14-4 and Figure 14-3.

Table 14-4 Deerfield DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	26,127				
2001	26,995				
2002	27,365	0.0412	1,127	2.083	2,347
2003	27,742	0.0412	1,143	2.107	2,408
2004	28,116	0.0412	1,158	2.131	2,467
2005	28,494	0.0412	1,174	2.154	2,528
2006	28,863	0.0412	1,189	2.175	2,586
2007	29,233	0.0412	1,204	2.196	2,644
2008	29,601	0.0412	1,219	2.216	2,701
2013	31,432	0.0412	1,295	2.215	2,867
2023	35,102	0.0412	1,446	2.120	3,065
Growth Rates					
2002 - 2003	1.38%	0.00%	1.38%	1.19%	2.59%
2002 - 2008	1.32%	0.00%	1.32%	1.04%	2.37%
2002 - 2013	1.27%	0.00%	1.27%	0.56%	1.84%
2002 - 2023	1.19%	0.00%	1.19%	0.09%	1.28%

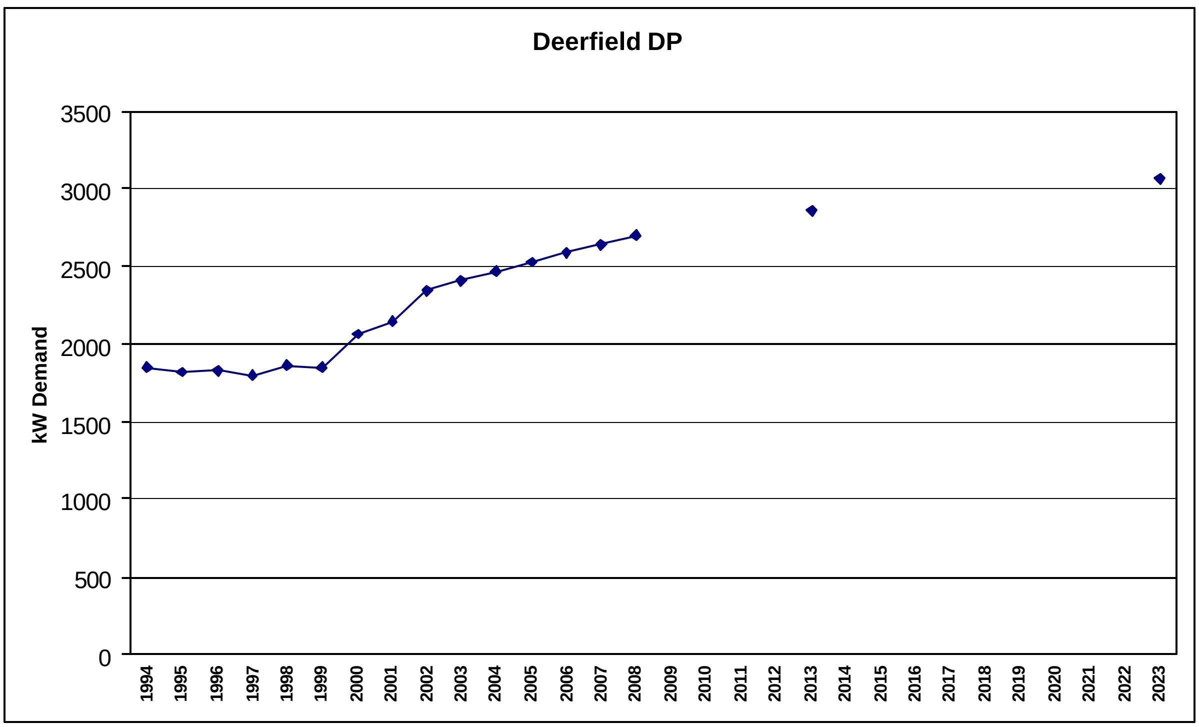


Figure 14-3 Historical and Forecasted Deerfield DP Demands

The Derry delivery point currently has about 2.0% as many consumers as population in the towns that it serves. That ratio is expected to remain fixed which translates to consumer growth at an annual rate of 1.5% from 2002 to 2023. The anticipated addition of active consumers on this delivery point is 513.

Demand per consumer for this delivery point was 2.15 kW in 2002 and is expected to increase very slightly in the future. Added load for this point will be about 1.1 MW over the next two decades. That growth includes a school addition and a commercial/industrial strip development as shown in Table 14-6. Expected changes as shown in Table 14-5 and Figure 14-4.

Table 14-5 Derry DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	65,731				
2001	67,153				
2002	68,303	0.0199	1,360	2.150	2,924
2003	69,557	0.0199	1,385	2.152	2,980
2004	70,806	0.0199	1,410	2.153	3,036
2005	72,064	0.0199	1,435	2.155	3,092
2006	73,298	0.0199	1,459	2.157	3,147
2007	74,534	0.0199	1,484	2.158	3,203
2008	75,760	0.0199	1,508	2.159	3,257
2013	81,870	0.0199	1,630	2.165	3,530
2023	94,060	0.0199	1,873	2.174	4,071
Growth Rates					
2002 - 2003	1.84%	0.00%	1.84%	0.08%	1.92%
2002 - 2008	1.74%	0.00%	1.74%	0.07%	1.82%
2002 - 2013	1.66%	0.00%	1.66%	0.06%	1.73%
2002 - 2023	1.54%	0.00%	1.54%	0.05%	1.59%

Table 14-6 Derry DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR 2004-2008	YEAR 2009-2013	YEAR 2014-2023
			Load (kW)		
Derry	DY11	School Addition	300	100	
		Commercial/Industrial Strip	100	100	100

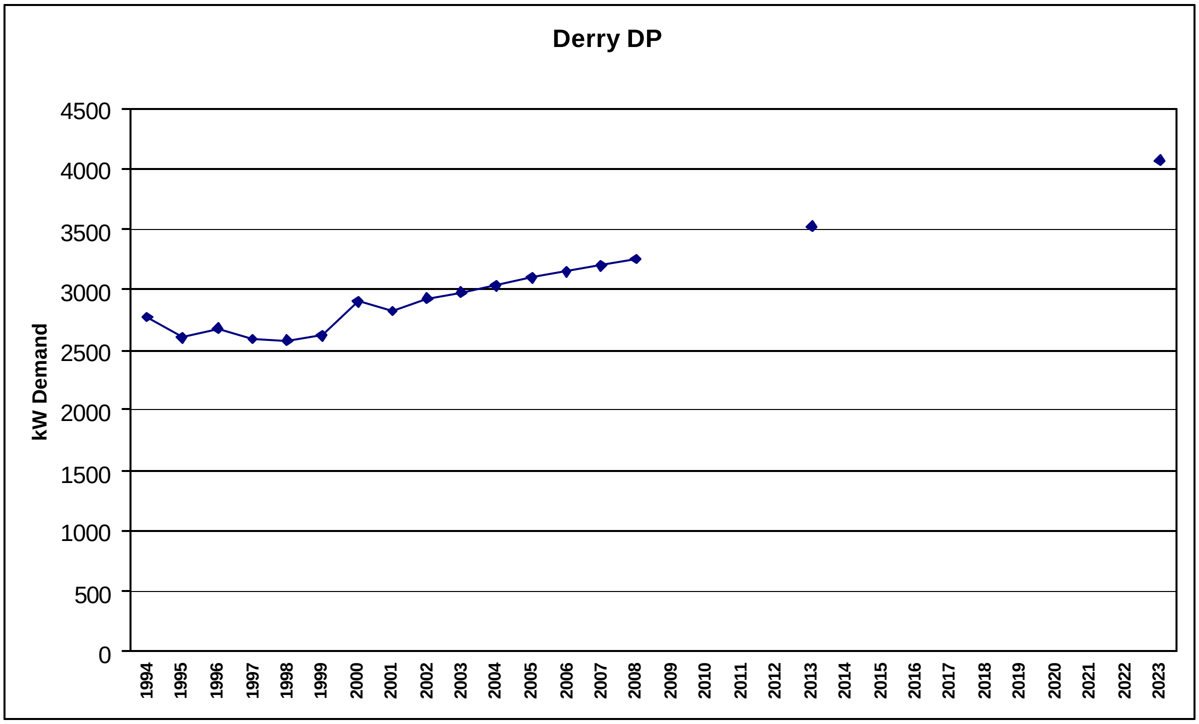


Figure 14-4 Historical and Forecasted Derry DP Demands

The Lee delivery point CPR was about 12.5%. Conversion of farm land to residential use in this area will lead to increases in the CPR. A marginal rate of 14.5% is anticipated which will increase the CPR to about 13.1% by 2023. As a result the number of active consumers served by this delivery point is expected to increase by 457 which translates to an annual growth rate of 1.8% over the planning period.

Demand per consumer was 2.1 kW in 2002. A slightly higher figure of 2.2 kW is expected for customers added in the next five years. For the remainder of the forecast period, a figure of 2.0 kW per new consumer has been assumed.

The net result of these changes is annual load growth through 2023 at a rate of 1.7 % as shown in Table 14-7 and Figure 14-5. Table 14-8 identifies a school addition and two new potential developments as spot loads to be included in the planning effort.

Table 14-7 Lee DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	7,846				
2001	8,056				
2002	8,192	0.1248	1,022	2.068	2,114
2003	8,339	0.1251	1,043	2.074	2,164
2004	8,485	0.1255	1,065	2.079	2,213
2005	8,633	0.1258	1,086	2.084	2,263
2006	8,779	0.1261	1,107	2.088	2,312
2007	8,926	0.1265	1,129	2.092	2,361
2008	9,072	0.1268	1,150	2.096	2,411
2013	9,806	0.1283	1,258	2.062	2,594
2023	11,300	0.1309	1,479	2.045	3,025
Growth Rates					
2002 - 2003	1.79%	0.28%	2.08%	0.26%	2.34%
2002 - 2008	1.71%	0.27%	1.99%	0.22%	2.21%
2002 - 2013	1.65%	0.25%	1.91%	-0.03%	1.88%
2002 - 2023	1.54%	0.23%	1.78%	-0.06%	1.72%

Table 14-8 Lee DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR 2004-2008 Load (kW)	YEAR 2009-2013 Load (kW)	YEAR 2014-2023 Load (kW)
Lee	LE11	Potential Developments	100	50	50
	LE12	School Addition	200	100	
		Potential Developments	100	50	50

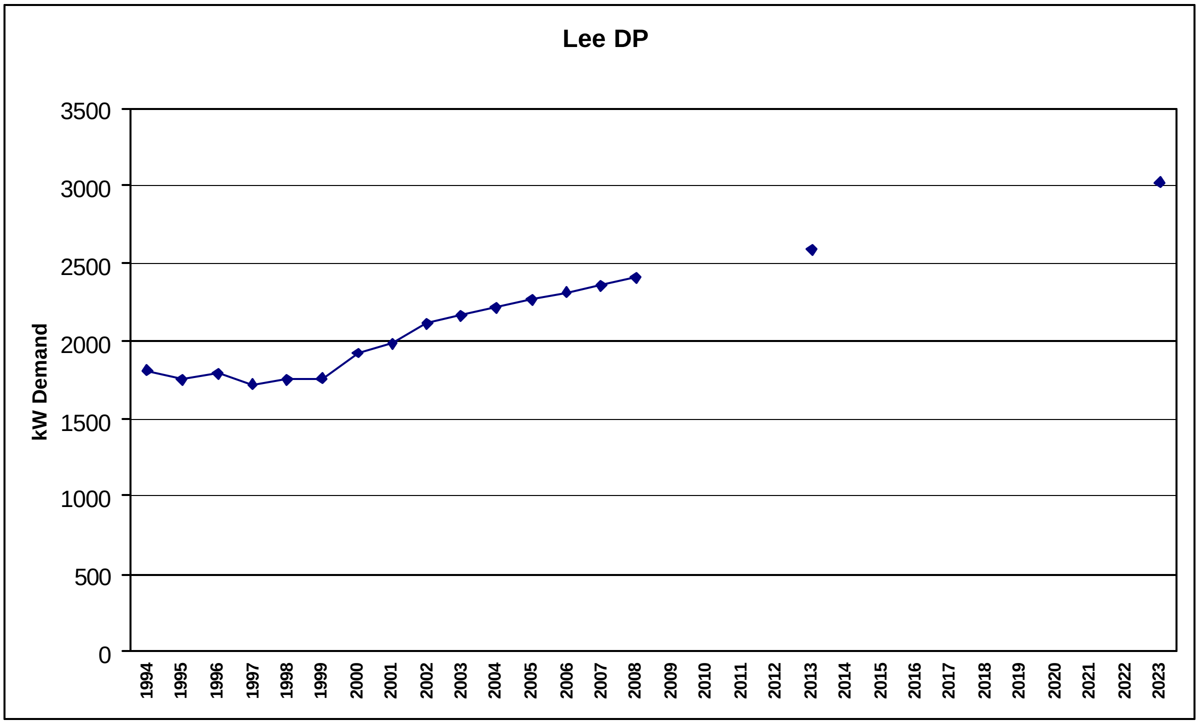


Figure 14-5 Historical and Forecasted Lee DP Demands

The portions of the towns served through the Raymond delivery point are not expected to grow as quickly as other areas in these towns. The 2002 CPR was 7.6% but the share of future growth is expected to be 6.6%. This leads to a CPR of 7.3% by 2023 and an annual growth rate of 1.5% in active consumers served through this delivery point.

Demand per consumer for this delivery point was relatively low at 1.971 kW in 2002. Growth in demand per consumer is expected to be modest with a DPC of 1.984 by 2023. The result of these expected changes as shown in Table 14-9 and Figure 14-6. Demand grows by 1.6 MW from 2002 to 2023 which reflects an annual growth rate of 1.5%. One spot load has been identified for this delivery point as shown in Table 14-10.

Table 14-9 Raymond DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	26,153				
2001	27,267				
2002	27,800	0.0760	2,112	1.971	4,162
2003	28,375	0.0758	2,150	1.972	4,239
2004	28,949	0.0756	2,188	1.973	4,316
2005	29,527	0.0754	2,226	1.974	4,392
2006	30,096	0.0752	2,263	1.974	4,468
2007	30,665	0.0750	2,300	1.975	4,543
2008	31,231	0.0748	2,337	1.976	4,617
2013	34,058	0.0740	2,520	1.979	4,988
2023	39,717	0.0726	2,882	1.984	5,719
Growth Rates					
2002 - 2003	2.07%	-0.27%	1.80%	0.05%	1.85%
2002 - 2008	1.96%	-0.25%	1.70%	0.05%	1.75%
2002 - 2013	1.86%	-0.24%	1.62%	0.04%	1.66%
2002 - 2023	1.71%	-0.22%	1.49%	0.03%	1.52%

Table 14-10 Raymond DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Raymond	RA11	Potential Developments	150	150	250

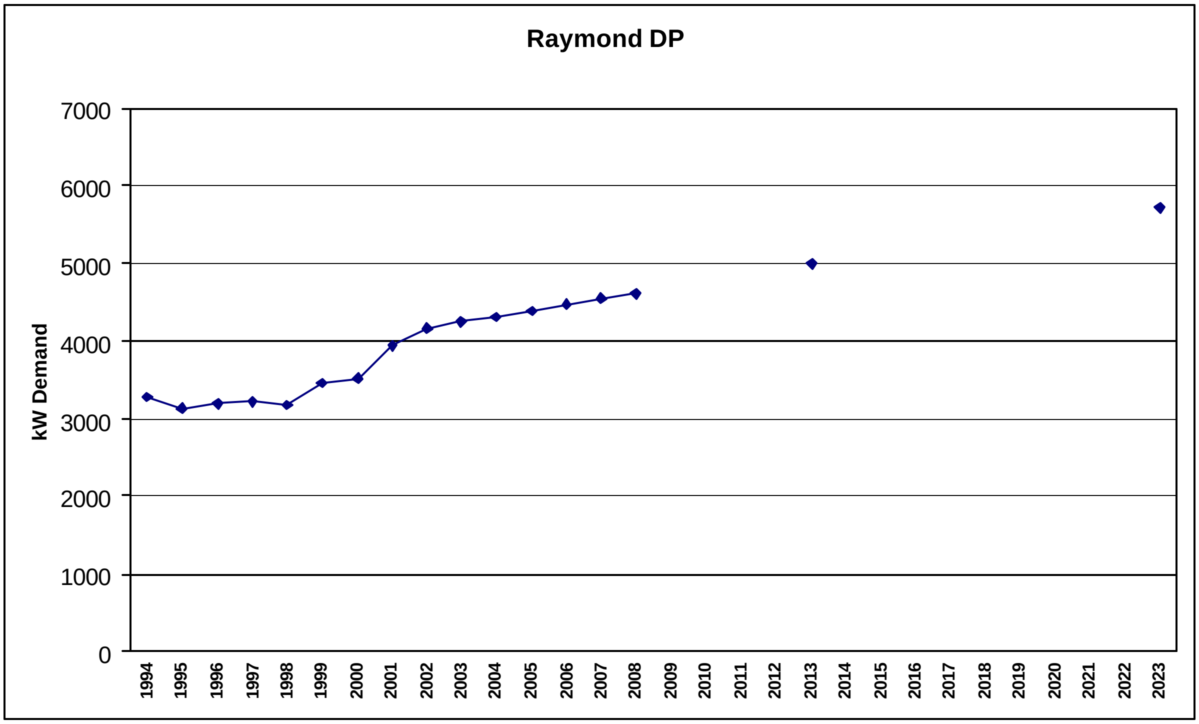


Figure 14-6 Historical and Forecasted Raymond DP Demands

14.2 Transmission System

14.2.1 Bulk Power Transmission System

NHEC's Raymond District is served at 34.5 kV from PSNH's Chester, Kingston, Madbury and Mammoth Road 115-34.5 kV substations. These substations are supplied from the 115 kV system. All of the 115 kV circuits supplying the Raymond District are looped and operated in a networked configuration. Scobie Pond 345-115 kV Substation and the Merrimack Generating Station are major PSNH bulk supply substations present in the area to supply the 115 kV system.

PSNH's Madbury Substation serves NHEC's Raymond Substation and Brentwood and Lee metering points. PSNH's Chester Substation serves NHEC's Chester Substation and the Deerfield and Derry metering points.

Substation transformer capacity and base case and coincident peak demands are depicted in Table 14-11. Future loads are based upon an annual summer peak and winter peak load growth rate of 1.87 percent.

Table 14-11 Raymond District Transmission and Loading Information

PSNH	115.34 kV Transformer Capacity		34.5 kV	Coincident Peak Loads - MVA			
				Summer		Winter	
Substation	Summer Capacity	Winter Capacity	Feeders	2003	2023 [5]	2002	2023
Chester	1-51 MVA	1-63 MVA	2	42.2	44.5	41.0	62.5
Madbury	1-49, 1-52 MVA	1-62,1-65 MVA	5	76.1	87.7	92.6	140.2
Kingston	1-52 MVA	1-65 MVA	4	45.3	50.1	36.7	36.7
Mammoth Road	1-57 MVA	1-62 MVA	3	41.6	65.9	47.6	68.7

14.2.2 Base System Performance

The PSNH 34.5 kV system is generally characterized by three of four 115–3 4.5 kV substations with single transformers and a number of heavily loaded 34.5 kV feeders. There are a number of deficiencies in the base cases and include:

• 2002 Winter Peak	Madbury 380 feeder	Load exceeds 30 MVA
• 2023 Winter Peak	Madbury transformers	Overloaded
	Madbury 380, 3137 and 3152	Overloaded
	Chester 3141 and 3115	Load exceeds 30 MVA with low feeder voltages
	Mammoth Road transformer	Overloaded
	Mammoth Road 365 feeder	Load exceeds 30 MVA

PSNH plans to add a 115–34.5 kV 44 MVA transformer to Chester Substation in 2004 and develop a new Brentwood 115–34.5 kV Substation at a new site near the intersection of US route 11 and State route 31. The proposed substation would be initially configured with one 115-34.5 kV transformer and three 34.5 kV feeders in 2005. A second transformer is planned for Mammoth Road Substation in 2006.

Ultimately, near the end of the planning period PSNH plans to add a second transformer and a fourth 34.5 kV feeder to the proposed Brentwood Substation. PSNH is also negotiating with Unitil Corporation on Unitil's desire to obtain a 34.5 kV feeder from the proposed Brentwood Substation.

14.2.3 Contingency Performance

With the existing system and present peak load conditions, the contingency outage of a transformer at Madbury, the transformer at Chester or a feeder outage of Madbury 380/3152 or Chester 3115 feeders, there is not enough feeder or transformer capacity to ensure all load could be immediately restored to service. Some load would need to be shed for an extended period of time of up to 24 hours. The most likely NHEC loads to be shed are NHEC's Derry and Raymond metering points along with PSNH loads. In 2004, with the additional PSNH transformer planned for installation at Chester, the system can survive a contingent transformer

[5] Reflects the addition of the proposed 115–34.5 kV Brentwood Substation site.

outage. In 2005, with the installation of the new PSNH Brentwood Substation, with one transformer and development of three new feeders, full first contingency capability is restored for all NHEC Raymond District metering points.

In 2010, an outage of the Chester 3115 feeder will overload the Epping to Raymond 34.5 kV line. An additional Brentwood 34.5 kV eleven mile long feeder to connect into the system near NHEC's Raymond Substation is proposed to address this deficiency.

Finally, in 2017, PSNH proposes to add a second 44 MVA transformer to Brentwood Substation to relieve a contingent overload of the single Brentwood transformer for the outage of the Chester 3115 feeder.

