Unitil Energy Systems

Report on
Least Cost Integrated Resource Planning
2013

Prepared By:

Unitil

July 2013

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

Unitil Energy Systems ("UES") submits its 2013 Least Cost Integrated Resource Plan ("LCIRP") pursuant to RSA 378:38.

Unitil Energy Systems ("UES"), as a utility distributing electric power to the homes and businesses in the communities it serves, has a responsibility to plan, build and operate an electric distribution system to meet the present and future needs of its customers in a cost effective manner. UES, through its affiliate Unitil Service Corp. ("Unitil"), fulfills its planning obligation by performing various and ongoing assessments of the short-term and long-term requirements and capabilities of its system. These various assessments are integrated into a comprehensive, least-cost plan that ensures adequate and reliable electric service.

The planning efforts that are performed by Unitil include its own studies of UES distribution circuits, substations, and subtransmission facilities. They also include collaborative review with neighboring utilities and regional entities on planning activities for the external facilities that provide UES with access to the region's transmission and generation resources. This report provides a description of these various planning processes, a forecast of future electrical demand for the UES service areas, the assessment of transmission and distribution requirements, and a listing of projects that represent Unitil's least-cost integrated transmission and distribution plan.

Demand side planning is creating the need for change in the historical distribution and system planning processes. Customer acceptance of distributed generation technology coupled with expansion of existing energy efficiency and net metering initiatives is causing an increase in demand side resources. Historically the effect of these resources is generally included in the historical load data. The output of these distributed resources, while measurable and known, cannot be fully incorporated into future load forecasts due to the intermittent and uncontrollable nature of the distributed resources being installed. In many cases, the output of the distributed resource does not align with the summer peaks. It is difficult at this point to determine the reliability and coincidence of these resources with the system peak. As more distributed resources are installed in the future, the diversity will begin to stabilize and increase the reliability of these units with respect to system planning.

2 OVERVIEW OF LCIRP

UES, through its affiliate Unitil Service Corp. ("Unitil"), performs various and ongoing planning activities to assess the short-term and long-term requirements and capabilities of its electric distribution system. These activities include distribution system planning to evaluate primary distribution circuits and substations, electric system planning to evaluate UES subtransmission facilities and system supply points, joint system planning to evaluate the external delivery system which provides UES access to regional transmission and generation resources, and participation in statewide and regional transmission planning efforts. In addition, Unitil's LCIRP includes demand side resource planning.

The result of these activities is the development of a least-cost, integrated plan for the UES distribution system and the transmission and distribution systems that serve it. The following sections describe the various planning activities performed by Unitil. Attached to this report are appendices that provide planning studies, load forecasts, reliability planning, joint system planning and demand resource planning. This document including the attachments constitute Unitil's least-cost integrated transmission and distribution plan.

3 TERMINOLOGY

The following terms are used throughout the document.

System Supply – A collection of electrical facilities, including lines, transformers, and protection and control equipment that steps down electric power from the transmission system to the Subtransmission System. At this time UES does not own any System Supplies. All System Supplies to UES are owned by PSNH (i.e. Timber Swamp, Kingston, Great Bay, Garvins, and Oak Hill) . UES connects to the System Supplies at 34.5kV. The System Supplies of UES connect to the transmission system at 115kV and 345kV.

Subtransmission System – A collection of parallel 34.5kV lines, switching stations, and substations that are operated as redundant supplies that serve distribution substations. The system is designed such that for the loss of a subtransmission line, switching is performed to reconfigure the subtransmission system to serve the Distribution System from a different subtransmission line. The Subtransmission System may be operated radially or looped between multiple System Supplies. Unitil refers to Subtransmission System Planning as Electric System Planning.

Distributed Energy Resources – the various technologies including energy efficiency and local generation that can offset electricity supply imports and reduce effective demands on the Company's Distribution and Subtransmission System.

Distribution System – A collection of Distribution Lines, Distribution Substations, and isolation devices that directs the electric power from the Subtransmission System to the customers.

Distribution Substation – A collection of equipment and transformers used to step the subtransmission voltage (34.5kV) down to a lower voltage (13.8kV or 4kV).

Distribution Circuit – A radial feeder that serves customer load directly. A Distribution Circuit may originate from a Distribution Substation or a Subtransmission Line. The primary voltages of UES distribution circuits are 4kV, 13.8kV, or 34.5kV. Some Distribution Circuits include stepdown transformers that convert the primary voltage from 34.5kV or 13.8kV to 13.8kV or 4kV. A Distribution Circuit may include a normally open switch that would allow a tie to another Distribution Circuit during planned or emergency system switching.

Planning Criteria – A set of guidelines by which the Unitil electric system is designed and operated.

Peak Design Load – The forecasted load level at which there is a 90% probability that the load in a given year will be below this level. In any given year there is a 1-in-10 chance that the load will exceed this level. This load level is used with contingency analysis (N-1) in the planning process.

Extreme Peak Load - The forecasted load level at which there is a 96% probability that the load in a given year will be below this level. In any given year there is a 1-in-25 chance that the peak load will exceed this level. This load level is used to evaluate the system in its normal configuration (N-0) without any other contingencies. There is no acceptable load loss when using the Extreme Peak Load in the planning process.

Dedicated Use Facility – A facility which provides electric service to a single utility.

Dual Use Facility – A facility which provides both retail and wholesale service to more than one utility.

4 SYSTEM DESCRIPTION

Unitil Energy Systems consists of two electric distribution systems – the UES–Capital system and the UES–Seacoast system. Both systems are geographically separate and operate independently of each other. The UES–Capital system serves customers in Concord, New Hampshire and surrounding towns. The UES–Seacoast system serves customers in the Seacoast region of New Hampshire.

UES does not own any generating facilities within either of its operating systems, nor does it own any transmission facilities. Therefore, UES is dependent on others to provide the physical access to the region's transmission and generation resources. UES receives Transmission Service from Northeast Utilities (NU) for connection to the region's transmission system. However, because the UES system does not presently include transformation facilities to step down directly from the NU transmission system, power is delivered to both the UES–Capital and the UES–Seacoast systems at the 34.5 kV distribution level at several locations via supplemental Distribution Service from Public Service Company of New Hampshire (PSNH).

4.1 UES–Capital System

The UES–Capital distribution system is comprised of 48 distribution circuits operating at primary voltages of 4.16, 13.8 and 34.5 kV. The majority of these circuits originate from 15 distribution substations supplied off the UES– Capital 34.5 kV subtransmission system, while 3 circuits and a few other single customer taps are supplied directly off 34.5 kV subtransmission lines.

The UES–Capital 34.5 kV subtransmission system is a collection of 7 lines, generally constructed in off-road rights-of-way ("ROW"). The subtransmission system is a subset of the UES distribution system, and is classified as distribution facilities. However, UES uses the term "subtransmission" to distinguish these portions of the system for their particular function of transporting power from the various supply points to traditional distribution substations and circuits. The NU/PSNH supply into the UES–Capital system is delivered at PSNH's Garvins substation, and at UES's Penacook (from PSNH's Oak Hill substation) and Hollis substations (from PSNH's Garvins substation).

PSNH's Garvins substation is located in Bow, NH, and is supplied off the 115 kV transmission system. It consists of a 115 kV high-side straight bus with three incoming line breakers, two 115 – 34.5 kV, 36/48/60/67.2 MVA transformers, and two 34.5 kV low-side bus halves with a total of six line breakers plus a breaker interconnecting to the adjacent Garvins Falls Hydro station. UES's 374, 375 and 396 subtransmission lines take delivery directly at the substation from three of the 34.5 kV line breakers.

UES's Hollis substation is located in Concord, NH. It takes delivery off the PSNH 318 subtransmission line, which is fed from a fourth line breaker at Garvins substation. That line runs north to supply PSNH distribution loads before tapping into Hollis substation.

UES's Penacook substation is located in Concord (Penacook), NH. It takes delivery at two line breakers on its 34.5 kV bus from PSNH's 317 and 3122 subtransmission lines. These two lines are supplied out of PSNH's Oak Hill substation, also located in Concord, NH. Oak Hill substation is supplied off the 115 kV transmission system. It consists of two 115 – 34.5 kV, 24/32/40/44.8 MVA transformers, and two 34.5 kV low-side bus halves with a total of four line breakers plus a bus tie breaker.

There are several independently owned and operated non-utility generating facilities connected to the UES–Capital system.

4.2 UES–Seacoast System

The UES–Seacoast distribution system is comprised of 43 distribution circuits operating at primary voltages of 4.16, 13.8 and 34.5 kV. The majority of these circuits originate from 13 distribution substations supplied off the UES–Seacoast 34.5 kV subtransmission system, while 14 circuits and a few other single customer taps are supplied directly off 34.5 kV subtransmission lines.

The UES–Seacoast 34.5 kV subtransmission system is a collection of 18 lines, generally constructed in off-road rights-of-way ("ROW"). The subtransmission system is a subset of the UES distribution system, and is classified as distribution facilities. However, UES uses the term "subtransmission" to distinguish these portions of the system for their particular function of transporting power from the various supply points to traditional distribution substations and circuits. The NU/PSNH supply into the UES–Seacoast system is delivered at PSNH's Timber Swamp, Kingston, and Great Bay substations.

PSNH's Timber Swamp substation is located in Hampton, NH, and consist of a 345 kV high-side ring bus, two 345 – 34.5 kV, 75/100/125/140 MVA transformers, and two 34.5 kV low-side buses with a normally open bus tie breaker. Each transformer separately supplies one of the low-side buses in the normal configuration. UES's 3160 and 3171 subtransmission lines take delivery directly at the substation from two line breakers off one of the 34.5 kV buses.

PSNH’s Kingston substation is located in Kingston, NH, and consists of an incoming 115 kV radial transmission line, a single 115 – 34.5 kV, 24/32/40/44.8 MVA transformer, and an outgoing 34.5 kV line which delivers power to the adjacent UES Kingston Stepdown substation.

PSNH’s Great Bay Substation is located in Stratham, NH, and consists of a 115 kV high-side bus, a single 115 – 34.5 kV, 24/32/40/44.8 MVA transformer, and a 34.5 kV low-side bus. UES’s 3351 and 3362 subtransmission lines take delivery directly at the substation from two line breakers off the 34.5 kV bus.

The UES-Seacoast system also has the ability to be served from alternate lines out of Timber Swamp substation and from PSNH’s 3141X distribution line out of their Chester substation in certain planned or emergency situations.

5 DISTRIBUTION SYSTEM PLANNING

Distribution planning consists of radial circuit analysis planning on UES’ 34.5kV, 13.8kV and 4kV distribution circuits. Distribution planning also includes circuit load forecasting and loading reviews of UES’ distribution substation transformers and equipment. Distribution system planning is conducted annually and covers a five year timeframe. Since the UES system is comprised of two geographically separate and distinct systems (Capital and Seacoast) separate planning studies are completed for each system.

5.1 Distribution Planning Objectives

The main objective of Unitil’s distribution planning process is to provide safe, economical, and reliable service to our customers. System enhancements are planned with consideration for normal and reasonably foreseeable contingency situations, load levels, and generation in order to optimize existing distribution system capacity and optimize capital expenditures all while maintaining acceptable standards of service. The capability and reliability of the system is analyzed each year to identify planned investments required for the electric system.

5.2 Distribution Planning Process

The distribution system planning process evaluates distribution substations and distribution circuits based upon a five year load forecast to identify individual equipment loading and voltage performance concerns, and propose specific system modification recommendations. This process also updates a master plan for the development of a robust and efficient distribution system to accommodate long-term improvement and expansion throughout and beyond the study years. Recommendations are based on safety, system adequacy, reliability and economy among available alternatives. Unitil’s Distribution Planning Guidelines can be referenced in Appendix A.

5.2.1 Circuit and Substation Load Projections

A five year history of summer and winter peak demands for each individual circuit is compiled from the monthly peak demand readings. A linear regression analysis is performed on the historical loads to forecast future peak demands for substation transformers, circuits and other major devices. Attempts are made to take into account known significant load additions or reductions, shifts in load between circuits, etc. In some instances, the peak loads do not present a confident trend over the historical period, so estimates are made using the best available information and knowledge of the circuit. In general, one standard deviation is added into these calculations to account for year to year variations in weather and other varying factors.

5.2.2 Substation Transformer and Circuit Position Loading

A detailed review is made of the limiting factors associated with the circuit positions and transformers at each substation. The limiting factors include current transformer (CT) ratings, protection device settings, switch ratings, circuit exit conductor ratings, regulator ratings, and transformer ratings. Overall Summer Normal and Winter Normal ratings for each circuit positions or substation transformers are based upon the most restrictive of these limiting elements.

Summer and winter peak load projections for the five year study period are compared to these ratings. Individual assessments are made where projected loads reach 90% of the Normal ratings for any circuit position or transformer. These individual assessments determine whether the loading condition requires remediation or simply further monitoring. Where remediation is recommended, specific options are outlined, including project descriptions, justification, predicted benefits and associated cost estimates. System enhancements and/or modifications are made prior to the load reaching 100% of the limiting element rating.

In addition to the magnitude of loading on the substation transformers and circuit positions, the balance of per-phase loading is reviewed. Recommendations are made to remedy per-phase loads measured or projected in excess of 20% imbalance.

5.2.3 Distribution Stepdown Transformer Loading

The loading of pole-top distribution stepdown transformers are also reviewed as part of the annual distribution system planning process. These units convert from one primary voltage level to another at certain locations on distribution circuits, and are of particular interest because they can often feed many customers similar to substation transformers.

Individual assessments are made where the existing or projected load on any unit reaches the transformer nameplate rating. Peak loading up to 120% of nameplate[1] (for summer ambient temperature conditions) is usually accepted if there is no expectation of future load exceeding this and no related voltage drop concerns.

[1] - Based on loading capabilities in Table 7 of ANSI/IEEE C57.91 for normal sacrifice of life expectancy for an 8 hour peak load duration with 30°C ambient temperature and equivalent loading exclusive of peak at 90% of nameplate.

5.3 Distribution Circuit Modeling and Analysis

Circuit modeling and analysis is performed on a three year rotating cycle for both the UES–Capital and the UES–Seacoast distribution systems, where each circuit is reviewed at least once every three years and more often if required. WindMil® (version 7.2) circuit analysis software by Milsoft Utility Solutions[2] is used for modeling and power flow simulation to identify potential problem areas.

Each circuit is modeled based on its present construction and normal configuration directly from Unitil's GIS system. This ensures the engineers are starting with the most up to date model available. Loads are then applied across the circuit using the five year load projections discussed above. Current or power magnitudes are compared to the seasonal rating criteria for each conductor section or piece of equipment detailed in the model. If the projected loading appears to exceed the seasonal Normal rating for any portion of the circuit, or the projected operating voltage is expected to fall outside of an acceptable range (97.5% to 105% of nominal for primary voltages), an individual assessment is made to determine how likely this condition may be and what follow-up actions are needed.

Where a concern in considered likely to exist, specific options are outlined, including project descriptions, justification, predicted benefits and associated cost estimates. In some cases, the condition may need field measurements or future monitoring to verify whether or not a present or future concern truly exists. In other cases, a concern is considered likely based on the confidence in the data and knowledge of the situation.

5.4 Distribution Study Results

Recommendations resulting from the distribution system planning process for the 2013 through 2017 planning period are in included in Appendix B – UES–Capital Distribution System Planning Evaluation – 2013-2017, and Appendix C – UES–Seacoast Distribution Planning Study – 2013-2017.

6 SUBTRANSMISSION SYSTEM PLANNING

The Subtransmission System consists of parallel 34.5kV lines which serve Distribution Substations. The Subtransmission System is designed such that the loss of any one element (N-1 planning condition) will not result in the loss of load following restoration switching. Subtransmission System planning is conducted on an annual basis and covers a 10 year timeframe. Since the UES system is comprised of two geographically separate and distinct systems (Capital and Seacoast) separate planning studies are completed for each system. Unitil refers to Subtransmission System Planning as Electric System Planning.

6.1 Subtransmission Planning Objectives

The main objective of Unitil's Electric System planning process is to provide safe, economical, and reliable service of the subtransmission system. The Electric System planning process evaluates the UES subtransmission systems and the System Supply points serving the UES system. The study process examines a ten year forecast of system

[2] - Milsoft Utility Solutions, Inc., 4400 Buffalo Gap Road, Suite 5150, Abilene, Texas 79606 (Tel. 800 344-5647)

conditions to identify when individual equipment loading and voltage performance concerns will occur, and propose specific system modification recommendations to meet Unitil system planning guidelines (see Appendix D – Unitil Electric System Planning Guide). Recommended system improvements are based on safety, system adequacy, reliability and economy among available alternatives.

6.2 System Load Projections

The scheduling of system modifications is dependent on the projected timetable of system loads that drive system capacity requirements. For planning purposes, system design load forecasts are developed using a linear trend regression model that correlates a ten-year history of daily peak load versus daily average temperature. This approach accounts for variations in projected peak loads due to year to year variations in temperature as well as other varying factors.

6.2.1 Projection Methodology

The historical basis for each system is a series of yearly regression models that are developed to correlate actual daily loads to actual daily temperatures in that season. Once a model is established, an estimated peak load can be derived for that season for any given temperature. There are two dimensions of variability introduced with this modeling. First is the highest daily temperature experienced within a season, which varies with short-term weather trends from one year to another. Second is the model estimate of peak load at any specific temperature. This estimate has its own variation of possibilities due to the influence of other existent factors not incorporated into the model. These variations are characterized as randomness in making future projections. The probability distribution for annual highest temperatures is assumed to follow the discrete distribution of past historical highest temperatures. The random possibilities of peak load outcomes for any specific temperature are assumed to follow a standard probability distribution model with a mean centered on the point estimate of the peak load at that temperature and varying based on its individual standard deviation according to the fit of the seasonal model to the actual historical values.

To establish load projections, a Monte Carlo simulation is run to produce random annual highest temperatures and random peak load estimates at those temperatures from each year's seasonal model that makes up the historical basis. Each trial in the simulation is projected forward using linear trending. This results in a range of peak load possibilities for each future year assuming linear growth, and varying due to annual highest temperature possibilities and variability in loads versus temperature. The likelihood of specific peak load levels occurring in any particular future year can be estimated from an assumed probability distribution using the mean and standard deviation of the trial results for that year. The *Average Peak Load*, *Peak Design Load* and *Extreme Peak Load* forecasts are set at specific probability limits per the intent of planning guidelines.

6.2.2 Load Levels

The *Average Peak Load* is provided as a guide for general load growth decisions not related to system infrastructure planning. The attached *Average Peak Design Load* forecasts are set at the 50% probability limit. Based on the assumptions of the modeling and projection methods, each year there is an equal likelihood of that year's peak demand load being either higher or lower than the *Average Peak Load* level.

For the purpose of assessing the adequacy of system infrastructure, contingency studies for the loss of major system elements are evaluated against *Peak Design Load* levels to identify where and when system constraints do not meet planning guidelines. The attached *Peak Design Load* projections are set at the 90% probability limit. This is intended to roughly equate to only a 1-in-10 year likelihood that the *Peak Design Load* level will be exceeded.

It is important to recognize that with this level of study, constraints and reinforcements are not necessarily associated with major contingencies occurring only at the highest peak hour of the year. Instead, they are associated with contingencies occurring any time during broader stretches of heavy loading that may or may not encompass that one maximum peak hour. In situations when actual demand somewhat exceeds contingency design forecasts, there should be less concern that design criteria will be challenged unless a contingency condition also exists at the same time. The probability of major contingencies existing at times when loads exceed *Peak Design Load* levels should be quite small. Furthermore, the period of exposure to those unplanned conditions should be kept brief if such an event were to occur.

More demanding *Extreme Peak Load* levels are used for evaluation of system constraints under these higher conceivable load conditions, but without the loss of major equipment. The attached *Extreme Peak Load* projections are set at the 96% probability limit. This is intended to roughly equate to only a 1-in-25 year likelihood that the *Extreme Peak Load* level will be exceeded. Under conditions up to these *Extreme Peak Load* levels, it is essential that the system, with all major elements in service, meet planning guidelines while serving all customers. In the event that conditions exceed these *Extreme Peak Load* levels, load shedding and/or additional loss of equipment life may be acceptable.

6.2.3 Load Forecasts

Reference Appendix E – Load History and Ten-Year Design Forecasts for the UES–Capital and UES–Seacoast systems for system level load forecasts.

6.3 Element Ratings

Thermal ratings of each load-carrying element in the system are determined in order to obtain maximum use of the equipment. The same rating methodologies are used for subtransmission, substation and distribution equipment. The thermal ratings of each modeled system element reflect the most limiting series equipment within that element (including related station equipment such as buses, circuit breakers, and switches). Models will include three rating limits for each season's case; Normal, Long Term Emergency (LTE), and Short Term Emergency (STE).

6.4 System Modeling and Analysis

Traditional load flow analysis methods are used to evaluate the UES–Capital and UES–Seacoast systems for these studies. System modeling and power flow simulations are performed using Siemens PTI PSS/E power flow simulation software. Because summer hot weather conditions present the greatest thermal constraints on system equipment, and both UES–Capital and UES–Seacoast are historically summer peaking systems, these studies examined summer peak load conditions only.

An initial load flow model of each system is created to replicate actual conditions during their most recent past summer peak. Details of the system infrastructure are assembled using best available data on system impedances, transformer ratios, equipment ratings, etc. These models are added to a representation of the surrounding external power system in New Hampshire from load flow cases provided by PSNH, and the surrounding regional power system from a reduction of load flow cases developed by ISO-NE. UES–Capital and UES–Seacoast bus loads are compiled for the model by aggregating substation, circuit, and large customer load information for the summer peak timeframe. Much of this load information is available only as non-coincident, monthly peak demands. With the operating configuration, substation capacitors, and internal generation set in the model to actual conditions at the time, overall scaling adjustments are made to bus loads to reasonably match the power flow simulation results to actual recorded system flows for the peak day and hour. Once completed, this establishes confident models representing the UES–Capital and UES–Seacoast systems as they existed during their most recent actual summer peak hour.

Base case models for study of future years are developed from these historical peak models. System improvements and configuration changes that are anticipated to be completed during the year that the study is being performed are modeled, and known individual load adjustments are made. Then overall bus loads are grown by individual growth rates from separate distribution planning forecasts, and scaled to set the total UES–Capital or UES–Seacoast system load plus internal losses, as seen at the system supply delivery points, to the forecast loads for each year (Appendix C – Load History and Ten-Year Design Forecasts). Internal, non-utility generation is left set to their output levels at the time of the most recent actual summer peak.

These base cases are used to analyze normal operating conditions, extreme peak conditions, and all major design contingencies for each of the ten years under study. Unacceptable system conditions are identified as system deficiencies based on the Unitil Electric System Planning Guide (Appendix D). System improvement options are developed and analyzed to evaluate their cost effectiveness.

6.5 Recommendations

Recommendations resulting from the electric system planning process for the years of 2013 through 2022 are in included in Appendix F – UES–Capital 2013-2022 Electric System Planning Study, and Appendix G – UES-Seacoast 2013-2022 Electric System Planning Study.

7 JOINT SYSTEM PLANNING

A joint system planning process was set up between Unitil and PSNH to establish an annual review for the integrated, least cost planning of wholesale delivery facilities that affect both companies' systems.

7.1 Joint Planning Objectives

The goal of the Joint System Planning between UES and PSNH is to develop the most cost effective alternatives for the combined UES and PSNH system. Absent this process, UES and PSNH customers may be subject to more expensive system enhancements due to duplication of facilities between UES and PSNH. This process is intended to promote coordinated planning efforts between Unitil and PSNH to develop a single "best for all" plan that potentially affects both companies. The objective is to provide a consistent approach for the planning of safe, reliable, cost effective, and efficient expansion and enhancements to each other's local area systems while meeting regulatory and contractual requirements.

By agreement, this process establishes a Joint Planning Committee of PSNH and UES representatives. This committee meets several times on an annual schedule to bring all parties together to coordinate each company's individual plans. The committee considers the application of consistent planning criteria using agreed upon system data; the total cost of planned additions, including internal costs of each utility; the reliability impact of planned additions and modifications; operational considerations, system losses, and maintenance costs; technical considerations for standardized designs and equipment; and the intent of the wholesale supply contract.

7.2 Guidelines and Design Criteria

Each company uses its own guidelines and design criteria for their own individual planning. For joint planning, utility-specific criteria are applied for planning of Dedicated Use Facilities – those facilities which provide electric service to a single company. The design criteria of the affected system is applied for the planning of Dual Use Facilities – those facilities which provide both retail and wholesale service to more than one company. If there is a discrepancy between design criteria, the companies mutually agree on the solution.

Financial models for comparison of options employ a Net Present Value methodology, identifying capital expenditures on an annual basis. An annual return on equity shall be used in the Net Present Value calculations and is subject to review and agreement by each party annually.

System operating constraints and appropriate methods of evaluation are employed to determine preferred options. This includes but not be limited to: operation and maintenance costs, system losses, environment, reliability, and power quality. These criteria are mutually agreed upon.

Technical preference is often considered when evaluating alternatives. Technical preferences may include standard versus non-standard design. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of maintenance, ability to accommodate future expansion, or ability to implement. These criteria are mutually agreed upon.

7.3 Joint Recommendations

Joint recommendations are documented as a result of the Joint Planning Committee effort. These include recommendations for a 5 year construction plan and 10 year conceptual plan of *dual use* and *dedicated use* facilities, summary of potential planning issues and alternatives considered, discussion of unresolved issues, and summary of relevant changes from the previous year's recommendations.

8 TRANSMISSION PLANNING

Unitil evaluates the planning of the New Hampshire transmission system in several ways to ensure that it meets the short-term and long-term needs of the UES system and its customers. These facilities are external to the UES system and are owned and operated by others. However, they provide the UES system with access to the region's transmission and generation resources and Unitil's customers are affected by the ISO-NE transmission rates. Therefore, it is essential to Unitil's customers that the state's transmission system is built with the capacity and capability to supply UES system loads in a reliable and economical way.

8.1 NU Transmission Planning and NH Network Operating Committee

Unitil maintains a working relationship with the Transmission Planning department of Northeast Utilities in order to ensure that UES system needs are incorporated into NU transmission planning activities.

In addition, Unitil participates in an annual meeting of the New Hampshire Network Operating Committee. The NH Network Operating Committee is a group made up of representatives from NU and its transmission service customers in New Hampshire. These meetings establish a forum for Unitil to stay abreast of transmission planning activities in the state, and provide input concerning impacts to the UES system.

8.2 ISO-NE System Planning

Unitil also strives to keep informed on local and regional system planning issues independently from its relationship as a transmission customer of NU by regularly reviewing the activities of ISO-New England planning committees and working groups and contributing to these activities when it can.

Unitil regularly attends meetings of the ISO-NE Reliability Committee. This committee advises ISO-NE about design and oversight of reliability standards for the New England system, and about the development of the Regional System Plan, which UES also regularly reviews.

9 RELIABILITY PLANNING

Unitil believes that reliability planning is just as important as traditional load flow or circuit analysis planning. Reliability planning is conducted by Operations and Engineering staff on an ongoing basis. The various types of reliability planning are identified below.

Daily – Unitil Operations and Engineering personnel review every trouble report on a daily basis. This review focuses on system improvements that could be made in order to prevent that outage from reoccurring or ways to reduce the size or duration of the outage. Typically this review results in additional fusing locations or hot spot trimming activities.

Weekly – Until reports on overall company and individual operating center reliability performance compared to annual goals and past history. This review is used to track the current year reliability performance to benchmark it against company goals and historical performance.

Monthly – On a monthly basis, Unitil summarizes the largest outages that occurred in each of the operating companies over the past month. Unitil also reports on devices that have experienced multiple outages over a specific period of time and also reports on outages categorized by cause. The goal of this reporting is to identify trends and potential causes for the trends and initiate system improvements to address those trends.

System Event Report (SER) – Any outage that totals more and 300,000 customer minutes is required to have an SER report completed. An SER is a root cause analysis conducted by Operations and Engineering. The goal is to identify ways that the outage could either be avoided or the response shortened in the future. Typically an SER recommends action items that are assigned and completed.

Annual – Unitil conducts reliability analysis on an annual basis that is focused upon the overall reliability performance of the UES systems for an 18 month period. The report evaluates individual circuit reliability performance over the same time period. The report uses a combination of the Trouble Reporting System and GIS to spatially represent outages. The spatial representation allows Unitil to focus on areas of the system that has experienced below average reliability. Reliability improvement projects are designed and estimated. Reference Appendix I – UES-Capital Reliability Study 2012 and Appendix J – UES-Seacoast Reliability Study 2012 for the most recent annual reliability reports.