The overall PSNH expansion plan of the 34.5 kV system supplying the Raymond District is depicted below.

Table 14-12 PSNH 34.5 kV Subtransmission Expansion Plan

Year	PSNH Location	Project Element
2004	Chester Substation	Add a second 51/63 MVA 115-34.5 kV transformer
2005	Brentwood Substation (proposed)	Develop new 115–34.5 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.

This expansion plan will achieve design criteria standards and exceed them by providing first contingency capability in 2005 and maintaining it for the planning period.

14.2.4 Historical Reliability

A review of the 34.5 kV subtransmission outages for the period of 2000-2003 indicated the following average annual outage rates.

Table 14-13 Average Annual Outage Rates

Delivery Points	PSNH Outages	Total Average Annual Outages
Brentwood	9	3
Chester	5	1.67
Deerfield	7	2.33
Derry	3	1
Lee	7	2.33
Raymond	0	0

All annual outage rates are within the NHEC design criteria.

14.2.5 Reliability Improvement

The expansion plan presented in a previous section restores first contingency capability to the PSNH 34.5 kV subtransmission network serving this district by 2005 and maintains it to 2023. In general, having first contingency capability permits more rapid restoration of service although it may not reduce the total number of outages experienced.

However, in this expansion plan PSNH is developing a new 115–34.5 kV Brentwood Substation to relieve and offload the Madbury and Chester Substations which serve all of the NHEC's Raymond District delivery points. Development of the Brentwood 34.5 kV feeder system will result in shortening the length of the Chester and Madbury 34.5 kV feeders. Ideally, the feeder lengths would be reduced by 50 percent as would the number of feeder outage events on the these 34.5 kV feeder.

Therefore, in general and on average, NHEC can reasonably expect the average consumer in the Raymond district to experience 50% fewer power supplier feeder outages and because full first contingency capability is being restored, outage durations should reasonably be shorter because loads can be switched to alternate feeders and substations more rapidly and without the need to leave any loads unserved for up to 24 hours.

14.3 Distribution System

14.3.1 General

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 14.4, Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 14.0 shows the 2003, 2008, 2013 and 2023 peak load levels for each substation, DP and MP and circuit using the existing system configuration and the proposed system configuration.

14.3.2 New Substations, DP's and MP's

No new substations, delivery points or meter points are required in the Raymond District during this 20-year planning period for strictly voltage or capacity reasons. Although, there may be proposals for reliability reasons that are discussed in the Distribution System Reliability section near the end of the Raymond District discussion.

14.3.3 Substation, DP and MP Changes

The following table shows the projected kW for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for backup or for the ordinary replacement of aged transformers are shown in [**bold**]. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 14-14 Substation Transformer and Regulator Data

Name	Transformer							Voltage Regulator		
	Rating (kVA)					Est. Load (kW)	Capacity (%)	Size (AMP)	Est. Load (AMP)	Capacity (%)
	OA 55°	FA 55°	OA 65°	FA 65°	Win Season					
Brentwood DP/BT11	2-333	--	--	--	733	1,035	144	--	81	--
Brentwood DP/BT11 [2]	**3-333**	--	--	--	**1,100**	1,035	96	**100**	54	54
Brentwood DP/BT12 [3]	2,500	3,125 [1]	2,800	3,500 [1]	3,080	1,374	46	**150**	71	48
Chester Sub [4]	5,000	--	--	--	5,500	8,304	154	328	432	132
Chester Sub [5]	**10,000**	**12,500**	**11,200**	**14,000**	**15,400**	8,304	55	**656**	432	66
Deerfield DP, DF11	2,500	3,125 [1]	2,800	3,500 [1]	3,080	2,095	69	150	109	73
Deerfield DP, DF12	2,500	3,125 [1]	2,800	3,500 [1]	3,080	1,329	44	150	69	46
Deerfield DP, DF13	333	--	--	--	366	169	47	--	9	--
Derry MP	--	--	--	--	--	4,092	--	--	--	--
Lee DP	2,500	3,125 [1]	2,800	3,500 [1]	3,080	3,047	101	--	158	--
Lee DP [6]	2,500	**3,125**	2,800	**3,500**	**3,850**	3,047	81	--	158	--
Lee DP / LE11	--	--	--	--	--	1,107	--	100	58	58
Lee DP / LE11 [7]	--	--	--	--	--	1,107	--	**150**	58	38
Lee DP / LE12	--	--	--	--	--	1,922	--	100	100	100
Raymond Sub	10,000	--	--	--	11,000	4,792	44	463	249	54

[1] Fans are not installed.

[2] Third 333 kVA stepdown transformer is being added, Project BT-1, and voltage regulators, Project BT-2.

[3] Voltage regulators are being added. Project BT-6.

[4] Before upgrade to 10 MVA in 2003.

[5] After upgrade to 10 MVA in 2003.

[6] After installing fans.

[7] Upgrade voltage regulators to provide additional capacity for backup to Raymond RA11. Project LE-2.

At the Chester Substation, a new circuit is recommended to enable dividing the load on the heavily loaded Circuit CS14 over two circuits as discussed in Section 14.3.5. Project CS-1 is for the substation modification to accommodate the new circuit.

No conversion to a different distribution system operating voltage is recommended at any of the substations, meter points or delivery points. The distribution operating voltage is to remain at 7.2/12.47 kV.

14.3.4 Brentwood Delivery Point Service Area

14.3.4.1 Existing System Review

The main three-phase line from the Brentwood DP splits into two circuits, BT11 and BT12, approximately 700 feet from the DP. The main line and a very small portion of Circuits BT11 and BT12 are operated at 19.9/34.5 kV. Each circuit has stepdown transformers that convert the voltage to 7.2/12.47 kV. There are no voltage regulators at the DP site or out on the line.

The Brentwood DP is forecasted to serve 3.0 MW of peak load in 2023. Circuit BT11, that goes to the east, serves approximately 36 percent of the total load and BT12, that goes to the west, serves the remaining 64 percent.

Circuit BT11 is approximately 3.0 miles long and has no ties to other circuits. The main three-phase line is 0.5 miles long and is 1/0 ACSR. The remaining vee-phase and single-phase lines are mostly 1/0 ACSR. Capacity deficiencies were found on this circuit related to the size of the stepdown transformers. Also, the 2008 peak load on the main single-phase line going east along South Road exceeds the maximum design limit of 50 amps per phase. These deficiencies along with no existing voltage regulators and poor load balance with the existing system configuration will result in a low primary system voltage throughout much of the Circuit BT11 service area.

Circuit BT12 is approximately 4.8 miles long and has no ties to other circuits. The main three-phase line is 4.4 miles long and is 1/0 ACSR. The remaining vee-phase and single-phase lines are mostly 1/0 ACSR or 2 ACSR. Voltage deficiencies were found due to no existing voltage regulators at the DP and from poor load balance.

14.3.4.2 Recommended Plan

On Circuit BT11, it is recommended that the Phase B stepdown transformer be added and that the single-phase line going northeast along Lake Road be changed from Phase A to Phase B to improve load balance. The Phase B stepdown transformer should be a 333 kVA to match the existing 2-333 kVA transformers on Phases A and C. It is also recommended that the single-phase line going southeast of South Road be changed from Phase A to Phase C to improve load balance. This work is referred to as Project BT-1.

Project BT-2 is the installation of 3-100 amp, 7.2 kV, voltage regulators since no regulators presently exist at this DP. The regulators will provide a worthwhile improvement and will enable NHEC to better control their system performance. It is recommended that these regulators be installed just after the stepdown transformers.

Project BT-3 is the installation of a 300 kVAR switched capacitor bank to improve system performance.

Also on Circuit BT11, the existing single-phase line that goes along South Road is estimated to have 93 amps of peak load at the 2023 load level. Projects BT-4 and BT-5 will extend three-phase to provide the needed capacity. Project BT-4 is the conversion of a vee-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 1-1/0 ACSR phase conductors. Project BT-5 is the conversion of a single-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The three-phase line will also improve voltage and enable better load balance that will improve system performance.

On Circuit BT-12, Project BT-6 is the installation of 3-150 amp, 7.2 kV, voltage regulators since no regulators presently exist at this DP. The regulators will provide a worthwhile improvement and will enable NHEC to better control their system performance. It is recommended that these regulators be installed just after the 2,500 kVA padmounted stepdown transformer.

On Circuit BT-12, Project BT-7 is the installation of a 300 kVAR switched capacitor bank to improve system performance. Also, several tap phase changes are recommended to improve load balance. No other system improvements are anticipated to maintain proper voltage and system performance.

14.3.5 Chester Substation Service Area

14.3.5.1 Existing System Review

The Chester Substation is forecasted to serve 8.1 MW of peak load in 2023. The Chester area is served by three 7.2/12.47 kV circuits: CS11, CS13 and CS14. Circuit CS11 serves approximately 24 percent of the total load, CS13 serves 17 percent and CS14 the remaining 59 percent.

Circuit CS11 is approximately 4.8 miles long and has no ties to other circuits. The first 0.5 miles of three-phase is 4/0 ACSR. The remaining three-phase, vee-phase and single-phase lines are mostly 1/0 ACSR and small amounts of 2 ACSR. The 2013 peak load on the main single-phase line serving the Halls Village Road area exceeds the maximum design limit of 50 amps per phase and the line is therefore considered to have a capacity deficiency. No areas with low voltage are anticipated during this planning period.

Circuit CS13 is approximately 9.8 miles long. The main three-phase line is 4.5 miles long and is 4/0 ACSR. The remaining vee-phase and single-phase lines are mostly 1/0 ACSR and small amounts of 2 ACSR. Circuit CS13 ties to Circuit RA12 of the Raymond Substation. The vee-phase and single-phase lines serving the Brown Road and Flint Road areas are heavily loaded. The 2013 peak load on the main single-phase line along Brown Road exceeds the maximum design limit of 50 amps per phase and the line is therefore considered to have a capacity deficiency. This condition results in low voltage at the end of the circuit.

On Circuit CS14, the ends of the circuit are approximately 5.0 to 6.0 miles from the substation. The main three-phase line splits approximately 1.9 miles out from the substation into three three-phase feeders. Most of the first 1.9 miles are 1/0 ACSR. The north and east three-phase feeders are 1/0 ACSR and the southeast three-phase feeder is mostly 336 ACSR. Most of the single-phase lines are 1/0 ACSR with small sections of 2 ACSR.

The 2023 peak load on the main three-phase line is approaching the maximum design limit of 280 amps per phase. Also, the peak load on several single-phase lines is close to or exceeds the maximum design limit of 50 amps per phase and the line is therefore considered to have a capacity deficiency. These heavy load conditions result in a 6 volt drop just 1.9 miles from the substation and low voltage at the end of the circuit with the 2023 load level.

14.3.5.2 Recommended Plan

Project CS-1 will provide additional capacity by converting the single-phase 1/0 ACSR line that serves the Hall Village Road area to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 60 amps of peak load at the 2023 load level. The three-phase line is to be extended 1.2 miles so that single-phase taps can balance the load on the three-phase line.

On Circuit CS13, Project CS-2 will provide additional capacity by extending three-phase to the Brown Road area. The existing vee-phase line is estimated to have 42 amps of peak load on Phase B and 69 amps on Phase C at the 2023 load level. The first 1.2 miles is the conversion of the vee-phase 1/0 ACSR line along Chester Road to three-phase 1/0 ACSR by adding 1-1/0 ACSR phase conductor. The next 1.2 miles is a new three-phase 1/0 ACSR line to be located along road right-of-way rather than follow the existing route through private property. The final 1.5 miles is the conversion of the single-phase 1/0 ACSR line along Brown Road to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors.

On Circuit CS14, Project CS-4 will provide additional capacity and will improve voltage by replacing the existing three-phase 1/0 ACSR line with a three-phase 336 ACSR double circuit. This project will provide a 4 volt improvement and will also improve reliability by dividing the load over two circuits.

Project CS-5 is a single-phase 1/0 ACSR tie line that will enable transferring load from one of the heavily loaded single-phase lines to the three-phase line. This will provide better load balance and will also provide a loop for improved reliability.

Project CS-6 will provide additional capacity by converting the single-phase 1/0 ACSR line that serves the Nighting Gale Estates area to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 60 amps of peak load at the 2023 load level. The 1.0 mile three-phase extension will improve voltage at the end of the line by dividing the load over additional phases and will also improve load balance along the three-phase main line.

Project CS-7 will provide additional capacity by converting the single-phase 1/0 ACSR line that serves the area along Highway 121A to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 57 amps of peak load at the 2023 load level. The 0.7 mile three-phase extension will improve voltage at the end of the line by dividing the load over additional phases and will also improve load balance along the three-phase main line.

Project CS-8 will provide additional capacity by converting the single-phase 1/0 ACSR line that serves the area along Odell Road area to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 48 amps of peak load at the 2023 load level. The 0.7 mile three-phase extension will improve voltage at the end of the line by dividing the load over additional phases and will also improve load balance along the three-phase main line.

14.3.6 Deerfield Delivery Point Service Area

14.3.6.1 Existing System Review

The Deerfield DP serves three circuits, DF11, DF12 and DF13. A 1.0 mile three-phase 1/0 ACSR 19.9/34.5 kV line goes west from the DP and is then stepped down to 7.2/12.47 kV to serve Circuits DF11 and DF12. A 2,500 kVA padmounted stepdown transformer and 3- voltage regulators are installed on each circuit. The system is configured so that if the stepdown transformer of one circuit fails or needs to be taken out of service, the circuit can be switched over to the other stepdown transformer. A single-phase stepdown transformer is located at the DP to serve Circuit DF13.

The Deerfield DP is forecasted to serve 3.1 MW of peak load in 2023. Circuit DF11 serves approximately 51 percent of the total load, Circuit DF12 serves approximately 43 percent and DF13 serves the remaining 6 percent.

Circuit DF11 is approximately 7.9 miles long and ties to Circuit RA12 of the Raymond Substation. The three-phase main line conductor of DF11 is 336 ACSR. The 2008 peak load on the main single-phase line going east along Green Road exceeds the maximum design limit of 50 amps per phase and the line is therefore considered to have a capacity deficiency. This deficiency causes marginal voltage at the end of the single-phase line.

Circuit DF12 is radial and therefore has no ties to other circuits. The ends of the circuit are 9 to 10 miles from the DP. The three-phase main line conductor of DF12 is 336 ACSR. The remaining vee-phase and single-phase lines are mostly 1/0 ACSR and small amounts of 2 ACSR. Capacity deficiencies were found on the main vee-phase line going northwest along Middle Road. Line voltage regulators are presently installed which maintain proper voltage levels at the 2023 load level.

Circuit DF13 is single-phase and has no ties to other circuits. The end of the circuit is approximately 3.0 miles from the DP. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

14.3.6.2 Recommended Plan

Project DF-1 will provide additional capacity by rebuilding the single-phase 1/0 ACSR line to three-phase 4/0 ACSR. The existing single-phase line is estimated to have 60 amps of peak load at the 2023 load level. The three-phase line is to be extended 1.5 miles so that single-phase taps can balance the load on the three-phase line. It is also recommended that this three-phase line be extended to provide a three-phase tie to Circuit RA12 (see project RA-3). Since these projects create a three-phase loop, the use of 4/0 ACSR is recommended.

On Circuit DF12, Project DF-2 will provide additional capacity by rebuilding the vee-phase 1/0 ACSR line to three-phase 4/0 ACSR. The existing vee-phase line is estimated to have 73 amps of peak load on Phase A and 91 amps of peak load on Phase C at the 2023 load level. The three-phase line is to be extended 3.1 miles so that single-phase taps can balance the load on the three-phase line.

Project DF-3 is the installation of a 300 kVAR fixed capacitor bank to improve system performance.

On Circuit DF13, no new construction or existing line upgrades are needed to improve voltage or provide additional capacity during this planning period.

14.3.7 Derry Meter Point Service Area

14.3.7.1 Existing System Review

The Derry Meter Point takes service from PSNH at 7.2/12.47 kV. The MP consists of one circuit which is forecasted to serve 4.1 MW of peak load in 2023.

Circuit DY11 starts with 1.0 mile of three-phase 336 ACSR and then splits into two three-phase 1/0 ACSR feeders. The northwest feeder ends approximately 4.2 miles form the MP and the northeast feeder ends approximately 5.7 miles from the MP. These feeders are radial and have no ties to other circuits. The northwest feeder serves approximately 44 percent of the total load and the northeast feeder serves approximately 47 percent.

No line capacity deficiencies are anticipated during this planning period. The voltage drop from the MP to the end of the line is calculated to be 3.5 volts at the 2023 load level. Therefore, no low voltage problems are anticipated as long as the voltage at the MP is 122 volts or higher.

14.3.7.2 Recommended Plan

No major primary line construction projects are needed to provide additional capacity during this planning period. Some minor construction may be needed to divide the load so that good load balance is maintained. Voltage regulators should be installed on the northeast and northwest feeders if the supplied voltage is below 122 volts.

Project DY-1, is the upgrading of a 150 kVAR fixed capacitor bank to a 300 kVAR switched bank to improve system performance on the northwest feeder.

Project DY-2 is the installation of a 300 kVAR switched capacitor bank to improve system performance on the northeast feeder.

14.3.8 Lee Delivery Point Service Area

14.3.8.1 Existing System Review

The Lee DP serves two circuits, LE11 and LE12. A padmounted 2,500 kVA stepdown transformer converts the 19.9/34.5 kV supply voltage to the circuit operating voltage of 7.2/12.47 kV. Each circuit has 3-100 amp, 7.2 kV, voltage regulators which are located near the DP.

The Lee DP is forecasted to serve 3.0 MW of peak load in 2023. Circuit LE11, that goes to the west to Nottingham, serves approximately 37 percent of the total load and LE12, that goes to the east to Lee, serves the remaining 63 percent.

Circuit LE11 is approximately 5.1 miles long and ties to Circuit RA11 of the Raymond Substation. The main line conductor of LE11 is 1/0 ACSR. The remaining single-phase lines are mostly 1/0 ACSR. The 2008 peak load on the main single-phase line going north along Smoke Street in the Nottingham area exceeds the maximum design limit of 50 amps per phase and the line is therefore considered to have a capacity deficiency. This deficiency causes marginal voltage at the end of the single-phase line.

On Circuit LE12, the ends of the circuit are approximately 5.0 miles from the DP. Most of the three-phase, vee-phase and single-phase lines are 1/0 ACSR. A small amount of three-phase 2 ACSR and single-phase 2 and 4 ACSR are present. No major line capacity deficiencies or areas with low voltage are anticipated during this planning period.

14.3.8.2 Recommended Plan

Project LE-1 will provide additional capacity by converting the single-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 66 amps of peak load at the 2023 load level. The three-phase line is to be extended 2.2 miles so that single-phase taps can balance the load on the three-phase line.

Project LE-2 is the replacement of the 3-100 amp, 7.2 kV, voltage regulators with 3-150 amp, 7.2 kV, regulators. The larger sized regulators will provide additional capacity for backup to Circuit RA11 of the Raymond Substation.

Project LE-3, is the installation of a 300 kVAR fixed capacitor bank to improve system performance.

On Circuit LE12, Project LE-4 will provide additional capacity by converting the vee-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 1-1/0 ACSR phase conductor. The existing vee-phase line is estimated to have 26 amps of peak load on Phase B and 43 amps on Phase C at the 2023 load level. The three-phase line is to be extended 0.4 miles so that single-phase taps can balance the load on the three-phase line.

Project LE-5 is a 667 foot single-phase 1/0 ACSR to vee-phase 1/0 ACSR conversion by adding 1-1/0 ACSR phase conductor. The vee-phase line will enable the load beyond to be divided over two phases and will improve load balance along the three-phase line.

14.3.9 Raymond Substation Service Area

14.3.9.1 Existing System Review

The Raymond Substation is forecasted to serve 5.7 MW of peak load in 2023. The Raymond area is served by two 7.2/12.47 kV circuits, RA11 and RA12. Circuit RA11 serves approximately 33 percent of the total load and RA12 the remaining 67 percent.

Circuit RA11 is approximately 5.7 miles long and ties to LE11 of the Lee Delivery Point. The main line conductor of RA11 is 3/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period.

Circuit RA12 is approximately 8.6 miles long and ties to CS13 or the Chester Substation and to DF11 of the Deerfield Delivery Point. The main line conductor of RA12 is mostly 4/0 ACSR with a small amount of 336 ACSR. Voltage regulators are installed in the main line approximately 3.9 miles from the substation to maintain proper voltage levels at the end of the circuit. This circuit is heavily loaded and near the substation, the 2023 load level is approaching 50 percent of the conductor's current rating. Also, the single-phase line serving Liberty Tree Acres and Hammer Estates is heavily loaded. These conditions result in low voltage at the end of the single-phase line with the 2023 load level.

14.3.9.2 Recommended Plan

On Circuit RA11, no new construction or existing line upgrades are needed to improve voltage or provide additional capacity during this planning period.

Project RA-1, is the installation of a 300 kVAR switched capacitor bank to improve system performance.

On Circuit RA12, Project RA-2 will provide additional capacity by converting 0.4 miles of single-phase 1/0 ACSR to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 47 amps of peak load at the 2023 load level. Project RA-2 will improve voltage at the end of the line by dividing the load over additional phases and will also improve load balance along the three-phase main line.

Project RA-3 is a 0.5 mile three-phase 4/0 ACSR project that will provide a three-phase tie between the Old Bye Road area on Circuit RA12 and the three-phase line proposed as Project DF-1 along Green Road on Circuit DF11. These two areas combined have a 2023 forecasted load level of 912 kW. The three-phase tie will provide improved reliability and enables the Old Bye Road area to be transferred from the heavily loaded RA12 to the less loaded DF11.

It is recommended that the normal open between RA12 and CS13 be moved approximately 1.5 miles northeast (see Circuit Diagram for locations). This change will facilitate switching procedures between Circuits CS13 and DF11 during backup. Also, the change will transfer a small amount of load from the heavily loaded RA12 to the less loaded CS13.

14.4 Distribution System Reliability

14.4.1 Historical Reliability

The Raymond District has had lower than average reliability over the 2000-2002 sample period compared to the NHEC system wide average indices, and ranked fourth worst of all districts. The indices for each feeder and the entire Raymond district can be seen in the following figure.[6,7]

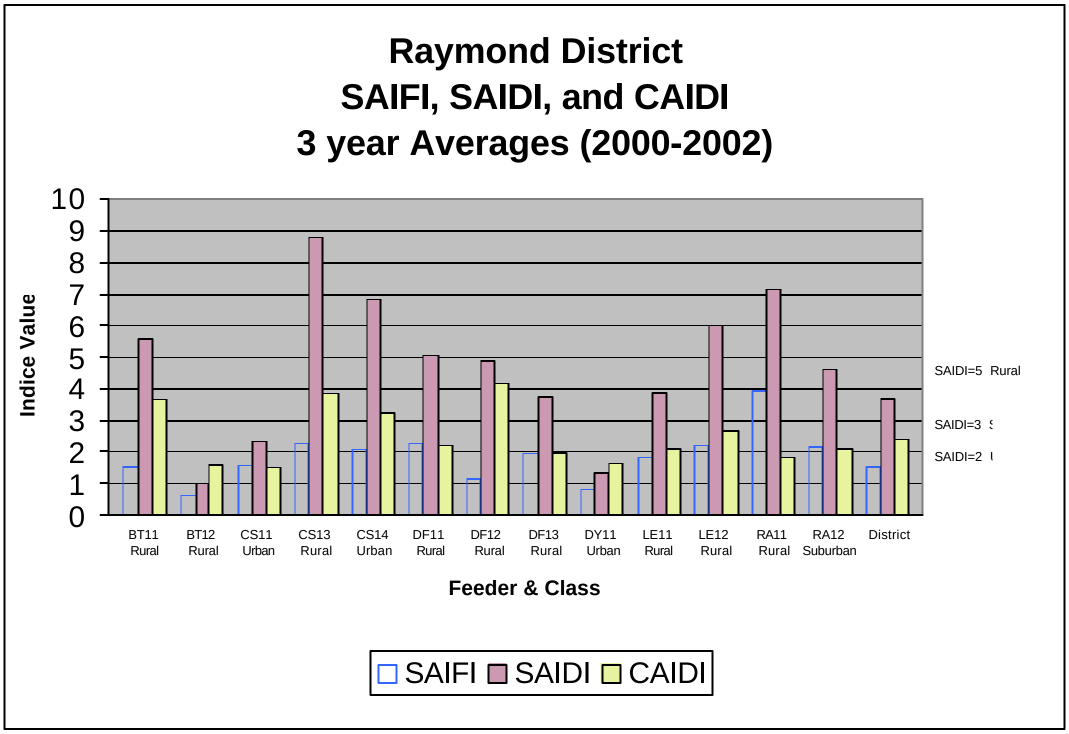


Figure 14-7 Raymond District Average Reliability Indices

[6]A long outage on the Chester Substation was excluded from the calculations. The outage was caused by weather contributing to the operation of the substation high-side fuses. Members on circuits CS11 and CS13 were without power for more than 5 hours, and members on circuit CS14 were without power for more than 17 hours. This outage was removed to defer skewing of the indices.

[7] Outages taking place on portions of Circuit BS13 of the Barnstead Substation were originally recorded under Raymond District outages. Even though this long feeder extends into the Raymond District, for the purposes of this study, the data was modified so that the outages were reflected in the Alton District reliability analysis. The Barnstead Substation is linked to the Alton District throughout the entire study since it is physically located within the Alton District territory.

14.4.1.1 SAIDI

Eight of the thirteen circuits exceeded the SAIDI reliability criteria. Circuits BT11, CS11, CS13, CS14, DF11, LE12, RA11, and RA12 were above their corresponding feeder classification limits.

14.4.1.2 SAIFI

Six circuits were above the SAIFI criteria of 2.0. These were circuits CS13, CS14, DF11, LE12, RA11, and RA12. Coincidentally, all of these circuits exceeded their corresponding SAIDI criteria as well.

14.4.2 Circuits That Exceed Reliability Criteria

14.4.2.1 Circuit BT11

The average SAIDI of 5.59 over the last three years was only slightly over the 5.0 criteria for rural classification. A review of the yearly indices indicates that 2002 had excessively high indices, in particular a SAIDI of 16.3. There were only two outages during 2000 and 2001, and nine outages in 2002. A breakdown of outages by cause can be seen in the figure below.

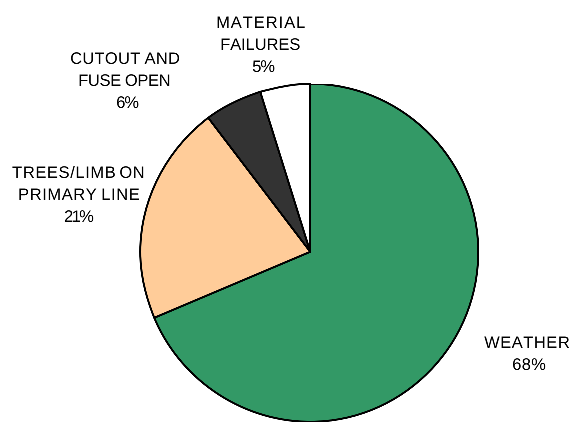


Figure 14-8 Circuit BT11 Percentage of Customer-Minutes Out by Outage Cause

The figure reflects that about 68% of customer-minutes were due to weather related causes. Particularly, one ten-hour outage in 2002 accounted for 47% of the total customer-minutes for the 2000-2002 period.

Circuit BT11 has a radial configuration in which two long single-phase lines serve all of the members. This configuration most likely contributed to the longer weather caused outages.

From a long-range distribution construction perspective, there appears to be no feasible alternatives that will significantly improve future reliability indices on this feeder due to the radial configuration. Although, projects BT-4 and BT-5 are recommended to provide additional voltage and capacity improvements, but also will most likely provide just as much reliability benefit due to new phase diversity and balance of members over all three phases. Generally, these construction projects will improve the reliability indices on this feeder by a factor of three, assuming that the potential of outages occurring along the feeder is uniform throughout.

Any future weather related outage should be logged in great detail, including the type of weather, what actually occurred as a result, and the type of equipment failure. This information will assist greatly in the review and mitigation process.

14.4.2.2 Circuit CS11

This circuit barely exceeded the SAIDI reliability criteria of 2.0 for the urban feeder classification. The outages by cause can be seen in the following figure.

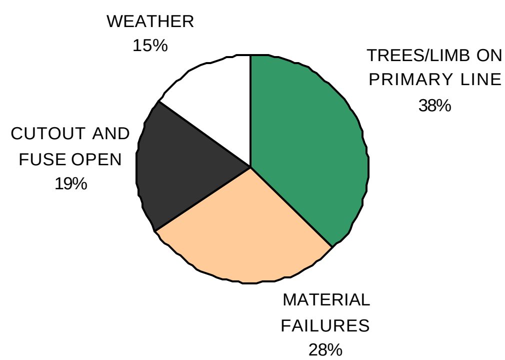


Figure 14-9 Circuit CS11 Percentage of Customer-Minutes Out by Outage Cause

There were three outages that caused the substation circuit reclosers to operate, therefore affecting all members on the circuit. These three outages were responsible for 55% of the customer-minutes of outages for the three-year period. Furthermore, there was a different cause for each one of these feeder outages.

After reviewing the overcurrent protection on this feeder, it appears that the first zone of protection extends to nearly the end of the three-phase line at Powell Road. There are two sets of fuse cutouts with solid blades along the main three-phase line within the first zone of protection. While these switches allow the restoration of members during an outage, from a sectionalizing and reliability point of view, they may provide more benefit if they were modified to provide overcurrent protection as well. With this change, the first zone of protection will become much shorter, therefore reducing the chances of an entire circuit outage.

About a half-mile out of the substation, there is a single-phase tap that serves about 60 members. It is recommended that this tap be converted to three-phase, which is designated as project CS-2 and described in Chester Substation service area portion of the distribution analysis. The conversion will improve the reliability to the members on this tap by dividing the members over three phases.

Overall, by increasing the number of protection devices and verifying they are properly coordinated, there may be a reduction in the frequency and duration of service interruptions. Furthermore, project CS-2 may assist in the goal of improving the feeder outage indices. These two items along with proper O&M review and practices should provide the needed reliability improvement.

14.4.2.3 Circuit CS13

This circuit had the highest SAIDI index, with a value of 8.77, in the Raymond District. Also, this circuit was the sixth worst performing circuit within the entire NHEC system. Half of the customer-minutes were due to trees, with most of the other half due to weather related outages as shown in the figure below.

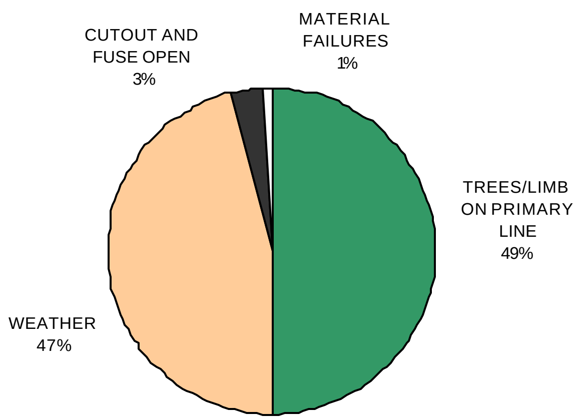


Figure 14-10 Circuit CS13 Percentage of Customer-Minutes Out by Outage Cause

There were a total of 37 outages over the three-year period on circuit CS13. Five of these were feeder outages responsible for 75% of the total customer-minutes. Two causes, weather and trees on primary line, were attributed to these five outages.

It appears that the first zone of protection extends to the normal-open air break switch between circuit CS13 and RA12. Since such a high percentage of customer-minutes of outages occurred within the first zone of protection, assuming adequate overcurrent protection coordination, the key to improving reliability on this circuit is to focus on decreasing these feeder outages. Therefore, depending upon the location of these main-line faults, additional overcurrent protection may improve reliability by dividing the circuit into additional zones of protection. Furthermore, more effective tree trimming should take place along the main three-phase line, and outages from weather related occurrences should be logged in great detail to assist in any future review and mitigation.

There are two other projects that may provide additional reliability improvement. Project CS-3, the conversion to three-phase as discussed in the Chester Substation service area section, will also provide more reliable service to the members on this long single-phase and vee-phase tap.

The addition of a new air break switch to provide a relocated normal-open location between Chester circuit CS13 and Raymond circuit RA12 will supply more switching options during contingencies.

14.4.2.4 Circuit CS14

This circuit had the third poorest reliability, in regards to the SAIDI index, with a value of 6.84. A summary of the causes of outages is shown the following figure.

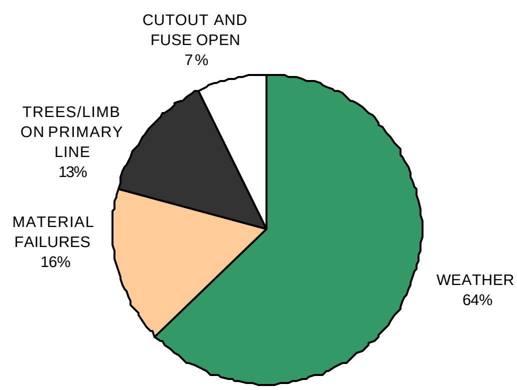


Figure 14-11 Circuit CS14 Percentage of Customer-Minutes Out by Outage Cause

Overall, there were 66 outages on this circuit with three feeder outages affecting all members. The three feeder outages caused 61% of the total customer-minutes. In particular, one of these feeder outages caused by weather was responsible for about 7,600 customer-minutes, or 38% of the feeder total. Therefore, once again, the high consumer-minute outages have caused poor reliability indices.

It's understandable that feeder outages are imminent, especially in this case since they're due to weather related events. Although, there are alternatives to help reduce outage durations and the number of members affected. Therefore, both of these are accomplished with project CS-4 as described in the Chester Substation service area portion of the Distribution System section. This project is needed for voltage and capacity improvements, and will also provide reliability improvement by dividing the members over two circuits and also reducing the amount of feeder exposure per member. One of the circuits should serve the members for 1.5 miles from the substation to the end of project CS-4. This circuit should also serve the members to the north three-phase tap to the north along Hale True Road. The second circuit should serve the remainder of the members, which are basically located along North Road and Sargeant Road. This configuration will allow the load and members to be divided fairly equally over the two circuits.

In addition to the double-circuit project CS-4, a new tie-line and/or a new metering or delivery point is recommended between Chester circuit CS14 and the Brentwood substation area. The tie-line is recommended mainly for backup to the Brentwood delivery point, but will also provide backup to some of the members located near the ends of circuit CS14. A more beneficial alternative is the addition of a metering or delivery point located near project BT-R1. Both of these options are discussed in the Circuit BT12 portion of the Distribution System Reliability section.

There are also a few recommended single-phase to three-phase conversions that are needed to meet voltage and capacity criteria, but may also provide reliability improvement. These projects are designated as CS-5, CS-6, and CS-7 and can be referenced in the Chester Substation service area portion of the Distribution System section.

14.4.2.5 Circuit DF11

Reliability on this circuit was generally adequate with a SAIDI value of 5.04, which slightly exceeded rural feeder criteria of 5.0. The following figure indicates the outages by cause. Similar to many of the other feeders in the Raymond district, weather was the cause of the highest percentage of outage-minutes.

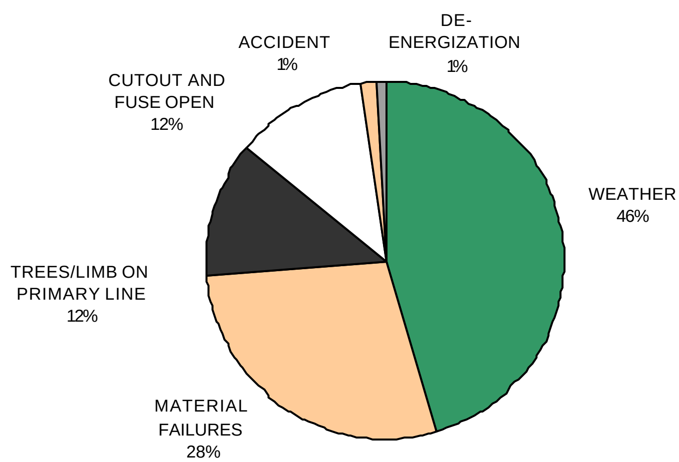


Figure 14-12 Circuit DF11 Percentage of Customer-Minutes Out by Outage Cause

Of the 51 total outages on this feeder, only three caused an entire circuit outage, but contributed 44% of the total customer-minutes. Therefore, it appears that the circuit contains adequate overcurrent protection and sufficient right-of-way clearances, in addition to various spans of tree-wire along the main three-phase line. Due to the small number of main feeder outages, a reduction in outage durations appears to be the best solution. In aid of this, a separate contingency study concluded that Raymond circuit RA12 is able to serve Deerfield circuit DF11 during an outage. This backup potential may reduce the duration of feeder outages in the future if implemented correctly. There are no long-term reliability projects proposed for this circuit. Periodic O&M and overcurrent protection review will aid in the reliability.

14.4.2.6 Circuit LE12

Both SAIDI and SAIFI criterion were exceeded on this feeder during 2000-2002. The figure below indicates that weather was the greatest contributor to consumer-hours of outages. 61% of consumer-hours for this cause were due to two outages of significant duration. Furthermore, only 10 of the 68 outages on this feeder were due to weather. Detailed descriptions for weather related outages should be logged in great detail to assist in any future review and mitigation.

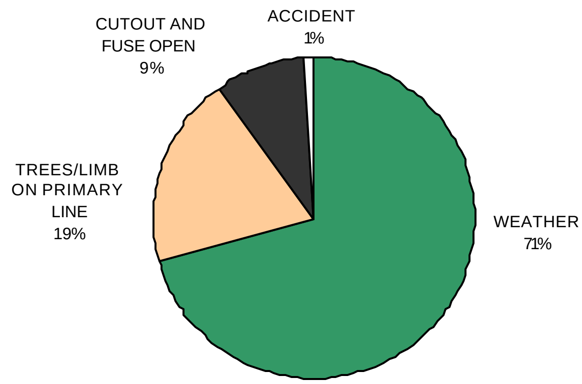


Figure 14-13 Circuit LE12 Percentage of Customer-Minutes Out by Outage Cause

To improve the future reliability on this feeder, and the Lee delivery point in general, a new delivery point is recommended. Project LE-R1 is the addition of 1.5 miles of new three-phase 1/0 ACSR and a new delivery point near PSNH's 3137X double-circuit 34.5 kV transmission line. The new distribution line route should follow Highway 155 right-of-way. As a result, the existing NHEC single-phase lines in the area can be served off the new three-phase.

With the addition of project LE-R1, a new normal-open location is recommended about 1.5 miles east of the Lee DP. This will divide the existing load, number of members, and miles of primary line exposure over two circuits. As a result, the reliability will be improved during both normal and backup system operation. The cost of project LE-R1 is about $250,000.

14.4.2.7 Circuit RA11

This rural classified circuit had the second highest SAIDI index in the Raymond district with a value of 7.06. The figure below indicates the consumer-hours due to various causes.

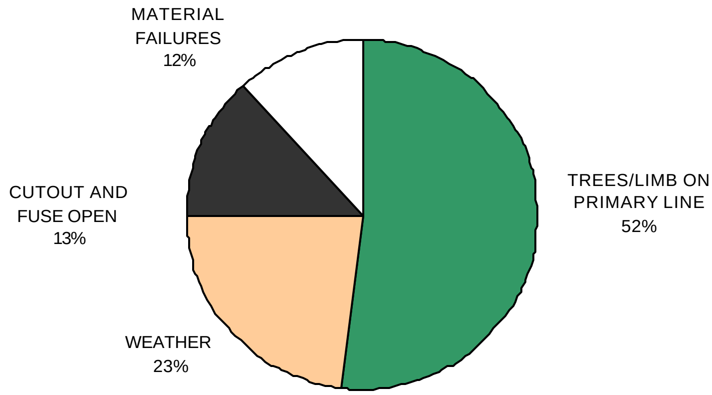


Figure 14-14 Circuit RA11 Percentage of Customer-Minutes Out by Outage Cause

The Raymond Substation has experienced no power supplier caused outages over the last three years as discussed previously in the transmission system reliability section. On the other hand, the distribution system reliability has been poor, primarily due to tree contact. There have been seven feeder outages, four of them due to trees falling on the primary lines, contributing 46% of the total consumer-hours on the feeder.

As is usually the case, the number and duration of the feeder outages affecting all members needs to be decreased to significantly improve reliability. Increased tree maintenance in addition to more overcurrent devices along the main line to reduce the length of the first zone of protection may provide improvement. If these do not prove to be effective, the main line could be upgraded to tree wire. In addition, the use of the Lee Delivery Point for backup needs to be fully utilized to permit rapid restoration of service during major outages. The addition of project LE-R1, as previously discussed in the Circuit LE12 section, will provide load relief to the Lee Delivery Point if needed during contingencies between Circuits LE11 and RA11.

There are no proposed distribution system reliability construction projects for this feeder.

14.4.2.8 Circuit RA12

The average SAIDI of 4.61 over the last three years exceeded the suburban feeder classification criterion. A review of the yearly indices indicates that there were four feeder outages out of the 100 total outages. These four were responsible for 70% of the consumer-hours of outages on this feeder. A breakdown of outages by cause can be seen in the following figure.

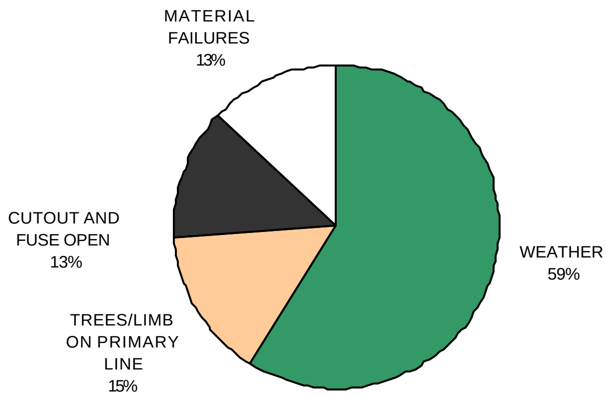


Figure 14-15 Circuit RA12 Percentage of Customer-Minutes Out by Outage Cause

Like the majority of the other feeders in the Raymond district, weather was the primary cause of consumer-hours of outages. There were only fourteen outage events of the 100 total outages due to weather.

Similar to Circuit RA11, the number and duration of the feeder outages affecting all members needs to be decreased to significantly improve reliability. The three-phase tie with Chester Substation Circuit CS13 needs to be utilized during feeder outages to reduce outage durations and restore service to as many members as possible.