Each of the projects is compared based upon a cost per saved customer minute and saved customer interruption basis. These projects are submitted for capital budget consideration. The report also analyzes:

a) Analysis of the ten worst outages that occurred over the timeframe along with their associated impact to UES-Seacoast system SAIDI and SAIFI
b) Analysis of the affect of sub-transmission outages on circuit performance.
c) Analysis of the worst performing distribution circuits over the reporting period
d) Analysis of the major causes of sustained interruptions.
e) Analysis of the performance issues on specific circuits as well as recommendations for improvement
f) Analysis of equipment failures to identify trends and provide recommendations when necessary.
g) Analysis of areas with multiple tree related outages for consideration for additional tree trimming.

10 DEMAND SIDE RESOURCES

Historically, the distribution system planning process focused exclusively on the capabilities of the distribution system infrastructure to satisfy the peak demands resulting from current and projected circuit and system load requirements. In recent years, the choices and technologies by which customers can change their apparent load characteristics on the distribution system have expanded significantly. Choices made by consumers which result in increasing demand include significantly higher penetration of air-conditioning and, more recently, expansion of home entertainment and computer equipment. Customers have also made choices which have reduced demand such as energy efficiency, stimulated both by price increases and market choices, as well as by energy efficiency programs. At the same time, customers may be more inclined to consider options for self-generation, and the incidence of distributed generation, particularly in response to state net metering policies and federal and state incentives, has also increased.

These changes have complicated the forecasting process. However, they now offer opportunities for the distribution utility, through specific programs, to directly influence consumer adoption of these technologies. As a result, these opportunities need to be factored into a utility's distribution system planning process in a more systematic way. Significantly, changing consumer demand profiles is a radically different utility intervention than building distribution facilities to meet utility distribution planning and design criteria.

Unitil has completed assessments of several different distributed energy resource technology options. In general, this analysis has identified that distributed energy resources do not compare favorably with traditional transmission and distribution investment from a cost or reliability perspective. However, Unitil has implemented or will implement pilot projects to continue to evaluate certain distributed energy alternatives. In December 2010, the Company prepared a Demand Side Management Planning Report which provides a more detailed evaluation of Demand Side Resources. A copy of this Report is attached as Appendix K.

As discussed in the Report, Unitil has been evaluating the same demand side resource planning challenges that many other utilities have been engaged in. The solutions to these challenges are critical for utilities to be able to accurately planning for these types of demand side resources.

1. Many demand side resources have diverse and highly uncertain peak load carrying characteristics which has an effect on the overall cost estimates. Unitil will continue to evaluate the different types of demand side resources to better develop reliable cost and performance data for planning.

2. From a planning standpoint, Unitil needs to rely on these demand side resources in the same way it depends on traditional system investment. Unitil needs to better understand how diversity will help the overall dependability of these resources.

3. Cost recovery and financial implications for demand side resources is entirely different than traditional investment and remains to be fully resolved. Uncertainty about cost recovery is a key impediment to demand side resource development and implementation.

11 CONCLUSION

The electric utility environment continues to challenge the traditional planning approach historically taken by utilities. Unitil believes that the approach demonstrated here demonstrates Unitil's balance of a traditional planning approach with an ever increasing demand side planning component.

Unitil's overall planning approach is resulting in a long range plan that provides safe, reliable and cost effective service to our customers. Unitil has and will continue to implement demand side resource pilot projects where they make sense to better understand some of the challenges listed above.

APPENDICES

A Unitil Distribution Planning Guidelines

B UES Capital Distribution System Planning Evaluation 2013-2017

C UES Seacoast Distribution System Planning Study 2013-2017

D Unitil Electric System Planning Guide

E Load History and Ten-Year Design Forecasts for the UES Capital and UES Seacoast systems.

F UES-Capital 2013-2022 Electric System Planning Study

G UES-Seacoast 2013-2022 Electric System Planning Study

H UES- Capital Reliability Study 2012

I UES-Seacoast Reliability Study 2012

J UES Demand Side Planning 2010

Unitil Service Corp.

Electric Distribution Planning & Design Guidelines

Prepared By:

Distribution Engineering Dept.
Unitil Service Corp

1. Distribution Voltages
   a. Steady-State Voltage
   b. Voltage Balance
   c. Voltage Fluctuations (Flicker) (future)
   d. Voltage Distortion (future)

2. Distribution Equipment Capacity and Loading (future)
   a. Conductors
   b. Power Transformers
   c. Regulators and Autoboosters
   d. Breakers and Reclosers
   e. Load Balance

3. Distribution Protection (future)

4. Design of Overhead Systems (future)
   a. Preferred Conductors
   b. Circuit Size
   c. Circuit Back-up

5. Design of Underground Systems (future)
   a. “Radial” vs. “Loop”

Distribution Voltages

Low Voltage Services

Electric distribution systems should be designed and constructed such that low voltage services (600 V and below) supplied to most customers most of the time operate within the following range under steady-state conditions, as measured at the point of delivery:

	Nominal Voltage	120/240 V	208Y/120 V	480Y/277 V
(A)	Upper limit (105%)	126 / 252 V	218 / 126 V	504 / 291 V
(A)	Lower limit (95%)	114 / 228 V	197 / 114 V	456 / 263 V

Practical design considerations or unusual operating circumstances may occasionally result in service voltages below the lower (A) limit conditions shown above. When these situations arise, the following extended lower limit may be tolerated:

	Nominal Voltage	120/240 V	208Y/120 V	480Y/277 V
(B)	Lower limit (91.7%)	110 / 220 V	191 / 110 V	440 / 254 V

Although such lower (B) limit conditions are occasionally part of practical utility design and operation, they shall be limited in extent, frequency, and duration.

(A) - corresponds to ANSI C84.1 Range A Service Voltage
(B) - corresponds to ANSI C84.1 Range B Service Voltage, below NHPUC Rules section PUC 304.02(c) minimum, but in compliance with section PUC 304.2(h)

Steady-state service voltages operating below the lower (B) limit are unacceptable under normal conditions.

Normal conditions include common system activity such as ordinary variations in loads and supply, voltage regulator or load-tap changer actions, routine system maintenance configurations, and emergency configurations after equipment failures or system faults have been removed.

Abnormal conditions beyond Unitil's immediate control (including area voltage reduction actions, and during active system faults) may result in infrequent and limited periods when steady-state voltages above the upper limit or below the lower (B) limit occur. When voltages occur outside these limits, prompt corrective action shall be taken.

Primary Voltage Services

Electric distribution systems should be designed and constructed such that primary voltage services operate within the following range under steady-state conditions, as measured at the point of delivery:

	Nominal Voltage	4160Y/2400 V	13800Y/7970 V	34500Y/19920 V
(A)	Upper limit (105%)	4370 / 2520 V	14490 / 8370 V	36230 / 20920 V
(B)	Lower limit (95%)	3950 / 2280 V	13110 / 7570 V	32780 / 18930 V

(A) - corresponds to ANSI C84.1 Range A Utilization and Service Voltage
(B) - corresponds to ANSI C84.1 Range B Service Voltage

Variations outside these limits shall be brief and infrequent.

Primary System Voltages

In order to meet the service voltage objectives described above, primary distribution systems should be designed and constructed to the following operating ranges for steady-state conditions:

Steady-state primary voltages operating below 125 V (on 120 V base, or 105%) and above 117 V (on 120 V base, or roughly 97.5%) shall be considered adequate to support all service voltage objectives. At best, a combined voltage drop of 2.5% (3 V on 120 V base) through the service transformer and the secondary and service conductors to the point of delivery will result in satisfactory service voltage. Primary system improvements will not be necessitated to remedy low service voltages if the primary system operates within this range.

Steady-state primary voltages operating as low as 114 V (on 120 V base, or roughly 95%) are tolerable if they do not result in extensive, or frequent, or long-lasting service voltage concerns. Primary system improvements may be necessary to resolve lengthy, recurring, widespread low service voltages.

Steady-state primary voltages operating below 114 V (on 120 V base, or roughly 95%) are unacceptable under normal conditions.

Voltage Unbalance

Electric distribution systems should be designed and operated to limit the maximum voltage unbalance to any three-phase customer to no more than 3% as measured at the point of delivery under no-load conditions.

Voltage unbalance of a three-phase system is expressed as a percentage of deviation from the average voltages.

$$\text{Voltage unbalance} = 100 \text{ X } \frac{\text{(max deviation from average voltage)}}{\text{(average voltage)}}$$

Voltage Fluctuations and Transients (future)

Unitil Energy Systems - Capital

Distribution System Planning Study 2013-2017

Prepared By:

Cyrus Esmaeili
Unitil Service Corp.
10/11/2012

TABLE OF CONTENTS

1. Executive Summary

This study is an evaluation of the Unitil Energy Systems Capital (UES-Capital) electric distribution system. The purpose of this study is to identify when system load growth is likely to cause main elements of the distribution system to reach their operating limits, and to prepare plans for the most cost-effective system improvements. The timeframe of this study is the winter and summer peak load periods over the next five years, from the summer of 2013 through the summer of 2017.

The following items will require action within the 5-year study period. All cost estimates provided in this report are without general construction overheads.

Year	Project Description	Justification	Cost($)
2013	*Circuit 1H3: Load Balance	Loading at 110% Voltage 116.7V	Minimal
	*Circuit 1H6: Load Balance	Loading at 90% Voltage 115.5V	Minimal
	*Circuit 2H1: Transfer 1H3 load to 6X3 & 1H2; 2H1 load to 1H3	Voltage116.7V	Minimal
	*Ckt 2H2: Install Regulators on Rumford St. , Transfer Load to 2H1, Change Protection Settings	Loading at 101% Voltage115.5V	55,000
	*Circuit 1H1/1H5: Transfer Load from 1H1 and 1H5 to 1H6	Loading at 94%	Minimal
	Circuit 3H1: Transfer load from 3H1 to 3H2	Loading at 97% Voltage 116.3V	Minimal(2013) 31,000(2017)
	Circuit 8X3: Load Balance and Recloser Upgrade on Main St	Voltage116.8V Loading 112%	10,000
	Circuit 4X1: Install a Regulator on Blackwater Rd	Voltage115.1V	35,000
2014	Circuit 8X3: Recloser Trip Coil Replacement on Goboro Rd	Load at 92%	4,500
	Circuit 18W2: Transfer Load to 7W3 and Install Regulator	Loading 91%	35,000
	Circuit 15H3: Reconductor Commercial St	Voltage 116.9V	65,000
	Circuit 8X3: Install a Regulator on Blackhall Rd	Voltage116.2V	35,000
	Circuit 13W2: Install a Regulator on High St	Votlage116.9V	35,000
2015	Circuit 37X1: Install a Regulator off Hannah Dustin Dr.	Voltage116.9V	35,000
	Circuit 4W4: Install a Regulator on Hutchins St	Voltage 116.9V Loading 90%(2016)	35,000
	Circuit 6X3: Install a Regulator on Fisk Rd	Voltage 116.9V	35,000
2017	Circuit 8X3: Upgrade Stepdown and Transfer Load on Horse Corner Rd	Loading at 96% Voltage 116.9V	25,000
	Circuit 15H3: Install Regulators on Commercial St.	Voltage 116.7V	35,000

*Part of the Concord Downtown Area Options

2. System Configuration

The UES-Capital Operating System takes service from the Public Service Company of New Hampshire, a division of Northeast Utilities (NU-PSNH). 34.5 kV service is taken at Garvins Substation, at Hollis Substation via the 318 Line (fed from Garvins S/S), and at Penacook Substation via the 3122 and 317 lines (fed from NU-PSNH Oak Hill Substation).

The UES-Capital subtransmission system is operated in a looped configuration between

Garvins and Oak Hill. The 34.5kV subtransmission system serves 16 distribution substations which serve distribution circuits at 34.5 kV, 13.8 kV, and 4.16 kV. The distribution system is equipped with various circuit ties that permit load swap between circuits.

3. Study Focus

This study is primarily focused on the 34.5, 13.8 and 4.16 kV distribution substations and circuits. System modifications are based upon general distribution planning criteria. An evaluation of the 34.5 kV subtransmission system is made under a separate electric system planning study.

The first objective of this distribution planning study is to identify and correct specific conditions that do not meet design or operating criteria. The second objective is to develop and communicate a master plan for the development of a robust and efficient distribution system to accommodate long-term improvement and expansion throughout and beyond the study years. Recommendations are based on system adequacy, reliability and economy among available alternatives.

4. Load Projections

A five year history of summer and winter peak demands for each individual circuit was developed from the monthly peak demand readings. A linear regression analysis was performed on the historical loads to forecast future peak demands for substation transformers, circuits and other major devices. Attempts were made to take into account known significant load additions, shifts in load between circuits, etc. In some instances, the peak loads did not present a confident trend over the historical period, so estimates were made using the best available information and knowledge of the circuit. In general, one standard deviation was added into these forecasts to account for differences from year to year in the severity of summer heat and other varying factors.

The following table shows the ten circuits with the highest estimated growth rates.

Ranking	Circuit	Loading Increase 2013-2017
1	2H4	23.9%
2	13W3	16.4%
3	13W2	14.8%
4	14X3	14.4%
5	1H1	13.6%
6	2H2	9.9%
7	14H1	9.8%
8	6X3	9.0%
9	4W4	7.2%
10	1H5	7.1%

The projection analysis can be referenced in Appendix A.

5. Rating Analysis

A detailed review of the limiting factors associated with each circuit was completed. The limiting factors included current transformer (CT) ratings, protection device settings, switch, circuit exit conductor, regulator, and transformer ratings. Overall circuit ratings are based upon the most restrictive of these limiting elements. Summer and winter peak load projections for the five year study period were compared to these circuit ratings. The distribution system circuit limitations can be referenced in Appendix B.

Projected loads reaching certain thresholds prompted a closer assessment of the conditions. Shading has been added to the projection analysis to provide a visual representation of potential problem areas.

Legend
loading < 50% of Normal Limit
50% ≤ loading ≤ 90% of Normal Limit
90% < loading ≤ 100% of Normal Limit
100% of Normal Limit < loading

6. Analysis and Findings

Transformer and circuit loadings have been compared to the limiting circuit elements. The monthly per phase transformer load readings are added together and then converted to kVA. In order to maintain some conservatism, those transformers and circuits which have reached 90% of the limiting factor have been highlighted and will be discussed later in the section. The threshold of 90% was taken to account for phase loading imbalance.

This section details the findings resulting from the analysis described in Section 5 as well as an analysis of stepdown transformer loadings and a review of circuit load phase imbalance. Individual project descriptions, justification, predicted benefits and associated cost estimates intended to address each of the identified issues are included in Section 8.

6.1. Substation Transformer Loadings

Transformers where the projected load reaches 90% or more of their seasonal rating are listed here. Summer and winter transformer loading graphs are included in Appendix C.

Bow Bog 18T1
Peak demand loading for the Bow Bog 18T1 transformer is projected to reach as much as much as 3,039 kVA (91% of Normal limit) by the summer of 2013, and increase to as much as 3,240 kVA (97% of Normal limit) by the summer of 2017, due to general load growth.

6.2. Distribution Circuit Loadings

Those circuit position elements where the projected load will reach 90% or more of their rating are listed below. Summer and winter circuit loading graphs are included in Appendix D.

Bridge St. – Circuit 1H5:
Peak demand loading for Circuit 1H5 out of Bridge St. S/S is projected to reach as much as 2,734 kVA (379 A avg. per phase) or 91% of 350 CU UG rating in 2017.

Bridge St. – Circuit 1H1:
Peak demand loading for Circuit 1H1 out of Bridge St. S/S is projected to reach as much as 2938 kVA (408 A avg. per phase) or 91% of the overcurrent protection minimum pick up flag in 2016, and increase to as much as 93% in 2017.

Gulf St. – Circuit 3H1:
Peak demand loading for Circuit 3H1 out of Gulf St. S/S is projected to reach as much as 2,295 kVA (318 A avg. per phase) or 95% of the overcurrent protection minimum pick up flag in 2013, and increase to as much as 97% in 2017.

W. Concord – Circuit 2H2:
Peak demand loading for Circuit 2H2 out of W. Concord S/S is projected to reach as much as 2,332kVA (324 A avg. per phase) or 96% of the overcurrent protection minimum pick up flag in 2013, and increase to as much as 106% in 2017.

6.3. Distribution Stepdown Transformer Loadings

The Summer Normal Limit used for distribution stepdown transformer loading analysis is 120% of the nameplate rating. This is based upon the "Normal Life Expectancy Curve" in ANSI/IEEE C57.91-latest. The ambient temperature assumed is 30°C (86°F).

The following table summarizes the distribution stepdown transformers that have been recently metered above nameplate. Shading has been added to the projections to provide a visual representation of potential overloads.

Legend
loading < 100% of Nameplate
100% < loading ≤ 120% of Nameplate
120% of Nameplate < loading

CIRCUIT # / LOCATION	TOWN	POLE #	TRANSFORMER SIZE			Recent Metered Peak			
			A	B	C	A	B	C	Bank kVa
4X1 Village St	Penacook	51	500		500	73%		115%	94%
8X3 Horse Corner Rd	Chichester			250			100%		100%
8X3 Main St	Chichester	165	500	333	500	19%	112%	73%	68%

6.4. Phase Imbalances

All of the circuits within the UES-Capital service territory were reviewed for phase balance. The per phase loading for each circuit was averaged over a timeframe of January 2011 through December 2011. Circuits and substation transformers were ranked based upon the worst average phase imbalances (greatest deviation from the average).

In general, the goal for phase balancing is 10%. The following is a list of circuits, where the imbalance is greater than 20% which is considered severe. The circuits below will be looked at in more detail to determine the severity of the problem and EWRs will be issued to reduce the phase imbalances if required. It is important to note that the phase imbalance experienced by transformers will be reduced as the circuits fed from that transformer are balanced. The values listed below are an absolute seasonal average and do not take diversity factor into consideration.

Circuit	% Imbalance	Solution
13W1	47%	Transfer Northwest Rd tap from phase A to phase C Transfer Southwest Rd tap from phase C to phase A
1H6	37%	Balanced for low voltage solution
14H2	35%	Balanced for low voltage solution
14H1	31%	Transfer Holly St. tap from phase B to phase C
15W1	29%	Transfer Lisa Lane taps from phase B to phase C Transfer Jennifer Dr tap from phase B to phase A
15W2	27%	Transfer one of the Broken Ground Rd taps from phase B to phase C
15H3	27%	This load varies month to month and cannot be easily balanced
1H2	25%	Load balance included in 4kV area study
4W3	23%	Load transferred for overload
1H4	21%	Transfer 10 kVA from phase A to phase C (this transformer feeds a whole street)
1H3	21%	Balanced for low voltage solution
2H1	20%	Load transferred for low voltage

7. Circuit Analysis Results

Circuit analysis is completed for the UES-Capital distribution system on a three year rotating cycle, where each circuit is reviewed once every three years. WindMil circuit analysis is used to identify potential problem areas. All identified problems should be followed up with verification from field measurements. Solutions to the deficiencies noted below are detailed in Section 8.

The following is a list of the circuits analyzed in 2012. Other circuits not shown on this listing were reviewed for planning purposes. However, those circuits were not part of the three year cycle.

Substation	Circuit	Substation	Circuit
Bridge St	1H6	Boscawen	13W1
	1H5		
	1H4		
	1H3		13W2
	1H2		
	1H1		
West Concord	2H1		13W3
	2H2		
	2H4		
Gulf St	3H1	Langdon	14H1
	3H2		
	3H3		
Hollis	8X5		14H2
	8X3		

7.1. Voltage Concerns

Circuit analysis is set to identify areas where the voltage on the circuit goes outside of a pre-determined acceptable range. The acceptable range used for this analysis is 117-125 V on a 120 V base. The following table summarizes the areas where voltage is predicted to be outside of this range. The table is sorted by circuit and year.

Circuit	Year	Voltage	Location
1H3	2013	116.7	Washington St
	2014	116.9	Beacon St
1H6	2013	115.5	[1]South State St
2H1	2013	116.7	[1]Tremont St
2H2	2013	116.8	Auburn St
		116.4	Ridgewood Lane
		115.9	[1]Westbourne Rd
		115.5	Little Pond Rd
2H4	2013	115.8	[1]Swenson Ave
3H1	2013	116.3	Oak St
4X1	2013	116.9	Blackwater Rd

Circuit	Year	Voltage	Location
		115.1	[1]River Rd (P.90)
8H2	2013	116.2	B ST
8X3	2013	116.2	[1]Wing Rd
		116.8	[1]Swiggey Brook Rd
		116.8	[1]Goboro Rd (P.68)
	2017	116.9	Horse Corner Rd
13W2	2014	116.9	Battle St
15H3	2014	116.9	Delta Dr
4W4	2015	116.9	District No.5 Rd
6X3	2015	116.9	Fisk Rd
8H1	2015	116.9	Salisbury Green
37X1	2015	116.9	South West Rd

[1]Voltage Readings at customer meters showed these locations to be within planning criteria.

7.2. Overload Conditions

The following summarizes distribution equipment which is expected to be loaded above 90% of normal ratings during the five year study period. The table is sorted by circuit and year.

Circuit	Year	Percent Loading	Distribution Equipment (summer normal rating)	Location
1H3	2013	110%	#4 Cu Conductor (179 Amps)	Washington St, Concord
1H3	2013	114%	350MCM AL UG (325 Amps – buried duct)	Storrs St, Concord
1H3	2017	90%	#4/0 AA SP Conductor (338 Amps)	North Main St, Concord
1H5	2013	94%	#4/0 ACSR Conductor (370 Amps)	Main line out of Bridge St. S/S, Concord
3H1	2013	94%	#4/0 AA Conductor (338 Amps)	From Theater St. to the Railroad, Concord
3H1	2013	97%	#1/0 Cu Covered Conductor (305 Amps)	South Main St, Concord
1H6	2014	90%	#2 ACSR Conductor (187 Amps)	South State St, Concord
4W4	2016	90%	#2/0 ACSR Conductor (283 Amps)	Village St, Concord
2H2	2017	90%	#6 Cu Conductor (130 Amps)	Penacook St, Concord

7.3. Protection Concerns

Analysis was performed the one third selected circuits to identify areas that violate Unitil's distribution protection sensitivity and coordination criteria. These circuits were also studied to identify unprotected mainline laterals. A summary of these findings can be found in the table below. A detailed list of the devices and settings that do not meet these requirements can be found in Appendix E. These areas will be looked at in more detail and EWR's will be issued to address these concerns if required.

Circuit	# of Unprotected Laterals	# of Device Mis-Coordinations	# Sensitivity Concerns
1H1	none	none	none
1H2	7	none	none
1H3	none	none	none
1H4	2	none	none
1H5	none	none	none
1H6	6	none	none
2H1	3	1	none
2H2	4	none	none
2H4	none	none	none
3H1	10	1	none
3H2	1	none	none
3H3	1	none	none
8X3	1	none	none
8X5	1	none	none
13W1	1	none	none
13W2	none	7	none
13W3	2	4	none
14H1	1	none	none
14H2	2	none	none

8. Detailed Recommendations

The following sections detail system improvement projects to address the deficiencies listed above. All cost estimates provided in this report are without general construction overheads. For all conductor loading percentages in this section the Unitil normal summer rating was used, unless otherwise stated. For all power transformers the Unitil normal summer rating was used, unless otherwise stated. Also, loading percentages in this section may not match up with loading percentages in section 6. This is due to the fact that this section takes into account unbalanced load conditions. Refer to section 6 to learn more about how the percentages in that section are calculated.

8.1. Concord Downtown Area Options – (2013)

Circuit analysis has indicated that the primary voltage at several locations on circuits 2H2, and 2H1 are expected to be below acceptable limits in 2013. Loading concerns were identified on 2H2 circuit overcurrent minimum pick up rating in 2013, 1H5 #4/0 ACSR conductor rating in 2013, 1H3 conductor ratings in 2013, 1H6 #2 ACSR conductor rating in 2013 and 1H1 circuit overcurrent minimum pick up rating in 2016.

The main focus of the options listed below was to off load the 4kV system, and evenly distribute load over the 4kV system. This utilizes what capacity we have in the surrounding circuits with minimal cost. A detailed solution to the voltage and loading concerns has been provided along with some long term area solutions. Below is a chart of the affected circuits loading before and after the provided solution in 2017.

Circuit	2017 loading (kva)	limiting element rating(kva)	% loading of Rating	2017 Loading after swap(kva)	% loading of Rating after projects
2H2	2562	[1]2419 -> 3226	106%	2402.4	74%
2H1	1580	2037.6	78%	1545.6	76%
1H3	2453	2340	105%	1874.4	80%
1H2	1493	2340	64%	1927.2	82%
1H1	2994	3225.6	93%	2736	85%
1H5	2734	2988	91%	2323.2	78%
1H6	1310	[2]2304 -> 3226	41%	1980	61%
6X3(past 4kv steps)	556.8	1252.8	44%	787	63%
Totals	15,682.8	20,865.6			75%

[1]As part of project 8.1.3, the minimum trip flag (80% of minimum trip) is expected to be increased from 336 Amps to 480 Amps. The 336 AA spacer cable becomes the limiting element with 448 amp rating

[2]As part of project 8.1.4, the minimum trip flag is expected to be increased from 320 Amps to 448 Amps.

8.1.1. Circuit 1H3: Load Balance - (2013)

Circuit analysis has indicated a primary voltage of 116.7 V at P.31 on Washington St., 115% loading on 350MCM AL conductor under Loudon Rd. and 110% loading on #4 CU conductor on Washington St. in 2013.

Transfer A phase load to C phase downline of P.3 on Beacon St.

TOTAL PROJECT COST: MINIMAL

Circuit analysis indicates this project is expected to increase the primary voltage at P.31 on Washington St. to 118.3 V (Phase A), decrease loading on the 350MCM AL conductor to 103%, and decrease loading on the #4 CU conductors to 87% in 2017.

8.1.2. Circuit 1H6: Load Balance– (2013)

Circuit analysis has indicated a primary voltage of 115.5V on South State St. and 90% loading on the #2 ACSR conductors on South State St. in 2013. Actual readings at an AMI meter (P.202/4) indicate a minimum service voltage of 115 V but using a calculated 1.5V drop from this location to the end of circuit gives an end of line service voltage of 113.5V.

Transfer the P.6 South State St. tap (Wall St) from phase A to phase C.

TOTAL PROJECT COST: MINIMAL

Circuit analysis indicates this project is expected to increase primary voltage to 117.9V and decrease loading on #2 ACSR conductors to 77% in 2017.

8.1.3. Circuit 2H1: Transfer 1H3 load to 6X3 & 1H2; 2H1 load to 1H3 – (2013)

Circuit analysis has identified that the primary voltage on Tremont St. may get as low as 116.7 V in 2013. Loading on the 1H3 350 MCM AL UG Conductor may reach 99% in 2013 after project 8.1.1. Actual AMI voltage meter readings (on Tremont St) indicate a service voltage of 115.5V.

- Transfer load on 2H1 downline of P. 34 North State St. to 1H3 via the tie at P.27 North State St.

- Transfer the load on 1H3 downline of P. 21 Academy St. to 6X3 via the tie on P.32 Academy St.. The single phase tap off P. 21 (Rumford St) will stay on 1H3. *(If Alternative 1 is selected for the Circuit 2H2 solution then this step would change to transfer to 2H2)*

- Transfer 1H3 load downline from P. 7 on Washington St. to 1H2 via the tie at P. 12 Montgomery St.

- Transfer the single phase tap at P.2 Court St. from phase B to phase A.

TOTAL PROJECT COST: MINIMAL

This project is expected to increase primary voltage to 117.8V on 2H1, 120.0V on 1H2, 117.7V on 6X3 in 2017. This project is expected to decrease loading on the 1H3 350MCM AL conductor to 84%, the 1H3 #4 CU conductor to 55%, and increase loading on the 1H2 350MCM AL UG conductor to 84% loading in 2017.

8.1.4. Ckt 2H2: Install Regulators on Rumford St, Transfer Load to 2H1, Change Protection Settings – (2013)

Circuit analysis has indicated wide spread low voltage concerns on 2H2, with voltages as low as 115.5V in 2013. Also, loading on 2H2 may reach 101% of the minimum pick up rating in 2013. Actual AMI voltage meter readings (on Auburn St/Ridge Rd) indicate a minimum service voltage of 110/112.5V respectively.

- Install (2) 437A ,2.4kV regulator in the vicinity of pole 52 on Rumford St, to be applied to phases A & C.

- Change the phase relay minimum pick-up tap from 7 to 10. This should increase the minimum pick up from 420 amps to 600 amps.

- Transfer Lyndon St. tap at P.15 Franklin St. from phase C to phase A.

- Transfer the load downline of P.6 on Walker St. from 2H2 to 2H1 via the tie at P.47 on North State St.

- Extend single phase 2 sections from P.49 on Penacook St. to P.49 and transfer load downline of P.34 on Auburn St. to the new line extension.

TOTAL PROJECT COST: $55,000

Circuit analysis indicates this project is expected to increase primary voltage to 117.8V on 2H2, and 117.8 on 2H1. 2H2 loading may increase to 74% of the circuit overcurrent minimum pick-up in 2017.

<u>Ckt 2H2: Transfer 2H2 Load to 33X4, Install (1) Regulator on 2H2, Transfer Load.-</u> Alterantive 1

- Install (3) 500kVA stepdowns, 200A 2.4kV regulators in the vicinity of P.24, Little Pond Rd and metering at 33X4 tap and transfer Penacook St/ Little Pond Rd tap (downline of P.18) onto these stepdowns.

- Extend single phase 2 sections from P.49 on Penacook St. to P.49 and transfer load downline of P.34 on Auburn St. to the new line extension.

- Install (1) 437A, 4.16kV/2.4kV, regulator in the vicinity of P.52 on Rumford St.

- Transfer load downline of P.21 on Academy St. (Rumford St. tap) from phase C to phase A.

- Transfer load downline of P.21 on Washington St. from 1H3 to 2H2.

- Transfer the load downline of P.6 on Walker St. from 2H2 to 2H1 via the tie at P.47 on North State St.

- Transfer tap on P.34 North Main St. from phase B to phase A.

TOTAL PROJECT COST: $165,000

Circuit analysis indicates this project is expected to increase primary voltage to 117.9V in 2017 on 2H2, decrease loading on minimum pick-up to 66% on 2H2 in 2017. 1H3 loading may increase to 85% of the 350MCM AL UG Conductor rating in 2017.

8.1.5. Circuit 1H1/1H5: Transfer load from 1H1 and 1H5 to 1H6 – (2013, 2016)

Circuit analysis indicates the #4/0 ACSR conductor on 1H5 will be loaded to 94% of its summer normal rating in 2013. Also, the minimum pick-up flag for the 1H1 circuit recloser will be loaded to 94% in 2016.

Increase the trip setting on 1H6 from 400A to 560A. Transfer P.3 tap next to the Railroad tracks from 1H5 to 1H6.

In 2016, Transfer load downline of P.3 on North Main St, 1H1, to 1H6 via tie point at P.10 on North Main St.

TOTAL PROJECT COST: MINIMAL

Circuit analysis indicates this project is expected to decrease 1H5 loading to 89% and 1H1 loading to 85% in 2017. This is expected to increase the 1T2 loading to 77% of its normal limits.

OPTION 2: Rebuild West Concord to 13.8kV (conceptual)

- Rebuild West Concord to 13.8kV, and rebuild most of 2H2, 2H1, and 2H4 to 13.8kV circuits.
- Transfer load onto 2W2 and 2W1 from 1H3 and 1H2
- Transfer part of 1H5 to 1H6

OPTION 3: Upgrade the Underground Circuit out of Bridge St. (conceptual)

- Reconductor the mainline underground portion of 1H3 circuit with 500MCM copper
- Reconductor a total of four sections on Washington St. and North Main St. with 336AA conductor
- Transfer part of 1H5 to 1H6
- Install a regulator on 2H2
- Transfer part of 2H1 to 1H3

OPTION 4: Upgrade the Underground System Put of Storrs & Montgomery (conceptual)

- Reconductor 2000ft of mainline underground on 21W1P with 350MCM copper (removes 2,000ft old low capacity underground)
- Extend small amounts of line and convert and transfer parts of 1H6, 1H3, 2H2 to these circuits (resolves future loading and voltage concerns)

8.2. Circuit 3H1: Transfer load from 3H1 to 3H2 - (2013)

Circuit analysis has indicated a primary voltage of 116.3V on Oak St., 97% loading on #1/0 CU Covered Conductor, and 94% loading on #4/0 AA Spacer Cable in 2013. Loading on 3H1 circuit protection is expected to reach 95% of the minimum trip rating flag in 2013 and 97% in 2017. Actual readings at an AMI voltage meter (on Perley St) indicate a minimum service voltage of 113V.

Transfer load from 3H1 to 3H2, and load balance – (2013) - Proposed
Transfer load between P.17 and P.23 on South State St.to 3H2. Add single phase line extension between P.16 and P.15 on Perley St. and transfer the 3H1 Perley St. tap to 3H2. Transfer the load downline of P.4 on South Spring St. (Lincoln St. tap) from phase A to phase C.

Circuit analysis indicates this project is expected to keep primary voltage and loading within the acceptable limits until 2017 in which the primary voltage on Monroe St. may get as low as 116.9, #4/0 AA Spacer Cable becomes 89% loaded, and #1/0 CU Covered Conductor becomes 92% loaded.

TOTAL PROJECT COST: MINIMAL

Build Single phase extension and transfer load to 3H2 – (2017) - Proposed
Add an additional #1/0 ACSR conductor extension from P.12 on Perley St. to P.30 on South St. and transfer up to P. 23 on South St. from 3H1 to 3H2.

Circuit analysis indicates this project is expected to increase primary voltage to 117.6V and decrease loading on the #4/0 AA conductor to 87%, decrease loading on the #1/0 CU covered conductor to 88% concerns in 2017, but will restrict tie capabilities between 3H3 and 3H2.

TOTAL PROJECT COST: $31,000

Transfer load from 3H1 to 14H2 and load balance – (2013) – Alternative 1
Build three phase construction from P. 22 on Broadway St. to P. 32 on South St. using 336 AA conductor with a #4/0 ACSR neutral, about 750ft. Extend a third phase 336 AA from P. 23 to P. 32 on South St., about 700ft. Then, transfer load on 3H2 downline from P. 5(south) on South Spring St. to 14H2 via a new tie built at P.32 South St.. Transfer Oak St. tap at P.3 on South Spring St. from phase A to phase C. Transfer P.28 South Spring St. tap from phase C to phase A (on 14H2 now). Transfer P.10 Broadway St. tap from phase A to phase B (on 14H2).

Circuit analysis indicates this project is expected to increase primary voltage to 117.2V on 14H2, 119.1V on 3H1, decrease loading on the #4/0 AA Spacer Cable to 80%, and decrease loading on the #1/0 CU covered conductor to 80%, in 2017. This project allows for the 1H6/3H1 tie to be used more times of the year and does not affect the 3H3/3H2 tying capabilities. 14T1 will still be less than 50% loaded in 2017.

TOTAL PROJECT COST: $110,000

Install Stepdowns and Transfer 3H1 load to 7W4, In 2016 install regulator on 7W4 – (2013) - Alternative 2

Install (3) 333kVA, 7.97kV to 2.4kV stepdowns at P.13 on South Spring St. and transfer all of 3H1 South Spring St. load onto 7W4. A regulator will be installed in the vicinity of P.5 on River Rd, to be applied on phase B (in 2016).

Circuit analysis indicates this project is expected to increase primary voltage to 119.5V on 7W4 past the stepdowns, 119.1V on 3H1, decrease loading on the #4/0 AA Spacer Cable to 71%, and decrease loading on the #1/0 CU covered conductor to 71% in 2017. This project will allow for the 1H6/3H1 tie to be used more times of the year and does not affect the 3H3/3H2 tying capabilities, but increases loading on 7T2 to 86% in 2017. This does not account for the 800kva being transferred from 18W2 to 7W3 in a future project.

TOTAL PROJECT COST: TBD

8.3. Circuit 8X3: Load Balance and Recloser Upgrade on Main St– (2013)

Circuit analysis has identified primary voltage on Swiggey Brook Rd may get as low as 116.8V in 2013. Loading on the B phase Main St. Step down has reached 112% of its nameplate rating. Loading on the reclosers at P.168 Main St.is expected to reach 100%

of their continuous rating in 2013. Actual readings at an AMI voltage meter (on Swiggey Brook Rd) indicate a minimum service voltage of 116V.

Transfer the Suncook Valley Rd tap at P. 268 on Main St. from phase B to phase A. Replace coils in the hydraulic reclosers on P.168 Main St. with 70A coils.

TOTAL PROJECT COST: $10,000

Circuit analysis indicates this project is expected to increase primary voltage on Swiggey Brook Rd to 117.0V, decrease loading on the B phase step to 112% in 2017.

8.4. Circuit 4X1: Install a Regulator on Blackwater Rd – (2013)

Circuit analysis has identified the primary voltage on River Rd in the vicinity of P.90 may get as low as 115.1V in 2013. Circuit analysis has identified the primary voltage on Blackwater Rd may get as low as 116.9 in 2013. Actual readings at an AMI meter (on Blackwater Rd) indicate a minimum service voltage of 113V. Actual readings at an AMI meter (on River Rd) indicate a minimum service voltage 115.5V.

Install a 100A regulator in the vicinity of P.42 Horse Hill Rd.

TOTAL PROJECT COST: $35,000

This is expected to increase voltage on Blackwater Rd above planning criteria past 2017.

8.5. Circuit 8X3: Recloser Trip Coil Replacement on Goboro Rd– (2014)

Circuit analysis has indicated loading on the recloser at P.2 on Goboro Rd has reached 92% of nameplate rating.

Replace the 100A minimum pick up (50A cont.) recloser trip coil with a 200A minimum pick up trip coil. And replace the high side fuse of the step downs on P.1, Goboro Rd, with 80K fuses.

TOTAL PROJECT COST: $4,500

Circuit analysis indicates this project is expected to increase loading on this recloser to 52% in 2017.

8.6. Circuit 18W2: Transfer Load to 7W3 and Install Regulator – (2014)

Circuit analysis has identified loading on the 18T1 transformer will be 91% of its summer normal rating in 2013 and 97% of its summer normal rating in 2017.

Transfer load downline of P.64 on Bow Bog Rd to 7W3 via the tie at P.67 on Bow Bog Rd (about 800 kVA). Install a regulator at P. 5 on Robinson Rd, to be applied to phase C.

TOTAL PROJECT COST: $35,000

Circuit analysis indicates this project is expected to decrease loading on 18T1 to 73% in 2017, but may increase loading on 7T1 to 87% in 2017.

8.7. Circuit 15H3: Reconductor Commercial St. – (2014)

Circuit models have identified that the primary voltage on Delta Dr may get as low as 116.9V in 2014. Actual readings at an AMI meter (P.123/37) indicate a minimum service voltage of 119 V but using a calculated 1.5V drop from this location to the end of circuit gives an end of line service voltage of 117.5V.

Reconductor the existing three phase from P.4 on Delta Dr to end of line (Approx. 850ft) with 336 AAC with a #4/0 ACSR neutral. (This will involve a highway crossing)

TOTAL PROJECT COST: $65,000

Circuit analysis indicates this project is expected to increase primary voltage on Delta Dr to 116.7V in 2017.

8.8. Circuit 8X3: Install a Regulator on Blackhall Rd – (2014)

Circuit analysis has identified primary voltage on Wing Rd may get as low as 116.2V in 2013. Actual readings at an AMI voltage meter (on Wing Rd) indicate a minimum service voltage of 117.5V. Due to these actual readings this project has been deferred to 2014.

Install (1) 100A, 7.97kV, regulator in the vicinity of P. 12 on Blackhall Rd. to be applied on phase C.

TOTAL PROJECT COST: $35,000

Circuit analysis indicates this project may is expected to increase primary voltage on Wing Rd to 119.4V in 2017.

8.9. Circuit 13W2: Install a Regulator on High St. – (2014)

Circuit models have identified that the primary voltage on Battle St. may get as low as 116.9V in 2014.

Install a 150A, 7.97kV regulator in the vicinity of P .159 on High St, to be applied to phase C.

TOTAL PROJECT COST: $35,000

Circuit analysis indicates this project is expected to increase primary voltage on Battle St. to 119.6V in 2017.

8.10. Circuit 37X1: Install a Regulator off Hannah Dustin Dr. – (2015)

Circuit analysis has identified that the primary voltage on Southwest Rd may get as low as 116.9 V in 2015.

Install a 100A, 13.8Y/7.97kV regulator in the vicinity of P. 5.

TOTAL PROJECT COST: $35,000

Circuit analysis indicates this project is expected to increase primary voltage on Southwest Rd to 122.2V.

8.11. Circuit 4W4: Install a Regulator on Hutchins St. – (2015)

Circuit analysis has identified that the primary voltage on District No.5 Rd may get as low as 116.9 in 2015. Loading on the Village St. 2/0 ACSR conductor may reach 90% in 2016. Actual readings at an AMI meter (on District No.5 Rd) indicate a minimum service voltage of 115V.

Install a 100A, 7.97kV, regulator in the vicinity of P.1 on Hutchins St. Transfer Snow St. and Manor St. taps from phase A to phase B.

TOTAL PROJECT COST: $35,000

Circuit analysis indicates this project is expected to increase primary voltage on Carter Hill Rd to 120.1V, but primary voltage before the regulator will be 119.3V in 2017. Loading on the 4W4, Village St, 2/0 ACSR may increase to 85% in 2017.

8.12. Circuit 6X3: Install a Regulator on Fisk Rd– (2015)

Circuit analysis has identified that the primary voltage on Fisk Rd may get as low as 116.9V in 2015. Actual readings at an AMI meter (on Fiskill Farm) indicate a minimum service voltage of 116.5V.

Install a regulator in the vicinity of P.10 on Fisk Rd

TOTAL PROJECT COST: $35,000

Circuit analysis indicates this project is expected to increase primary voltage on Fisk Rd to 119.2V in 2017.

8.13. Circuit 8X3: Upgrade Stepdown and Transfer Load on Horse Corner Rd – (2017)

Circuit analysis has identified primary voltage on Horse Corner Rd may get as low as 116.9 in 2017. The Bailey Rd stepdown, feeding load on Horse Corner Rd, has reached 96% of nameplate rating in 2011. The Horse Corner Rd 250kVA stepdown has reached 100% of nameplate rating in 2011.

Upgrade the 250kVA 19.9/7.97kV stepdown at P.160 on Horse Corner Rd to a 500kVA unit. Then, transfer the load downline of P.92 (including the Garvins Hill Rd tap) to this new transformer via the open point at P. 133 on Horse Corner Rd.

TOTAL PROJECT COST: $25,000

Circuit analysis indicates this project is expected to increase primary voltage on Horse Corner Rd to 118.1V and decrease loading on the Horse Corner Rd stepdown to 73% in 2017.

8.14. Circuit 15H3: Install Regulators on Commercial St. – (2017)

Circuit models have identified that the primary voltage on Delta Dr may get as low as 116.7V in 2017. Actual readings at an AMI meter (P.123/37) indicate a minimum service voltage of 119 V but using a calculated 1.5V drop from this location to the end of circuit gives an end of line service voltage of 117.5V.

Install (3) 300A, 2.4kV regulator in the vicinity of P .44 on Commercial St.

TOTAL PROJECT COST: $70,000

Circuit analysis indicates this is expected to increase end of line voltage to 117.9V.

9. Master Plan

This section describes a long range master plan for the UES-Capital system. The purpose of this plan is to provide strategic direction for the development of the electric distribution system as a whole. It does not, in and of itself, represent a cost-benefit justification for major system investments. Instead, it is intended to guide design decisions for various individual projects incrementally towards broader system objectives. The concepts detailed below should be considered in all future designs of the system. It is expected that this Master Plan will be modified, adjusted, and refined as system challenges and opportunities evolve.

This master plan has been separated into two different parts. The first part of the plan consists of an overview map of the UES distribution system. The second part of the master plan consists of more detailed future considerations. At this time some of these future considerations are not detailed.

9.1. Master Plan Map

The map in Appendix F identifies existing and future main line backbones at 34.5 kV, 13.8 kV and 4.16 kV. The map should be used as a tool when designing system improvement projects. Sections of conductor which have been identified as backbones will be constructed to 336.4 AA open wire conductor or equivalent and the appropriate insulation should be used, even if conditions do not require it at the time of construction. The distribution engineering department is currently developing guidelines for the use of spacer cable. At the time of this study, it is recommended that all new three-phase 34.5 kV construction be built with spacer cable for increased system reliability.

9.2. Future Considerations

This section of the master plan consists of several areas of the system which are known areas of potential concerns. Most of these considerations have been realized for quite some time but each one is still considered important from a system planning aspect. Residential load growth in general has generally been decreasing over the past few years. The same can be said for industrial and commercial load growth as well. All of this in combination has the potential to move some of the identified system improvements ahead in time.

9.2.1. Bow Area Load Growth

<u>Bow Bog 18T1</u>
Peak demand loading for the Bow Bog 18T1 transformer is projected to reach as much as much as 3039 kVA (91% of Normal limit) by the summer of 2013, and increase to as much as 3240 kVA (97% of Normal limit) by the summer of 2017, due to general load growth.

Three substations serve load in the southern part of the UES-Capital system; Bow Bog (18W2) with a 2.8 MVA padmount transformer, Bow Junction (7W3,7W4) with a 10.5 MVA transformer, and Iron Works Road (22W1, 22W2, 22W3) with a 10.5 MVA transformer. The total transformation capacity at these locations is just under 30 MVA (summer normal limit) with a combined June 2013 actual load of 20.9 MVA. Circuit forecasting projects this combined summer load to reach just under 22 MVA in 2017.

The existing substation is limited by transformer size (3.5 MVA Summer Normal limit) and underground #1/0 AL cables (174 A limit) exiting the substation. Iron Works, Bow Bog and Bow Junction substations were originally designed to back each other up in the event of a transformer failure. Bow Bog substation originally had two padmount transformers. One of the transformers failed so at that time 18W1 and 18W2 were tied at the substation creating one circuit (18W2). The Bow Bog area load is more residential as compared to the commercial/industrial load of the River Road and Johnson Road areas which are presently served by circuit 7W3 out of Bow Junction. For a new Bow Bog substation to serve this potentially greater industrial load, a large distribution improvement (mainline conductor upgrades) along Robinson Road would be required.

At this time the residential load growth seen in the past seems to have tapered off and as a result resent concerns regarding end of line voltage on 18W2 are no longer an issue for the time being. However, this may change in future years. To add ammunition to circuit analysis, actual field checks were performed in the past and have shown the voltage to be at reasonable level. Nonetheless, this area will be monitored closely in the future. The most cost effective solution to any potential voltage problems will be to install regulators out towards the end of the circuit. Further improvements include extending the mainline south along Woodhill Road, approximately 8,000 feet.

There are a few different ways to serve the load expansion in this area. The first alternative, which was done in summer 2011, consisted of installing a second 13.8kV circuit 7W4 from Bow Junction Substation. This was done in an effort to off load the Iron Works transformer by serving the majority of circuit 22W2 from Bow Junction, effectively splitting the load between the two transformers. This will mitigate transformer load through at least 2017.

A second alternative should it be required, is converting circuit 7W3 to 34.5kV. Some of the existing 13.8kV load will be served by stepdown transformers. Converting this circuit to 34.5kV may allow more load to be served in addition to providing better voltage support.

A third alternative requiring further study for is to build a new distribution substation down in the southern corner of the system. NU-PSNH has 34.5 kV lines which traverse the UES-Capital service territory serving load in the Manchester area from Garvins substation. The initial concerns with this approach are capacity constraints on the PSNH lines and property to build a substation. However, this would strategically place a distribution substation in the corner of the system with the ability to offload the Bow area load off of Bow Junction and Bow Bog substations. This approach would require a new system tie point with NU-PSNH. This alternative has yet to be discussed with NU-PSNH.

A fourth alternative for serving the Bow area would be to install a new substation transformer at Iron Works and splitting the load on 22W3 into two circuits, 22W3 and 22W4. This will require installing new breakers, voltage regulators and some bus work at Iron Works substation. For the existing configuration, circuit 22W3 comes out of the substation to Iron Works Road then crosses interstate 89 to feed Silk Farm Road. At Silk Farm Road, the circuit splits into two directions (East and West), the East side feeding towards Clinton Street which can be tied with circuit 22W1 and the West side feeding towards Bow Center Road which can be tied with circuit 18W2. The new transformer will carry circuit 22W3 and 22W4 leaving circuit 22W1 and 22W2 on the existing transformer. This will eliminate the overload concern on the existing Iron Works transformer and will also serve as a backup source for 21W1P, 7W3 and 18W2 circuits.

9.2.2. New Hollis Circuit – 8X4

The forecasted load on circuit 8X3 is approximately 12,665 kVA in the summer of 2013. This circuit has a tie to circuit 8X5 directly out of the substation; however, circuit 8X5 is also heavily loaded and projected to be at 9,490 kVA in the summer of 2013. The combined load served out of this substation is approximately 20% of the entire UES-Capital system load on peak.

Building a new 34.5 kV circuit out of a new substation, Broken Ground, is a first step toward resolving the issue of increasing size of the two existing 34.5 kV circuits, 8X3 and 8X5, the largest in the UES-Capital system. A new 34.5 kV circuit will eventually allow Hollis area loads to be re-distributed after additional improvements are completed. These additional improvements will be separate future projects detailed below.

The existing circuit along Old Loudon Rd, circuit 15W1, would be converted to 34.5kV and serve as part of the new 34.5kV circuits' mainline. The new circuit mainline would then be extended down Horse Corner Rd and serve as a second distribution circuit for the Chichester and Epsom area.

9.2.3. Circuit 4X1 – Bog Road Area

URD developments out at the end of circuit 4X1 will require converting to 34.5kV construction further out on the circuit. There are already several different regulator locations on this circuit; however the load in this area is projected to grow past the capability of the existing regulator locations. There is still a large amount of residential land available in this area. Once the Bow area is built out, residential building will increase in the area served by 4X1.

The plan in this area is to construct a 34.5 kV distribution loop from Bog Road, down Carter Hill Road, onto Lakeview Drive and connect back to the new 34.5 kV distribution on Little Pond Road. This would enable some of the 4X1 load to be transferred to adjacent circuits and reduce the voltage concerns on circuit 4X1.

9.2.4. Downtown Underground System

The downtown underground system consists of several circuits served at voltages of 34.5, 13.8 and 4kV. This system had encountered many different problems in the past couple of years. Most of these problems have been caused by the age and design of this system. The problems have consisted of multiple cable and connector failures. In addition, there have been switch failures.

The design of the underground system would not meet present design guidelines. The mainline cable loops through transformers instead of having a mainline cable with protected taps to each transformer. The underground system is predominantly served from Montgomery Street and Storrs Street transformers. These transformers have a summer rating of 11 MVA (460 A). The existing system is not operated over 150A due to the age of the system and past history of problems while operating the system closer to the 200A limit of the connectors.

All of the connections in the underground system are 200A non-loadbreak connectors. These connectors are stacked into “trees” in most of the manholes and cannot be properly secured together due to the quantity of connections. Over time, the receptacle end of the connectors has fatigued and the connectors have begun to burn due to poor electrical connections. In 2004, there were several connector failures. Some have resulted in outages and others were identified during manhole inspections.

Most of the 13.8kV cable was installed in the 1970’s. All of the cable is cross-linked poly. Many cable failures had led to testing of the failed cable by a cable manufacturer. The tests have indicated the insulation of cable sections tested had experienced an abnormal amount of treeing.

The future of the underground system will require capital investment to keep the system in reliable operating condition. The load growth in the downtown area is limited to predominantly increased air conditioner load. The first portion of the system which should be upgraded is the 13.8kV circuits. The mainline conductor should be increased to at least 350 kcmil Cu cable. All connections should be upgraded to 600A. The mainline of the circuits should be relocated so that it does not loop through transformers.

The 4kV system could have possible voltage and loading concerns given projected growth in the area is realized. Upgrading the 33X4 tap would allow for splitting part of West Concord load, which would give more opportunity for load shifting if need be on the 4kV system. An alternative to this is to upgrade 6X3 regulators and stepdown transformers which would allow Bridge St. and West Concord load to be transferred to 6X3. These are future considerations as the 4kV system has enough capacity to serve the load past 2017, given minor reconfigurations.

10. Conclusion

The projects identified in this study attempt address all of the system constraints that have been identified. The future of the UES–Capital system will rely predominantly on where load enters the system and growth occurs. In the future projects will continue to focus on improving system voltages and loading constraints to support long term system growth and improve circuit tie capability. Implementation of the master plan will enable the system to grow towards one common vision in a direct and cost effective manner. It is recognized that this study is a living document and it will be continually updated as the system's needs change or new system deficiencies are identified.

Appendix A

Summer and Winter Load Forecasts

UES-Capital
5-Year Load Forecast
2013-2017

	Winter Peak Loads (three-phase kVA)					Summer Peak Loads (three-phase kVA)				
	Projected					Projected				
Distribution Element	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2013**	**2014**	**2015**	**2016**	**2017**
Boscawen 13T1 Xfmr	4,014	4,059	4,105	4,151	4,196	4,133	4,254	4,375	4,496	4,618
13W1	1,330	1,345	1,360	1,375	1,391	1,273	1,288	1,302	1,317	1,331
13W2	2,813	2,845	2,877	2,909	2,941	3,020	3,131	3,243	3,354	3,466
Boscawen 13T2 Xfmr	3,675	3,717	3,758	3,800	3,842	3,725	3,878	4,031	4,184	4,337
13W3	3,675	3,717	3,758	3,800	3,842	3,725	3,878	4,031	4,184	4,337
Boscawen 13X4	2,470	2,470	2,470	2,470	2,470	2,681	2,681	2,681	2,681	2,681
Bow Bog 18T1 Xfmr	0	0	0	0	0	0	0	0	0	0
18W1	0	0	0	0	0	0	0	0	0	0
Bow Bog 18T2 Xfmr	2,805	2,837	2,869	2,901	2,932	3,039	3,089	3,139	3,189	3,240
18W2	2,805	2,837	2,869	2,901	2,932	3,039	3,089	3,139	3,189	3,240
Bow Junction 7X1	1,654	1,678	1,702	1,726	1,749	2,431	2,458	2,486	2,514	2,541
Bow Junction 7T2 Xfmr	7,312	7,395	7,478	7,562	7,645	8,744	8,844	8,943	9,043	9,142
7W3	5,110	5,168	5,226	5,284	5,342	5,907	5,974	6,041	6,109	6,176
7W4	2,202	2,227	2,252	2,277	2,302	2,837	2,870	2,902	2,934	2,966
Bridge Street 1T1 Xfmr	4,330	4,368	4,406	4,444	4,482	6,065	6,154	6,243	6,333	6,422
1H3	1,596	1,603	1,609	1,616	1,623	2,347	2,373	2,400	2,427	2,453
1H4	773	782	790	799	808	1,180	1,194	1,207	1,221	1,234
1H5	1,961	1,984	2,006	2,028	2,050	2,538	2,587	2,636	2,685	2,734
Bridge Street 1T2 Xfmr	3,856	3,966	4,076	4,186	4,296	5,419	5,505	5,591	5,678	5,764
1H1	2,106	2,196	2,286	2,376	2,466	2,769	2,825	2,882	2,938	2,994
1H2	875	885	895	905	915	1,428	1,444	1,461	1,477	1,493
1H6	875	885	895	905	915	1,253	1,267	1,282	1,296	1,310
Bridge Street 1X7P	1,814	1,834	1,855	1,875	1,896	2,874	2,903	2,932	2,961	2,990
Bridge Street 1X7A	1,952	1,974	1,997	2,019	2,041	2,838	2,867	2,896	2,926	2,955
Gulf Street 3T1 Xfmr	2,686	2,711	2,736	2,761	2,786	3,813	3,852	3,891	3,929	3,968
3H1	1,680	1,694	1,708	1,721	1,735	2,295	2,311	2,327	2,343	2,358
3H2	1,005	1,017	1,028	1,040	1,051	1,518	1,541	1,564	1,587	1,610
Gulf Street 3T2 Xfmr	1,066	1,078	1,090	1,102	1,115	1,589	1,607	1,625	1,643	1,661
3H3	1,066	1,078	1,090	1,102	1,115	1,589	1,607	1,625	1,643	1,661
Hazen Drive 24T1 Xfmr	1,414	1,430	1,446	1,462	1,478	1,050	1,062	1,074	1,086	1,098
24H1	1,414	1,430	1,446	1,462	1,478	1,050	1,062	1,074	1,086	1,098
Hazen Drive 24T2 Xfmr	2,005	2,028	2,050	2,073	2,096	1,955	1,977	2,000	2,022	2,044
24H2	2,005	2,028	2,050	2,073	2,096	1,955	1,977	2,000	2,022	2,044
24H3	2,005	2,028	2,050	2,073	2,096	1,955	1,977	2,000	2,022	2,044
Hollis 8T1 Xfmr	2,288	2,308	2,329	2,349	2,369	2,349	2,377	2,404	2,432	2,459
8H1	1,567	1,585	1,602	1,620	1,638	1,385	1,400	1,416	1,432	1,448
8H2	830	833	837	841	844	1,083	1,096	1,109	1,123	1,136
Hollis 8X3	11,283	11,412	11,540	11,668	11,796	12,665	12,785	12,905	13,025	13,144
Hollis 8X5	7,381	7,600	7,820	8,039	8,259	9,490	9,598	9,706	9,814	9,921
Iron Works Road 22T1 Xfmr	7,082	7,163	7,243	7,324	7,405	9,175	9,298	9,421	9,544	9,668
22W1	2,740	2,771	2,802	2,834	2,865	4,481	4,532	4,583	4,634	4,685
22W2	114	115	116	118	119	152	153	155	157	159
22W3	4,546	4,597	4,649	4,701	4,752	4,638	4,710	4,782	4,854	4,925
Langdon Street 14T1 Xfmr	1,361	1,376	1,392	1,407	1,422	1,658	1,682	1,705	1,729	1,753
14H1	374	379	383	387	391	414	424	434	444	454
14H2	1,108	1,120	1,133	1,145	1,158	1,341	1,356	1,372	1,387	1,402
Langdon 14X3 (McKerly's - Harris Hall (	570	577	583	590	596	787	815	843	872	900
Penacook 4X1	4,089	4,136	4,182	4,229	4,275	5,295	5,347	5,399	5,450	5,502
Penacook 4T3 Xfmr	7,181	7,222	7,262	7,302	7,342	8,844	8,955	9,067	9,179	9,290
4W3	3,030	3,065	3,099	3,134	3,168	3,563	3,579	3,595	3,610	3,626
4W4	4,249	4,255	4,261	4,268	4,274	5,281	5,377	5,472	5,568	5,664