There are no proposed distribution system reliability construction projects for this feeder. If basic O&M and sectionalizing improvements do not prove to be effective in the future, the possibility of building another source near the normal-open location between circuits RA12, CS13, and DF11 should be considered depending upon the availability of PSNH transmission and distribution lines in the area. With this addition, looped sectionalizing between the new source and feeders RA12, CS13, and DF11 could be accomplished to allow quicker restoration of service.

14.4.3 Circuits That Meet Reliability Criteria

14.4.3.1 Circuit BT12

Overall, this circuit has experienced adequate reliability over the past three years. Even though there were 16 outages over the past three years, many of these were either of short duration or affected few members. For example, only one outage affected more than 100 members. Furthermore, the average outage duration over the past three years has been 2.0 hours.

As discussed above, even though the reliability on Circuit BT12 has been above average, a three-phase tie line with Circuit CS14 of the Chester substation is recommended. The tie-line will provide contingency capabilities between CS14, BT11 and BT12. At the forecasted load level for 2023, circuit CS14 can serve the entire Brentwood service area at 80% peak load level as long as projects CS-4, CS-R2, BT-R1, CS-R1, and either BT-2 or BT-6 are implemented. Three of these projects, CS-R2, BT-R1, and CS-R1, are needed for reliability and contingency potential, while CS-4 is needed to provide voltage and capacity support during normal system peaks. Project CS-4 is discussed above in the Chester Substation Service Area section.

The possibility of creating a new metering or delivery point near the ends of the main three-phase lines of circuits BT11 and CS14, which is in the vicinity of project BT-R1, will dramatically improve the reliability and backup potential for both the Brentwood Metering Point service area and the heavily loaded circuit CS14 of the Chester Substation. The option of creating the metering of delivery point will be determined by the accessibility and availability of 34.5 kV or higher transmission in this area.

14.4.3.2 Circuit DF12

There are no proposed projects based solely on reliability for this feeder. Although, project DF-2 discussed in the Deerfield portion of the Distribution System Reliability section may improve reliability by dividing the members over three phases instead of two.

14.4.3.3 Circuit DF13

There are no proposed distribution system reliability projects for this feeder.

14.4.3.4 Circuit DY11

Overall, this circuit has very good reliability over the past three-years with a SAIDI index of 1.34. There are no proposed distribution system reliability projects for this feeder.

There have been approximately 80 outages along this feeder over the past three years, with none of them being entire feeder outages. This seems excessive when considering the number of miles of primary line on this circuit. Although, due to the configuration of this urban feeder, there are many short, overhead single-phase taps off the main line, which causes the operation of the protecting tap fuses to be the number one cause of consumer-hours of outages. In fact, about 73% of the outage events, and 60% of the consumer-hours were due to the operation of fuses. Furthermore, a review of the outages indicates that most of the outages affected relatively small numbers of members.

Mentioned previously in the transmission system reliability section of the Raymond District, the Derry MP experienced three feeder outages that were caused by PSNH. This is within the transmission system reliability criteria, and therefore no transmission changes are proposed due to reliability. If future power supplier reliability decreases, the possibility of establishing another source into the Derry service area should be examined.

14.4.3.5 Circuit LE11

A review of the outages over the last three years indicates there have been only two feeder outages affecting all members. Most of the outages have affected members on one phase along the single-phase taps off the main feeder. Furthermore, about 53% of the total customer-hours were due to weather on this feeder. Detailed descriptions for weather related occurrences should be logged in great detail to assist in any future review and mitigation.

There are no proposed distribution system reliability construction projects for this feeder.

14.5 Cost Estimates

A summary of the cost estimates for the proposed 5-Year, 10-Year and 20-Year Plans is provided in Table 14-15. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in Section 14.3 and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 14.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 14-15 Construction Cost Summary

	2004-2008 Cost ($)	2009-2013 Cost ($)	2014-2023 Cost ($)	2004-2023 Cost ($)
New Tie Lines	44,000	0	6,600	50,600
Conversions and Line Changes	886,270	530,360	64,380	1,481,010
New Substations, PD's and MP's	0	0	0	0
Substation, DP and MP Changes	156,300	100,000	0	256,300
Total	1,086,570	630,360	70,980	1,787,910
Projects for Improved Reliability	252,000	330,700	425,000	1,007,700

Table 14-16 Substation Load Data Projections

Substation Delivery Point or Meter Point Name	Ckt.	Season	Existing System Configuration 2003 Load level kW	Existing 2008 Load level kW	Existing 2013 Load level kW	Existing 2023 Load level kW	Proposed System Configuration 2008 Load level kW	Proposed 2013 Load level kW	Proposed 2023 Load level kW
Brentwood DP	BT13	W	1,640	2,081	2,516	2,967	2,081	2,516	2,967
	Sub	W	1,640	2,081	2,516	2,967	2,081	2,516	2,967
Chester Substation	CS11	W	1,027	1,416	1,676	1,910	1,416	1,676	1,910
	CS12	W	---	---	---	---	1,198	1,395	1,575
	CS13	W	1,073	1,107	1,219	1,355	1,397	1,538	1,710
	CS14	W	3,020	3,636	4,275	4,831	2,365	2,753	3,109
	Sub	W	5,120	6,159	7,170	8,096	6,376	7,362	8,304
Deerfield DP	DF11	W	1,229	1,379	1,463	1,564	1,847	1,960	2,095
	DF12	W	1,045	1,171	1,245	1,329	1,171	1,245	1,329
	DF13	W	132	149	158	169	149	158	169
	Sub	W	2,406	2,699	2,866	3,062	3,167	3,363	3,593
Derry MP	DY11	W	2,980	3,267	3,546	4,092	3,267	3,546	4,092
	Sub	W	2,980	3,267	3,546	4,092	3,267	3,546	4,092
Lee DP	LE11	W	847	887	933	1,121	887	933	1,121
	LE12	W	1,318	1,533	1,677	1,926	1,533	1,677	1,926
	Sub	W	2,165	2,420	2,610	3,047	2,420	2,610	3,047
Raymond Substation	RA11	W	1,100	1,310	1,519	1,896	1,310	1,519	1,896
	RA12	W	3,136	3,307	3,473	3,833	2,500	2,624	2,896
	Sub	W	4,236	4,617	4,992	5,729	3,810	4,143	4,792
Raymond District		W	**18,547**	**21,243**	**23,700**	**26,993**	**21,121**	**23,540**	**26,795**

Table 14-17 Construction Cost Details

(see following 2 pages)

Project Code	YR	Sub/Ckt	Project Description	Reason Code	@ Load (amps) [1]	Miles	Estimated Cost ($)
I. New Tie Lines							
CS-8	2023	Chester / CS14	1ph 1/0 ACSR	D	30	0.10	6,600
RA-3	2008	Raymond / RA12	3ph 4/0 ACSR	S	-	0.50	44,000
	Total New Tie Lines					0.60	50,600
II. Conversions and Line Changes							
BT-3	2004	Brentwood / BT11	Add 3-100 kVAR Capacitors, Switched	S	40	--	5,100
BT-4	2004	Brentwood / BT11	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)	C,D,V	40	0.40	5,200
BT-5	2004	Brentwood / BT11	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D,V	40	1.20	34,800
BT-7	2004	Brentwood / BT12	Add 3-100 kVAR Capacitors, Switched	C,V	30	--	5,100
CS-2	2013	Chester / CS11	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D,V	45	1.20	34,800
CS-3	2013	Chester / CS13	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)	C,D,V	50	1.20	15,600
CS-3	2013	Chester / CS13	1ph 1/0 ACSR to 3ph 1/0 ACSR			1.20	81,600
CS-3	2013	Chester / CS13	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)			1.50	43,500
CS-4	2013	Chester / CS14	3ph 1/0 ACSR to DBL CKT 3ph 336 ACSR	C,D,V	200	2.00	300,000
CS-5	2013	Chester / CS14	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D,V	45	1.00	29,000
CS-6	2023	Chester / CS14	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D,V	45	0.70	24,360
CS-7	2023	Chester / CS14	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D,V	45	0.70	24,360
DF-1	2008	Deerfield / DF11	1ph 1/0 ACSR to 3ph 4/0 ACSR	C,D,V	45	1.50	127,500
DF-2	2005	Deerfield / DF12	2ph 1/0 ACSR to 3ph 4/0 ACSR	C,D,V	45	3.10	269,700
DF-3	2005	Deerfield / DF12	Add 3-100 kVAR Capacitors, Fixed	C,V	45	--	2,500
DY-1	2013	Derry / DY11	Upgrade Capacitors from 3-50 to 3-100 kVAR, Sw	C,V	40	--	5,100
DY-2	2004	Derry / DY11	Add 3-100 kVAR Capacitors, Switched	C,V	40	--	5,100
LE-1	2007	Lee / LE11	1ph 1/0 ACSR to 3ph 4/0 ACSR	C,D,V	45	2.20	187,000
LE-3	2004	Lee / LE11	Add 3-100 kVAR Capacitors, Fixed	C,V	40	--	2,500
LE-4	2023	Lee / LE12	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)	C,D,V	40	0.40	15,660
LE-5	2007	Lee / LE12	1ph 1/0 ACSR to 2ph 1/0 ACSR (add 1)	D	20	0.13	3,770
LE-6	2007	Lee / LE11	1ph 1/0 ACSR to 3ph 4/0 ACSR	B,C,D,V	[1]	2.80	238,000
RA-1	2013	Raymond / RA11	Add 3-100 kVAR Capacitors, Switched	C,V	30	--	5,100
RA-2	2013	Raymond / RA12	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D,V	40	0.40	15,660
	Total Conversions and Line Changes					21.63	1,481,010
III. Projects that have Potential Reliability Improvement							
BT-R1	2013	Brentwood / BT12	1ph 1/0 ACSR to 3ph 336 ACSR			0.50	48,000
BT-R1	2013	Brentwood / BT12	New 3ph 336 ACSR			2.00	192,000
BT-R1	2013	Brentwood / BT12	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)			0.40	5,200
CS-R1	2013	Chester / CS14	Add 3-150 amp, 7.2 kV, voltage regulators			--	36,000
CS-R2	2013	Chester / CS14	3ph 1/0 ACSR to 3ph 336 ACSR			0.50	49,500
DF-R1	2023	Deerfield / DF12	New 3ph 4/0 ACSR			5.00	425,000
LE-R1	2008	Lee / LE12	New 3ph 1/0 ACSR			1.50	102,000
LE-R1	2008	Lee / LE12	New Delivery Point, 2.5/3.5 MVA, 19.9/34.5 - 7.2/12.47 kV			--	150,000
	Total Potential Reliability Improvements					9.90	1,007,700
	Total of all projects					32.13	2,539,310
Total by year for first 4 years (includes reliability projects)							
	2004					1.60	57,800
	2005					3.10	272,200
	2006					0.00	0
	2007					5.13	428,770
	2008					3.50	423,500
	2013					11.90	861,060
	2023					6.90	495,980
			Total			32.13	2,539,310

Reason Code(s)

- A To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life.
- B To improve **B**ackup between circuits and substations.
- C To provide additional **C**apacity.
- D To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
- F To accommodate **F**uture load.
- S To accommodate new **S**ystem configuration as a result of other projects.
- U To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
- V To improve **V**oltage.
- WP As per NHEC 2001-2005 Construction **W**ork **P**lan.
- [1] Recommended when peak load on Barnstead Circuit BS13 reaches 100 amps/phase.

1 @ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				
			None	
2009-2013 Time Period				
			None	
2014-2023 Time Period				
			None	
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				
BT-1	2004	Brentwood DP	Add 1-333 kVA 19.9/34.5 to 7.2/12.47 kV stepdown transformer	7,000
BT-2	2004	Brentwood DP	Add 3-100 amp, 7.2 kV, voltage regulators	27,300
BT-6	2004	Brentwood DP	Add 3-150 amp, 7.2 kV, voltage regulators	36,000
LE-2	2004	Lee DP	Upgrade regulators from 3-100 to 3-150 amp	36,000
LE-7	2007	Lee DP	Add 1-2500 kVA 19.9/34.5 to 7.2/12.47 kV stepdown transformer	50,000
			Total 2004-2008	156,300
2009-2013 Time Period				
CS-1	2013	Chester Sub	Modify to accommodate 4th circuit	100,000
			Total 2009-2013	100,000
2014-2023 Time Period				
			None	

Table 14-18 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
RAYMOND	BT11	2000	9	23	180		0.05	0.13	2.56
		2001	32	65	180		0.18	0.36	2.03
		2002	782	2,932	180		4.34	16.29	3.75
	Totals		823	3,020	540	Average	1.52	5.59	3.67
	BT12	2000	10	13	280		0.04	0.05	1.30
		2001	177	334	280		0.63	1.19	1.89
		2002	335	481	280		1.20	1.72	1.44
	Totals		522	828	840	Average	0.62	0.99	1.59
	CS11	2000	111	181	325		0.34	0.56	1.63
		2001	936	1,242	325		2.88	3.82	1.33
		2002	478	869	325		1.47	2.67	1.82
	Totals		1,525	2,292	975	Average	1.56	2.35	1.50
	CS13	2000	40	202	361		0.11	0.56	5.05
		2001	639	3,923	361		1.77	10.87	6.14
		2002	1,791	5,378	361		4.96	14.90	3.00
	Totals		2,470	9,503	1,083	Average	2.28	8.77	3.85
	CS14	2000	1,153	3,589	978		1.18	3.67	3.11
		2001	2,551	5,078	978		2.61	5.19	1.99
		2002	2,425	11,395	978		2.48	11.65	4.70
	Totals		6,129	20,062	2,934	Average	2.09	6.84	3.27
	DF11	2000	93	193	463		0.20	0.42	2.08
		2001	1,501	2,876	463		3.24	6.21	1.92
		2002	1,566	3,936	463		3.38	8.50	2.51
	Totals		3,160	7,005	1,389	Average	2.28	5.04	2.22
	DF12	2000	450	1,142	451		1.00	2.53	2.54
		2001	623	3,092	451		1.38	6.86	4.96
		2002	516	2,384	451		1.14	5.29	4.62
	Totals		1,589	6,618	1,353	Average	1.17	4.89	4.16
	DF13	2000	10	10	63		0.16	0.16	1.00
		2001	86	185	63		1.37	2.94	2.15
		2002	268	517	63		4.25	8.21	1.93
	Totals		364	712	189	Average	1.93	3.77	1.96
	DY11	2000	701	1,137	1,300		0.54	0.87	1.62
		2001	1,577	2,356	1,300		1.21	1.81	1.49
		2002	949	1,745	1,300		0.73	1.34	1.84
	Totals		3,227	5,238	3,900	Average	0.83	1.34	1.62
	LE11	2000	288	561	383		0.75	1.46	1.95
		2001	470	913	383		1.23	2.38	1.94
		2002	1,323	2,980	383		3.45	7.78	2.25
	Totals		2,081	4,454	1,149	Average	1.81	3.88	2.14
	LE12	2000	224	418	535		0.42	0.78	1.87
		2001	1,821	5,567	535		3.40	10.41	3.06
		2002	1,532	3,653	535		2.86	6.83	2.38
	Totals		3,577	9,638	1,605	Average	2.23	6.00	2.69
	RA11	2000	2,280	4,450	571		3.99	7.79	1.95
		2001	1,718	2,563	571		3.01	4.49	1.49
		2002	2,777	5,237	571		4.86	9.17	1.89
	Totals		6,775	12,250	1,713	Average	3.96	7.15	1.81
	RA12	2000	1,560	2,630	1,221		1.28	2.15	1.69
		2001	3,930	8,725	1,221		3.22	7.15	2.22
		2002	2,496	5,547	1,221		2.04	4.54	2.22
	Totals		7,986	16,902	3,663	Average	2.18	4.61	2.12
	District Total	2000	6,929	14,549	7,111		0.97	2.05	2.10
		2001	16,061	36,919	7,111		2.26	5.19	2.30
		2002	17,238	47,054	7,111		2.42	6.62	2.73
	Totals		40,228	98,522	21,333	Average	1.89	4.62	2.45

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side"Outages).*

15.0 Sunapee District

15.1 Load Analysis

The Sunapee District contains 4 delivery points, which accounted for nearly 4.0 percent of NHEC's load in 2002. The delivery points of Calavant, Charlestown, Cornish, and Sunapee, had respective 2002 peak demands of 413, 1,500, 1,405, and 3,716 kW. The Charlestown and Sunapee delivery points have remained winter peaking while Cornish moved from winter to summer peaking in 2002. Calavant has been summer peaking in recent history.

The Calavant delivery point serves a small portion of the towns in its service area with a CPR of 2.1%. No change in this ratio is anticipated. Consumer growth will then follow the rather slow growth trajectory of service area population with an annual growth rate of 0.4 percent from 2002 to 2023.

Demand per consumer for Calavant the fourth highest on the NHEC system in 2002 at 4.05 kW. New loads are anticipated to have demands of 2.0 kW, which will lead to declines in this figure to 3.73 by 2023.

Growth in consumers for this delivery point are offset by the decreasing use per consumer so total demand is expected to remain fixed at 2002 levels through 2023 as shown in Table 15-1 and Figure 15-1.

Table 15-1 Calavant DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	4,749				
2001	4,811				
2002	4,815	0.0212	102	4.049	413
2003	4,830	0.0212	102	4.037	413
2004	4,845	0.0212	103	4.024	413
2005	4,862	0.0212	103	4.010	413
2006	4,879	0.0212	103	3.996	413
2007	4,895	0.0212	104	3.983	413
2008	4,912	0.0212	104	3.969	413
2013	5,009	0.0212	106	3.894	413
2023	5,240	0.0212	111	3.731	414
Growth Rates					
2002 - 2003	0.30%	0.00%	0.30%	-0.30%	0.00%
2002 - 2008	0.33%	0.00%	0.33%	-0.33%	0.00%
2002 - 2013	0.36%	0.00%	0.36%	-0.35%	0.00%
2002 - 2023	0.40%	0.00%	0.40%	-0.39%	0.01%

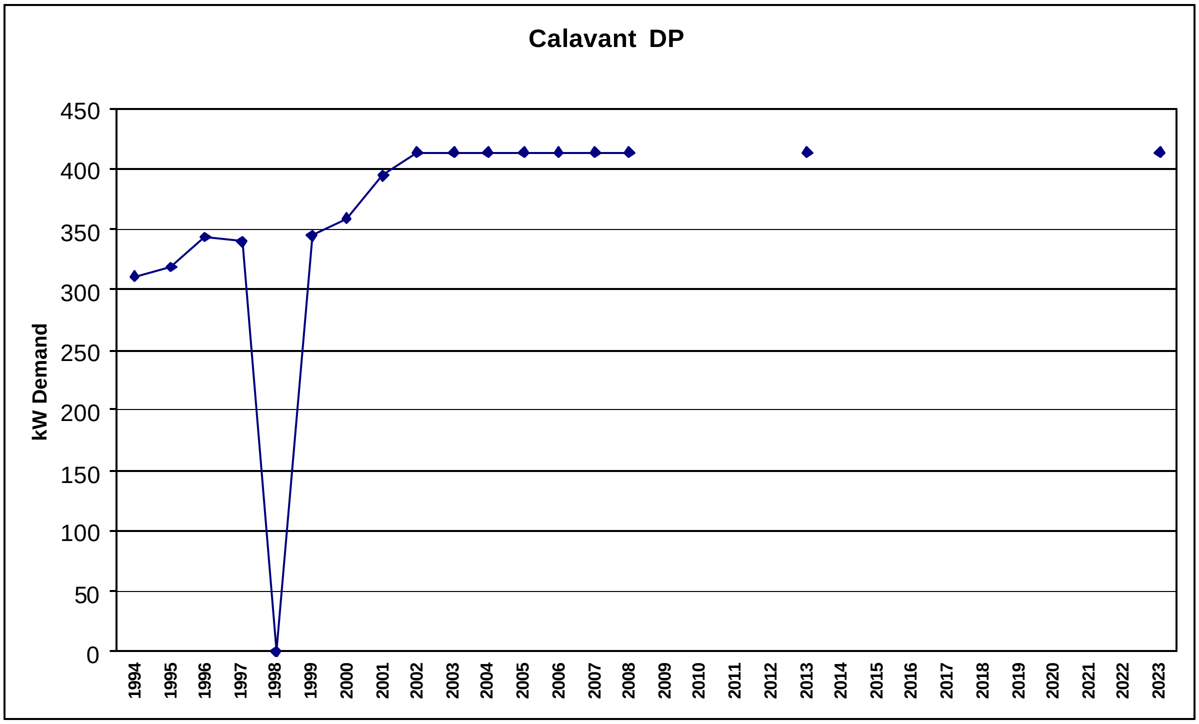


Figure 15-1 Historical and Forecasted Calavant DP Demands

The Charlestown delivery point serves a significant proportion of the service area population with a 2002 CPR of 13.2 percent. The share of area population served through this delivery point is expected to remain constant for the next two decades. Thus, the number of consumers will grow at the same rate as service area population or 0.6 percent per year from 2002 to 2023.

Slight increases in the demand per consumer are anticipated with an increase from 1.45 in 2002 to 1.46 by 2023.

These expected changes combine to yield growth in the peak demands on this delivery point from 1,500 in 2002 to 1,715 kW by 2023 as shown in Table 15-2 and Figure 15-2. In addition to this growth, a spot load of 20 kW is anticipated in the 2004 to 2008 time frame at Bascom Farms.