UES-Capital
5-Year Load Forecast
2013-2017

	Winter Peak Loads (three-phase kVA)					Summer Peak Loads (three-phase kVA)				
	Projected					Projected				
Distribution Element	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2013**	**2014**	**2015**	**2016**	**2017**
Pleasant Street 6X3	7,861	7,991	8,120	8,249	8,379	10,803	11,046	11,289	11,532	11,775
Montgomery Street 23T1 Xfmr	1,741	1,761	1,780	1,800	1,820	5,102	5,160	5,218	5,276	5,334
21W1P	1,741	1,761	1,780	1,800	1,820	2,539	2,568	2,597	2,625	2,654
21W1A	1,741	1,761	1,780	1,800	1,820	2,563	2,592	2,621	2,651	2,680
Storrs Street 21T1 Xfmr	1,659	1,682	1,705	1,729	1,752	5,102	5,160	5,218	5,276	5,334
21W1P	0	0	0	0	0	2,539	2,568	2,597	2,625	2,654
21W1A	1,659	1,682	1,705	1,729	1,752	2,563	2,592	2,621	2,651	2,680
Terrill Park 16T1 Xfmr	1,968	1,991	2,013	2,036	2,058	3,125	3,155	3,185	3,215	3,245
16H1	1,064	1,076	1,088	1,100	1,112	1,487	1,504	1,521	1,538	1,555
16H3	1,210	1,224	1,237	1,251	1,265	1,638	1,651	1,664	1,677	1,690
Terrill Park 16X4	2,384	2,396	2,408	2,420	2,432	2,833	2,837	2,841	2,845	2,849
Terrill Park 16X5	1,905	1,927	1,948	1,970	1,991	2,163	2,163	2,163	2,163	2,163
Terrill Park 16X6	571	578	584	591	597	838	838	838	838	838
West Concord 2T1 Xfmr	3,909	3,953	3,997	4,042	4,086	4,486	4,608	4,730	4,852	4,974
2H1	991	1,003	1,014	1,025	1,036	1,551	1,558	1,566	1,573	1,580
2H2	2,070	2,093	2,117	2,140	2,164	2,332	2,389	2,447	2,504	2,562
2H4	1,298	1,313	1,327	1,342	1,357	1,256	1,331	1,406	1,481	1,556
West Portsmouth 15T1 Xfmr	3,533	3,562	3,591	3,621	3,650	4,848	4,903	4,958	5,013	5,067
15W1	2,426	2,453	2,481	2,508	2,536	3,268	3,305	3,342	3,379	3,415
15W2	1,107	1,109	1,111	1,112	1,114	1,580	1,598	1,616	1,634	1,652
West Portsmouth 15T2 Xfmr	856	863	870	877	885	1,119	1,131	1,144	1,157	1,170
15H3	856	863	870	877	885	1,119	1,131	1,144	1,157	1,170
33 Line - Little Pond Tap	126	128	129	131	132	175	177	179	181	183

Legend

loading < 50% of Normal Limit
50% ≤ loading ≤ 90% of Normal Limit
90% < loading ≤ 100% of Normal Limit
100% of Normal Limit < loading

Legend

loading < 50% of Normal Limit
50% ≤ loading ≤ 90% of Normal Limit
90% < loading ≤ 100% of Normal Limit
100% of Normal Limit < loading

Appendix B

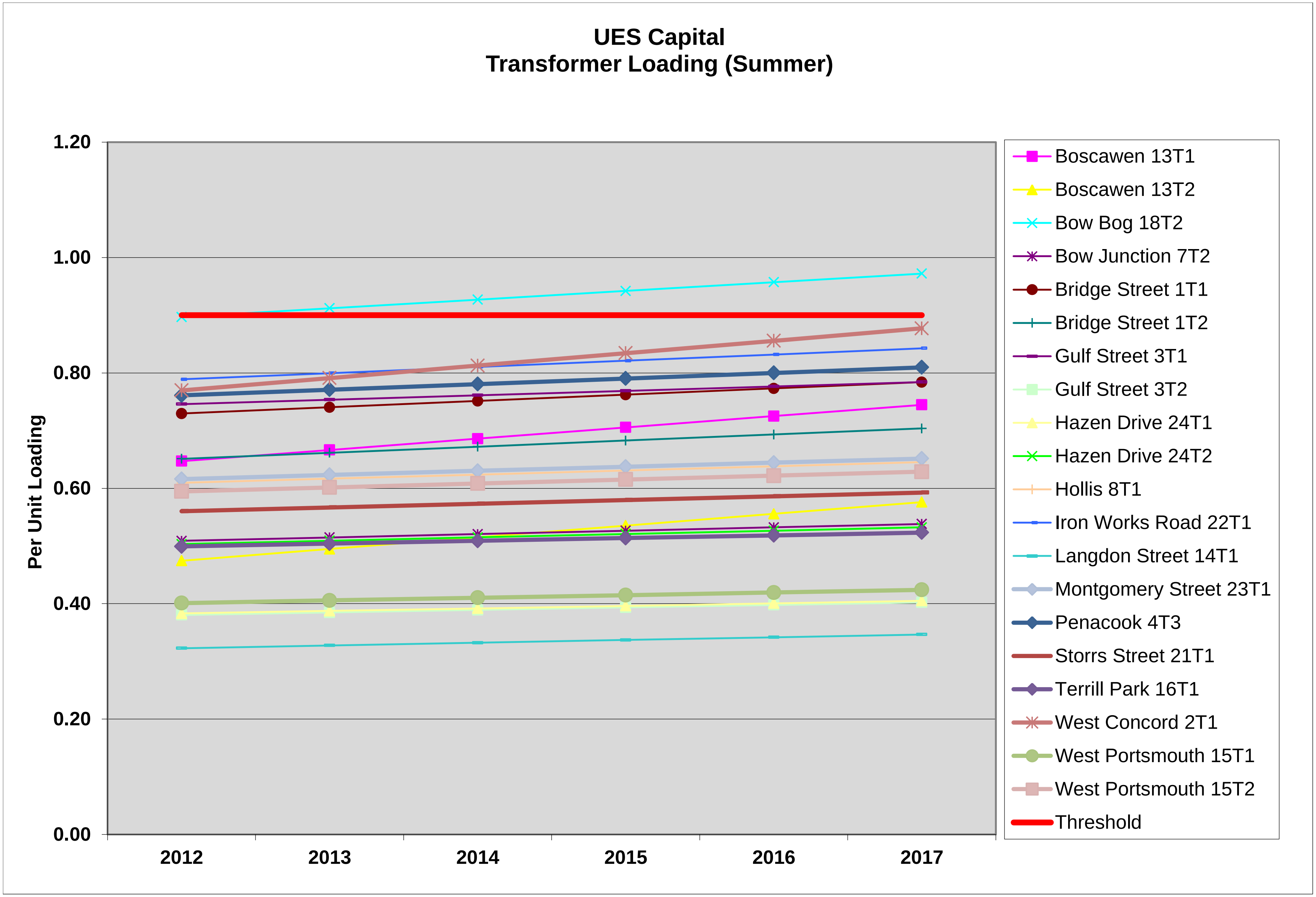
Distribution Circuit Limitations

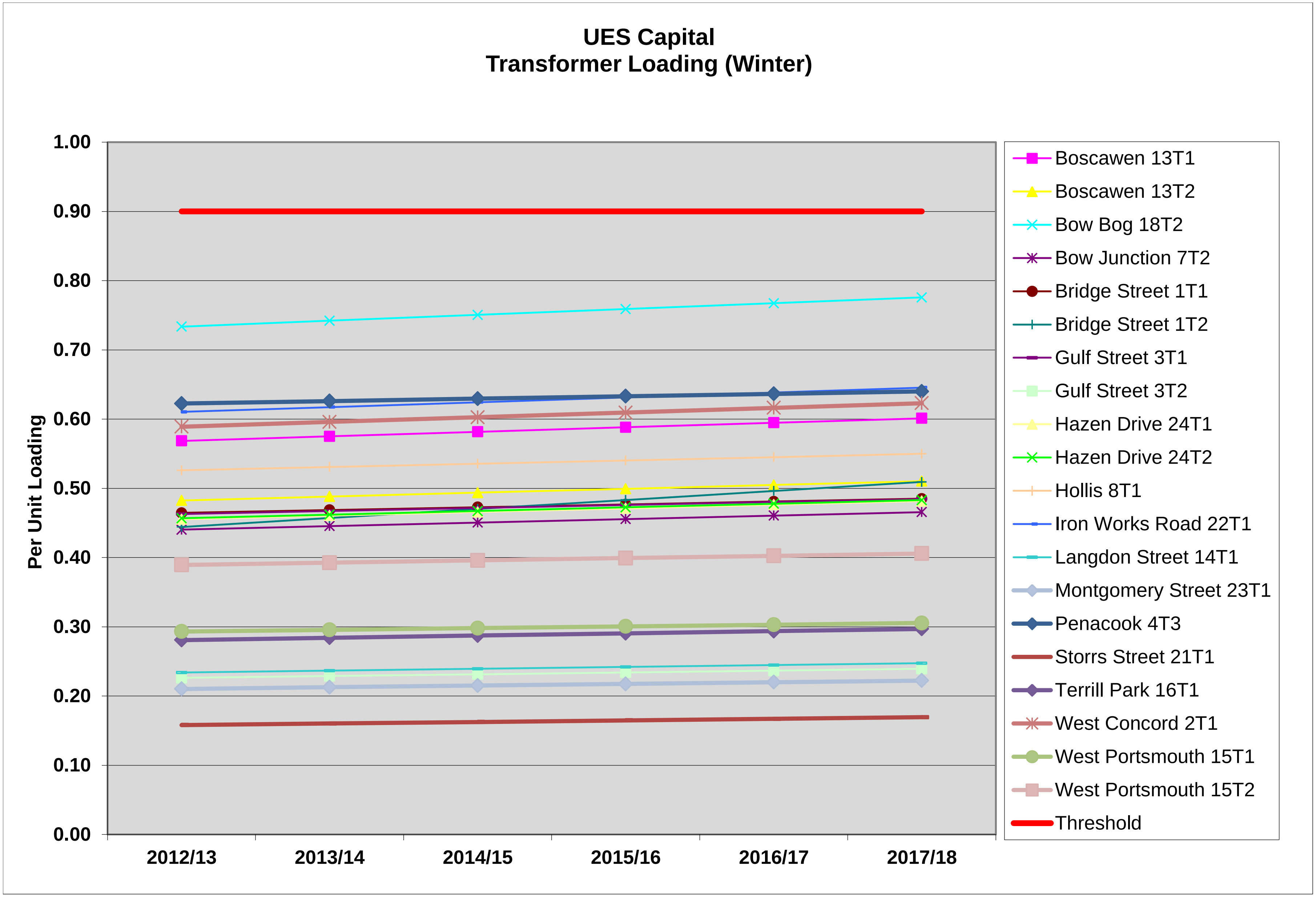
Distribution Element	Voltage Base	Breaker or Recloser Continuous Rating		Breaker or Recloser Trip Level		Current Transformer Present Tap Selection		Switch Continuous Rating		Fuse Minimum Melt		Regulator Rating		Conductor Rating		Transformer Rating		Overall Rating (kVA)		Overall Rating (A)		SCADA Alarm Operational	SCADA Alarm Emergency	Bypass: Fuse or Switch Min. Melt or Rating				Limiting Element	
	(kV)	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	High	High	Normal	LTE			Normal	LTE
Boscawen 13T1 Xfmr	13.8									365	365					259	264	6,200	6,320	259	264	233	264			8	8	Xfmr	Xfmr
13W1	13.8	560	560	224	252	300	300	600	600			240	240	179	215			4,279	5,139	179	215	161	215			7	7	Wire	Wire
13W2	13.8	560	560	224	252	300	300	600	600			240	240	370	438			5,354	5,737	224	240	202	240			2	6	Trip	Reg
Boscawen 13T2 Xfmr	13.8									315	315					343	353	7,529	7,529	315	315	284	315			5	5	Fuse	Fuse
13W3	13.8	560	560	224	252	600	600	600	600			393.6	459.2	531	645			5,354	6,023	224	252	202	252			2	2	Trip	Trip
Boscawen 13X4	34.5	560	560	272	306					202	202			247	294			12,071	12,071	202	202	182	202			5	5	Fuse	Fuse
Bow Bog 18T1 Xfmr	13.8																	0	0	0	0	0	0			9	9	?	?
18W1	13.8																	0	0	0	0	0	0			9	9	?	?
Bow Bog 18T2 Xfmr	13.8															139	141	3,332	3,375	139	141	125	141			8	8	Xfmr	Xfmr
18W2	13.8	560	560	160	180	600	600	200	200	280	280			174	174			3,824	4,159	160	174	144	174			2	7	Trip	Wire
Bow Junction 7X1	34.5	560	560	192	216	600	600							247	294			11,473	12,907	192	216	173	216			2	2	Trip	Trip
Bow Junction 7T2 Xfmr	13.8									480	480					516	529	11,473	11,473	480	480	432	480			5	5	Fuse	Fuse
7W3	13.8	800	800	384	432	600	600					393.6	459.2	531	645			9,178	10,326	384	432	346	432			2	2	Trip	Trip
7W4	13.8	800	800	480	540	600	600					589.2	687.4	531	645			11,473	12,907	480	540	432	540			2	2	Trip	Trip
Bridge Street 1T1 Xfmr	4.16									1659	1659					1137	1171	8,190	8,436	1137	1171	1023	1171			8	8	Xfmr	Xfmr
1H3	4.16	560	560	448	504							480	480	415	415			2,990	2,990	415	415	374	415			7	7	Wire	Wire
1H4	4.16	560	560	320	360							480	480	500	607			2,306	2,594	320	360	288	360			2	2	Trip	Trip
1H5	4.16	600	600	480	540							480	480	415	415			2,990	2,990	415	415	374	415			7	7	Wire	Wire
Bridge Street 1T2 Xfmr	4.16									1659	1659					1137	1171	8,190	8,436	1137	1171	1023	1171			8	8	Xfmr	Xfmr
1H1	4.16	560	560	448	504							480	480	531	645			3,228	3,459	448	480	403	480			2	6	Trip	Reg
1H2	4.16	560	560	448	504							480	480	325	325			2,342	2,342	325	325	293	325			7	7	Wire	Wire
1H6	4.16	560	560	320	360							480	480	531	645			2,306	2,594	320	360	288	360			2	2	Trip	Trip
Bridge Street 1X7P	34.5	560	560									160	160	174	174			9,561	9,561	160	160	144	160			6	6	Reg	Reg
Bridge Street 1X7A	34.5									80	80			174	174			4,780	4,780	80	80	72	80			5	5	Fuse	Fuse
Gulf Street 3T1 Xfmr	4.16									1211	1211					702	716	5,060	5,160	702	716	632	716			8	8	Xfmr	Xfmr
3H1	4.16	600	600	336	378							480	480	475	475			2,421	2,724	336	378	302	378			2	2	Trip	Trip
3H2	4.16	600	600	336	378							480	480	373	451			2,421	2,724	336	378	302	378			2	2	Trip	Trip
Gulf Street 3T2 Xfmr	4.16									663	663					573	587	4,130	4,230	573	587	516	587			8	8	Xfmr	Xfmr
3H3	4.16	560	560	400	450									325	385			2,342	2,774	325	385	293	385			7	7	Wire	Wire
Hazen Drive 24T1 Xfmr	4.16									647	647					376	383	2,710	2,760	376	383	338	383			8	8	Xfmr	Xfmr
24H1	4.16	560	560	384	432									247	294			1,780	2,118	247	294	222	294			7	7	Wire	Wire
Hazen Drive 24T2 Xfmr	4.16									1045	1045					533	544	3,840	3,920	533	544	480	544			8	8	Xfmr	Xfmr
24H2	4.16	1200	1200	384	432									385	385			2,767	2,774	384	385	346	385			2	7	Trip	Wire
24H3	4.16	1200	1200	384	432									385	385			2,767	2,774	384	385	346	385			2	7	Trip	Wire
Hollis 8T1 Xfmr	4.16									829	829					529	540	3,810	3,890	529	540	476	540			8	8	Xfmr	Xfmr
8H1	4.16	600	600	384	432	300	300							475	475			2,162	2,162	300	300	270	300			3	3	CT	CT
8H2	4.16	600	600	384	432	300	300							531	645			2,162	2,162	300	300	270	300			3	3	CT	CT
Hollis 8X3	34.5	560	560	448	504							668.8	668.8	373	451			22,289	26,950	373	451	336	451			7	7	Wire	Wire
Hollis 8X5	34.5	560	560	400	450							668.8	668.8	373	451			22,289	26,890	373	450	336	450			7	2	Wire	Trip
Hollis - Alton Woods URD	34.5									40	40			174	174			2,390	2,390	40	40	36	40			5	5	Fuse	Fuse
~~Hollis 38 Line~~	~~34.5~~			320	360													19,122	21,512	320	360	288	360			2	2	Trip	Trip
Iron Works Road 22T1 Xfmr	13.8									480	480					521	530	11,473	11,473	480	480	432	480			5	5	Fuse	Fuse
22W1	13.8	560	560									240	240	247	294			5,737	5,737	240	240	216	240			6	6	Reg	Reg
22W2	13.8	560	560	224	252							240	240	531	645			5,354	5,737	224	240	202	240			2	6	Trip	Reg
22W3	13.8	560	560			300	300					393.6	459.2	531	645			7,171	7,171	300	300	270	300			3	3	CT	CT
Langdon Street 14T1 Xfmr	4.16									1211	1211					702	716	5,060	5,160	702	716	632	716			8	8	Xfmr	Xfmr
14H1	4.16	560	560	448	504							480	480	463	562			3,228	3,459	448	480	403	480			2	6	Trip	Reg
14H2	4.16	560	560	448	504							480	480	537	653			3,228	3,459	448	480	403	480			2	6	Trip	Reg
Langdon 14X3 (McKerly's - *Harris Hall Cer*	34.5									40	40							2,390	2,390	40	40	36	40			5	5	Fuse	Fuse
Penacook 4X1	34.5	560	560	224	252					490	490			531	645			13,385	15,058	224	252	202	252			2	2	Trip	Trip
Penacook 4T3 Xfmr	13.8					600	600			480	480					521	530	11,473	11,473	480	480	432	480			5	5	Fuse	Fuse
4W3	13.8	400	400	320	360							240	240	415	415			5,737	5,737	240	240	216	240			6	6	Reg	Reg
4W4	13.8	400	400	320	360	400	400					393.6	459.2	283	336			6,764	8,031	283	336	255	336			7	7	Wire	Wire
Pleasant Street 6T1 Xfmr	4.16																	0	0	0	0	0	0			9	9	?	?
6H1	4.16																	0	0	0	0	0	0			9	9	?	?
Pleasant Street 6X3	34.5	800	800									241.2	281.4					14,413	16,815	241	281	217	281			6	6	Reg	Reg
Montgomery Street 23T1 Xfmr	13.8					600	600			343	343					377	388	8,187	8,187	343	343	308	343			5	5	Fuse	Fuse
21W1P	13.8							600	600					174	174			4,159	4,159	174	174	157	174			7	7	Wire	Wire
21W1A	13.8													174	174			4,159	4,159	174	174	157	174			7	7	Wire	Wire
Storrs Street 21T1 Xfmr	13.8									490	490					377	388	9,000	9,270	377	388	339	388			8	8	Xfmr	Xfmr
21W1P	13.8													174	174			4,159	4,159	174	174	157	174			7	7	Wire	Wire
21W1A	13.8	560	560											174	174			4,159	4,159	174	174	157	174			7	7	Wire	Wire
Terrill Park 16T1 Xfmr	4.16									1211	1211					860	877	6,200	6,320	860	877	774	877			8	8	Xfmr	Xfmr
16H1	4.16	560	560									480	480	340	411			2,450	2,961	340	411	306	411			7	7	Wire	Wire
16H2	4.16	560	560									480	480	531	645			3,459	3,459	480	480	432	480			6	6	Reg	Reg
16H3	4.16	560	560	448	504							480	480	531	645			3,228	3,459	448	480	403	480			2	6	Trip	Reg
Terrill Park 16X4	34.5	560	560	224	252													13,385	15,058	224	252	202	252			2	2	Trip	Trip
Terrill Park 16X5	34.5									90	90							5,378	5,378	90	90	81	90			5	5	Fuse	Fuse
Terrill Park 16X6	34.5									112	112							6,693	6,693	112	112	101	112			5	5	Fuse	Fuse
West Concord 2T1 Xfmr	4.16									1211	1211					787	811	5,670	5,840	787	811	708	811			8	8	Xfmr	Xfmr
2H1	4.16	600	600	336	378							480	480	283	336			2,039	2,421	283	336	255	336			7	7	Wire	Wire
2H2	4.16	600	600	336	378							480	480	475	475			2,421	2,724	336	378	302	378			2	2	Trip	Trip
2H3	4.16									200	200							1,441	1,441	200	200	180	200			5	5	Fuse	Fuse
2H4	4.16	560	560	320	360							480	480	373	451			2,306	2,594	320	360	288	360			2	2	Trip	Trip
West Portsmouth 15T1 Xfmr	13.8									500	500					520	528	11,951	11,951	500	500	450	500			5	5	Fuse	Fuse
15W1	13.8	600	600	248	279							240	240	240	289			5,737	5,737	240	240	216	240			6	6	Reg	Reg

Distribution Element	Voltage Base (kV)	Breaker or Recloser Continuous Rating		Breaker or Recloser Trip Level		Current Transformer Present Tap Selection		Switch Continuous Rating		Fuse Minimum Melt		Regulator Rating		Conductor Rating		Transformer Rating		Overall Rating (kVA)		Overall Rating (A)		SCADA Alarm		Bypass: Fuse or Switch Min. Melt or Rating				Limiting Element	
		Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Operational High	Emergency High	Normal	LTE			Normal	LTE
15W2	13.8	600	600	320	360							240	240	531	645			5,737	5,737	240	240	216	240			6	6	Reg	Reg
West Portsmouth 15T2 Xfmr	4.16									403	403					258	268	1,860	1,930	258	268	232	268			8	8	Xfmr	Xfmr
15H3	4.16													240	289			1,729	2,082	240	289	216	289			7	7	Wire	Wire
33 Line - Grappone Ford																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
33 Line - *Village Press ?*																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
33 Line - St. Paul's School	34.5									112	112							6,693	6,693	112	112	101	112			5	5	Fuse	Fuse
33 Line - *Jefferson Pilot ?*																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
33 Line - NH State Prison																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
33 Line - Little Pond Rd	13.8									263	263	120	140	141	168	17	17	400	400	17	17	15	17			8	8	Xfmr	Xfmr
34 Line - *Concord Center ?*																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
34 Line - Crowley Foods																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
35 Line - Locke Rd. tap																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
35 Line - *p.20 tap*																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
35 Line - *p.23 tap*																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
35 Line - *other? tap*																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
37X1	34.5													531	645			31,730	38,542	531	645	478	645			7	7	Wire	Wire
38 Line - Hollis to J-2	34.5	560	560	320	360													19,122	21,512	320	360	288	360			2	2	Trip	Trip
38 Line - J-2 to 35 Line	34.5			320	360													19,122	21,512	320	360	288	360			2	2	Trip	Trip
374 Line - (374A) So. Main St. Industrial Park																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
375 Line - *Flanders Office ?*																#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!			###	###	#DIV/0!	#DIV/0!
396 Line - Z-Tech	34.5									126	126							7,529	7,529	126	126	113	126			5	5	Fuse	Fuse

Appendix C

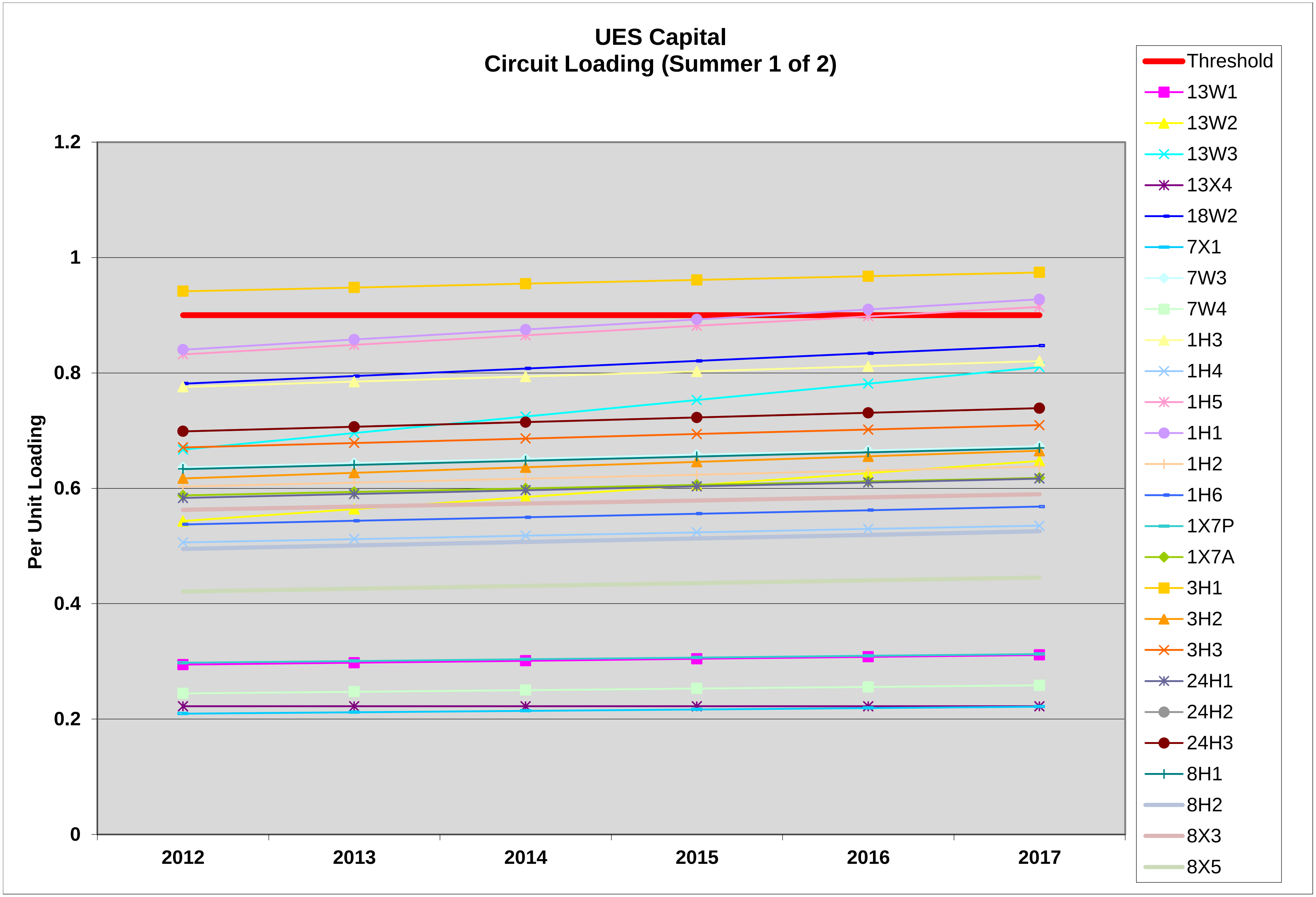
Transformer Loading Charts
(in Per Unit)