Table 15-2 Charlestown DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	7,701				
2001	7,809				
2002	7,833	0.1320	1,034	1.451	1,500
2003	7,873	0.1320	1,039	1.451	1,508
2004	7,916	0.1320	1,045	1.452	1,517
2005	7,960	0.1320	1,051	1.452	1,526
2006	8,004	0.1320	1,057	1.453	1,535
2007	8,048	0.1320	1,062	1.453	1,544
2008	8,092	0.1320	1,068	1.454	1,553
2013	8,335	0.1320	1,100	1.456	1,603
2023	8,886	0.1320	1,173	1.462	1,715
Growth Rates					
2002 - 2003	0.51%	0.00%	0.51%	0.03%	0.55%
2002 - 2008	0.54%	0.00%	0.54%	0.04%	0.58%
2002 - 2013	0.57%	0.00%	0.57%	0.04%	0.60%
2002 - 2023	0.60%	0.00%	0.60%	0.04%	0.64%

Table 15-3 Charlestown DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR		
			2004-2008	2009-2013	2014-2023
			Load (kW)		
Charlestown	CT11	Bascom Farms Maple**	20		
** In addition to base forecast					

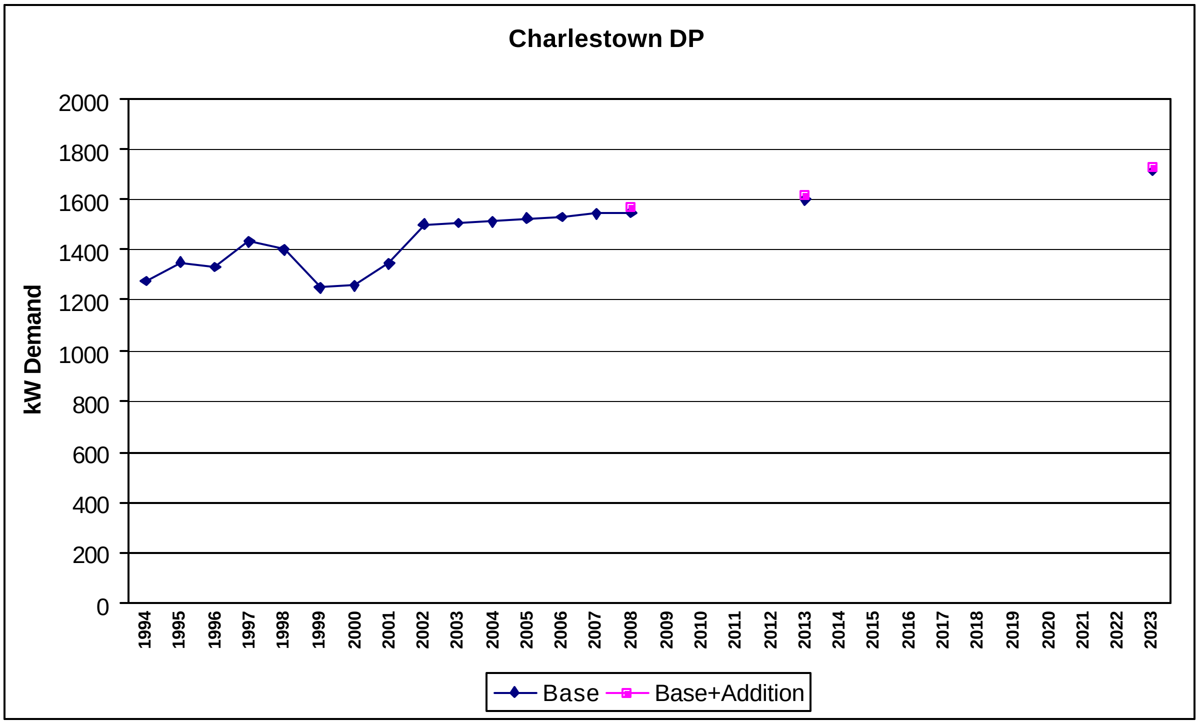


Figure 15-2 Historical and Forecasted Charlestown DP Demands

The Cornish delivery point serves a small share of the area population which is expected to stay constant in the future. Slight declines in population are projected for the towns in the service area of this delivery point. No significant change is anticipated in the total number of consumers served from this delivery point.

Demand per consumer was 1.858 kW in 2002. While new consumers are expected to have demands of 2.0 kW, no net growth in consumers is expected. Thus, loads are expected to remain at current levels over the planning horizon.

The load forecasts are presented in Table 15-4 and Figure 15-3.

Table 15-4 Cornish DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	23,322				
2001	23,516				
2002	23,438	0.0323	756	1.858	1,405
2003	23,409	0.0323	755	1.858	1,403
2004	23,386	0.0323	754	1.857	1,401
2005	23,369	0.0323	754	1.856	1,399
2006	23,350	0.0323	753	1.856	1,398
2007	23,332	0.0323	753	1.855	1,396
2008	23,313	0.0323	752	1.855	1,395
2013	23,287	0.0323	751	1.854	1,393
2023	23,391	0.0323	755	1.856	1,401
Growth Rates					
2002 - 2003	-0.12%	0.00%	-0.12%	-0.05%	-0.17%
2002 - 2008	-0.09%	0.00%	-0.09%	-0.03%	-0.12%
2002 - 2013	-0.06%	0.00%	-0.06%	-0.02%	-0.08%
2002 - 2023	-0.01%	0.00%	-0.01%	-0.01%	-0.01%

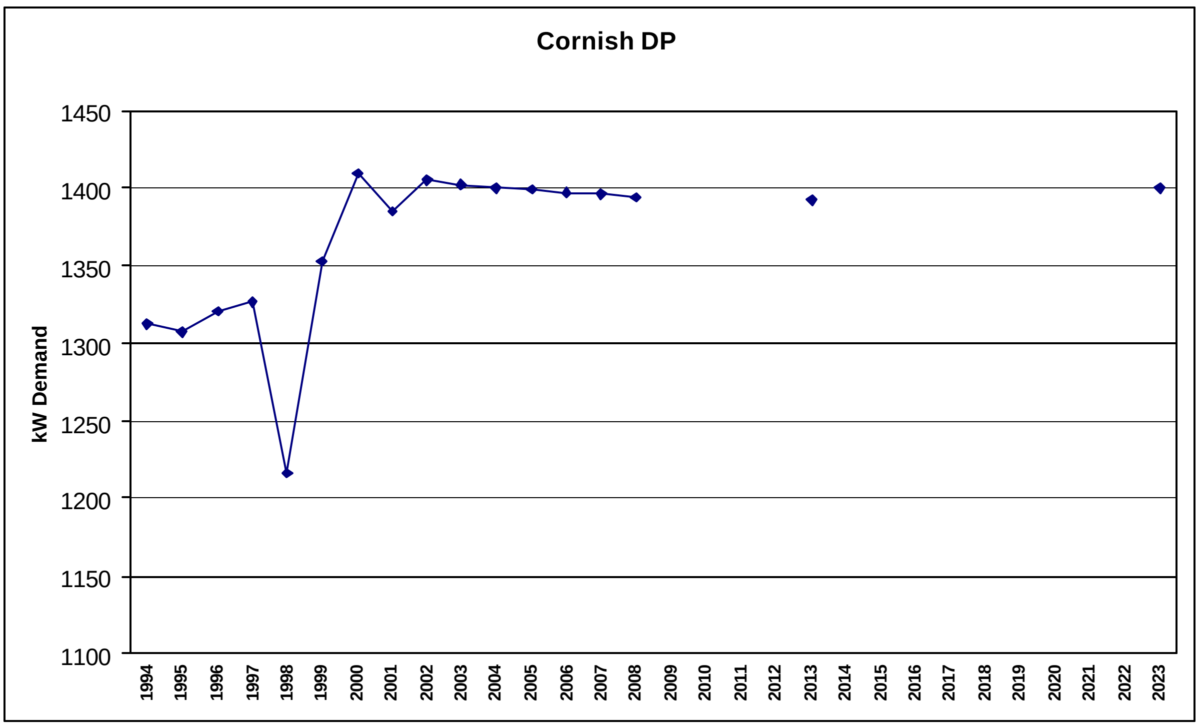


Figure 15-3 Historical and Forecasted Cornish DP Demands

The Sunapee delivery point serves a significant proportion of the service area population with a 2002 CPR of 11.6 percent. Consumer growth for this delivery point is expected to be proportionate to growth in the service area population at an annual rate just over 1.0% over the next two decades. This leads to an increase of 630 consumers served by this delivery point which represents a 24.3 percent increase.

Demand per consumer for this delivery point is 1.435 kW which is expected to increase slightly to 1.458 kW by 2023.

The combined result of these expected changes, as shown in Table 15-5 and Figure 15-4, is an increase of 978 kW in the Sunapee DP load by 2023. Spot loads included in that growth forecast relate to new condominium developments at Washington Island.

Table 15-5 Sunapee DP Non-Coincident Peak Demand Base (Historic & Forecasted)

Year	Town Population	CPR	Active Consumers	DPC	Peak kW
2000	21,745				
2001	22,127				
2002	22,277	0.1163	2,590	1.435	3,716
2003	22,510	0.1163	2,617	1.436	3,758
2004	22,747	0.1163	2,645	1.437	3,801
2005	22,990	0.1163	2,673	1.439	3,846
2006	23,230	0.1163	2,701	1.440	3,889
2007	23,472	0.1163	2,729	1.441	3,933
2008	23,714	0.1163	2,757	1.442	3,977
2013	24,979	0.1163	2,904	1.448	4,205
2023	27,697	0.1163	3,220	1.458	4,694
Growth Rates					
2002 - 2003	1.04%	0.00%	1.04%	0.09%	1.14%
2002 - 2008	1.05%	0.00%	1.05%	0.09%	1.14%
2002 - 2013	1.05%	0.00%	1.05%	0.08%	1.13%
2002 - 2023	1.04%	0.00%	1.04%	0.08%	1.12%

Table 15-6 Sunapee DP Spot Loads Identified

Substation	Circuit	Load Type	YEAR 2004-2008 Load (kW)	YEAR 2009-2013 Load (kW)	YEAR 2014-2023 Load (kW)
Sunapee	SP12	Washington Island Condos	50	50	100
		Washington Island Condos	50	50	100

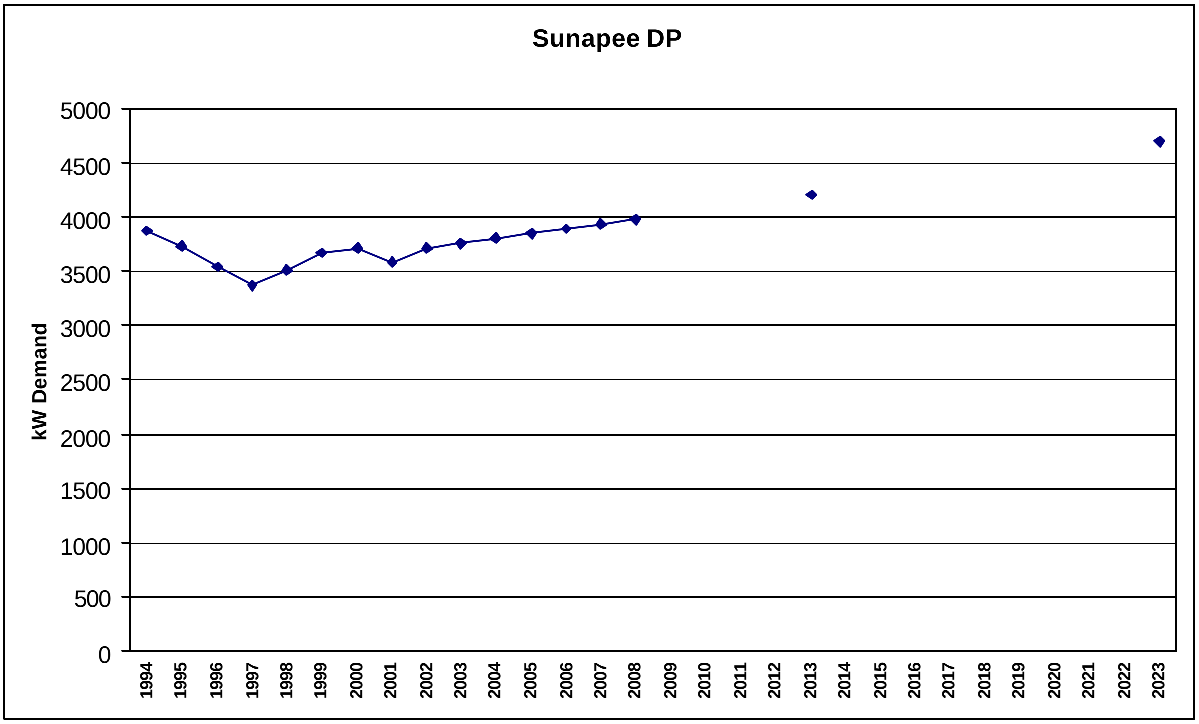


Figure 15-4 Historical and Forecasted Sunapee DP Demands

15.2 Transmission System

15.2.1 Bulk Transmission System

NHEC's Sunapee Substation is supplied by PSNH's North Road Substation. North Road Substation is supplied by two 115 kV circuits, Webster-North Road 115 kV and Ascutny (VELCO) – North Road 115 kV transmission lines.

15.2.2 34.5 kV Subtransmission System

Substation capacity and base case and forecasted load levels are depicted in Table 15-7 and are based on an annual area load growth rate of 0.985% in coincident peak loads for both the summer and winter peak load periods.

Table 15-7 34.5 kV Subtransmission System

PSNH Substation	115 – 34.5 kV Transformer Capacity Summer Capacity	Winter Capacity	34.5 kV Feeders	Peak Loads – MVA Summer 2003	Summer 2023	Winter 2002	Winter 2022
North Road	1-55 MVA, 1-56 MVA	1-64 MVA, 1-65 MVA	3	23.4	31.9	30.4	40.5

North Road Substation has three 34.5 kV feeders. PSNH 34.5 kV feeders 3161 and 3410 are looped for improved reliability and backup. Feeder 3161 has a significant level of small power producer generation capacity located at Hemphill, 14.1 MVA. NHEC's Sunapee Substation is served from the North Road Substation feeder 3410. PSNH feeder 3410 currently peaks at 5.4 MVA in summer and 7.0 MVA in winter and is projected to be at 6.6 MVA in summer and 8.4 MVA in winter in 2022-23. There are no deficiencies during the planning period.

15.2.3 Historical Reliability

Sunapee Substation has not experienced any power supplier outages in the 2000-2002 time period. This is within the NHEC design criteria limits.

15.2.4 Contingency Performance

The outage of a single 115 kV transmission line or a North Road 115-34.5 kV transformer will not result in an outage to Sunapee Substation. An outage of PSNH 34.5 kV feeder 3410 will not result in Sunapee Substation being unserved for more time than it takes PSNH to isolate the fault and restore service by line switching to the adjacent PSNH 3161 feeder.

15.3 Distribution System

15.3.1 General

The following discusses the recommended construction projects by substation, DP or MP service area along with various alternatives. Project item numbers referred to in the discussion are shown on the Proposed System Circuit Diagram and in the cost tables. The projects and item numbers shown in GREEN are anticipated in the 2003-2008 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 based on improving reliability are shown in ORANGE and are discussed in Section 15.4, Distribution System Reliability. Section 5.0, Planning Approach, provides information related to the development of the Long Range Plan. The "Substation Load Data Projections [table]" at the end of Section 15.0 shows the 2003, 2008, 2013 and 2023 peak load levels for each substation, DP and MP and circuit using the existing system configuration and the proposed system configuration.

15.3.2 New Substations, DP's and MP's

The East Lempster Delivery Point is recommended to improve voltage and provide additional capacity to the area served by Circuit SP12 of the Sunapee Substation. This circuit is forecasted to have a peak load of 3,807 kW in 2023. At the present time, three sets of voltage regulators are cascaded to maintain proper voltage levels. The ends of Circuit SP12 are approximately 25 miles from the Sunapee Substation.

The East Lempster Delivery Point will be served by a 34.5 kV line. The existing three-phase 336 ACSR distribution line between the Sunapee Substation and the East Lempster DP location is operated at 7.2/12.47 kV but is insulated for 34.5 kV operation and was constructed to accommodate three-phase underbuild. Project SP-1 is the addition of three-phase 336 ACSR, 7.2/12.35 kV, underbuild to the existing three-phase 336 ACSR line. This will enable the load to be transferred to the underbuild and be served at 7.2/12.47 kV and the 34.5 line can then provide service to the East Lempster DP.

Projects EL-1 and EL-2 are the addition of 34.5 kV to 7.2/12.47 kV, 5000 kVA padmounted stepdown transformers and 219 amp voltage regulators on the south and west main three-phase lines for continued operation at 7.2/12.47 kV. A normally open 7.2/12.47 kV tie between the south and west lines and to Circuit SP12 is recommended to enable serving these areas from either one of the stepdown transformers. The transformer and regulators on the west line have also been sized to provide the capacity to backup the Charleston Meter Point.

15.3.3 Substation, DP and MP Changes

The following table shows the projected kW for the Long Range Plan design load level, Proposed System Arrangement, as a percent of existing and proposed substation transformer and regulator capacity. The percent of capacity is calculated using a 98 percent power factor and 10 percent load unbalance. Proposed capacity upgrades that are anticipated for serving normal load and/or for backup or for the ordinary replacement of aged transformers are shown in [**bold**]. The notes at the bottom of the table indicate the reason for the change and provide the project number.

Table 15-8 Substation Transformer And Regulator Data

Name	Transformer							Voltage Regulator		
	Rating (kVA)					Est. Load (kW)	Capacity (%)	Size (AMP)	Est. Load (AMP)	Capacity (%)
	OA 55°	FA 55°	OA 65°	FA 65°	Win Season					
Calavant MP	--	--	--	--	--	801	--	--	42	--
Charlestown DP [1]	5,000	--	--	--	5,500	1,735	32	75	90	120
Charlestown DP [1]	5,000	--	--	--	5,500	1,735	32	**150**	90	60
Charlestown DP [2]	5,000	--	--	--	5,500	1,324	25	75	69	92
Charlestown DP [2]	5,000	--	--	--	5,500	1,324	25	**150**	69	46
Cornish MP	--	--	--	--	--	1,396	--	--	73	--
E. Lempster-South	**5,000**	--	**5,600**	--	**6,160**	1849	31	219	96	44
E. Lempster-West	**5,000**	--	**5,600**	--	**6,160**	957	16	219	50	23
Sunapee [3]	5,000	5,750	5,600	6,440	7,000	4,745	69	**328**	247	75
Sunapee [4]	5,000	5,750	5,600	6,440	7,000	1,678	24	**328**	87	27

[1] Estimated peak load is before load transfer to Calavant MP.
[2] Estimated peak load is after load transfer to Calavant MP.
[3] Estimated peak load is before the installation of the East Lempster DP.
[4] Estimated peak load is after the installation of the East Lempster DP.

No conversion to a different distribution system operating voltage is recommended at any of the substations, meter points or delivery points. The distribution operating voltage is to remain at 7.2/12.47 kV.

After completion of Projects SP-1, EL-1 and EL-2, which create the East Lempster DP, it is recommended that 3-328 amp voltage regulators be installed at the Sunapee Substation and the two sets of line regulators on Circuit SP-12 be removed. The 328 amp voltage regulators will provide the capacity for backup to the new East Lempster DP. One capacitor bank can also be removed.

Project CT-1 will upgrade the 3-75 amp voltage regulators at the Charlestown DP to 3-150 amp regulators to provide adequate capacity.

15.3.4 Calavant Meter Point Service Area

15.3.4.1 Existing System Review

The Calavant Meter Point takes service at 7.2/12.47 kV. The MP, which is forecasted to serve 415 kW of peak load in 2023, supplies two circuits, CA11 and CA12. Circuit CA11 serves approximately 25 percent of the total load with CA12 serving the remaining 75 percent. There are no voltage regulators installed at the MP or out on the line.

Circuit CA11 is single-phase, approximately 1.5 miles long and has no ties to other circuits. The main line conductor is 1/0 ACSR. No main line capacity deficiencies or areas with low voltage are anticipated for Circuit CA11 during this planning period provided the voltage at the MP is 120 volts or higher.

Circuit CA12 is approximately 1.6 miles long and has a vee-phase tie to Circuit CT11 of the Charlestown Delivery Point. The main three-phase line is 1.0 miles long and consists of 1/0 ACSR. No line capacity deficiencies or areas with low voltage are anticipated during this planning period provided the voltage at the MP is 120 volts or higher.

15.3.4.2 Recommended Plan

On Circuit CA12, Project CA-1 will provide a three-phase tie to the northern end of the Charleston Meter Point's service area by converting the existing vee-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 1-1/0 ACSR phase conductor. The end of the line that is served from the Charleston Meter Point is over 14 miles from the MP. The end of the line that is served from the Calavant Meter Point is less than 2 miles from the MP. This tie line will enable the transfer of 383 kW of peak load, at the 2023 load level, from the Charleston Meter Point to the Calavant Meter Point. This transfer provides a 6 to 9 volt improvement in the area and will also improve reliability by reducing the amount of line exposure that serves the area. An alternative to Project CA-1 is a more lengthy vee-phase to three-phase conversion on the Charleston Meter Point main line along Black North Road. However, this alternative would not provide as much voltage improvement nor would it reduce the amount of line exposure to improve reliability. Therefore, Project CA-1 is recommended.

15.3.5 Charlestown Meter Point Service Area

15.3.5.1 Existing System Review

The Charlestown Meter Point takes service at 7.2/12.47 kV. The MP consists of one circuit which is forecasted to serve 1.7 MW of peak load in 2023. Voltage regulators are installed at the MP.

Circuit CT11 has a vee-phase tie to Circuit CA12 of the Calavant MP approximately 14.3 miles from the Charlestown MP and a vee-phase tie to the Circuit SP12 of the Sunapee Substation approximately 13.5 miles from the Charlestown MP. The main three-phase line of CT11 begins with 2.7 miles of 336 ACSR and then 2.7 miles of 4/0 ACSR. The main vee-phase and single-phase lines are mostly 1/0 ACSR. Voltage regulators are installed in the vee-phase line approximately 9.5 miles from the MP to maintain proper voltage levels at the ends of the circuit. The vee-phase line from the end of the three-phase to where the vee-phase splits is heavily loaded. Also, the single-phase line serving "5 Points" and the area beyond is becoming heavily loaded. These conditions result in low voltage before the voltage regulators and at the end of the single-phase line beyond "5 Points".

15.3.5.2 Recommended Plan

Project CT-2 will provide additional capacity by converting the single-phase 1/0 ACSR line to three-phase 1/0 ACSR by adding 2-1/0 ACSR phase conductors. The existing single-phase line is estimated to have 44 amps of peak load at the 2023 load level. The 2.2 mile three-phase extension will improve voltage at the end of the line by dividing the load over additional phases and will also improve load balance along the three-phase main line.

15.3.6 Cornish Meter Point Service Area

15.3.6.1 Existing System Review

The Cornish Meter Point takes service at 7.2/12.47 kV. The MP consists of one circuit which is forecasted to serve 1.4 MW of peak load in 2023. There are no voltage regulators installed at the MP.

Circuit CN11 starts with 0.7 miles of three-phase 1/0 ACSR and then splits into a north and south feeder. The north and south feeders both start with a small amount of three-phase 1/0 ACSR but are mostly vee-phase 1/0 ACSR. The north branch ends approximately 11.2 miles from the MP and the south branch approximately 11.5 miles from the MP. Both branch lines have voltage regulators installed approximately 5 miles from the MP to maintain proper voltage levels at the ends of the circuit. The beginning of the vee-phase line on the south branch is beginning to be heavily loaded. The voltage drop from the MP to the line voltage regulators is calculated to be 4 volts at the 2023 load level. No single-phase line capacity deficiencies or areas with low voltage are anticipated during this planning period provided the voltage at the MP is 122 volts or higher.

15.3.6.2 Recommended Plan

Project 378 is the replacement of an old vee-phase 1/0 ACSR with a new three-phase 1/0 tree wire line. The existing line was built in 1941 and most of the poles are in bad condition and a complete line rebuild is needed. This 10.7 mile project was included in year 1 of the 2001-2005 Construction Work Plan.

It is recommended that since there are no voltage regulators at the Meter Point, if the supplied voltage goes below 122 volts, the line voltage regulators should be moved closer to the Meter Point.

15.3.7 Sunapee Substation Service Area

15.3.7.1 Existing System Review

The Sunapee Substation, which is forecasted to serve 4.7 MW of peak load in 2023, supplies two circuits, SP12 and SP13. Circuit SP12 serves approximately 80 percent of the total load with SP13 serving the remaining 20 percent. There are no voltage regulators installed at the substation.

Circuit SP12 is approximately 26.8 miles long and has a vee-phase tie to Circuit CT11 of the Charlestown MP. The main three-phase line is 24.8 miles long and consists of 9.8 miles of 336 ACSR and 15.0 miles of 1/0 ACSR. The three-phase line splits into a south and west branch approximately 9.8 miles from the substation. The south branch serves 66 percent of the load and the west branch serves 33 percent. Two sets of voltage regulators are installed in the main line. The first set is approximately 5.6 miles from the substation and the second set is approximately 9.3 miles from the substation. Additional voltage regulators are installed further out on the line to maintain proper voltage levels at the ends of the circuit.

Circuit SP12 serves approximately 46 percent of the total Sunapee District load. The 2023 load level does not exceed the capacity rating of the existing 336 ACSR or the 1/0 ACSR three-phase feeder mains and 1/0 ACSR single-phase feeder mains. However, low voltage does occur in places due to the large amount of load on the circuit and the long length of the circuit.

Circuit SP13 is approximately 28.6 miles long and has no ties to other circuits. The main three-phase line is 11.3 miles long and consists of 2.6 miles of 336 ACSR and 8.7 miles of 1/0 ACSR. The remaining main line consists of 7.2 miles of vee-phase 1/0 ACSR and 10.1 miles of single-phase 1/0 ACSR. Voltage regulators are installed in the approximately 9.1 miles from the substation to maintain proper voltage levels at the ends of the circuit. No line capacity deficiencies or areas with low voltage are anticipated during this planning period provided the voltage at the substation is 122 volts or higher.

15.3.7.2 Recommended Plan

Project 379 is the replacement of old poles and crossarms as needed. The existing line was built in the late 1930's and it is estimated that 48 poles need replacement along with many crossarms. This 10.5 mile project was included in year 1 of the <u>2001-2005 Construction Work Plan</u>. The Work Plan indicates that the existing conductors will be used. However, it is recommended that the poles being replaced from East Lempster south be sized to accommodate a future conductor change to three-phase 4/0 ACSR. It is also recommended that the poles being replaced from East Lempster north be sized for future conversion to a double circuit 336 ACSR line. This double circuit would continue the 34.5 kV with 7.2/12.47 kV underbuild that is recommended as Project SP-1.

Project 380 is the replacement of 2.3 miles of old three-phase line. This project was included in year 1 of the <u>2001-2005 Construction Work Plan</u>. The poles are in bad condition and hendrix cable is recommended because of the difficulty in obtaining permission to clear or trim the right-of-way. Due to the age and condition of the line, a complete three-phase line rebuild is needed. Since a complete rebuild is needed, the use of 4/0 Hendrix cable is recommended to provide additional capacity on this main line.

Project 381 is the replacement of old phase conductors for 3.3 miles. The existing line has 1-4 ACSR phase conductor and 2-1/0 ACSR phase conductors and will be replaced with 1/0 tree wire. The use of different sized phase conductors can cause uneven tensions and twisted crossarms and replacement is recommended. This project was included in year 3 of the <u>2001-2005 Construction Work Plan</u>.

Project 382 is the replacement of 3.8 miles of old single-phase 1/0 ACSR with a new single-phase 1/0 tree wire line. The poles are in bad condition and parts of the line are difficult to access because of being in a wooded area on private right-of-way. The new line will follow road right-of-way where possible. This project was included in year 4 of the 2001-2005 Construction Work Plan.

Project 383 is the replacement of 2.7 miles of old vee-phase 1/0 ACSR with a new three-phase 1/0 tree wire line. The poles are in bad condition and parts of the line are difficult to access because of being in a wooded area on private right-of-way. The new line will follow road right-of-way where possible. This project was included in year 4 of the 2001-2005 Construction Work Plan.

Project 384 is the replacement of 2.3 miles of old three-phase line. This project was included in year 1 of the 2001-2005 Construction Work Plan. The poles are in bad condition and hendrix cable is recommended because of the difficulty in obtaining permission to clear or trim the right-of-way. Due to the age and condition of the line, a complete three-phase line rebuild is needed. Since a complete rebuild is needed, the use of 4/0 Hendrix cable is recommended to provide additional capacity on this main line.

As indicated in Section 15.3.2, Projects SP-1, EL-1 and EL-2 create the new East Lempster DP. Project SP-1 is the addition of a three-phase 336 ACSR, 7.2/12.35 kV, underbuild to the existing three-phase 336 ACSR line. This line is presently operated at 7.2/12.47 kV but was insulated for operation at 34.5 kV when built. The line was also built to accommodate an underbuild line. To improve voltage and provide additional capacity, it is recommended that the underbuild be installed and the load be transferred to the underbuild and served at 7.2/12.47 kV to enable the overbuild line to be operated at 34.5 kV to serve the new East Lempster DP. Projects EL-1 and EL-2 are the addition of 34.5 kV to 7.2/12.47 kV, 5000 kVA padmounted stepdown transformers and 219 amp voltage regulators on the south and west main three-phase lines for continued operation at 7.2/12.47 kV.

Project EL-4 is the replacement of a single-phase 1/0 ACSR line with a new three-phase 4/0 ACSR line and includes the addition of the third underground cable at the southern end of the project. This project will divide the estimated 1450 kW of peak load at the 2023 load level south of East Lempster thereby providing additional capacity and improved reliability. Reliability will also be improved by providing a three-phase loop. Dividing the load will provide a 12 to 14 volt improvement at the end of the circuit and will extend the life of the existing three-phase line along Highway 10.

15.4 Distribution System Reliability

15.4.1 Historical Reliability

The overall reliability in the Sunapee district during 2000-2002 has been much lower than the NHEC system average. In fact, the Sunapee district was the worst performing district in the NHEC system. Long feeders and heavy forestry are most likely some of the reasons for the higher outage indices. The following figure shows the reliability for each of the Sunapee district feeders, as well as the district total.

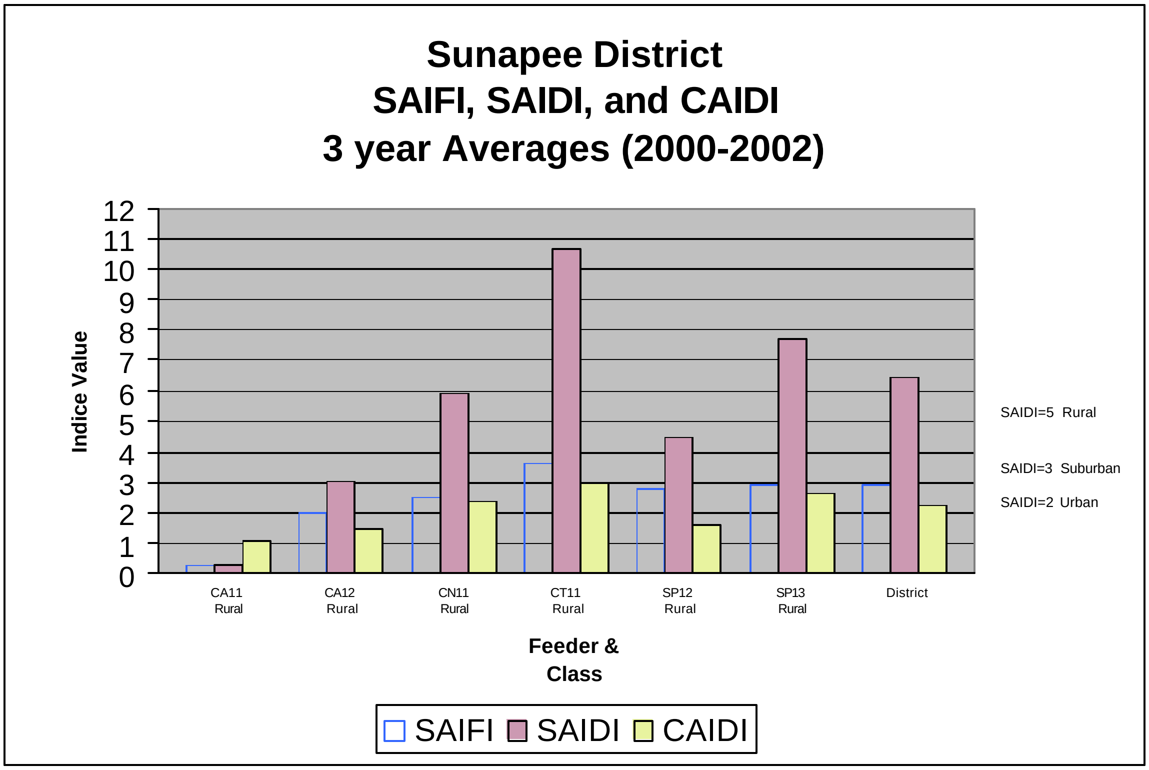


Figure 15-5 Sunapee District Reliability

15.4.1.1 SAIDI & SAIFI

Circuits CN11, CT11, and SP13 exceeded the SAIDI reliability criteria limit of 5.0 for rural classified feeders. All circuits except CA11 exceeded the general SAIFI limit of 2.0.

15.4.2 Circuits That Exceed Reliability Criteria

15.4.2.1 Circuit CA12

This short, three-phase circuit slightly exceeded the SAIFI criteria as mentioned above, but was well within the SAIDI criteria with an index of 3.03. There were only 19 outages on this feeder over the three-year sample period. A breakdown of outages by cause can be seen in the following Figure.

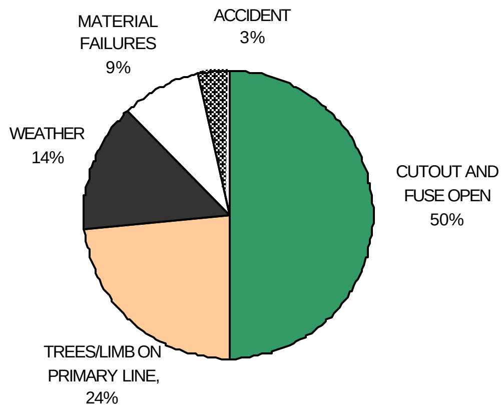


Figure 15-6 Circuit CA12 Percentage of Customer-Minutes Out by Outage Cause

There were no distribution feeder outages on this circuit over the last three years. Therefore, obviously due to the short length of the first zone of protection, most of the outages occurred on the single-phase taps off the main line. The fused taps resulted in the "cutout and fuse open" category ranking the highest in number of customer-hours of outages.

There are no recommended distribution construction projects or O&M improvements on this circuit. Although, project CA-R1, the upgrade of V-phase to three-phase by adding one phase conductors, will provide potential reliability improvement during outages to major feeders. Project CA-R1, in conjunction with the other three-phase conversion projects CT-R4 and CT-R5, will allow the Calavant Metering Point to be served by either the Charlestown delivery point or proposed East Lempster delivery point during contingencies.

15.4.2.2 Circuit CN11

As discussed in Cornish Metering Point service area of the distribution section, this one circuit actually splits into long north and south v-phase lines that extend approximately thirteen miles from the metering point.[8] The higher SAIDI index value of 5.89 was due to many single-phase feeder and tap outages compared to entire main feeder outages affecting all members. For example, there were five distribution feeder outages on the two circuits, with two occurring on the north circuit and three on the south circuit. These outages contributed only 17% of the total customer-hours. More importantly, there were numerous faults on the main lines causing the single-phase north and south circuit feeder reclosers to operate. In fact, 42% of the customer-hours of outage were due to the single-phase main feeder outages. Therefore, the remaining 40% of the customer-minutes occurred from outages on single-phase taps off the main v-phase lines. The percentage of customer-minutes of outages is shown in the following figure.

[8] For discussion purposes, these will be considered the "north" and "south" circuits.

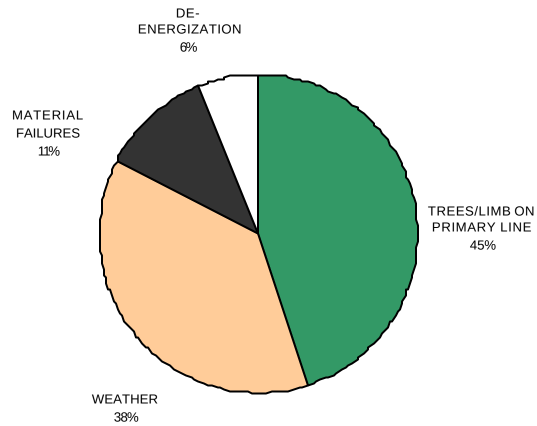


Figure 15-7 Circuit CN11 Percentage of Customer-Minutes Out by Outage Cause

The figure indicates that an increase in tree trimming and right-of-way clearing along the main lines may improve future reliability. As mentioned above, these main line outages were responsible for approximately 60% of the total consumer-hours of outages. Depending upon the location of these faults, additional zones of overcurrent protection may prove to be helpful as well.

Presently, the Cornish metering point is served by CVEC and does not have any ties with other sources during contingency situations. Although, construction project 378, the upgrade of V-phase to three-phase along the south circuit, which is proposed in NHEC's current 2001-2005 Construction Work Plan, along with a new tentative PSNH transmission line, will increase backup potential, and therefore reliability, for the Cornish metering point. Furthermore, there were fifteen outages caused by the power supplier over the past three years on this metering point. It us unknown at this time whether this PSNH line from Newport to Claremont along Highway 11/103 will be 12.47 kV distribution or 34.5 kV transmission. Either way, it is recommended that NHEC establish a metering or delivery point in this area to serve some load and provide backup for the south circuit of Cornish. The north circuit of Cornish may also be served from this new source, depending on voltage and capacity constraints, during an outage at the Cornish metering point. For purposes of this study, the proposed Newport delivery point, project CN-R1, is estimated at $150,000.

Three recommended tie-lines are recommended if the long single-phase lines within the project areas have experienced outage problems. Projects CN-R2, CN-R3, and CN-R4 will provide looped capability to 70, 84, and 36 members, respectively.

15.4.2.3 Circuit CT11

This was the worst performing circuit of the Sunapee district with a SAIDI of 10.64. There were three feeder outages of extremely long duration that accounted for about 48% of the consumer-hours. The breakdown of consumer-hours by cause can be seen in the following figure.

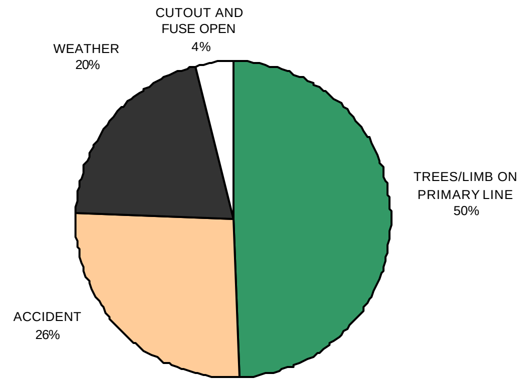


Figure 15-8 Circuit CT11 Percentage of Customer-Minutes Out by Outage Cause

Backup capability from the Calavant metering point or the proposed East Lempster delivery point will allow restoration of service to Charlestown during a transmission, substation, or major three-phase line outage. To implement this, projects CT-R4 and CT-R5 are recommended. Both projects are proposed strictly for backup capacity and reliability purposes, and therefore are not needed during normal system configuration at the 2023 load levels. Project CT-R4, the 3.6-mile conversion of V-phase 1/0 ACSR to three-phase 1/0 ACSR by adding one phase conductor is estimated at $47,000. Project CT-R5, the six-mile conversion of V-phase 1/0 ACSR to three-phase 1/0 ACSR by adding one phase conductor is estimated to cost approximately $80,000.

There are four potential tie-lines within the Charlestown delivery point service area that will provide looped capability. Project CT-R1 will increase reliability for the 160 members that are served on these two long single-phase taps. Projects CT-R2 and CT-R3 should be implemented to provide more dependable service to the 102 members on the long single-phase tap. Likewise, project CT-R6 will provide backup potential to the 60 members on the single-phase tap.

15.4.2.4 Circuit SP12

This is one of the longest feeders on NHEC's system, but has much better reliability than would be expected of a typical circuit of this configuration. The SAIDI criterion was met with a value of 4.48, while the SAIFI criterion was exceeded with a value of 2.78. There were 180 distribution system outages during 2000-2002, with four of them being entire feeder outages. These four were caused by tree contact and contributed about 48% of the entire consumer-hours of outages. The following figure reflects percentage of consumer-hours by cause.

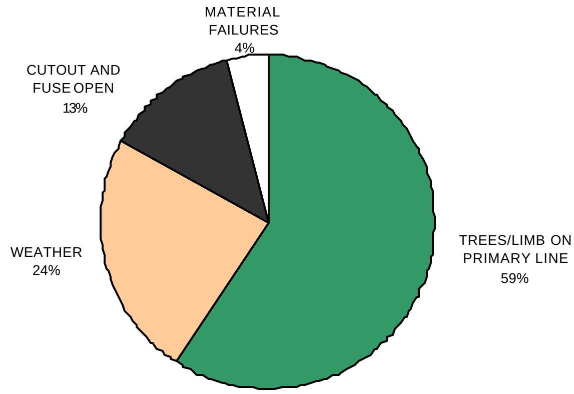


Figure 15-9 Circuit SP12 Percentage of Customer-Minutes Out by Outage Cause

After subtracting the 48% of customer-minutes from the tree/limb category that were due to the four feeder outages, only 11% of the remaining customer-minutes were due to tree contact. This means that weather had more of an effect than the above figure indicates.

As discussed in the Sunapee Substation service area distribution section, there are major system configuration proposals that will provide huge benefits from both a load serving and reliability standpoint. First, project CT-R5, the conversion to three-phase, will allow portions of Circuit SP12 to be served by either Calavant or Charlestown. This project is also discussed in the Circuit CT11 reliability section above, and is proposed to provide more benefit for the backup of Calavant and Charlestown, but will also benefit Sunapee circuit SP12.

Four projects to provide single-phase looped capability on some of the longer taps of this circuit are recommended. The projects are designated as SP-R1 through SP-R4. The amount of reliability impact each tie-line will provide, the number of members and the amount of load on the taps, and the historical outage rates should be studied to determine the feasibility of each project.

15.4.2.5 Circuit SP13

This was the second worst performing feeder in the Sunapee district with a SAIDI of 7.71. The following figure shows the outage cause percentages.