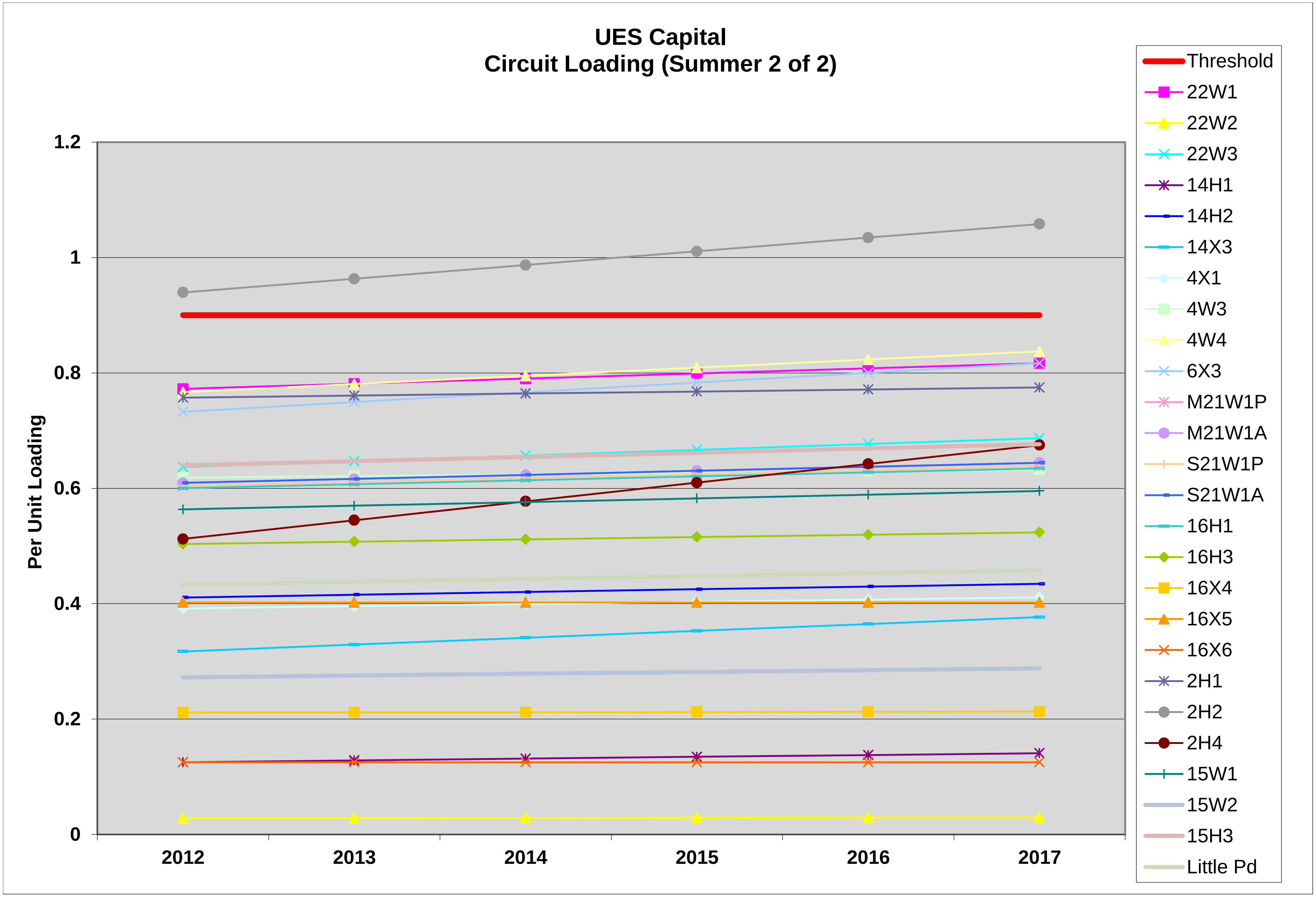

UES Capital
Transformer Loading (Summer)
Per Unit Loading
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2012
2013
2014
2015
2016
2017
Boscawen 13T1
Boscawen 13T2
Bow Bog 18T2
Bow Junction 7T2
Bridge Street 1T1
Bridge Street 1T2
Gulf Street 3T1
Gulf Street 3T2
Hazen Drive 24T1
Hazen Drive 24T2
Hollis 8T1
Iron Works Road 22T1
Langdon Street 14T1
Montgomery Street 23T1
Penacook 4T3
Storrs Street 21T1
Terrill Park 16T1
West Concord 2T1
West Portsmouth 15T1
West Portsmouth 15T2
Threshold


UES Capital
Transformer Loading (Winter)
Per Unit Loading
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Boscawen 13T1
Boscawen 13T2
Bow Bog 18T2
Bow Junction 7T2
Bridge Street 1T1
Bridge Street 1T2
Gulf Street 3T1
Gulf Street 3T2
Hazen Drive 24T1
Hazen Drive 24T2
Hollis 8T1
Iron Works Road 22T1
Langdon Street 14T1
Montgomery Street 23T1
Penacook 4T3
Storrs Street 21T1
Terrill Park 16T1
West Concord 2T1
West Portsmouth 15T1
West Portsmouth 15T2
Threshold

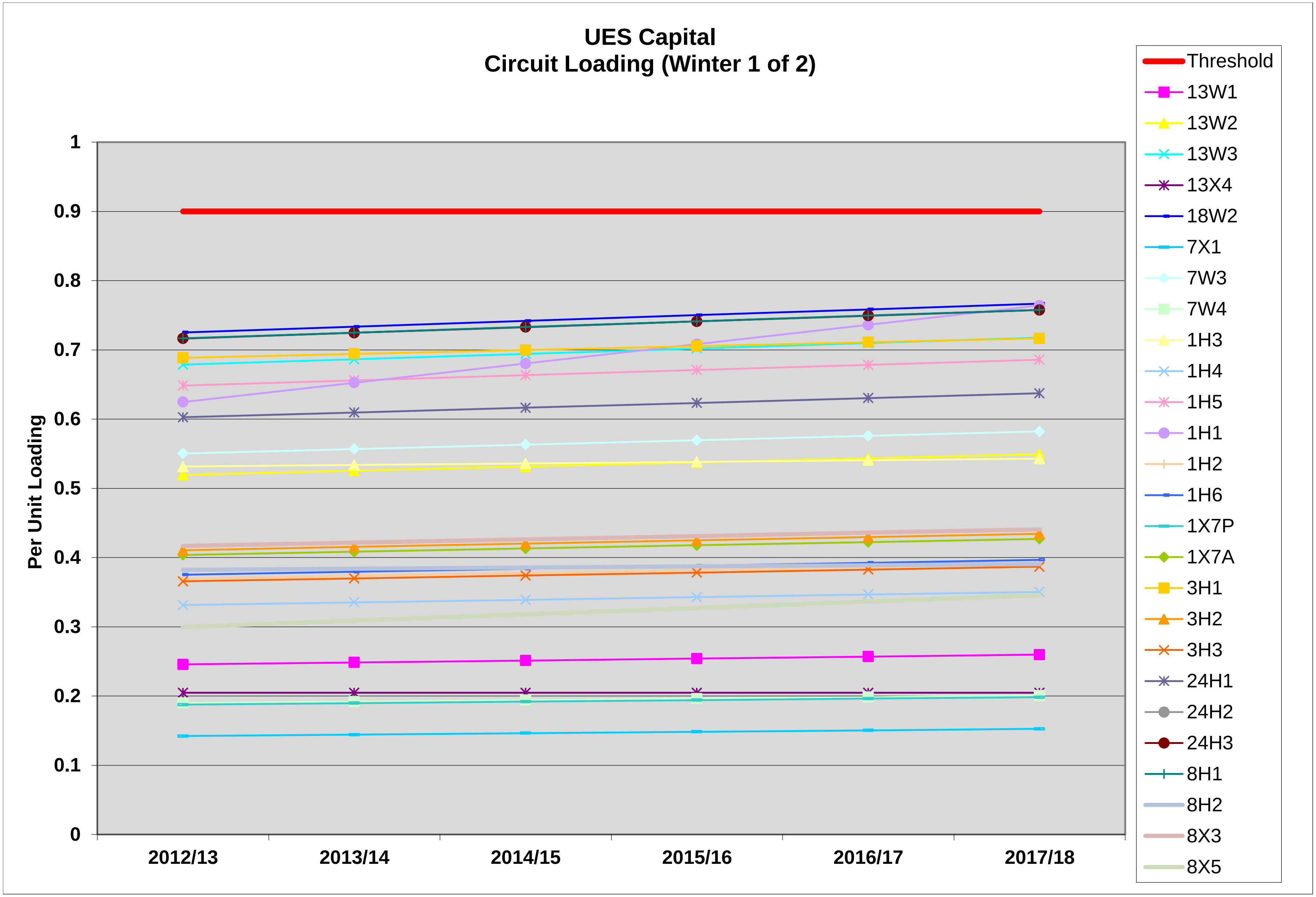
Appendix D

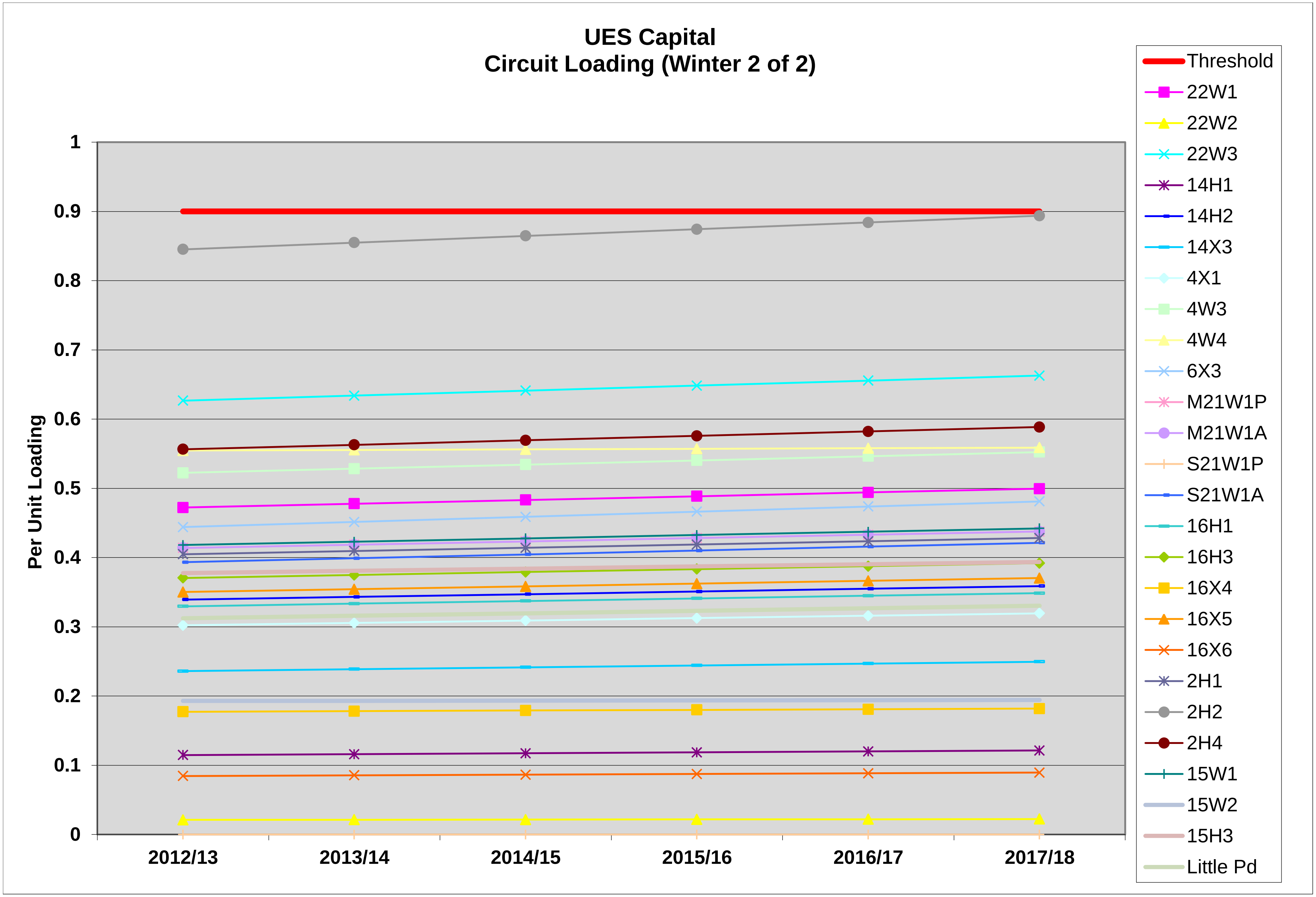
Circuit Loading Charts
(in Per Unit)


UES Capital
Circuit Loading (Summer 1 of 2)
Per Unit Loading
0
0.2
0.4
0.6
0.8
1
1.2
2012
2013
2014
2015
2016
2017
Threshold
13W1
13W2
13W3
13X4
18W2
7X1
7W3
7W4
1H3
1H4
1H5
1H1
1H2
1H6
1X7P
1X7A
3H1
3H2
3H3
24H1
24H2
24H3
8H1
8H2
8X3
8X5



UES Capital
Circuit Loading (Summer 2 of 2)
Per Unit Loading
0
0.2
0.4
0.6
0.8
1
1.2
2012
2013
2014
2015
2016
2017
Threshold
22W1
22W2
22W3
14H1
14H2
14X3
4X1
4W3
4W4
6X3
M21W1P
M21W1A
S21W1P
S21W1A
16H1
16H3
16X4
16X5
16X6
2H1
2H2
2H4
15W1
15W2
15H3
Little Pd


UES Capital
Circuit Loading (Winter 1 of 2)
Per Unit Loading
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Threshold
13W1
13W2
13W3
13X4
18W2
7X1
7W3
7W4
1H3
1H4
1H5
1H1
1H2
1H6
1X7P
1X7A
3H1
3H2
3H3
24H1
24H2
24H3
8H1
8H2
8X3
8X5



UES Capital
Circuit Loading (Winter 2 of 2)
Per Unit Loading
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Threshold
22W1
22W2
22W3
14H1
14H2
14X3
4X1
4W3
4W4
6X3
M21W1P
M21W1A
S21W1P
S21W1A
16H1
16H3
16X4
16X5
16X6
2H1
2H2
2H4
15W1
15W2
15H3
Little Pd

Appendix E

Protection Violations

Coordination Concerns:

Circuit	Protecting (down-line) Device			Protected (up-line) Device		
	Recloser/ Fuse	Pole	Street, Town	Recloser/ Fuse	Pole	Street, Town
2H1	150 N	p. 45-2	Keanes Ave., Concord	85 N	p. 45	Keanes Ave., Concord
3H1	20 N	p. 25	South St., Concord	75 N	p. 4	Concord St. Concord
13W1	30 N	p. 1	Randall Rd., Canterbury	100 N	p. 84	Old Tilton Rd., Canterbury
13W1	40 N	p. 36	Hackleboro Rd., Canterbury	50 N	p. 3	Hackleboro Rd., Canterbury
13W1	10 N	p. 17	Wilson Rd., Canterbury	30 N	p. 1	Wilson Rd., Canterbury
13W2	30 N	p. 94	Mill Rd., Salisbury	40 N	p. 1	W. Salisbury Rd., Salisbury
13W2	25 N	p. 109	Mill Rd., Salisbury	30 N	p. 94	Mill Rd., Salisbury
13W2	10 N	p. 4	Plains Rd., Salisbury	25 N	p. 109	Mill Rd., Salisbury
13W2	25 N	p. 198	Old Turnpike Rd., Salisbury	40 N	p. 145	Old Turnpike Rd., Salisbury
13W2	20 N	p. 1	Hollings Dr., Webster	40 N	p. 1	S. Lake Rd., Webster
13W2	65 N	p. 69	Battle St., Webster	75 N	p. 41	Battle St., Webster
13W2	25 N	p. 25	Multon Rd., Webster	40 N	p. 1	Multon Rd., Webster
13W3	75 N	p. 104	Queen St., Boscawen	75 N	p. 123	Queen St., Boscawen
13W3	25 N	p. 2	Bluebird Ln., Boscawen	75 N	p. 104	Queen St., Boscawen
13W3	40 N	p. 3	Eddy Dr., Boscawen	75 N	p. 112	King St., Boscawen
13W3	50 N	p. 3	Wellington Dr., Boscawen	75 N	p. 99	King St., Boscawen
8X3	Various locations have been found and will be addressed					

*

Sensitivity Concerns:

Circuit	Recloser/ Fuse	Pole	Street, Town	Sensitivity Ratio
none				

Unprotected Laterals:

Circuit	Pole	Mainline Street, Town	Lateral Street	# Sections
1H2	15	Centre St.	Pole# 15-B	1
1H2	7	Green St.	Greenwood St.	2
1H2	2	South State St.	Blake St.	1
1H2	2	South State St.	Pole# 2-A	1
1H2	1	South State St.	Pleasant St.	7
1H2	3	South State St.	Pole# 3-A	1
1H2	2	South State St.	Fayette St.	1
1H4	13	Ferry Rd.	Concord Moving & Storage	1
1H4	11	Horse Shoe Pond Rd.	Pole# 11-1	1
1H6	3	Theater St.	Storres St.	3
1H6	11	South State St.	Fayette St.	1
1H6	3	South State St.	Pole# 3-A	1
1H6	1	South State St.	Pleasant St.	6
1H6	2	South State St.	Blake St.	1
1H6	2	South State St.	Pole# 2-A	1
2H1	62	North State St.	Waverly St.	1
2H1	57	North State St.	Brooks Pharmacy	1
2H1	55	North State St.	Pole# 55-A	1
2H2	4	N. State St.	N/A	3
2H2	43	Rumford St.	Wymann St.	3
2H2	32	Rumford St.	Beacon St.	8
2H2	28	Rumford St.	Celtic St.	2
3H1	17	S. Main St.	N/A	1
3H1	21	S. Main St.	N/A	2
3H1	19	Concord St.	S. State St.	1
3H1	16	S. State St.	N/A	1
3H1	10	Thompson St.	South St.	1
3H1	10	Thompson St.	South St.	6
3H1	4	South Spring St.	Lincoln St.	2
3H1	3	South Spring St.	Oak St.	5
3H1	2	South Spring St.	Marshall St.	2

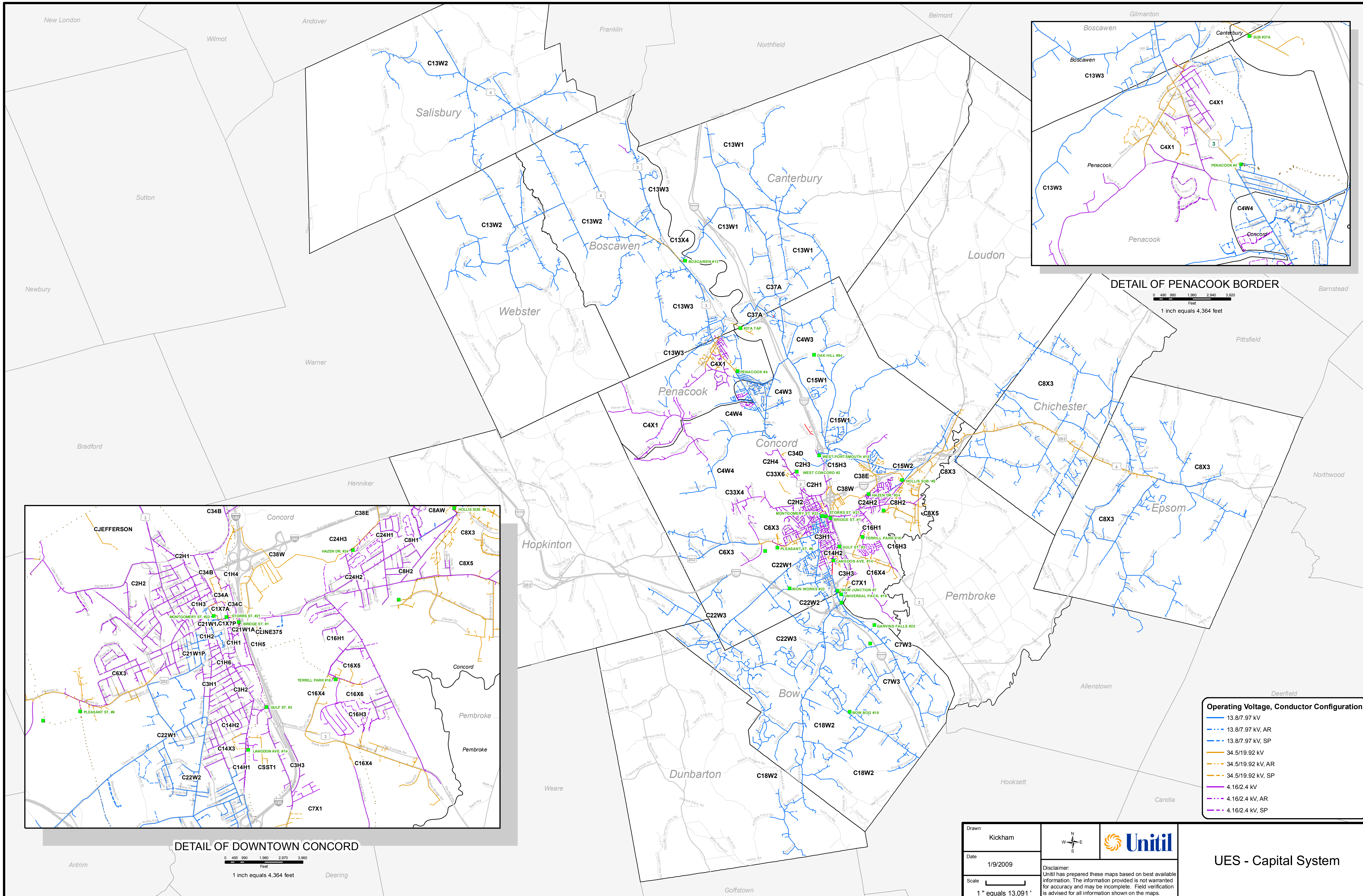
Circuit	Pole	Mainline Street, Town	Lateral Street	# Sections
3H1	13	South Spring St.	Thorndike St.	3
3H2	29	S. Main St.	Pole# 29-A	1
3H3	13	Hall St.	Hammond St.	3
8X3	38	Dover Rd.	N/A	2
8X5	19	Regional Dr.	Hodges Development Corp.	2
8X5	4	Regional Dr.	Pole# 4-1	1
13W1	57	West Rd.	Pole# 57-AB	3
13W3	6	Depot St.	All States Asphalt	4
13W3	135-S	King St.	Kapelli's INC.	1
14H1	78	S. Main St.	Wilfred Ave.	2
14H2	6-E	Langdon Ave.	N/A	5
14H2	55	S. Main St.	S. State St.	10

Note: The table above summarizes the unprotected laterals tapped directly off the mainline of distribution circuits identified in the UES-Unprotected Lateral Study. Only the circuits analyzed this year have had the UES-Unprotected Lateral Study findings detailed above.

For the purposes of this report, a distribution circuit main line is defined as all three phase sections of a distribution circuit that is currently protected by a substation recloser, breaker, or fuse.

Appendix F

Master Plan Map



Salisbury
Webster
Boscawen
Canterbury
Loudon
Penacook
Concord
Chichester
Epsom
Hopkinton
Pembroke
Bow
Dunbarton
New London
Wilmot
Andover
Franklin
Northfield
Belmont
Gilmanton
Sutton
Newbury
Warner
Bradford
Henniker
Barnstead
Pittsfield
Northwood
Allenstown
Deerfield
Hooksett
Candia
Weare
Antrim
Deering
Goffstown
C13W2
C13W3
C13X4
C13W1
C37A
C4W3
C15W1
C4X1
C4W4
C15W1
C8X3
C34D
C2H4
C2H3
C15H3
C33X6
C38E
C15W2
C2H1
C38W
C33X4
C2H2
C24H2
C8H2
C8X5
C6X3
C16H1
C3H1
C16H3
C14H2
C22W1
C3H3
C16X4
C7X1
C22W2
C22W3
C22W3
C7W3
C18W2
BOSCAWEN #13
#37A TAP
OAK HILL #94
PENACOOK #4
WEST PORTSMOUTH #11
WEST CONCORD #2
HOLLIS SUB #8
HAZEN DR. #24
STORRS ST. #21
MONTGOMERY ST. #23
BRIDGE ST. #1
TERRILL PARK #16
GULF ST. #3
PLEASANT ST. #6
LANGDON AVE. #14
IRON WORKS #22
BOW JUNCTION #7
UNIVERSAL PACK. #19
GARVINS FALLS #25
BOW BOG #18
DETAIL OF PENACOOK BORDER
Canterbury
SUB #37A
C4X1
C4W4
1 inch equals 4,364 feet
DETAIL OF DOWNTOWN CONCORD
CJEFFERSON
C34B
C38E
C8AW
C24H3
C24H1
C8H1
C8X3
C8X5
C1H4
C34A
C34C
C1X7A
C21W1,C1X7P
C21W1A
CLINE375
C1H1
C1H5
C21W1P
C1H6
C16X5
C16X6
C14X3
C14H1
CSST1
Operating Voltage, Conductor Configuration
13.8/7.97 kV
13.8/7.97 kV, AR
13.8/7.97 kV, SP
34.5/19.92 kV
34.5/19.92 kV, AR
34.5/19.92 kV, SP
4.16/2.4 kV
4.16/2.4 kV, AR
4.16/2.4 kV, SP
Drawn
Kickham
Date
1/9/2009
Scale
1 " equals 13,091 '
Unitil
Disclaimer:
Unitil has prepared these maps based on best available information. The information provided is not warranted for accuracy and may be incomplete. Field verification is advised for all information shown on the maps.
UES - Capital System

Unitil Energy Systems – Seacoast

Distribution System Planning Study 2013-2017

Prepared By:

Jake Dusling
Unitil Service Corp.
August 23, 2012

TABLE OF CONTENTS

1. Executive Summary

This study is an evaluation of the Unitil Energy Systems – Seacoast (UES–Seacoast) electric distribution system. The purpose of this study is to identify when system load growth is likely to cause main elements of the distribution system to reach their operating limits, and to prepare plans for the most cost-effective system improvements. The timeframe of this study is the summer peak load period over the next five years, from the summer of 2013 through the summer of 2017.

The following items will require action within the 5-year study period. All cost estimates provided in this report are without general construction overheads.

Year	Project Description	Justification	Cost
2013	**Plasitow/Atkinson Area Improvements**	**Various Loading Various Voltage**	**$1,520,000**
	Westville S/S – Install 2nd Transformer Westville S/S		$850,000
	Circuit 21W1 – Reconductor East Road		$210,000
	Circuit 5H1 – Transfer to 21W1		$250,000
	Circuit 13W2 – Install Regulators		$120,000
	Circuit 21W2 – Install Regulators		$90,000
	Circuit 3W4 – Reconductor Ocean Blvd / Add Stepdown Metering	Loading 109% Voltage 116.8 V	$200,000
	Circuit 11X2 – Install Regulators along Route 88	Voltage 111.3 V	$60,000
	Circuit 19X3 – Reconductor Newfields Road	Voltage 115.0 V	$190,000
	Circuit 22X1 – Phase Swaps Sandown Road	Voltage 115.6 V	Minimal
	Circuit 23X1 – Convert Amesbury Road – 27X1	Loading 100% Voltage 112.0 V	$340,000
	Circuit 28X1 – Rebuild Wakeda Campground Three-phase	Loading 99% Voltage 115.7 V	$85,000
	Circuit 56X1 – Convert Portion of Hunt Road	Loading 107% Voltage 113.5 V	$112,000
	Circuit 58X1 – Install Regulator Forrest Street	Voltage 116.8 V	$30,000
	Circuit 43X1 – Install Regulators Route 111	Voltage 115.8 V	$50,000
	Circuit 43X1 – Convert Kingston Road	Voltage 113.7 V	$360,000
	Hampton Beach S/S – Increase 3HT1 Trip Setting	Loading 93%	Minimal
2014	Circuit 3H2 – Load Transfer to Circuit 3H3	Loading 101% Voltage 116.0 V	Minimal
	Circuit 18X1 – Install Distribution Regulator	Voltage 115.0 V	$30,000
	Circuit 46X1 – Add Regulation along 46X1	Voltage 111.1 V	$120,000

2014	Circuit 59X1 – Install Regulator Goodwin Road	Voltage 116.8 V	$30,000
	Circuit 43X1 – Reconductor South Road	Voltage 116.6 V	$75,000
	Circuit 59X1 – Reconductor Exeter Road	Voltage 116.7 V	$150,000
	Circuit 1H4 – Load Balance	Voltage 116.8 V*	Minimal
2015	Circuit 22X1 – Phase Swap Sandown Road	Voltage 116.8 V	Minimal
	Circuit 6W1 – Convert Chase Road to 13.8 kV	Loading 127% Voltage 116.8 V*	$225,000
2016	Circuit 23X1 – Reconductor Beaverdam Road	Loading 99%	$75,000
	Circuit 19H1 – Install Voltage Regulator	Voltage 116.7 V*	$30,000
	Circuit 5H2 – Install Voltage Regulator	Voltage 116.8 V	$30,000
2017	Circuit 22X1 – Reconductor Pine Street and Upgrade Regulator	Loading 105%	$155,000
	Circuit 7X2 – Install Regulator Farm Lane	Voltage 116.7 V	$30,000

* Expected voltage based on 2012 AMI voltage measurements and projected load growth.