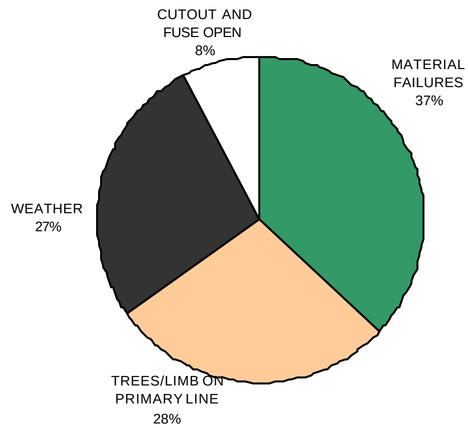


Figure 15-10 Circuit SP13 Percentage of Customer-Minutes Out by Outage Cause

There were two feeder outages, out of the 73 total outages, that were responsible for 32% of the total customer-minutes. In addition, nine other individual outages affected over 100 members, therefore contributing to the poor reliability indices.

A summary of the outages that occurred in the main zones can be seen in the following table.

Table 15-9 Circuit SP13 Outage Information By Overcurrent Protection Zone

Protection Zone	Recloser Number	Phase	Outages	%	Customer-Hours	%
1	SP13R-ABC	ABC	17	24	4300	34
2[1]	SP13R11	B	21	29	1560	13
2	SP13R12	ABC	16	22	5200	41
3	SP13R13	AC	18	25	1550	12

[1] Single-phase tap off the first zone of protection

There are no proposed investment projects on this feeder to aid in future reliability improvement. Studying the possibilities of looped feeders or new interconnections with neighboring utilities proved they were impractical for the cost and amount of reliability gained. Therefore, on circuit SP13, basic periodic operations and maintenance review appear to be the only reasonable ways to improve upon the historical reliability.

15.4.3 Circuits That Meet Reliability Criteria

15.4.3.1 Circuit CA11

It appears this circuit had no distribution caused outages in 2000 or 2001, and only had one outage in 2002. Therefore, there are no distribution construction projects recommended for reliability on circuit CA11.

15.5 Cost Estimates

A summary of the cost estimate for the proposed 5-Year, 10-Year and 20-Year Plans is provided in Table 15-10. Cost estimate details for the proposed New Tie Lines, Conversions and Line Changes, New Substations, Delivery Points and Meter Points and Substation, Delivery Point and Meter Point Changes, which were discussed in Section 15.3 and shown on the Proposed System Circuit Diagram, are provided in the "Construction Cost Details [table]" at the end of Section 15.0. Unit cost information is included in this report as Exhibit III. When future reference is made to these cost estimates, material and labor prices should be reviewed to incorporate existing market conditions.

Table 15-10 Construction Cost Summary

	2004-2008 Cost ($)	2009-2013 Cost ($)	2014-2023 Cost ($)	2004-2023 Cost ($)
New Tie Lines	0	0	0	0
Conversions and Line Changes	2,040,800	14,300	641,800	2,696,900
New Substations, PD's and MP's	196,000	0	0	196,000
Substation, DP and MP Changes	50,000	0	0	50,000
Total	2,286,800	14,300	641,800	2,942,900
Projects for Improved Reliability	248,600	599,570	150,000	998,170

Table 15-11 Substation Load Data Projections

Substation or Meter Point	Ckt.	Season	Existing System Configuration				Proposed System Configuration		
			2003 Load kW	2008 Load kW	2013 Load kW	2023 Load kW	2008 Load kW	2013 Load kW	2023 Load kW
Calavant MP	CA11	W	104	104	104	105	104	104	105
	CA12	W	309	309	309	310	309	670	696
	Sub	W	413	413	413	415	413	774	801
Charlestown MP	CT11	W	1,507	1,574	1,624	1,735	1,574	1,230	1,324
	Sub	W	1,507	1,574	1,624	1,735	1,574	1,230	1,324
Cornish MP	CN11	W	1,407	1,400	1,398	1,406	1,400	1,398	1,406
	Sub	W	1,407	1,400	1,398	1,406	1,400	1,398	1,406
East Lempster DP	West	W	--	--	--	--	778	834	957
	South	W	--	--	--	--	1,503	1,611	1,849
	Sub	W	--	--	--	--	2,281	2,445	2,806
Sunapee Substation	SP12	W	2,886	3,094	3,317	3,807	601	644	740
	SP13	W	821	847	875	938	847	875	938
	Sub	W	3,707	3,941	4,192	4,745	1,448	1,519	1,678
Sunapee District		W	**7,034**	**7,328**	**7,627**	**8,301**	**7,116**	**7,366**	**8,015**

Table 15-12 Construction Cost Details

(see following 2 pages)

Project Code	YR	Sub/Ckt	Project Description	Reason Code	@ Load (amps)[1]	Miles	Estimated Cost ($)
I. New Tie Lines							
			None				0
II. Conversions and Line Changes							
CA-1	2013	Calavant / CA12	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)	C,D,V	[1]	1.10	14,300
CT-2	2023	Charlestown / CT11	1ph 1/0 ACSR to 3ph 1/0 ACSR (add 2)	C,D,V	40	2.20	63,800
378	2005	Cornish / CN11	3ph 1/0 ACSR to 3ph 1/0 Tree Wire	WP	-	10.70	600,000
379	2004	Sunapee / SP12	Pole and crossarm replacement	WP	-	--	70,000
380	2005	Sunapee / SP12	3ph 1/0 ACSR to 3ph 4/0 Hendrix	WP	-	2.30	202,400
381	2004	Sunapee / SP12	3ph (1-4ACSR, 2-1/0 ACSR) to 3ph 1/0 Tree Wire	WP	-	3.30	100,000
382	2005	Sunapee / SP12	1ph 1/0 ACSR to 1ph 1/0 Tree Wire	WP	-	3.80	160,000
383	2005	Sunapee / SP12	2ph 1/0 ACSR to 3ph 1/0 Tree Wire	WP	-	2.70	170,000
384	2005	Sunapee / SP12	3ph 1/0 ACSR to 3ph 4/0 Hendrix	WP	-	2.30	202,400
SP-1	2005	Sunapee / SP12	3ph 336 ACSR Underbuild	C,V	150	10.00	500,000
EL-3	2005	East Lempster/South	Add 3-150 amp voltage regulators	V	75	--	36,000
EL-4	2023	East Lempster/South	1ph 1/0 ACSR to 3ph 4/0 ACSR	B,C,D,V	100	6.80	578,000
	Total Conversions and Line Changes					45.20	2,696,900
III. Projects that have Potential Reliability Improvement							
CA-R1	2013	Calavant / CA12	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)			4.80	62,400
CN-R1	2023	Cornish / CN11	Newport DP, 2.5/3.5 MVA, 19.9/34.5 - 7.2/12.47 kV			--	150,000
CN-R2	2013	Cornish / CN11	1ph 1/0 ACSR			1.70	74,800
CN-R3	2013	Cornish / CN11	1ph 1/0 ACSR			0.80	40,480
CN-R4	2013	Cornish / CN11	1ph 1/0 ACSR			0.50	28,600
CT-R1	2006	Charlestown / CT11	1ph 1/0 ACSR			3.00	132,000
CT-R2	2006	Charlestown / CT11	1ph 1/0 ACSR			2.00	88,000
CT-R3	2006	Charlestown / CT11	1ph 1/0 ACSR			0.50	28,600
CT-R4	2013	Charlestown / CT11	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)			3.60	46,800
CT-R5	2013	Charlestown / CT11	2ph 1/0 ACSR to 3ph 1/0 ACSR (add 1)			6.00	78,000
CT-R6	2013	Charlestown / CT11	1ph 1/0 ACSR			0.30	18,480
SP-R1	2013	Sunapee / SP12	1ph 1/0 ACSR			0.20	12,760
SP-R2	2013	Sunapee / SP12	1ph 1/0 ACSR			0.50	8,450
SP-R3	2013	Sunapee / SP12	1ph 1/0 ACSR			1.70	74,800
SP-R4	2013	Sunapee / SP12	1ph 1/0 ACSR			3.50	154,000
	Total Potential Reliability Improvements					29.10	998,170
	Total of all projects					74.30	3,695,070
	Total by year for first 4 years (includes reliability projects)						
	2004					3.30	170,000
	2005					31.80	1,870,800
	2006					5.50	248,600
	2007					0.00	0
	2008					0.00	0
	2013					24.70	613,870
	2023					9.00	791,800
			Total			74.30	3,695,070

Reason Code(s)

A	To replace **A**ged and deteriorated lines that are expected to reach the end of their useful life.
B	To improve **B**ackup between circuits and substations.
C	To provide additional **C**apacity.
D	To **D**ivide the load for improved load balance, voltage, sectionalizing and reliability.
F	To accommodate **F**uture load.
S	To accommodate new **S**ystem configuration as a result of other projects.
U	To replace old 175 Mil bare concentric neutral **U**nderground cable in poor condition.
V	To improve **V**oltage.
WP	As per NHEC 2001-2005 Construction **W**ork **P**lan.
[1]	Recommended when load on vee-phase line of CT11 reaches 35 amps/phase.
1	@ Load (amps) column indicates the load at which the project is to be implemented.

Project Code	YR	Name	Project Description	Estimated Cost ($)
IV. New Substations, Delivery Points and Meter Points				
2004-2008 Time Period				
EL-1	2005	East Lempster / South	5000 kVA 34.5 kV to 7.2/12.47 kV transformer	50,000
EL-1	2005	East Lempster / West	3-219 amp voltage regulators	48,000
EL-2	2005	East Lempster / West	5000 kVA 34.5 kV to 7.2/12.47 kV transformer	50,000
EL-2	2005	East Lempster / West	3-219 amp voltage regulators	48,000
			Total 2004-2008	196,000
2009-2013 Time Period				
			None	
2014-2023 Time Period				
			None	
V. Substation, Delivery Point and Meter Point Changes				
2004-2008 Time Period				
SP-2	2005	Sunapee	Add 3-328 amp, 7.2 kV, voltage regulators	26,000
CT-1	2004	Charlestown	Upgrade regulators from 3-75 amp to 3-150 amp	24,000
			Total 2004-2008	50,000
2009-2013 Time Period				
			None	
2014-2023 Time Period				
			None	

Table 15-13 Summary of Reliability Indices by Feeder

DISTRICT	CKT	YEAR	Members Out	Cons-Hours	# Consumers	-	SAIFI	SAIDI	CAIDI
SUNAPEE	CA11	2000	0	0	42		0.00	0.00	0.00
		2001	0	0	42		0.00	0.00	0.00
		2002	34	37	42		0.81	0.88	1.09
	Totals		34	37	126	Average	0.27	0.29	1.09
	CA12	2000	87	150	48		1.81	3.13	1.72
		2001	76	96	48		1.58	2.00	1.26
		2002	127	190	48		2.65	3.96	1.50
	Totals		290	436	144	Average	2.01	3.03	1.50
	CN11	2000	696	1,708	644		1.08	2.65	2.45
		2001	2,129	5,598	644		3.31	8.69	2.63
		2002	1,982	4,075	644		3.08	6.33	2.06
	Totals		4,807	11,381	1,932	Average	2.49	5.89	2.37
	CT11	2000	5,145	16,491	880		5.85	18.74	3.21
		2001	2,240	5,945	880		2.55	6.76	2.65
		2002	2,125	5,660	880		2.41	6.43	2.66
	Totals		9,510	28,096	2,640	Average	3.60	10.64	2.95
	SP12	2000	3,706	6,817	1,826		2.03	3.73	1.84
		2001	6,628	10,910	1,826		3.63	5.97	1.65
		2002	4,875	6,816	1,826		2.67	3.73	1.40
	Totals		15,209	24,543	5,478	Average	2.78	4.48	1.61
	SP13	2000	1,912	5,635	550		3.48	10.25	2.95
		2001	2,078	5,771	550		3.78	10.49	2.78
		2002	834	1,318	550		1.52	2.40	1.58
	Totals		4,824	12,724	1,650	Average	2.92	7.71	2.64
	District Total	2000	11,546	30,801	3,990		2.89	7.72	2.67
		2001	13,151	28,320	3,990		3.30	7.10	2.15
		2002	9,977	18,096	3,990		2.50	4.54	1.81
	Totals		34,674	77,217	11,970	Average	2.90	6.45	2.23

**-Indices EXCLUDE: outages affecting <5 members, outages <5 minutes duration, Power Supplier Caused, Major Storms, any 34.5 kV outages on either NHEC or PSNH's system ("High Side"Outages).*

Exhibits

Exhibit I - Summary Table of Load Forecast Variables

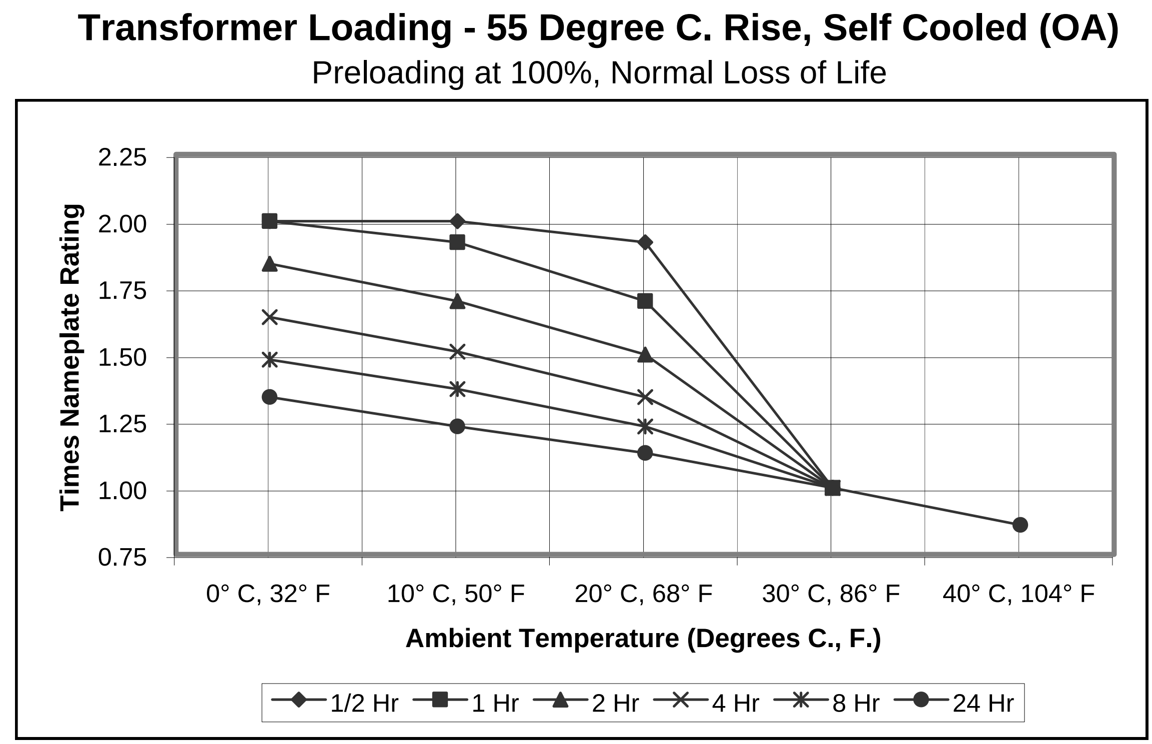
District	Delivery Point	CPR[1]	DPC[2]	LPL Additions[3]		Loads (kW)		AGR	Multiplier
				Type	Load (kW)	2002	2023		
Alton	New Durham (Alton and New Durham Subs)	Retain constant share of service area, therefore sustaining 20.6% of area population throughout forecast.	Large number of summer camps causing variable to be lower than future connects. New connects to represent larger homes and a few businesses with average demands of 1.66 kW compared to 2002 variable of 1.456 kW.	Movie Theatre High School	1,000 2,000	10,388	17,578	2.7%	1.69
	Pittsfield (Barnstead Sub)	Benchmark forecast of 8.7% felt low due to more growth potential in NHEC service area compared to neighboring utilities service areas.	1.70 kW used for new consumers due to the potential of an increase in average home size and faster commercial growth.	-	-	2,874	4,193	1.9%	1.46
Andover	Alexandria	District Manager projected slight increase for this variable.	Expected to remain stable at 1.42 kW for next twenty years.	-	-	624	930	2.0%	1.49
	Franklin (Webster Sub)	Expected to remain constant at 14.4%.	For the next ten years, homes will be larger, therefore contributing more demand (2.0 kW per consumer). For the following ten years, as the larger lots slowly sell and become saturated with new housing, lot sizes will be smaller, therefore accommodating smaller homes with average demand (1.85 kW per consumer).	-	-	4,800	5,667	0.8%	1.18
	Northfield	Projected to slightly increase.	2002 variable of 3.66 kW per consumer slightly high due to Freudenberg, Inc., a large industrial load. New connects expected to contribute approximately 2.20 kW to delivery point non-coincident peak.	-	-	3,118	3,435	0.5%	1.10
Colebrook	Colebrook	This variable is projected to dramatically increase. The 2002 percentage was 23.7%. The marginal percentage for the next twenty years is estimated to be 38.7%. This is due to the fact that many new connects will be for secondary homes that do not contribute to the population count.	1.50 kW per new consumer. 2002 demand per consumer was 2.17 kW. This is high due to the contributions from the Tillotson Health Care Facility and other large loads. After subtracting these large loads, the demand was 1.2 kW per active consumer.	-	-	2,707	2,960	0.4%	1.09
Conway	Conway (Conway and Perkins Corner Subs)	Marginal CPR is estimated at 43.5% over the next decade compared to the current figure of 33.5% due to land availability. The CPR then remains at 34.1% through 2023.	The 2002 demand per active consumer totaled 4.17 kW. Businesses with larger demands caused this variable to be high. After subtracting the large load contributions, the average demand totaled 2.7 kW. Therefore, this demand was used for new connects throughout the 20 year horizon. Existing businesses are expected to continue at current demand levels.	-	-	16,361	18,828	0.7%	1.15
	Saco (Bartlett, Glen, and Jackson Subs)	Significant growth anticipated in this service area due to ski resorts and land availability. A marginal CPR of 63.3% is assumed throughout the forecast horizon.	The demand of 3.46 kW per active consumer for 2002 is high due to some larger businesses and ski resort loads. For the next twenty years, a demand projection of 2.5 kW per new consumer was used which is a more accurate representation after subtracting the large load contributions.	-	-	18,800	23,350	1.1%	1.24
Lisbon	Haverhill	Very rural area. CPR of 10.1% expected to continue.	Very rural area. 1.24 kW per consumer expected to remain steady.	-	-	708	807	0.7%	1.14
	Lisbon	Very rural area. Variable of 7.0% expected to remain steady.	Very rural area. 1.50 kW per consumer for the entire planning horizon.	-	-	939	986	0.2%	1.05
	Monroe	Very rural area. Variable of 3.8% expected to remain steady.	Very rural area. 1.91 kW per consumer expected to remain steady.	-	-	524	557	0.3%	1.06
Meredith	Center Harbor	No change expected in CPR of 38.7%.	New connects expected to have higher demands due to larger homes and more amenities in the first five years. Expect service upgrades at existing homes. 1.88 kW per consumer for 2002 expected to increase. Used 2.5 kW per new consumer for next five years, and 2.2 kW per new consumer for remaining fifteen years.			10,613	17,098	2.4%	1.61
	Melvin Village	No change in CPR of 20.7% expected.	Significantly residential with few commercial/industrial loads. 2002 variable equal to 1.70 kW. New connects expected to contribute about 1.8 kW on average.	Castle Springs Bottling Plant	1,000	3,732	6,674	2.9%	1.79
	Meredith 1	No change in CPR of 20.9% expected.	2002 variable equal to 1.85 kW. New connects expected to contribute about 2.0 kW on average due to slightly larger size homes.	Church	400	6,682	9,686	1.9%	1.45
	Meredith 2	No change in CPR of 8.3% expected.	Mix of residential and business. Lower taxes in Moultonborough township will cause more growth, larger homes. 2002 variable equal to 2.28 kW which is high due to business contributions. New connects expected to contribute 2.0 kW.			5,273	6,189	0.8%	1.17
Ossipee	Tamworth	Land availability in NHEC service area, and access to/from Massachusetts will cause CPR to increase. 2002 percentage is 9.3%. Marginal CPR of 19.3% assumed for the next decade. Total CPR then stabilizes at about 11%.	Includes King Pine Ski Area load contribution. After eliminating ski contribution, demand per consumer is around 1.4 kW. Therefore, 1.4 kW per new connect used for next twenty years.	-	-	1,223	1,906	2.2%	1.56
	Tuftonboro	Saturation in PSNH's service area will cause more growth on NHEC's system than in the past. Marginal CPR will increase by 2.0% per year in next decade and then stabilize for the following decade.	New homes will be larger than average. Existing homes are upgrading and adding air conditioning which will cause the demand per consumer to increase. Use 1.8 kW per new consumer for first 10 years, and 1.5 kW per new consumer for remaining 10 years of planning horizon.	-	-	3,677	5,600	2.1%	1.52