2. System Configuration

The UES–Seacoast distribution system is comprised of 44 distribution circuits operating at primary voltages of 4.16, 13.8 and 34.5 kV. The majority of these circuits originate from 15 distribution substations supplied off the UES–Seacoast 34.5 kV subtransmission system, while 12 circuits are tapped directly off subtransmission lines. Additionally, there are 2 customer-owned subtransmission line taps supplied off the 34.5 kV subtransmission system and a few other distribution taps off the subtransmission lines to serve single customers.

The UES–Seacoast 34.5 kV subtransmission system consists of 18 lines. Transmission service is taken from Northeast Utilities/Public Service Company of New Hampshire (NU/PSNH) at 34.5kV and delivered into the UES–Seacoast subtransmission system at three system supply substations –Timber Swamp substation, Kingston substation and Great Bay substation, with additional back-up ties available at UES–Seacoast's Guinea Switching substation, and from the NU/PSNH 3141X circuit at the 3141J12 tie switch in Danville.

3. Study Focus

This study is primarily focused on the 34.5, 13.8 and 4.16 kV distribution substations and circuits. System modifications are based upon general distribution planning criteria. An evaluation of the 34.5 kV subtransmission system is made under a separate electric system planning study.

The first objective of this distribution planning study is to identify and correct specific conditions that do not meet design or operating criteria. The second objective is to develop and communicate a master plan for the development of a robust and efficient distribution system to accommodate long-term improvement and expansion throughout and beyond the study years. Recommendations are based on system adequacy, reliability and economy among available alternatives.

4. Load Projections

A five year history of summer and winter peak demands for each individual circuit was developed from the monthly peak demand readings. A linear regression analysis was performed on the historical loads to forecast future peak demands for substation transformers, circuits and other major devices. Attempts were made to take into account known significant load additions, shifts in load between circuits, etc. In some instances, the peak loads did not present a confident trend over the historical period, so estimates were made using the best available information and knowledge of the circuit. In general, one standard deviation was added to these forecasts to account for differences from year to year in the severity of summer heat and other varying factors.

The following table shows the ten circuits with the highest estimated growth rates.

Ranking	Circuit	Loading Increase 2013-2017
1	11X1	19.6%
2	13W2	16.1%
3	5H1	15.7%
4	59X1	15.5%
5	47X1	14.6%
6	5H2	13.2%
7	6W1	13.1%
8	6W2	13.1%
9	11X2	12.7%
10	51X1	11.3%

The projection analysis can be referenced in Appendix A.

5. Rating Analysis

A detailed review of the limiting factors associated with each circuit was completed. The limiting factors included current transformer (CT), switch, circuit exit conductor, regulator, and transformer ratings and protective device settings. Overall circuit ratings are based upon the most restrictive of these limiting elements. Summer and winter peak load projections for the five year study period were compared to these circuit ratings. The distribution system circuit limitations can be referenced in Appendix B.

Projected loads reaching certain thresholds prompted a closer assessment of the conditions. Shading has been added to the projection analysis to provide a visual representation of potential problem areas.

Legend
loading < 50% of Normal Limit
50% ≤ loading ≤ 90% of Normal Limit
90% < loading ≤ 100% of Normal Limit
100% of Normal Limit < loading

6. Analysis and Findings

Transformer and circuit loadings have been compared to the limiting circuit elements. The monthly per phase transformer load readings are added together and then converted to kVA. In order to maintain some conservatism, those transformers and circuits which have reached 90% of the limiting factor have been highlighted and will be discussed later in the section. The threshold of 90% was taken to account for phase loading imbalance.

This section details the findings resulting from the analysis described in Section 5 as well as an analysis of stepdown transformer loadings and a review of circuit load phase imbalance. Individual project descriptions, justification, predicted benefits and associated cost estimates intended to address each of the identified issues are included in Section 8.

6.1. Substation Transformer Loadings

Transformers where the projected load reaches 90% or more of their seasonal rating are listed here. Summer and winter transformer loading graphs are included in Appendix C.

Plaistow 5T1
Peak demand loading for the Plaistow 5T1 transformer is projected to reach as much as 3,489 kVA (91% of summer normal rating) by the summer of 2013, and increase to as much as 3.982 kVA (104% of Normal limit) by the summer of 2017.

Westville 21T1
Peak demand loading for the Westville 21T1 transformer is projected to reach as much as 11,348 kVA (91% of summer normal rating) by the summer of 2014, and increase to as much as 12,093 kVA (97% of Normal limit) by the summer of 2017.

Additionally the 21T1 source side power fuses (FA21) are projected to reach as much as 11,099 kVA (97% of rating) by the summer of 2013, and increase to as much as 12,093 kVA (105% of rating) by the summer of 2017.

Hampton Beach 3HT1 Transformer Breaker
Peak demand loading for the Hampton Beach 3HT1 transformer breaker is projected to reach as much as 5,127 kVA (93% of phase overcurrent minimum pick-up flag) by the summer of 2013, and increase to as much as 5,467 kVA (99% of phase overcurrent minimum pick-up flag) by the summer of 2017.

6.2. Distribution Circuit Loadings

Those circuit elements where the projected load will reach 90% or more of their rating are listed below. Summer and winter circuit loading graphs are included in Appendix D.

Plaistow – Circuit 5H2
Peak demand loading for Circuit 5H2 out of Plaistow S/S is projected to reach as much as 2,455 kVA (341 A avg. per phase – 114% of Current Transformer 300:5 winding tap rating) by the summer of 2013, and increase to as much as 2,779 kVA (386 A avg. per phase – 129% of Current Transformer rating) by the summer of 2017.

Westville – Circuit 21W1
Peak demand loading for Circuit 21W1 out of Westville S/S is projected to reach as much as 6,544 kVA (274 A avg. per phase – 91% of Current Transformer 300:5 winding tap rating) by the summer of 2013, and increase to as much as 6,800 kVA (284 A avg. per phase) – 95% of Current Transformer rating) by the summer of 2017.

Timberlane – Circuit 13W2
Peak demand loading for Circuit 13W2 out of Timberlane S/S is projected to reach as much as 4,971 kVA (208 A avg. per phase – 93% of phase overcurrent minimum pick-up flag) by the summer of 2017.

6.3. Distribution Stepdown Transformer Loadings

The Summer Normal Limit used for distribution stepdown transformer loading analysis is 120% of the nameplate rating. This is based upon the "Normal Life Expectancy Curve" in ANSI/IEEE C57.91-latest. The ambient temperature assumed is 30°C (86°F).

The following table summarizes the distribution stepdown transformers that have been recently metered above nameplate. Shading has been added to the projections to provide a visual representation of potential overloads.

Legend

loading < 100% of Nameplate
100% < loading ≤ 120% of Nameplate
120% of Nameplate < loading

CIRCUIT / LOCATION	TOWN	POLE #	TRANSFORMER SIZE (kVA)			Recent Metered Peak			
			A	B	C	A	B	C	BANK
21W1 Meditation Lane	Atkinson	p. 56/33	167	167	167	60%	86%	101%	83%
56X1 Hunt Road (East)	Kingston	p. 65/8 & 9	500	500	500	94%	56%	119%	90%
58X1 Whitton Place	Plaistow	p. 107/3		333			103%		103%
O Street*	Hampton	p. 196/1	333	333	333	107%	33%	64%	68%
6W1 Chase Road*	South Hampton	p. 2/1	100			127%			127%
28X1 Route 88*	Hampton Falls	p. 12/124, 125 & 126	500	500	500	23%	119%	13%	51%
23X1 Amesbury Road*	Kensington	p. 1/141	500	500	500	44%	98%	120%	88%
58X1 Forest Street*	Plaistow	p. 35/1	167			118%			118%

* stepdown transformers that are not metered or were not read in 2011 but have been indicated by circuit analysis as possible overloads.

6.4. Phase Imbalances

All of the circuits within the UES-Seacoast service territory were reviewed for phase balance. The per phase loading for each circuit was averaged over a timeframe of January 2011 through December 2011. Circuits and substation transformers were ranked based upon the worst average phase imbalances (greatest deviation from the average).

In general, the goal for phase balancing is 10%. The following is a list of circuits, where the imbalance is greater than 20% which is considered severe. The circuits below will be looked at in more detail to determine the severity of the problem and EWRs will be issued to reduce the phase imbalances if required. It is important to note that the phase imbalance experienced by transformers will be reduced as the circuits fed from that transformer are balanced. The values listed below are an absolute seasonal average and do not take diversity factor into consideration.

Circuit	% Imbalance	Solution
2H1	38%	Transfer 25 kVA from Phase B to Phase A Transfer 50 kVA from Phase C to Phase A
7X2	37%	Transfer 250 kVA from Phase B to Phase A Transfer 150 kVA from Phase B to Phase C
46X1	33%	Transfer 125 kVA from Phase C to Phase A Transfer 50 kVA from Phase B to Phase A
47X1	27%	Transfer 200 kVA from Phase A to Phase C Transfer 100 kVA from Phase A to Phase B
2X3	22%	Transfer 100 kVA from Phase B to Phase A Transfer 50 kVA from Phase C to Phase A

7. Circuit Analysis Results

Circuit analysis is completed for the UES-Seacoast distribution system on a three year rotating cycle, where each circuit is reviewed once every three years. WindMil circuit analysis is used to identify potential problem areas. All identified problems should be followed up with verification from field measurements. Solutions to the deficiencies noted below are detailed in Section 8.

The following is a list of the circuits analyzed in 2012. Other circuits not shown on this listing were reviewed for planning purposes. However, those circuits were not part of the three year cycle.

Substation	Circuit	Substation	Circuit
Exeter S/S	1H3	Exeter Sw/S	19H1
	1H4		19X2
East Kingston S/S	6W1		19X3
	6W2	Shaw's Hill Tap	27X1
Portsmouth Ave S/S	11X1		27X2
	11X2	Mill Lane Tap	23X1
Willow Road Tap	43X1	Westville Road Tap	58X1

7.1. Voltage Concerns

Circuit analysis is set to identify areas where the voltage on the circuit goes outside of a pre-determined acceptable range. The acceptable range used for this analysis is 117-125 V on a 120 V base. The following table summarizes the areas where voltage is predicted to be outside of this range. The table is sorted by circuit and year.

Circuit	Year	Voltage	Location
1H4	2013	116.5 V	Front Street, Exeter
3H2	2013	116.0 V	C Street, Hampton
3W4	2013	116.8 V	Epping Road, Hampton
6W1	2013	115.0 V	Chase Road, South Hampton
13W2	2013	115.5 V	Peaslee Crossing Road, Newton
		116.0 V	Merrimac Street, Newton
		116.0 V	Bartlett Street, Newton
		115.8 V	Main Street, Newton
18X1	2013	115.0 V	Timber Swamp Road, Hampton
19H1	2013	115.4 V	Drinkwater Road, Kensington
19X3	2013	115.0 V	Newfields Road, Exeter
21W1	2013	116.3 V	Juniper Lane, Atkinson
	2015	116.8 V	Meditation Lane, Atkinson
21W2	2013	116.4 V	Industrial Way, Atkinson
22X1	2013	115.6 V	Sandown Road, Danville
	2015	116.8 V	Beechwood Drive, Danville
23X1	2013	As low as 112.0 V	Various Location beyond Amesbury Road Stepdowns, Kensington
		116.6 V	South Road, Kensington
28X1	2013	115.7 V	Wakeda Campground, Hampton Falls
43X1	2013	115.8 V	Route 111, Kingston
		113.7 V	Kingston Road, Exeter
	2014	116.6 V	South Road, Exeter
46X1	2013	As low as 111.1 V	Majority of Circuit
56X1	2013	113.5 V	Ordway Lane, Kingston
58X1	2013	116.8 V	Harriman Road, Plaistow
59X1	2014	116.7 V	Route 84, Hampton Falls
		116.8 V	Crank Road, Hampton Falls
	2016	116.7 V	Nason Road, Hampton Falls
5H2	2016	116.8 V	Sweet Hill Road, Plaistow
7X2	2017	116.7 V	Farm Lane, Seabrook

7.2. Overload Conditions

The following summarizes distribution equipment which is expected to be loaded above 90% of normal ratings during the five year study period. The table is sorted by circuit and year.

Circuit	Year	Percent Loading	Distribution Equipment (summer normal limit)	Location
3H2	2013	91%	Solid Blades (300 Amps)	Ashworth Ave, Hampton
		95%	Solid Blades (300 Amps)	Hobson Ave, Hampton
		101%	Solid Blades (300 Amps)	Church Street, Hampton
3W4	2013	109%	#6 Cu Conductor (130 Amps)	Ocean Boulevard, Hampton
5H2	2013	90%	168A Regulator (202 Amps)	Sweet Hill Road, Plaistow
21W1	2013	102%	1/0 ACSR Conductor (247 Amps)	East Road, Atkinson
	2017	91%	Solid Blades (300 Amps)	East Road, Atkinson
22X1	2013	93%	100 Amp AutoBoost (120 Amps)	Pine Street, Danville
	2015	91%	#6 Cu Conductor (130 Amps)	Pine Street, Danville
23X1	2013	94%	#6 Cu Conductor (130 Amps)	Beaverdam Road, Kensington
28X1	2015	90%	200 Amp Regulator (240 Amps)	Wakeda Campground, Hampton Falls
56X1	2013	107%	#1/0 ACSR Conductor (247 Amps)	Hunt Road, Kingston
		99% (83% of bank)	219A Regulators (263 Amps)	Hunt Rad, Kingston
43X1	2014	91%	#2 Cu Conductor (240 Amps)	Route 111, Exeter
59X1	2015	91%	#6 Cu Conductor (130 Amps)	Route 84, Hampton Falls

7.3. Protection Concerns

Analysis was performed on the circuits analyzed to identify areas that violate Unitil's distribution protection sensitivity and coordination criteria. These circuits were also studied to identify unprotected mainline laterals. A summary of these findings can be found in the table below. A detailed list of the devices and settings that do not meet these requirements can be found in Appendix E. These areas will be looked at in more detail and EWR's will be issued to address these concerns if required.

Circuit	# of Unprotected Laterals	# of Device Mis-Coordinations	# Sensitivity Concerns
1H3	None	3	None
1H4	7	None	None
6W1	1	7	None
6W2	2	None	None
11X1	3	3	None
11X2	None	4	None
19H1	2	None	1
19X2	2	2	None
19X3	None	13	1
23X1	None	1	None
27X1	None	None	None
27X2	None	None	None
43X1	None	7	None
58X1	None	11	None

8. Detailed Recommendations

The following sections detail system improvement projects to address the deficiencies listed above. All cost estimates provided in this report are without general construction overheads.

8.1. Plaistow/Atkinson Area Options – (2013)

Distribution load projections indicate that the 5T1 transformer at Plaistow substation is expected to exceed 91% of its normal summer rating in 2013, which is approximately 300 kVA below its normal limit and the 5H2 current transformers are expected to exceed 114% of their rating during the summer of the same year.

Projections also indicate that the 21T1 source side power fuses at Westville are expected to reach as much as 97% (400 kVA below their rating) of their rating in the summer of 2013 and the 21T1 transformer is expected to exceed 91% of its normal summer rating in 2014. The 21W1 current transformers are expected to exceed 91% of their rating during the summer of 2013.

The 13W2 breaker at Timberlane substation is expected to exceed 80% of its over current trip setting during summer conditions in 2017.

The primary voltage is expected to be as low as 116.8 V along Sweet Hill Road in Plaistow during the summer of 2016 and the Sweet Hill Road regulator is expecting reach 101% of its rating during peak conditions in 2013.

Circuit analysis indicates that the primary voltage at various locations on circuits 21W1 and 21W2 is expected to be as low as 116.4 V during summer conditions in 2013. Additionally, circuit analysis has identified that the #1/0 ACSR conductor along East Road is expected to exceed its normal summer rating in 2013 and the solid blades along East Road are expected to loaded to 91% of their rating during the summer of 2017. AMI voltage recording meters recorded service voltages of 112.9 V at 9 Juniper

Lane (21W1) on June 20, 2012 and 113.9 V at 29 Mill Stream Drive (21W2) on June 21, 2012.

Circuit analysis also indicates that the primary voltage at various locations on circuit 13W2 is expected to be as low as 115.5 V during summer conditions in 2013. An AMI voltage recording meter recorded a service voltage of 112.5 V at 19 Smith Corner Road on June 21, 2012.

Finally, Circuit 13W2 was the worst performing circuit in 2011 and has been on UES-Seacoast's worst performing circuit list three of the last five years. Several customers on this circuit experienced 10 or more outages from January 1, 2011 to December 31, 2011.

8.1.1. Add Capacity at Westville - Proposed

This project will consist of purchasing a new 7.5/10.5 MVA 34.5/19.92 kV to 13.8/7.97 kV substation transformer to be installed at Westville substation.

The remaining portion of #1/0 ACSR conductor (approximately 15 sections) on circuit 21W1 will be reconductored with 336 AA conductor and all solid blades along East Road Will be removed. New regulators will be installed along circuit 21W2 for voltage support.

A portion of circuit 5H1 will be transferred to circuit 21W1 to offload the Plaistow transformer and phase swaps will be performed along 5H2 to balance the load on the transformer. This load balancing will require two voltage regulators to be installed on circuit 5H2. The portion of Maple Street supplied by circuit 5H2 will be transferred to 5H1 to balance the load and customers between the two Plaistow circuits.

Additionally, two sets of three voltage regulators will be installed on circuit 13W2. One set to supply Whittier Street and the other set regulating Main Street. The Westville 21W1 and 21W2 current transformer ratios and the 21W2 over current trip setting will be increased as part of this project.

This project resolves all loading and voltage concerns throughout the five year study period and leaves the option for ether 13.8 kV or 34.5 kV expansion throughout this area in the future.

This project provides little reliability benefit for this area and transfers additional load to the 3358 line, which is a radial subtransmission line with no back-up. However, the overall cost of this project is significantly less than other options making it the proposed option.

Westville S/S:	$ 850,000
Reconductor East Road	$ 210,000
5H1 Transfer to 21W1	$ 250,000
13W2 Regulators	$ 120,000
21W2 Regulators	$ 90,000
Total Project Cost:	$1,520,000

8.1.2. Construct New Substation at Plaistow - Option

This project will consist of rebuilding Plaistow substation. Construction will include the construction of a new high voltage structure and the installation of a new a 7.5/10.5 MVA, 34.5 kV to 13.8 kV substation transformer. Two new 15 kV circuit bays will be constructed and populated with new reclosers and regulators for circuits 5H1 and 5H2.

Circuits 5H1 and 5H2 will be converted to 13.8 kV and the remaining portion of Smith Corner Road will be rebuilt to three-phase construction and converted to 13.8 kV. A portion of 13W2 will be transferred to circuit 5W2.

All load along the double circuited portion of 21W1 and 21W2 will be transferred to circuit 21W1 and circuit 21W2 will be used as an express circuit to supply the load beyond the double circuited portion of the Westville circuits. Circuit 21W1 will be transferred to circuit 5W1 to offload the Westville transformer. Three voltage regulators will be installed along circuit 21W2 as part of this project.

This project resolves all loading and voltage concerns throughout the five year study period and creates several circuit ties between the 13.8 kV circuits in this area.

Approximately 650 customers will be transferred from circuit 13W2 to circuit 5W2, saving interruptions to those customers for faults at Timberlane substation and along the main line of circuit 13W2. This transfers approximately 2 MW of load off the 3358 line, which is a radial subtransmission line with no back-up.

Plaistow S/S:	$1,050,000
5H1 and 5H2 Conversion:	$ 500,000
Smith Corner Road Rebuild	$ 350,000
21W2 Regulators	$ 90,000
Total Project Cost:	$1,990,000

8.2. Circuit 3W4: O Street Stepdown Alternatives – (2013)

Circuit analysis has identified a portion of #6 Cu conductor along Ocean Boulevard that could reach 109% of its normal conductor rating in the summer of 2013. The analysis has also indicated that the primary voltage will be as low as 116.8 V along Epping Road during the summer of the same year. Circuit analysis shows that the phase A stepdown on O street is expected to be loaded above nameplate during the summer of 2013. An AMI voltage recording meter recorded a service voltage of 113.4 V at 3 Ocean Boulevard on July 17, 2012.

<u>Reconductor Ocean Boulevard and Add Stepdown Metering – Proposed</u>
This project will consist of reconductoring approximately 3 sections of two-phase #6 copper conductor with #1/0 ACSR conductor. Stepdown metering will be installed at the O Street stepdowns to monitor stepdown loading.

Total Project Cost: $75,000

Convert to 13.8 kV operation – Alternative
This project will consist of converting from the O Street stepdown transformers to the end of the line to 13.8 kV operation. The existing stepdown transformers on O Street will be removed.

Total Project Cost: $200,000

8.3. Circuit 11X2: Install Regulators Route 88 – (2013)

An AMI voltage recording meter recorded a service voltage of 112.0 V at 48 Hampton Falls Road on June 21, 2012.

This project consists of installing three single phase voltage regulators along Route 88 in Exeter. Once complete the voltage along Hampton Falls Road is expected to be within planning guidelines until 2017 and beyond.

Total Project Cost: $ 60,000

8.4. Circuit 19X3: Reconductor Newfields Road and Load Balance – (2013)

Circuit modeling has indicated that the voltage at the end of Epping Road is expected to be as low as 115.0 V during summer peak conditions in 2013. An AMI voltage recording meter recorded a service voltage of 112.3 V at 75 Newfields Road on June 21, 2012.

This project will consist reconductoring approximately 25 sections of three-phase #6 copper conductor with new 336 AA conductor along Newfields Road. Load will be balanced downline of the Newfields Road stepdown transformers as part of this project. Once this project is complete voltages along Epping Road are expected to be within planning guidelines throughout the study period.

Total Project Cost: $190,000

8.5. Circuit 22X1: Phase Swaps Sandown Road – (2013)

Circuit analysis has indicated that the primary voltage on phase A may be as low as 115.6 V at prior to the Sandown Road voltage regulators in the summer of 2013.

Transferring all distribution transformers between the Sandown Road stepdown transformers and the voltage regulators currently supplied from phase A to phase B is expected to resolve the identified voltage concern throughout the study period.

Total Project Cost: Minimal

8.6. Circuit 23X1: Amesbury Road Alternatives – (2013)

Circuit analysis has indicated that the primary voltage at various locations beyond the Amesbury Road stepdown transformers will be as low as 112.0 V during summer conditions in 2013. Additionally, circuit analysis has identified that the phase C Amesbury Road stepdown transformer is expected to be loaded to 120% of nameplate and the stepdown bank could be loaded to 88% of nameplate during the summer of the same year. AMI voltage recording meters recorded service voltages of 108.6 V at 36 Muddy Pond Road on June 21, 2012 and 112.6 V at 35 Cottage Road on June 20, 2012.

Load balancing was considered to resolve these constraints, but did not achieve adequate results.

<u>Convert Amesbury – 27X1 – Proposed</u>
This project will consist of rebuilding approximately 35 sections of three-phase 4 kV construction along Amesbury Road, circuit 27X1 with new three-phase 35 kV spacer cable and converting to 34.5 kV operation. The existing 27X1 Amesbury Road stepdown transformers will be removed and new stepdown transformers will be installed on Trundlebed Lane and Amesbury Road.

Trundlebed Lane and a portion of Amesbury Road will be transferred from circuit 23X1 to circuit 27X1 as part of this project.

Marginally low voltage prior to the Stumpfield Road regulators will remain during summer peak conditions in 2016. However, new stepdown metering on Trundlebed will allow this area to be modeled in more detail and if the low voltage remains, regulators can be relocated/added to address the concern.

Total Project Cost: $340,000

<u>Convert Amesbury Road – 23X1 – Alternative/Option to Above</u>
This project will consist of rebuilding the 23X1 portion of Amesbury Road (65 sections) with 35 kV three-phase spacer cable construction and converting to 19.9 kV operation. Stepdown transformers will be installed on Cottage Road, Hampton Falls Road and Wild Pasture Road.

This project being constructed as an alternative to the option above will have additional stepdowns installed on Trundlebed Lane. Marginally low voltage prior to the Stumpfield Road regulators will remain during summer peak conditions in 2016. However, new stepdown metering on Trundlebed will allow this area to be model in more detail and if the low voltage remains, regulators can be relocated/added to address the concern.

If this is constructed as an optional adder to the proposed project above new gang operated switches will be installed at strategic sectionalizing locations on 23X1 and 27X1 and to create a circuit tie between 23X1 and 27X1

Total Project Cost: $740,000

8.7. Circuit 28X1: Rebuild Wakeda Campground Lateral to Three-Phase – (2013)

Circuit analysis has indicated that the primary voltage within Wakeda Campground is expected to be as low as 115.7 V during summer conditions in 2013. Circuit analysis also indicates that the phase B Route 88 stepdown is expected to be loaded to 119% of nameplate in the summer of the same year. Additionally, the Wakeda Campground regulator is expected to be loaded above 90% of its rating in the summer of 2015.

This project consists of rebuilding approximately 22 sections of the Wakeda campground lateral to three-phase and balancing the load. Once this project is complete the voltage and loading along circuit 28X1 is expected to be within planning guidelines throughout the study period and beyond.

Converting a portion of Route 88 and the Waked Campground lateral to 35 kV was considered as an alternative to this project. However, due to the heavily treed nature of the campground this was not a desirable option.

Total Project Cost: $85,000

8.8. Circuit 56X1: Hunt Road Alternatives – (2013)

Circuit analysis has indicated that the primary voltage beyond the Hunt Road stepdown transformers will be as low as 113.5 V during summer conditions in 2013. Circuit analysis has also identified that the Hunt Road regulators (Highest phase 99%) and the Hunt Road stepdown transformers (126% highest phase) are approaching their limit during the summer of the same year. Additionally, the #1/0 ACSR conductor along Hunt Road is expected to be loaded to 107% of rating during the summer of 2013. An AMI voltage recording meter recorded a service voltage of 114.6 V at 23 Ordway Lane on July 17, 2012.

Load balancing was considered as an to resolve these constraints, However load could not be adequately shifted to resolve all loading and voltage concerns.

Both alternatives described below are expected to resolve all loading and voltage concerns along circuit 56X1 throughout the scope of this study.

<u>Convert Portion of Hunt Road – Proposed</u>
This project will consist of rebuilding and converting approximately 10 sections of three-phase 4 kV construction along Hunt Road, 34.5 kV. The existing Hunt Road Stepdowns and regulators will be removed and new stepdowns and regulators will be installed on Newton Junction Road and Route 125. Approximately 2 spans of three-phase #6 copper wire along Route 125 will be reconductored as part of this project.

Total Project Cost: $112,000

<u>Convert Route 125 – Option to Above</u>
This project will consist of rebuilding and converting approximately 35 sections along Route 125 to 34.5 kV and creating a circuit tie with Dorre Road Tap circuit 56X2. Gang operated switches will be installed at strategic sectionalizing points and the circuit tie location.

Total Project Cost: $250,000

<u>Convert Transfer Portion of Route 125 to 56X2 – Alternative</u>
This project will consist of installing three stepdown transformers along Route 125 and transferring a portion of circuit 56X1 to circuit 56X2. A recloser and voltage regulators will be installed on circuit 56X2 at Dorre Road Tap as part of this project.

Installing regulators along Route 125 is an alternative to installing regulators at Dorre Road Tap. However, the Route 125 regulators will not provide long-term voltage support for the southern portion of circuit 56X2.

Total Project Cost: $375,000

8.9. Circuit 58X1: Install Regulator Forrest Street – (2013)

Circuit analysis has indicated that the primary voltage along Harriman Road in Plaistow may be as low as 116.8 V in the summer of 2013. An AMI voltage recording meter recorded a service voltage of 112.8 V at 32 Harriman Road on June 21, 2012.

This project consists of installing a voltage regulator along Forest Street on phase C. This project is expected to increase the end of line voltage on Harriman Road to 120 V in 2017.

Loading balancing was considered as an alternative to this project. However, due to large section of two phase construction, this did adequately address the voltage concern.

Total Project Cost: $30,000

8.10. Circuit 43X1: Install Regulator Route 111 – (2013)

Circuit analysis has indicated that the primary voltage along Route 111 in Kingston may be as low as 115.8 V in the summer of 2013. An AMI voltage recording meter recorded a service voltage of 103.1 V at 9 Chase Street on June 21, 2012.

Installing a voltage regulators on phase B and C along Route 111, swapping Chase Street to phase A and splitting the secondary crib on chase Street is expected to resolve the identified voltage concern throughout the study period.

Total Project Cost: $50,000

8.11. Circuit 43X1: Route 111/Kingston Road Alternatives – (2013)

Circuit analysis has indicated that the primary voltage at various locations beyond the Kingston Road stepdown transformers will be as low as 113.7 V during summer conditions in 2013. Additionally, circuit analysis has identified that the #2 copper conductor along Kingston Road is expected to exceed 90% of its conductor rating during summer peak conditions in 2014. An AMI voltage recording meter recorded a service voltage of 111.3 V at 35 Charter Street on June 21, 2012.

Load balancing was considered to resolve these constraints, but did not achieve adequate results.

<u>Convert Kingston Road to 34.5 kV – Proposed</u>
This project will consist of converting the remainder of Route 111/Kingston Road on circuit 43X1 to 34.5 kV operation in place of the existing 2.4 kV. The existing stepdown transformers will be removed and a circuit tie will be created with circuit 19X3. Once

this project is complete this portion of Kingston Road is expected to be well within planning criteria.

Total Project Cost: $360,000

Rebuild Washington Street 3 Phase 35 kV – Option to Above
This project will consist of rebuilding and converting approximately 15 sections along Washington Street to 34.5 kV and transferring Brentwood Road from circuit 19X3 to circuit 43X1. Gang operated switches will be installed at strategic sectionalizing points and the circuit tie location.

This optional adder reduces the exposure of circuit 19X3 and creates a circuit tie between 43X1 and 19X3 farther out on the distribution system than the tie created without this option.

Total Project Cost: $200,000

Convert Front Street to 34.5 kV and Transfer to 19X3 – Alternative
This project will consist of rebuilding and converting a portion of Front Street along circuit 43X1 to 34.5 kV and transferring it to circuit 19X3.

This is the least costly option to resolve the identified concerns. However, this is not preferred because it increases the customer exposure and overall circuit size of 19X3.

Total Project Cost: $250,000

8.12. Hampton Beach S/S: 3HT1 Trip Setting Alternatives – (2013)

Distribution load projections indicated that the trip setting of the 3HT1 breaker at Hampton Beach is expected to exceed 93% of the phase overcurrent pick-up flag during summer conditions in 2013.

Increase the Overcurrent Pick-Up Setting – Proposed
Increase to 3HT1 trip setting to achieve a rating that exceeds the transformer rating. This will require a protection review of the 4.16 kV portion of Hampton Beach substation.

Total Project Cost: Minimal

Convert Circuit 3H2 to 13.8 kV – Alternative (2014 if trip setting cannot be increased)
This project will consist of rebuilding and converting circuit 3H2 in its entirety to 13.8 kV and creating a circuit tie with circuit 3W4.

Total Project Cost: $350,000

8.13. Circuit 3H2: Load Transfer to Circuit 3H3 – (2014)

Circuit analysis has identified several cutouts with 300 amp solid blades along circuit 3H2 that are expected to reach as much as 101% of rating during summer peak conditions in 2013. The analysis has also indicated that the primary voltage could be as low as 116.0 V at the end of C Street in the summer of 2013. An AMI voltage recording meter recorded a minimum service voltage of 114.3 V along Ocean Blvd in 2012 allowing this project to be deferred until 2014.

This project will consist of transferring the C Street lateral from circuit 3H2 to circuit 3H3. Once the transfer is complete equipment loading and voltages are expected to remain below planning criteria through the five year study period.

Project Cost: Minimal

8.14. Circuit 18X1: Install Voltage Regulator – (2014)

Circuit analysis has indicated that the primary voltage may be as low as 115.0 V along Avery Ridge Lane in Hampton Falls during the summer of 2013. An AMI voltage recording meter recorded a service voltage of 114.4 V at 7 Avery Ridge Lane on July 17, 2012 allowing this project to be deferred until 2014.

This project consists of installing a single phase regulator along Old Stage Road in Hampton. Once complete the voltage along Avery Ridge Lane is expected to be within planning guidelines until 2017 and beyond.

Total Project Cost: $ 30,000

8.15. Circuit 46X1: Add Regulation to Circuit 46X1 – (2014)

Circuit analysis has indicated wide spread low voltage (as low as 111.1 V) along circuit 46X1 during summer peak conditions in 2013. This low voltage is due to a modeled source voltage of approximately 118 V obtained from the system planning study. An AMI voltage recording meter recorded a service voltage of 113.5 V at 6 Elaine Street on June 21, 2012. It has been decided to except minimal risk and defer this project until 2014.

This project will consist of installing two sets of three voltage regulators along High Street on circuit 46X1, one set regulating the voltage towards Ocean Blvd and other regulating towards Route 1.

Transferring 46X1 load to adjacent circuits and eliminating the Winnacunnet Road Tap was considered as an alternative to the above project. This would require significant circuit upgrades to other distribution circuits in the area, making it a significantly more costly option.

Total Project Cost: $120,000

8.16. Circuit 59X1: Install Regulator Goodwin Road – (2014)

Circuit analysis has indicated that the primary voltage along Crank Road and Goodwin may be as low as 116.8 V in the summer of 2014.

Installing a voltage regulator along Goodwin Road is expected to resolve the identified voltage concern throughout the study period.

Total Project Cost: $30,000

8.17. Circuit 43X1: Reconductor South Road – (2014)

Circuit analysis has indicated that the primary voltage at the end South Road, Brentwood is expected to be as low as 116.6V during summer conditions in 2014.

This project will consist of reconductoring approximately 10 sections of single-phase #6 copper conductor with 336 AA conductor.

Once completed the expected end of line voltage along South Road is expected to remain within planning limits throughout the scope of this study.

Total Project Cost: $75,000

8.18. Circuit 59X1: Reconductor Exeter Road – (2014)

Circuit analysis has indicated that the primary voltage along Route 84 will be as low as 116.7 V during summer conditions in 2014. Circuit models also have identified that the #6 copper wire along Exeter Road in Hampton Fall is expected reach 91% of its rating during summer peak conditions in 2015.

This project will consist of reconductoring approximately 20 sections of single phase #6 copper conductor with 336 AA conductor along Exeter Road/Route 84. Once this project is complete voltage along Route 84 is expected to be within normal limits throughout the study period.

Total Project Cost: $150,000

8.19. Circuit 1H4: Load Balance – (2014)

Circuit analysis has indicated that the primary voltage may be as low as 116.8 V along Front Street in Exeter during the summer of 2014.

This project will consist of swapping load from phase B to phase C along circuit 1H4.

This is expected to address voltage concerns along circuit 1H4 throughout the study period.

Total Project Cost: Minimal

8.20. Circuit 22X1: Phase Swaps Sandown Road – (2015)

Circuit analysis has indicated that the primary voltage along Beechwood Drive may be as low as 116.8 V in the summer of 2015.

Transferring Hummingbird Drive from Beechwood Estates to Fairview Drive is expected to resolve the identified voltage concern throughout the study period.

Total Project Cost: Minimal

8.21. Circuit 6W1: Convert Chase Road to 13.8 kV – (2015)

Circuit models have identified that the primary voltage along Chase Road in South Hampton is expected to be as low as 115.0 V in the summer of 2013. Circuit models also indicate that the Chase Road stepdown transformer is expected to be loaded to 127% during summer conditions of the same year. An AMI voltage recording meter recorded a service voltage of 117.5 V at 57 Chase Road on June 21, 2012 allowing this project to be deferred until 2015.

This project will consist of rebuilding from the Chase Road stepdown to the end of line to standard single-phase, 15 kV construction in place of the existing 4800 V ungrounded construction. Once this project is complete the voltage along Chase Road is expected to be within normal limits throughout the study period.

Total Project Cost: $225,000

8.22. Circuit 23X1: Reconductor Beaverdam Road – (2016)

Circuit analysis has identified a portion of #6 Cu conductor along Beaverdam Road in Kensington that could reach 99% of its normal conductor rating in the summer of 2016.

This project will consist of reconductoring approximately 10 sections of two-phase and single-phase #6 copper conductor with 336 AA conductor.

Total Project Cost: $75,000

8.23. Circuit 19H1: Install Voltage Regulator on Drinkwater Road – (2016)

Circuit analysis has indicated that the primary voltage on phase B may be as low as 115.4 V at the end of circuit 19H1 during the summer of 2013. An AMI voltage recording meter recorded a service voltage of 117.1 V at 6 Laurel Lane on June 21, 2012 allowing this project to be deferred until 2016.

This project consists of installing a voltage regulator along Drinkwater Road on phase B. This project is expected to increase the end of line voltage on Drinkwater Road to 122 V in 2017.

Loading balancing was considered as an alternative to this project. However, due to a single phase lateral being a majority of the load on phase B, this did adequately address the voltage concern.

Total Project Cost: $30,000

8.24. Circuit 22X1: Reconductor Pine Street and Upgrade Voltage Regulator – (2017)

Circuit models have identified that the #6 copper wire along Pine Street in Danville is expected reach 97% of its rating during summer peak conditions in 2017. Circuit Models also indicate that the Pine Street 100 amp AutoBoost is expected to exceed its rating during summer conditions of the same year.

This project will consist of reconductoring approximately 15 sections of single phase #6 copper conductor with #1/0 ACSR conductor along Pine Street. The existing 100 amp AutoBoost will be replaced with a voltage regulator as part of this project.

Once this project is complete all equipment loading and voltage concerns are expected to be within normal limits throughout the study period.

Total Project Cost: $155,000

8.25. Circuit 7X2: Install Regulator Farm Lane – (2017)

Circuit analysis has indicated that the primary voltage may be as low as 116.7 V along Farm Lane in Seabrook during the summer of 2017.

This project will consist installing a voltage regulator on Farm Lane in Seabrook. This project is expected to resolve the voltage concern along Farm Lane in 2017 and beyond.

Total Project Cost: $30,000

9. Master Plan

This section describes a long range master plan for the UES–Seacoast system. The purpose of this plan is to provide strategic direction for the development of the electric distribution system as a whole. It does not, in and of itself, represent a cost-benefit justification for major system investments. Instead, it is intended to guide design decisions for various individual projects incrementally towards broader system objectives. The concepts detailed below should be considered in all future designs of the system. It is expected that this Master Plan will be modified, adjusted, and refined as system challenges and opportunities evolve. Projects currently in construction that are expected to be completed in 2012 are assumed to be in service for the beginning year of this study.

This master plan has been separated into two different parts. The first part of the plan consists of an overview map of the Seacoast distribution system. The second part of the master plan consists of more detailed future considerations. At this time some of these future considerations are not detailed.

9.1. Master Plan Map

The map in Appendix G identifies existing and future main line backbones at 34.5 kV, 13.8 kV and 4.16 kV. The map should be used as a tool when designing system improvement projects. Sections of conductor which have been identified as backbones will be constructed to 336.4 AA open wire conductor or equivalent and the appropriate insulation should be used, even if conditions do not require it at the time of construction. At the time of this study, it is recommended that all new three-phase 34.5 kV construction in treed areas be built using spacer cable for increased system reliability. The following sections provide detailed descriptions of specific areas of the system.

8.1.1. Portsmouth Ave., Stratham

Portsmouth Ave. in its entirety will be converted to 34.5 kV three-phase main line construction creating ties to circuits 47X1 and 51X1.

8.1.2. Kingston, East Kingston, Kensington, and Hampton Falls

The Shaw's Hill 34.5 kV distribution tap is now comprised of 2 circuit positions. Portions of circuits 19X3, 23X1 and 19H1 will be transferred to this new source. This will provide circuit ties between circuits 27X1 and 27X2 to 23X1, 19X3, 19X2, 28X1 and 43X1.

Exeter Switching circuit 19H1 will be converted to 34.5 kV. This will involve the conversion of Drinkwater Road to the south and will create ties to circuits 27X1, 19X2.

Also Dow's Hill S/S and circuit 20H1 will be converted to 34.5 kV. This will involve the conversion of Route 27 and Route 88 and will create ties with circuits 18X1, 47X1 and 28X1.

In addition, Route 125 in Kingston will be converted to 34.5 kV. This will include converting portions of circuits 54X1, 22X1, 56X1 and 56X2 to allow the creation of circuit ties.

8.1.3. Hampton and Hampton Beach

Drinkwater road will be converted to 34.5 kV, creating a circuit tie between 2X3 and 28X1.

Hampton Beach substation and circuits 3H1, 3H2, 3H3 will be converted to 13.8 kV. Winnacunnet Road Tap will be eliminated and the circuit will be transferred to 17W1, 2X2 and 3H1. Circuit ties will be created between the Hampton Beach circuits and High Street circuits.

8.1.4. Atkinson, Plaistow and Newton

As part this concept, Plaistow S/S will be converted to 13.8 kV including all of circuits 5H1 and 5H2. This will create circuit ties to 13W1, 13W2 and possibly 21W1 and allow for the offloading of circuits 13W1 and 13W2 in the future.

Route 108 in Plaistow and Newton will be convert to 34.5 kV mainline to allow for a tie between 54X1 and 58X1.

Additionally, Route 125, Old County Road and Smith Corner Road will be converted to 34.5 kV, creating additional 34.5 kV supply to the Westville area and creating circuit ties with 58X1.

9.2. Future Considerations

This section of the master plan consists of several areas of the system which are known areas of potential concerns. Most of these considerations are driven by load growth in the area. Load growth has allowed in recent years, but industrial and commercial load or large residential developments have the potential to move some of the identified system improvements ahead in time.

9.2.1. Challenges of Stepdown Transformers

The UES–Seacoast system currently has a large number of stepdown transformers. These transformers, when heavily loaded, can create low voltage issues and protection challenges when trying to add protective devices or increase the size of existing devices.

One way to solve the issues created by stepdown transformers is to eliminate them whenever the opportunity presents itself, by way of voltage conversions or load transfers. Care should be taken to balance the short term benefits of stepdown transformers with longer term advantages of reliability, voltage performance, and economics.

9.2.2. Long Distances of Single-Phase 2.4 kV

The UES–Seacoast system was designed such that there are several areas of single phase 2.4 kV being supplied on small conductor, which was more than adequate at the time of construction. As load increases it becomes more difficult to keep voltage within normal limits at the end of these lines.
There are a few different ways to address the issue of single phase 2.4 kV. The first option consists of adding phases and balancing the load along the way. In most cases this is the most costly option, because it requires the addition of cross arms to the poles and more material than the options discussed below.

The second option is converting to a higher operating voltage. This allows for more load to be served on the same size conductor with less voltage drop over the same distance.

The final option to improve this situation would be to reconductor the existing lines with larger conductor. Reconductoring can be effective when used with voltage regulators as long as the area is built to a higher voltage class to allow for future voltage conversions. If the area of concern is identified as future circuit backbones, the line will need to be reconductored at the time of conversion anyway, so reconductoring prior to conversion is building toward the master plan. If the area of concern isn't identified as future circuit backbones, reconductoring along with voltage regulation may provide all of the load and voltage capacity needed while operating at historically more reliable lower system voltages.

The correct course of action to the concerns described above depends on the type and amount of load, as well as the long term plans for the area.

10. Conclusion

The projects identified in this study attempt to address all of the system constraints that have been identified. The future of the UES–Seacoast system will rely predominantly on where load enters the system and growth occurs. In the future projects will continue to focus on improving system voltages, by eliminating the bottle necks caused by stepdown transformers and single-phase 2.4 kV distribution. Implementation of the master plan will enable the system to grow towards one common vision in a direct and cost effective manner. It is recognized that this study is a living document and it will be continually updated as the system's needs change or new system deficiencies are identified.

Appendix A

Summer and Winter Load Forecasts

UES-Seacoast
5-Year Load Forecast
2013-2017

	Summer Peak Loads (three-phase kVA)					
	Projected					
Distribution Element	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Cemetery Lane 15X1	7,807	8,005	8,203	8,400	8,598	8,796
Dorre Road Tap 56X2	1,647	1,688	1,730	1,772	1,814	1,855
Dow's Hill 20T1	1,303	1,316	1,329	1,342	1,356	1,369
20H1	1,303	1,316	1,329	1,342	1,356	1,369
East Kingston 6T1	5,529	5,716	5,902	6,089	6,276	6,462
6W1	2,599	2,686	2,774	2,862	2,950	3,037
6W2	2,931	3,029	3,128	3,227	3,326	3,425
Exeter 1T1	1,764	1,810	1,855	1,901	1,946	1,991
Exeter 1T2	1,570	1,587	1,603	1,619	1,636	1,652
1H3	1,764	1,810	1,855	1,901	1,946	1,991
1H4	1,570	1,587	1,603	1,619	1,636	1,652
Exeter Switching 19T1	665	682	699	715	732	749
19H1	665	682	699	715	732	749
Exeter Switching 19X2	5,532	5,669	5,806	5,943	6,079	6,216
Exeter Switching 19X3	13,016	13,295	13,574	13,853	14,132	14,411
Guinea Road Tap 47X1	6,000	6,228	6,456	6,684	6,912	7,140
Guinea Switching 18X1	7,295	7,400	7,506	7,611	7,717	7,823
Hampton 2T1	1,137	1,164	1,191	1,217	1,244	1,271
2H1	1,137	1,164	1,191	1,217	1,244	1,271
Hampton 2X3	4,251	4,358	4,466	4,574	4,682	4,789
Hampton 2X2	9,421	9,659	9,898	10,137	10,376	10,614
Hampton Beach 3T1	5,042	5,127	5,212	5,297	5,382	5,467
3H1	2,048	2,095	2,141	2,188	2,235	2,282
3H2	1,979	1,989	1,999	2,010	2,020	2,030
3H3	1,287	1,319	1,352	1,384	1,417	1,450
Hampton Beach 3T3	4,172	4,274	4,376	4,478	4,580	4,682
3W4	4,172	4,274	4,376	4,478	4,580	4,682
High Street 17T1	5,870	6,022	6,175	6,327	6,480	6,633
17W1	3,915	4,014	4,114	4,213	4,312	4,411
17W2	2,119	2,177	2,234	2,292	2,350	2,407
Hunt Rd Tap 56X1	2,862	2,934	3,007	3,079	3,152	3,224
Kingston 22X1	5,774	5,925	6,076	6,227	6,379	6,530
Mill Lane Tap 23X1	4,229	4,330	4,430	4,531	4,632	4,733
Munt Hill 28X1	1,601	1,638	1,674	1,711	1,748	1,785
New Boston Rd. 54X1	4,279	4,378	4,478	4,577	4,677	4,777
Plaistow 5T1	3,351	3,489	3,613	3,736	3,859	3,982
5H1	1,405	1,480	1,538	1,596	1,654	1,712
5H2	2,374	2,455	2,536	2,617	2,698	2,779
Portsmouth Ave. 11X1	0	6,202	6,506	6,810	7,114	7,418
Portsmouth Ave. 11X2	11,003	5,272	5,439	5,606	5,774	5,941
Seabrook 7T1	3,458	3,545	3,633	3,720	3,808	3,896
7W1	3,458	3,545	3,633	3,720	3,808	3,896
Seabrook 7X2	6,008	6,161	6,313	6,465	6,617	6,770
Shaw's Hill Tap	2,692	2,759	2,825	2,892	2,958	3,025
27X1	2,032	2,083	2,133	2,183	2,233	2,284
27X2	660	676	692	708	725	741
Stard Road Tap 59X1	7,183	7,472	7,761	8,050	8,339	8,628
Timberlane 13T1	7,386	7,583	7,780	7,977	8,174	8,371
13W1	3,598	3,631	3,665	3,698	3,731	3,765
13W2	4,110	4,283	4,455	4,627	4,799	4,971
Timberlane 13X3	1,173	1,202	1,231	1,260	1,289	1,318

UES-Seacoast
5-Year Load Forecast
2013-2017

	Summer Peak Loads (three-phase kVA)					
	Projected					
Distribution Element	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Westville 21T1	10,851	11,099	11,348	11,596	11,844	12,093
21W1	6,159	6,287	6,415	6,544	6,672	6,800
21W2	5,223	5,356	5,488	5,620	5,753	5,885
Westville Tap 58X1	10,910	10,970	11,029	11,088	11,147	11,206
58X1E	5,145	5,183	5,221	5,258	5,296	5,334
58X1W	6,270	6,294	6,318	6,342	6,366	6,390
Willow Road Tap 43X1	6,253	6,412	6,570	6,729	6,887	7,046
Winnacunnet Road Tap 46X1	2,473	2,535	2,598	2,661	2,723	2,786
Winnicutt Road Tap 51X1	6,115	6,292	6,469	6,646	6,823	7,001

Legend

loading < 50% of Normal Limit
50% ≤ loading ≤ 90% of Normal Limit
90% < loading ≤ 100% of Normal Limit
100% of Normal Limit < loading

UES-Seacoast
5-Year Load Forecast
2013-2017

	Winter Peak Loads (three-phase kVA)					
	Projected					
Distribution Element	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Cemetery Lane 15X1	6,009	6,365	6,722	7,078	7,435	7,791
Dorre Road Tap 56X2	1,429	1,465	1,502	1,538	1,574	1,610
Dow's Hill 20T1	768	788	807	827	846	866
20H1	768	788	807	827	846	866
East Kingston 6T1	4,630	4,730	4,829	4,928	5,027	5,127
6W1	2,176	2,223	2,270	2,316	2,363	2,410
6W2	2,454	2,507	2,559	2,612	2,665	2,717
Exeter 1T1	1,437	1,480	1,524	1,567	1,610	1,654
Exeter 1T2	1,466	1,503	1,540	1,578	1,615	1,652
1H3	1,437	1,480	1,524	1,567	1,610	1,654
1H4	1,466	1,503	1,540	1,578	1,615	1,652
Exeter Switching 19T1	665	682	699	715	732	749
19H1	665	682	699	715	732	749
Exeter Switching 19X2	3,428	3,513	3,597	3,682	3,767	3,852
Exeter Switching 19X3	8,338	8,550	8,761	8,972	9,184	9,395
Guinea Road Tap 47X1	3,938	4,038	4,137	4,237	4,337	4,437
Guinea Switching 18X1	5,517	5,596	5,676	5,756	5,836	5,916
Hampton 2T1	517	530	543	556	570	583
2H1	517	530	543	556	570	583
Hampton 2X3	3,086	3,164	3,243	3,321	3,399	3,477
Hampton 2X2	6,131	6,287	6,442	6,598	6,753	6,908
Hampton Beach 3T1	2,512	2,575	2,639	2,703	2,766	2,830
3H1	1,257	1,289	1,321	1,352	1,384	1,416
3H2	434	445	456	467	478	489
3H3	821	842	862	883	904	925
Hampton Beach 3T3	2,601	2,664	2,728	2,791	2,855	2,918
3W4	2,601	2,664	2,728	2,791	2,855	2,918
High Street 17T1	4,335	4,492	4,648	4,805	4,962	5,118
17W1	2,865	3,009	3,153	3,297	3,440	3,584
17W2	1,648	1,667	1,686	1,706	1,725	1,744
Hunt Rd Tap 56X1	1,723	1,764	1,805	1,846	1,887	1,928
Kingston 22X1	4,639	4,760	4,882	5,003	5,125	5,246
Mill Lane Tap 23X1	2,866	2,934	3,002	3,071	3,139	3,207
Munt Hill 28X1	738	780	823	865	907	949
New Boston Rd. 54X1	3,167	3,248	3,328	3,408	3,488	3,569
Plaistow 5T1	2,440	2,502	2,563	2,625	2,687	2,749
5H1	1,202	1,226	1,251	1,275	1,300	1,324
5H2	1,605	1,645	1,686	1,727	1,767	1,808
Portsmouth Ave. 11X1	0	3,558	3,624	3,689	3,754	3,819
Portsmouth Ave. 11X2	7,169	3,722	3,767	3,813	3,859	3,905
Seabrook 7T1	1,471	1,509	1,546	1,583	1,620	1,658
7W1	1,471	1,509	1,546	1,583	1,620	1,658
Seabrook 7X2	3,780	3,876	3,971	4,067	4,163	4,259
Shaw's Hill Tap	2,165	2,220	2,275	2,329	2,384	2,439
27X1	1,634	1,676	1,717	1,759	1,800	1,842
27X2	530	544	557	571	584	598
Stard Road Tap 59X1	5,722	5,867	6,012	6,157	6,302	6,447
Timberlane 13T1	5,678	5,810	5,943	6,076	6,208	6,341
13W1	2,931	2,994	3,057	3,120	3,183	3,246
13W2	2,747	2,816	2,886	2,955	3,025	3,095
Timberlane 13X3	981	1,006	1,031	1,055	1,080	1,105

UES-Seacoast
5-Year Load Forecast
2013-2017

	Winter Peak Loads (three-phase kVA)					
	Projected					
Distribution Element	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Westville 21T1	6,551	6,717	6,883	7,049	7,215	7,381
21W1	3,826	3,923	4,020	4,117	4,214	4,311
21W2	2,820	2,892	2,963	3,035	3,106	3,178
Westville Tap 58X1	7,122	7,510	7,614	7,719	7,824	7,929
58X1E	3,577	3,577	3,577	3,577	3,577	3,577
58X1W	4,516	4,631	4,745	4,860	4,974	5,089
Willow Road Tap 43X1	4,403	4,435	4,468	4,500	4,532	4,564
Winnacunnet Road Tap 46X1	1,678	1,720	1,763	1,805	1,848	1,890
Winnicutt Road Tap 51X1	4,884	5,008	5,131	5,255	5,379	5,503

Legend

loading < 50% of Normal Limit
50% ≤ loading ≤ 90% of Normal Limit
90% < loading ≤ 100% of Normal Limit
100% of Normal Limit < loading