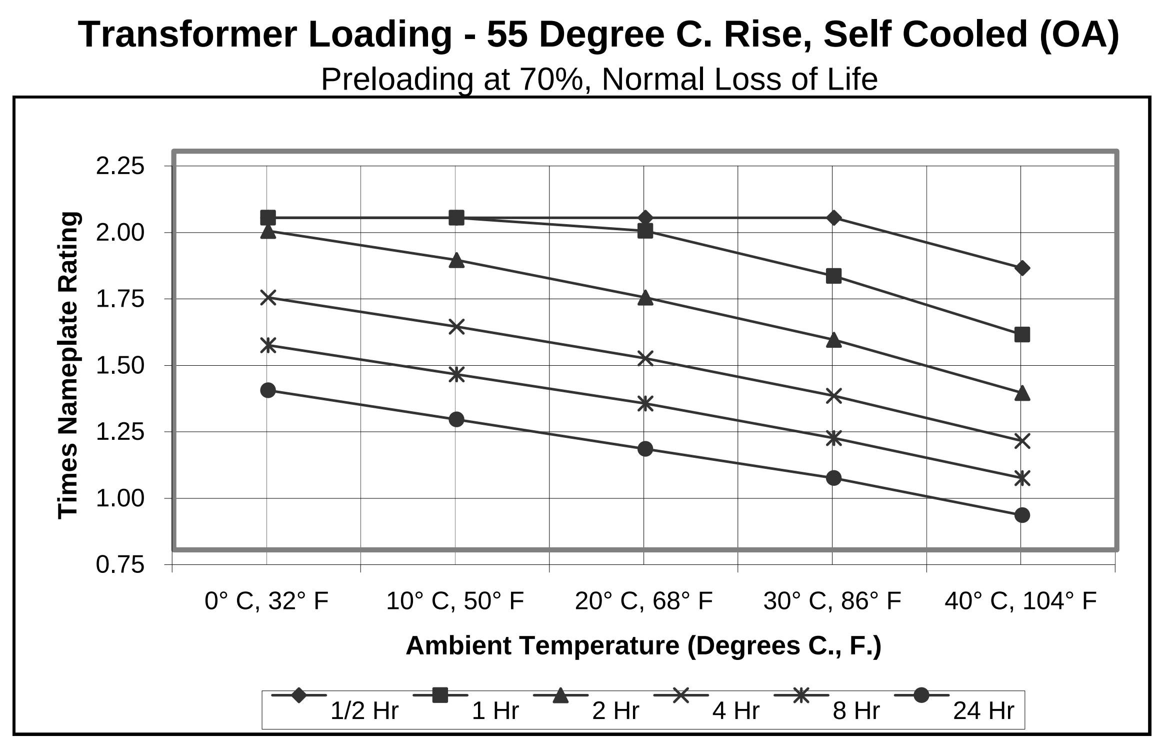
Exhibit I - Summary Table of Load Forecast Variables

District	Delivery Point	CPR[1]	DPC[2]	LPL Additions[3] Type	LPL Additions[3] Load (kW)	Loads (kW) 2002	Loads (kW) 2023	AGR	Multiplier
Plymouth	Bridgewater	Residential load. Serves townships with lower taxes. Next twenty year CPR projected to remain at 14.6%.	Variable expected to remain constant at a level of 1.7 kW per new consumer. Current 2002 demand per consumer is 1.64 kW.	-	-	4,442	5,458	1.0%	1.23
	Lyme	CPR expected to remain constant at 4.0%.	Larger homes expected in the first five years of study that will increase demand per consumer. Therefore, use 2.0 kW per new consumer for first five years and decrease to 1.7 kW for remaining fifteen years.	-	-	1,051	1,365	1.3%	1.30
	Plymouth 1 (Green Street Sub)	2002 value of 14.2% expected to remain constant throughout 20 year study.	2002 value of 1.80 kW expected to remain constant throughout 20 year study.	Plymouth College	350	2,086	2,734	1.4%	1.31
	Plymouth 2 (Fairgrounds Sub)	Percentage of new population served by NHEC projected to increase significantly for first five years. Marginal CPR of 30% used for next five years and 23% for rest of forecast period.	Many large commercial businesses causing this variable to be higher than average at 2.96 kW per consumer for 2002. Expect same mix and size of residential and commercial for next ten years that will cause variable to stay around 3.0 kW. Expect decrease to 2.5 kW per new consumer in 2013-2023.	Tenney Mtn. Ski Area	1,000	6,741	9,069	1.5%	1.35
	Rumney	Residential load with some small commercial. 34% for 2002 expected to remain for 20 year study period.	2002 value of 1.5 kW per consumer expected to stay relatively constant for entire study period.	-	-	5,692	6,992	1.0%	1.23
	Thornton (Thornton and Waterville Valley Subs)	CPR to remain at 37.1% for next twenty years.	Waterville Valley Ski Area causing this variable to be significantly higher than average at 7.0 kW per consumer for 2002. Growth at and around Waterville Valley consisting of townhouses/condo and larger residential, along with Waterville Valley Ski Resort growth, felt to cause demand to remain around 7.0 kW on average for new connects.	School	500	16,157	21,221	1.4%	1.31
	Woodstock (Woodstock and Lincoln Subs)	Serves Loon Mtn. Ski area. 152% for 2002. Variable is over 100% because of a significant amount of secondary residences in area, that are not included in population count. Marginal CPR projected to increase to 200% in first five years, 190% in second five year study period, and 170% in the last ten years of the study.	Loon Mtn. Ski Area causing this variable to be significantly higher than average at 5.4 kW per consumer for 2002. Growth at and around Loon Mtn. consisting of townhouses/condo and larger residential, along with Loon Mtn. Ski Resort growth, felt to cause demand to increase to about 8.0 kW on average for new connects for first five years of study. Saturation will cause demand per consumer to decrease to 7.0 kW and 6.0 kW in 2008-2012 and 2013-2023, respectively.	Loon Mountain South	2,000	21,958	27,824	1.2%	1.27
Raymond	Brentwood	CPR is 3.1% in 2002. Marginal CPR of 5.1% for first ten years of study, and 4.1% for last ten years are anticipated.	2.87 kW in 2002. Larger subdivisions will cause variable to increase for next ten years. Demands of 3.5 kW per new consumer are used for 2003-2012, followed by demands of 3.0 kW for 2013-2023.	-	-	1,550	2,965	3.3%	1.91
	Chester	Same scenario as Brentwood. Marginal CPR's are 17.8% and 14.8%.	2.44 kW in 2002. 3.0 kW per new consumer projected for first ten years. 2.5 kW per new consumer projected for remaining years.	-	-	4,910	8,025	2.5%	1.63
	Deerfield	CPR expected to remain at 4.1%.	2.08 kW per consumer in 2002. New connects projected to contribute 3.0 kW on average for next five years. Estimate 2.5 kW and 2.0 kW per new consumer for last two periods of study.	-	-	2,347	3,065	1.3%	1.31
	Derry	Maintain 2002 level of 2.0% throughout study period.	Maintain 2.2 kW per new consumer throughout study period.	-	-	2,924	4,071	1.7%	1.39
	Lee	12.5% in 2002. Farmland sales for residential development will cause variable to increase. Lee township will see most growth in the area. Projected 14.5% for entire study period.	2.07 kW per consumer in 2002. Larger homes will cause demand contribution to slightly increase for the first five years at 2.2 kW per new consumer. Remaining fifteen years projected at 2.0 kW per new consumer.	-	-	2,114	3,025	1.8%	1.43
	Raymond	Due to saturation in NHEC's service area, this variable is expected to slightly decrease during the next twenty years. 7.6% in 2002. NHEC expected to serve 6.6% of new population throughout planning period.	1.97 kW per consumer in 2002. Expected to continue throughout study period.	-	-	4,162	5,719	1.6%	1.37
Sunapee	Calavant (Maple Ave. Sub)	2.1% in 2002. Projected to remain at this level throughout study period.	4.05 kW per consumer in 2002. Diversification of load type causing variable to be higher than system average. New connects projected at 2.0 kW on average for next twenty years.			413	414	0.0%	1.00
	Charlestown	13.2% in 2002. Projected to remain at this level throughout study period.	1.45 kW per consumer in 2002. Felt this level would be maintained throughout study.	Bascom Farms Maple	20	1,500	1,715	0.7%	1.14
	Cornish	3.2% in 2002. Projected to remain at this level throughout study period.	1.86 kW per consumer in 2002. 2.2 kW per new connect anticipated for next ten years, followed by ten years at 1.9 kW per new consumer.			1,405	1,401	0.0%	1.00
	Sunapee	11.6% in 2002. Projected to remain at this level throughout study period.	1.45 kW per consumer in 2002. Maintain this consumer demand contribution throughout study period.			3,716	4,695	1.2%	1.26

[1] Consumer Population Ratio: Count of Active Consumers divided by total population 2 Demand Per Consumer: Delivery Point Non-Coincident Peak kW divided by total number of active consumers served 3 Large Power Load Additions: Loads in addition to the base projected forecast

Exhibit II - Transformer Loading Guide



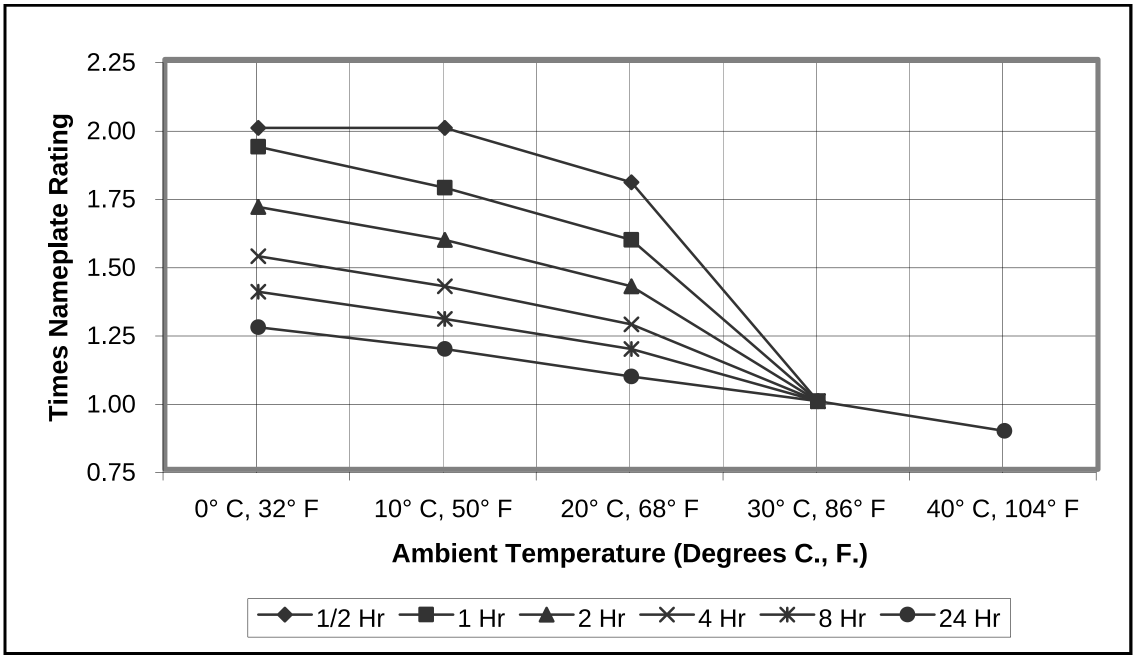


Based on ANSI/IEEE C57.92-1981

Exhibit II - Transformer Loading Guide

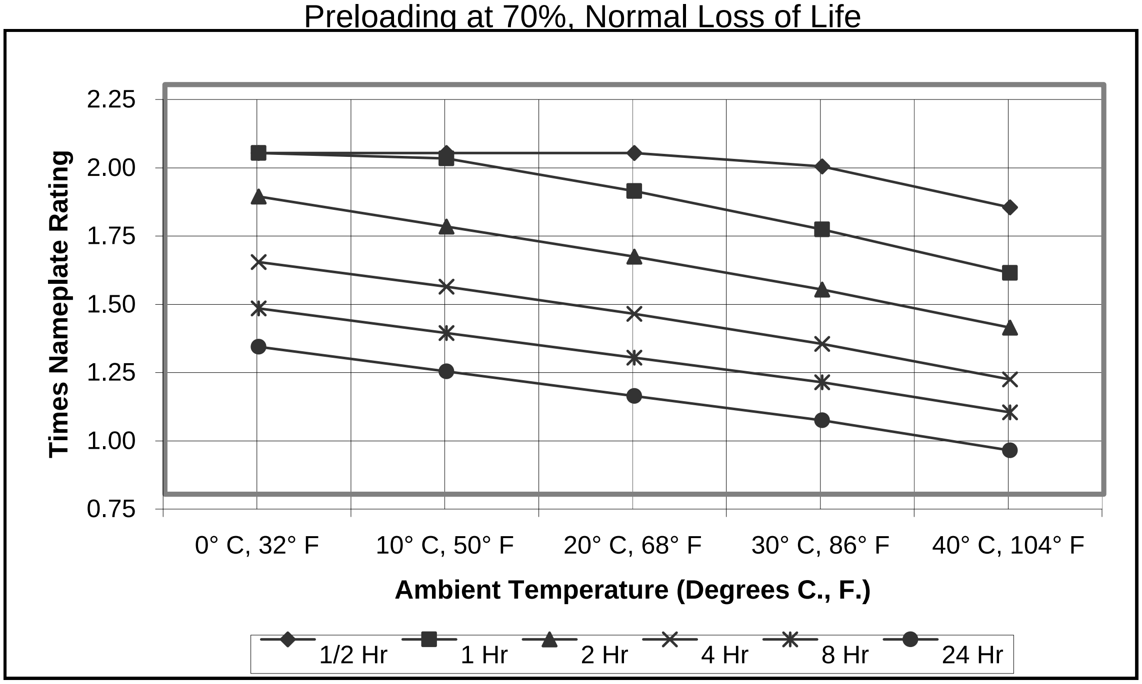
Transformer Loading - 65 Degree C. Rise, Self Cooled (OA)

Preloading at 100%, Normal Loss of Life



Transformer Loading - 65 Degree C. Rise, Self Cooled (OA)

Preloading at 70%, Normal Loss of Life



Based on ANSI/IEEE C57.92-1981

Exhibit III – Unit Cost Estimates

UNIT COST ESTIMATES [1/]

I. Distribution

New Overhead Tie Line

	Cost Per Mile by kV ($)								
	1f			Vf			3f		
Size (ACSR)	7.2	14.4	19.9	7.2/12.5	14.4/24.9	19.9/34.5	7.2/12.5	14.4/24.9	19.9/34.5
1/0	44,000	48,000	53,000	57,000	63,000	69,000	68,000	75,000	82,000
4/0	---	---	---	67,000	74,000	81,000	85,000	94,000	103,000
336 KCM	---	---	---	76,000	81,000	89,000	96,000	106,000	116,000
477 KCM	---	---	---	---	---	---	104,000	114,000	126,000
556 KCM	---	---	---	---	---	---	110,000	121,000	133,000

New Underground Tie Line

	1f		Vf		3f	
Size (AL)	15 kV	25 kV	15 kV	25 kV	15 kV	25 kV
1/0	49,000	54,000	70,000	77,000	91,000	100,000
4/0	---	---	82,000	90,000	106,000	117,000
500 KCM	---	---	---	---	150,000	165,000

Overhead to Overhead Conversion

		Cost Per Mile by kV ($)		
Existing	New (ACSR)	7.2/12.5	14.4/24.9	19.9/34.5
1 f	1f -1/0	44,000	48,000	53,000
1f	Vf -1/0	57,000	63,000	69,000
1f	3f -1/0	68,000	75,000	82,000
1f -1/0 ACSR	3f -1/0 (add 2)	29,000	32,000	35,000
1f	3f -4/0	85,000	94,000	103,000
1f -4/0 ACSR	3f -4/0 (add 2)	36,000	40,000	44,000
1f -336 KCM	3f -336 KCM (add 2)	41,000	45,000	49,000
Vf	Vf -1/0	59,000	65,000	71,000
Vf -1/0 ACSR	3f -1/0 (add 1)	13,000	14,000	15,000
Vf	3f -1/0	70,000	77,000	85,000
Vf	3f -4/0	87,000	96,000	105,000
Vf -4/0 ACSR	3f -4/0 (add 1)	22,000	24,000	26,000
Vf -336 KCM	3f -336 KCM (add 1)	24,000	28,000	32,000
3f	3f -1/0	71,000	78,000	86,000
3f	3f -4/0	88,000	97,000	106,000
3f	3f -336 KCM	99,000	109,000	120,000
3f	3f -477 KCM	107,000	118,000	129,000
3f	3f -556 KCM	113,000	124,000	137,000

Overhead to Underground Conversion

		Cost Per Mile by kV ($)	
Existing	New	15 kV	25 kV
1f	1f -1/0 AL	49,000	54,000
1f	Vf -1/0 AL	70,000	77,000
1f	3f -1/0 AL	91,000	100,000
1f	3f -4/0 AL	106,000	117,000
3f	3f -1/0 AL	94,000	103,000
3f	3f -4/0 AL	109,000	120,000
3f	3f -500 KCM	153,000	168,000

[1/] Costs are for 2003 construction and include an allowance for engineering, legal, and overhead expenses.

Exhibit III – Unit Cost Estimates

UNIT COST ESTIMATES [1/] (CONT.)

I. Distribution (Cont.)

	1f	Vf	3f
Retirement of Overhead Line ($)	6,000	8,000	9,000

Equipment

Capacitors [2/]	Unit Cost ($)	Extended Cost ($)
3-50 kVAR units with 6 unit rack	15.67 / kVAR	2,350
3-100 kVAR units with 6 unit rack	8.33 / kVAR	2,500
3-150 kVAR units with 6 unit rack	6.00 / kVAR	2,700
3-200 kVAR units with 6 unit rack	5.33 / kVAR	3,200
3 oil switches	1,300	1,300
VAR Control	1,300	1,300

Regulators	Unit Cost ($)	Extended Cost ($)
50 amp	8,600	8,600
100 amp	9,100	9,100
150 amp	12,000	12,000
219 amp	16,000	16,000

II. Distribution Substations, 12.5 kV Low Side

Land, Structure, Fence, etc.		Transformer		Voltage Regulators	
High Side Voltage (kV)	Estimated Cost ($)	Size (kVA) / High Side (kV)	Estimated Cost ($)	Size (Amp)	Estimated Cost ($)
34.5	515,000	3,750 / 34.5	86,000	3-219	23,000
115	530,000	5,000 / 34.5	120,000	3-328	26,000
		7,500 / 34.5	140,000	3-438	32,000
		10,000 / 34.5	170,000	3-656	46,000
		5,000 / 115	175,000		
		7,500 / 115	205,000		
		10,000 / 115	250,000		

III. Transmission Line (Rural)

Description	Estimated Cost ($) / Mile
34.5 kV	200,000
69 kV	250,000
115 kV	350,000

Appendix

Appendix A – Distributed Generation Analysis

Distributed Generation Analysis for NHEC's 2003 Long Range Plan

PSE has screened the projects proposed in the 2003 Long Range Plan for potential deferral by using distributed generation (DG) as an alternative. Some utilities across the United States have found DG viable on both a temporary and permanent basis in deferring transmission and distribution grid reinforcement projects. The deferrals were viable because:

- There was a critical need for a back-up supply (a high value was placed on the additional reliability provided by the back-up source).
- Other alternatives for providing a completely redundant back-up supply from the power delivery grid were quite expensive.
- There were significant generating capacity credits available by allowing the power supplier the right to operate the DG units as needed for power supply requirements.

The situation for NHEC at this time is that significant generating capacity credits are not available (Section 5.3.3.3 in the Long Range Plan report). The following examples show the economic comparison for using DG in place of grid reinforcement.

Assumptions

An 1800 kW diesel powered DG unit has become a popular choice for semi-mobile generator installations. These units cost about $700,000 (purchase and installation costs for parallel operation with the electric system) plus $33,000/year for 200 hours of operation. NHEC should be able to realize about $9,700 of power supply credits per year based on current load usage patterns for 200 hours of operation during peak load periods (20% of $2.25/kW/mo. x 12 months x 1800 kW). Assume NHEC's cost of funds for this type of project is 10%.

Example 1-Alton Circuit 14

This circuit currently averages 7 hours of outage time per year. About 80% of this circuit has no back-up supply and no grid reinforcement alternatives appear feasible for providing back-up during this planning period. Placing a DG unit on this circuit in the neighborhood of proposed project 308 could allow deferral of proposed project AL-7 for 20 years. The present value of the generator cost (including 20 years of operation and maintenance costs less power supply credits) is approximately $908,000. The estimated construction cost of project AL-7 is $374,000. This analysis shows that the net cost of using DG to improve the reliability on this circuit would be $908,000 - $374,000 = $534,000. NHEC should consider other line improvement alternatives (more line clearance, installing covered wire in high tree contact areas and replacing equipment in poor condition) as part of deciding what should be done for this situation.

Example 2 – Melvin Village Circuit 13

This circuit currently has marginal reliability (about 4.5 hours of outage time per year) with no back-up supply. The outage data shows that major tree issues exist, which should be addressed first. This circuit serves a growing suburban area, which will require $455,000 of capacity improvements by 2013 to adequately serve the additional load. DG could be used to defer the capacity improvements if economical. However, at a starting cost of $700,000 for the initial generator installation, DG would not be preferred unless the additional reliability resulting from its back-up capability is worth the extra cost.

Appendix A – Distributed Generation Analysis

Example 3 – Sunapee Circuit 12

This situation is a combination of Examples 1 and 2. The existing circuit is over 20 miles long with very minimal back-up connections to other circuits. The circuit load is expected to increase significantly during the planning period which could require nearly $700,000 of capacity improvements during 2005 (projects SP-1, EL-1 and EL-2). DG could be used to defer the capacity improvements if sufficient generation capacity credits would become available to offset the cost of operation (the cost of the proposed line improvements is about the same as the generator installation cost). DG is not recommended at this time because the potential $9,700 power supply credit would not cover the $34,000 annual cost of generator operation and maintenance. However, any significant change in power supply or other costs could easily justify taking another look at this DG example before going ahead with the proposed system improvements.