Appendix B

Distribution Circuit Limitations

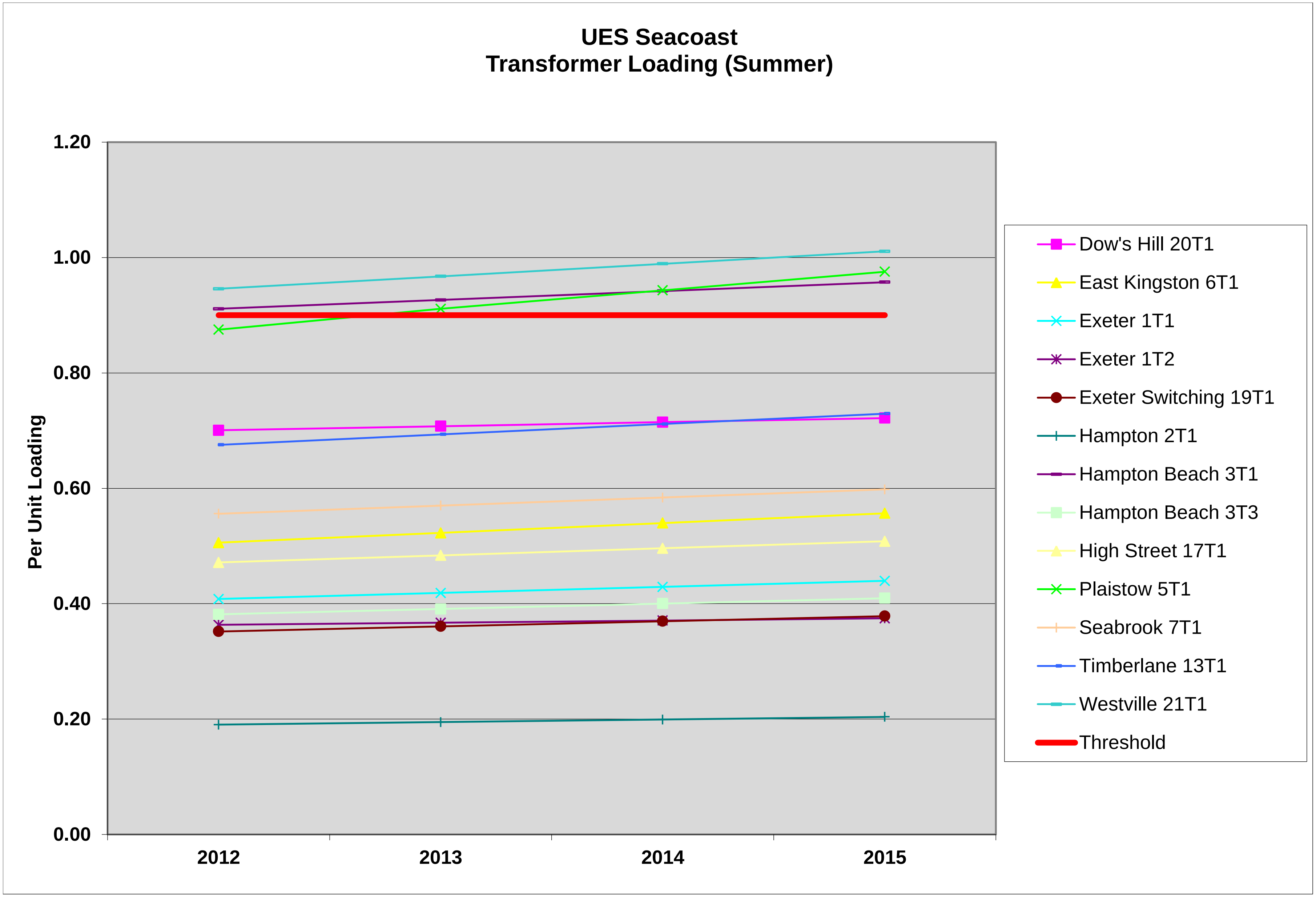
UES-Seacoast Summer Circuit Ratings

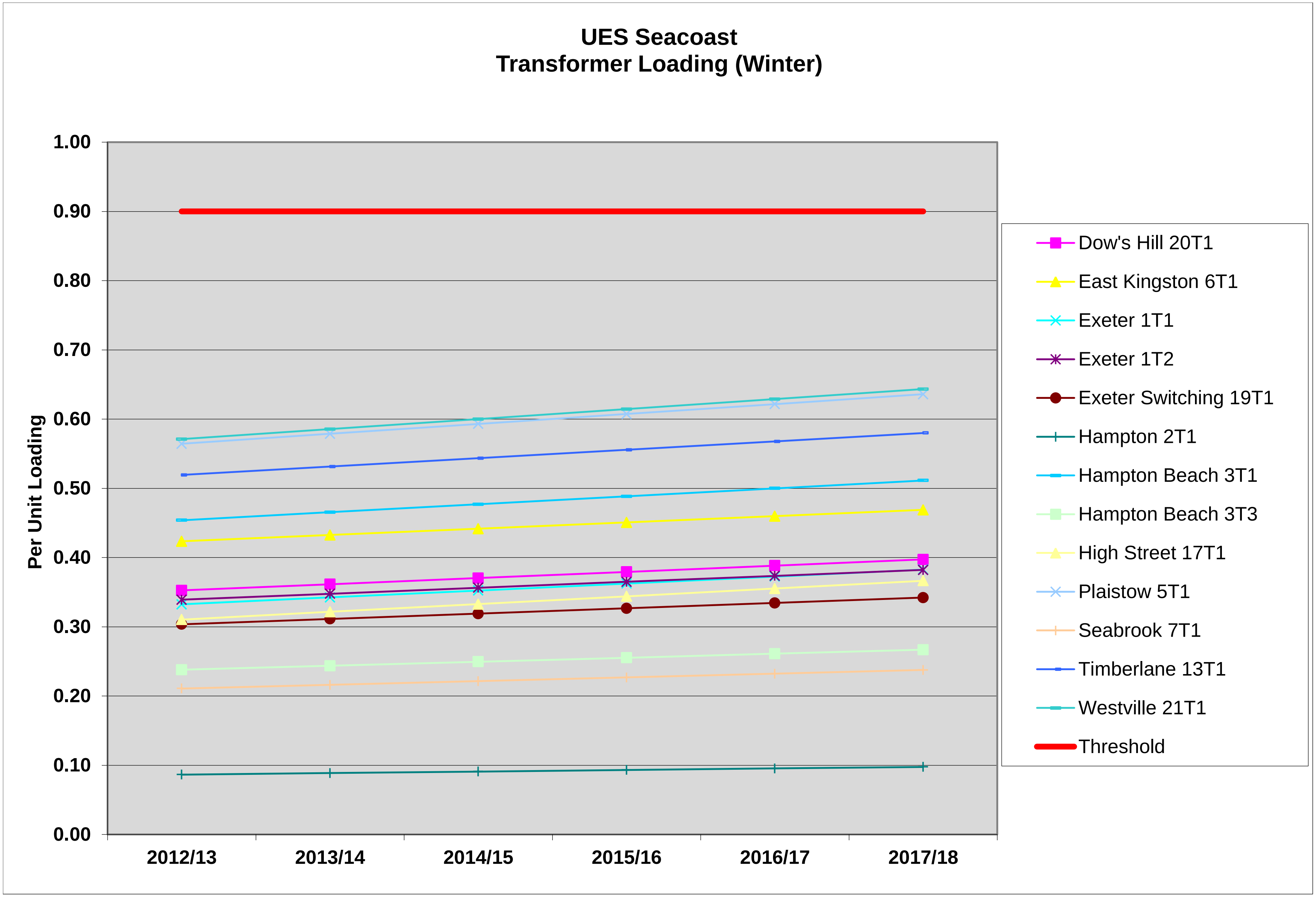
Distribution Element	Voltage	Breaker or Recloser				Current Transformer		Switch		Fuse		Regulator		Conductor		Transformer		Overall Rating		Overall Rating		Limiting	
	Base	Continuous Rating		Trip Level		Present Tap Selection		Continuous Rating		Continuous Rating		Rating		Rating		Rating		(kVA)		(A)		Element	
	(kV)	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE
Cemetary Lane 15X1	34.5	800	800	432	486	600	600	900	900			450	525	531	645			25,814	29,041	432	486	Trip	Trip
Dorre Road Tap 56X2	34.5							600	600	125	125			247	294			7,469	7,469	125	125	Fuse	Fuse
Dow's Hill 20T1	4.16									663	663					258	268	1,860	1,930	258	268	Xfmr	Xfmr
20H1	4.16	600	600	480	540	600	600	600	600			480	560	531	645			3,459	3,891	480	540	Trip	Trip
East Kingston 6T1	13.8									458	458					521	530	10,935	10,935	458	458	Fuse	Fuse
6W1	13.8	800	800	416	468			600	600			589	687	531	645			9,943	11,186	416	468	Trip	Trip
6W2	13.8	800	800	416	468							589	687	531	645			9,943	11,186	416	468	Trip	Trip
Exeter 1T1	4.16	1200	1200	768	864	600	600	900	900	1037	1037					623	636	4,323	4,323	600	600	CT	CT
Exeter 1T2	4.16	1200	1200	768	864	600	600	900	900	1037	1037					623	636	4,323	4,323	600	600	CT	CT
1H3	4.16	800	800	448	504			900	900					448	448			3,228	3,228	448	448	Trip	Wire
1H4	4.16	800	800	448	504			900	900					448	448			3,228	3,228	448	448	Trip	Wire
Exeter Switching 19T1	4.16									332	332	480	560			262	271	1,890	1,950	262	271	Xfmr	Xfmr
19H1	4.16	560	560	320	360	600	600	400	400			480	560	340	411			2,306	2,594	320	360	Trip	Trip
Exeter Switching 19X2	34.5	400	400	320	360	600	600	600	600			450	525	448	448			19,122	21,512	320	360	Trip	Trip
Exeter Switching 19X3	34.5	560	560	320	360	600	600	600	600			450	525	531	645			19,122	21,512	320	360	Trip	Trip
Guinea Road Tap 47X1	34.5	560	560	448	504	200	200	300	300			240	280	531	645			11,951	11,951	200	200	CT	CT
Guinea Switching 18X1	34.5	600	600	448	504	600	600							531	645			26,771	30,117	448	504	Trip	Trip
Hampton 2T1	4.16	1200	1200							829	829					860	877	5,976	5,976	829	829	Fuse	Fuse
2H1	4.16	560	560	448	504	600	600	600	600			802	935	340	411			2,450	2,961	340	411	Wire	Wire
Hampton 2X3	34.5	800	800	336	378	600	600	900	900			450	525	531	645			20,078	22,588	336	378	Trip	Trip
Hampton 2X2	34.5	800	800	336	378	600	600	400	400			450	525	531	645			20,078	22,588	336	378	Trip	Trip
Hampton Beach 3T1	4.16	1200	1200	768	864					1037	1037					863	879	5,534	6,225	768	864	Trip	Trip
3H1	4.16	600	600	576	648	600	600	900	900			802	935	531	645			3,826	4,323	531	600	Wire	Brkr/Rclsr
3H2	4.16	600	600	576	648	600	600	900	900			360	420	531	645			2,594	3,026	360	420	Reg	Reg
3H3	4.16	600	600	576	648	600	600	900	900			360	420	531	645			2,594	3,026	360	420	Reg	Reg
Hampton Beach 3T3	13.8					600	600			458	458					518	528	10,935	10,935	458	458	Fuse	Fuse
3W4	13.8	800	800	320	360	600	600	600	600			263	307	400	400			6,282	7,328	263	307	Reg	Reg
High Street 17T1	13.8									1518	1518					521	530	12,450	12,670	521	530	Xfmr	Xfmr
17W1	13.8	800	800	320	360	600	600	600	600			589	687	531	645			7,649	8,605	320	360	Trip	Trip
17W2	13.8	800	800	320	360	600	600	600	600			589	687	531	645			7,649	8,605	320	360	Trip	Trip
Hunt Rd Tap 56X1	34.5	800	800	300	337.5	600	600	600	600			270	315	531	645			16,134	18,823	270	315	Reg	Reg
Kingston 22X1	34.5	1200	1200	384	432	1200	1200	600	600					531	645			22,946	25,814	384	432	Trip	Trip
Mill Lane Tap 23X1	34.5	400	400	320	360	400	400					240	280	531	645			14,341	16,732	240	280	Reg	Reg
Munt Hill Tap 28X1	34.5	800	800	208	234	600	600	600	600			450	525	531	645			12,429	13,983	208	234	Trip	Trip
New Boston Rd. 54X1	34.5	800	800	288	324	600	600	600	600			241	281	531	645			14,413	16,815	241	281	Reg	Reg
Plaistow 5T1	4.16					600	600			979	979					532	541	3,830	3,900	532	541	Xfmr	Xfmr
5H1	4.16	1200	1200	480	540	300	300							470	470			2,162	2,162	300	300	CT	CT
5H2	4.16	1200	1200	480	540	300	300							470	470			2,162	2,162	300	300	CT	CT
Portsmouth Ave 11X1	34.5	800	800	296	333	600	600	600	600			450	525	531	645			17,688	19,899	296	333	Trip	Trip
Portsmouth Ave 11X2	34.5	800	800	296	333	600	600	600	600			450	525	531	645			17,688	19,899	296	333	Trip	Trip
Seabrook 7T1	13.8									1319	1319					260	265	6,220	6,330	260	265	Xfmr	Xfmr
7W1	13.8	800	800	640	720	600	600	900	900			263	307	531	645			6,282	7,328	263	307	Reg	Reg
Seabrook 7X2	34.5	800	800	208	234	600	600	900	900			200	234	531	645			11,975	13,971	200	234	Reg	Reg
Shaw's Hill Tap	34.5	800	800	256	288	600	600	600	600			450	525	531	645			15,297	17,210	256	288	Trip	Trip
27X1	34.5	800	800	256	288									531	645			15,297	17,210	256	288	Trip	Trip
27X2	34.5	800	800	256	288									531	645			15,297	17,210	256	288	Trip	Trip
Stard Road Tap 59X1	34.5	800	800	336	378			600	600			241	281	531	645			14,413	16,815	241	281	Reg	Reg
Timberlane 13T1	13.8					600	600			458	458					523	532	10,935	10,935	458	458	Fuse	Fuse
13W1	13.8	560	560	448	504	300	300	600	600			524	612	531	645			7,171	7,171	300	300	CT	CT
13W2	13.8	560	560	224	252	300	300	400	400			263	307	531	645			5,354	6,023	224	252	Trip	Trip
Timberlane 13X3	34.5	800	800	192	216			800	800			241	281	531	645			11,473	12,907	192	216	Trip	Trip
Westville 21T1	13.8					600	600			480	480					521	530	11,473	11,473	480	480	Fuse	Fuse
21W1	13.8	560	560	448	504	300	300	600	600			589	687	531	448			7,171	7,171	300	300	CT	CT
21W2	13.8	560	560	304	342	300	300	600	600			589	687	554	554			7,171	7,171	300	300	CT	CT
Westville Tap 58X1	34.5	560	560			300	300	300	300			241	281					14,413	16,815	241	281	Reg	Reg
58X1E	34.5	800	800	400	450									531	645			23,902	26,890	400	450	Trip	Trip
58X1W	34.5	800	800	160	180									663	808			9,561	10,756	160	180	Trip	Trip
Willow Road Tap 43X1	34.5	560	560	448	504	200	200					270	315	531	645			11,951	11,951	200	200	CT	CT
Winnacunnet Road Tap 46X1	34.5	560	560	160	180	100	100	300	300					531	645	60	60	3,600	3,600	60	60	Xfmr	Xfmr
Winnicutt Road Tap 51X1	34.5	800	800	600	675			900	900					531	645			31,730	38,542	531	645	Wire	Wire

Distribution Element	Voltage Base (kV)	Breaker or Recloser Continuous Rating		Breaker or Recloser Trip Level		Current Transformer Present Tap Selection		Switch Continuous Rating		Fuse Minimum Melt		Regulator Rating		Conductor Rating		Transformer Rating		Overall Rating (kVA)		Overall Rating (A)		Limiting Element	
		Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE	Normal	LTE
Cemetary Lane 15X1	34.5	800	800	432	486	600	600	900	900			544	525	694	777			25,814	29,041	432	486	Trip	Trip
Dorre Road Tap 56X2	34.5							600	600	125	125			322	354			7,469	7,469	125	125	Fuse	Fuse
Dow's Hill 20T1	4.16									663	663					303	321	2,180	2,310	303	321	Xfmr	Xfmr
20H1	4.16	600	600	480	540	600	600	600	600			580	560	694	777			3,459	3,891	480	540	Trip	Trip
East Kingston 6T1	13.8									458	458					580	580	10,935	10,935	458	458	Fuse	Fuse
6W1	13.8	800	800	416	468			600	600			712	687	694	777			9,943	11,186	416	468	Trip	Trip
6W2	13.8	800	800	416	468							712	687	694	777			9,943	11,186	416	468	Trip	Trip
Exeter 1T1	4.16	1200	1200	768	864	600	600	900	900	1037	1037					704	747	4,323	4,323	600	600	CT	CT
Exeter 1T2	4.16	1200	1200	768	864	600	600	900	900	1037	1037					704	747	4,323	4,323	600	600	CT	CT
1H3	4.16	800	800	448	504			900	900					448	448			3,228	3,228	448	448	Trip	Wire
1H4	4.16	800	800	448	504			900	900					448	448			3,228	3,228	448	448	Trip	Wire
Exeter Switching 19T1	4.16									332	332	580	560			304	321	2,190	2,310	304	321	Xfmr	Xfmr
19H1	4.16	560	560	320	360	600	600	400	400			580	560	443	495			2,306	2,594	320	360	Trip	Trip
Exeter Switching 19X2	34.5	400	400	320	360	600	600	600	600			544	525	448	448			19,122	21,512	320	360	Trip	Trip
Exeter Switching 19X3	34.5	560	560	320	360	600	600	600	600			544	525	694	777			19,122	21,512	320	360	Trip	Trip
Guinea Road Tap 47X1	34.5	560	560	448	504	200	200	300	300			290	280	694	777			11,951	11,951	200	200	CT	CT
Guinea Switching 18X1	34.5	600	600	448	504	600	600							694	777			26,771	30,117	448	504	Trip	Trip
Hampton 2T1	4.16	1200	1200							829	829					969	1008	5,976	5,976	829	829	Fuse	Fuse
2H1	4.16	560	560	448	504	600	600	600	600			969	935	443	464			3,192	3,343	443	464	Wire	Wire
Hampton 2X3	34.5	800	800	336	378	600	600	900	900			544	525	694	777			20,078	22,588	336	378	Trip	Trip
Hampton 2X2	34.5	800	800	336	378	600	600	400	400			544	525	694	777			20,078	22,588	336	378	Trip	Trip
Hampton Beach 3T1	4.16	1200	1200	768	864					1037	1037					955	1002	5,534	6,225	768	864	Trip	Trip
3H1	4.16	600	600	576	648	600	600	900	900			969	935	694	777			4,150	4,323	576	600	Trip	Brkr/Rclsr
3H2	4.16	600	600	576	648	600	600	900	900			435	420	694	777			3,134	3,026	435	420	Reg	Reg
3H3	4.16	600	600	576	648	600	600	900	900			435	420	694	777			3,134	3,026	435	420	Reg	Reg
Hampton Beach 3T3	13.8					600	600			458	458					580	603	10,935	10,935	458	458	Fuse	Fuse
3W4	13.8	800	800	320	360	600	600	600	600			318	307	400	400			7,590	7,328	318	307	Reg	Reg
High Street 17T1	13.8									1518	1518					584	613	13,970	14,660	584	613	Xfmr	Xfmr
17W1	13.8	800	800	320	360	600	600	600	600			712	687	694	777			7,649	8,605	320	360	Trip	Trip
17W2	13.8	800	800	320	360	600	600	600	600			712	687	694	777			7,649	8,605	320	360	Trip	Trip
Hunt Rd Tap 56X1	34.5	800	800	300	337.5	600	600	600	600			326	315	694	777			17,927	18,823	300	315	Trip	Reg
Kingston 22X1	34.5	1200	1200	384	432	1200	1200	600	600					694	777			22,946	25,814	384	432	Trip	Trip
Mill Lane Tap 23X1	34.5	400	400	320	360	400	400					290	280	694	777			17,329	16,732	290	280	Reg	Reg
Munt Hill Tap 28X1	34.5	800	800	208	234	600	600	600	600			544	525	694	777			12,429	13,983	208	234	Trip	Trip
New Boston Rd. 54X1	34.5	800	800	288	324	600	600	600	600			291	281	694	777			17,210	16,815	288	281	Trip	Reg
Plaistow 5T1	4.16					600	600			979	979					608	608	4,323	4,323	600	600	CT	CT
5H1	4.16	1200	1200	480	540	300	300							470	470			2,162	2,162	300	300	CT	CT
5H2	4.16	1200	1200	480	540	300	300							470	470			2,162	2,162	300	300	CT	CT
Portsmouth Ave 11X1	34.5	800	800	296	333	600	600	600	600			544	525	694	777			17,688	19,899	296	333	Trip	Trip
Portsmouth Ave 11X2	34.5	800	800	296	333	600	600	600	600			544	525	694	777			17,688	19,899	296	333	Trip	Trip
Seabrook 7T1	13.8									1319	1319					292	307	6,980	7,330	292	307	Xfmr	Xfmr
7W1	13.8	800	800	640	720	600	600	900	900			318	307	694	777			7,590	7,328	318	307	Reg	Reg
Seabrook 7X2	34.5	800	800	208	234	600	600	900	900			242	234	694	777			12,429	13,971	208	234	Trip	Reg
Shaw's Hill Tap	34.5	800	800	256	288	600	600	600	600			544	525	694	777			15,297	17,210	256	288	Trip	Trip
27X1	34.5	800	800	256	288									694	777			15,297	17,210	256	288	Trip	Trip
27X2	34.5	800	800	256	288									694	777			15,297	17,210	256	288	Trip	Trip
Stard Road Tap 59X1	34.5	800	800	336	378			600	600			291	281	694	777			17,416	16,815	291	281	Reg	Reg
Timberlane 13T1	13.8					600	600			458	458					589	618	10,935	10,935	458	458	Fuse	Fuse
13W1	13.8	560	560	448	504	300	300	600	600			634	612	694	777			7,171	7,171	300	300	CT	CT
13W2	13.8	560	560	224	252	300	300	400	400			318	307	694	777			5,354	6,023	224	252	Trip	Trip
Timberlane 13X3	34.5	800	800	192	216			800	800			291	281	694	777			11,473	12,907	192	216	Trip	Trip
Westville 21T1	13.8					600	600			480	480					584	612	11,473	11,473	480	480	Fuse	Fuse
21W1	13.8	560	560	448	504	300	300	600	600			712	687	694	777			7,171	7,171	300	300	CT	CT
21W2	13.8	560	560	304	342	300	300	600	600			712	687	554	554			7,171	7,171	300	300	CT	CT
Westville Tap 58X1	34.5	560	560			300	300	300	300			291	281					17,416	16,815	291	281	Reg	Reg
58X1E	34.5	800	800	400	450									694	777			23,902	26,890	400	450	Trip	Trip
58X1W	34.5	800	800	160	180									868	974			9,561	10,756	160	180	Trip	Trip
Willow Road Tap 43X1	34.5	560	560	448	504	200	200					326	315	694	777			11,951	11,951	200	200	CT	CT
Winnacunnet Road Tap 46X1	34.5	560	560	160	180	100	100	300	300					694	777	60	60	3,600	3,600	60	60	Xfmr	Xfmr
Winnicutt Road Tap 51X1	34.5	800	800	600	675			900	900					694	777			35,853	40,335	600	675	Trip	Trip

Appendix C

Transformer Loading Charts
(in Per Unit)

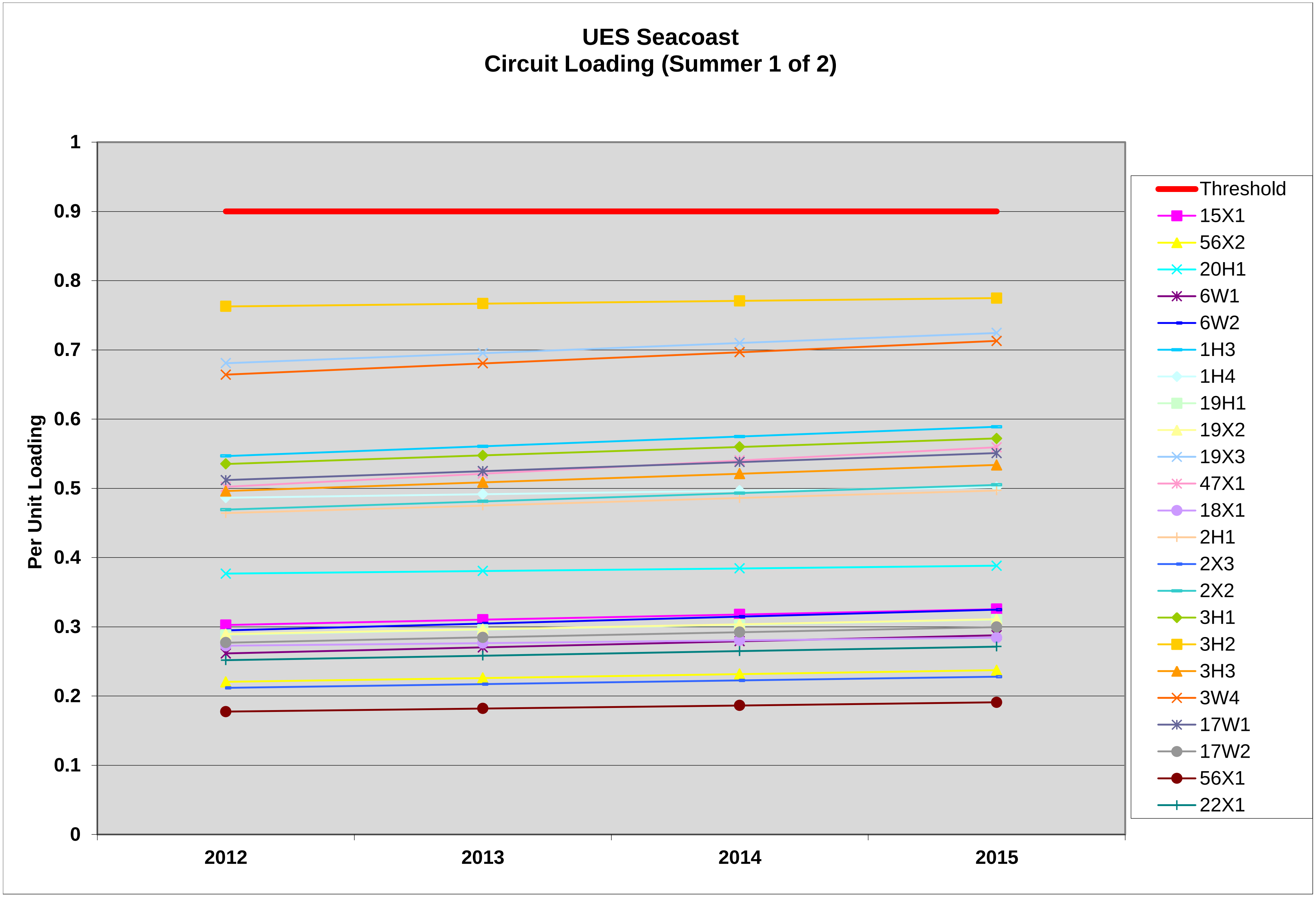

UES Seacoast
Transformer Loading (Summer)
Per Unit Loading
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2012
2013
2014
2015
Dow's Hill 20T1
East Kingston 6T1
Exeter 1T1
Exeter 1T2
Exeter Switching 19T1
Hampton 2T1
Hampton Beach 3T1
Hampton Beach 3T3
High Street 17T1
Plaistow 5T1
Seabrook 7T1
Timberlane 13T1
Westville 21T1
Threshold

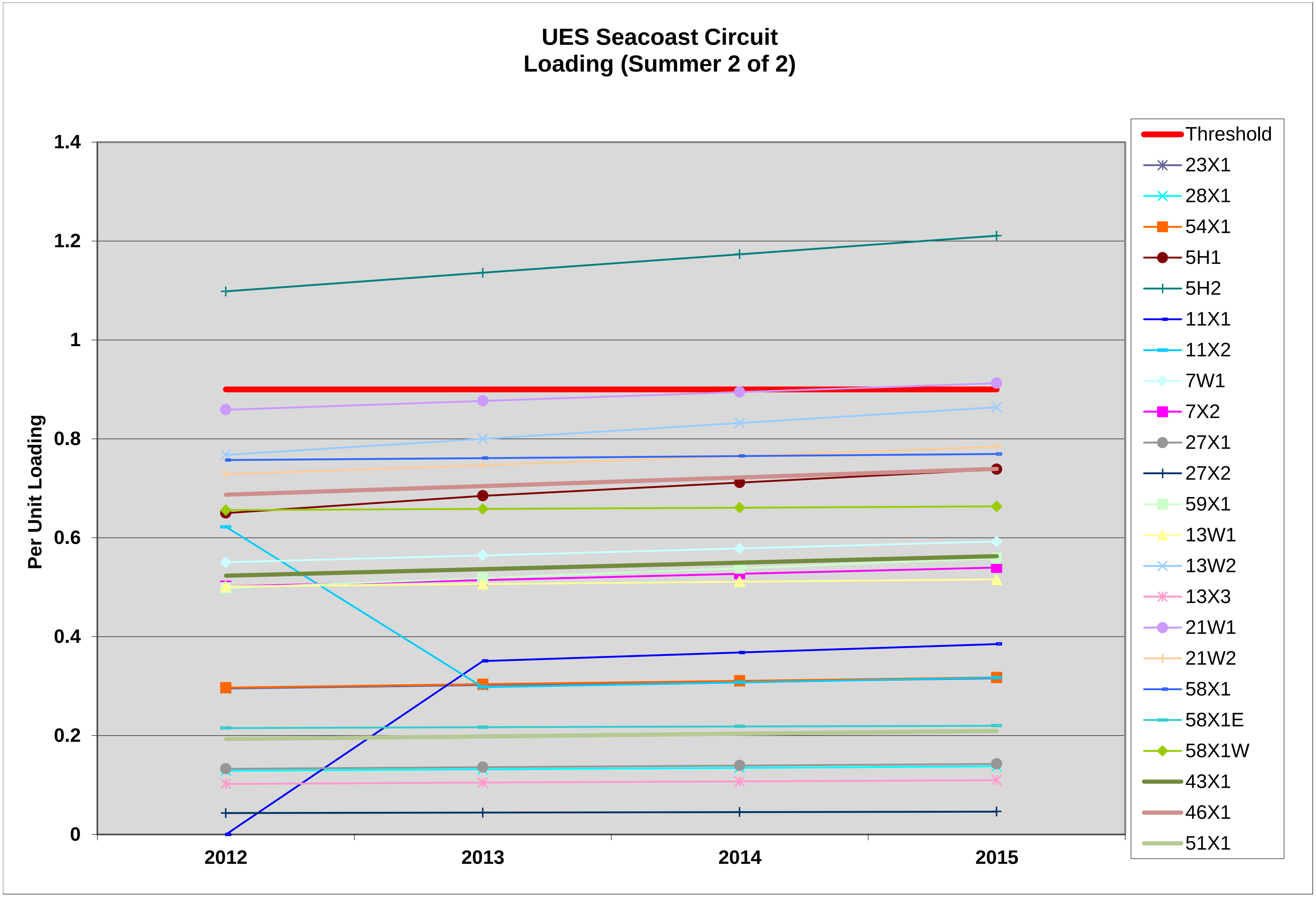


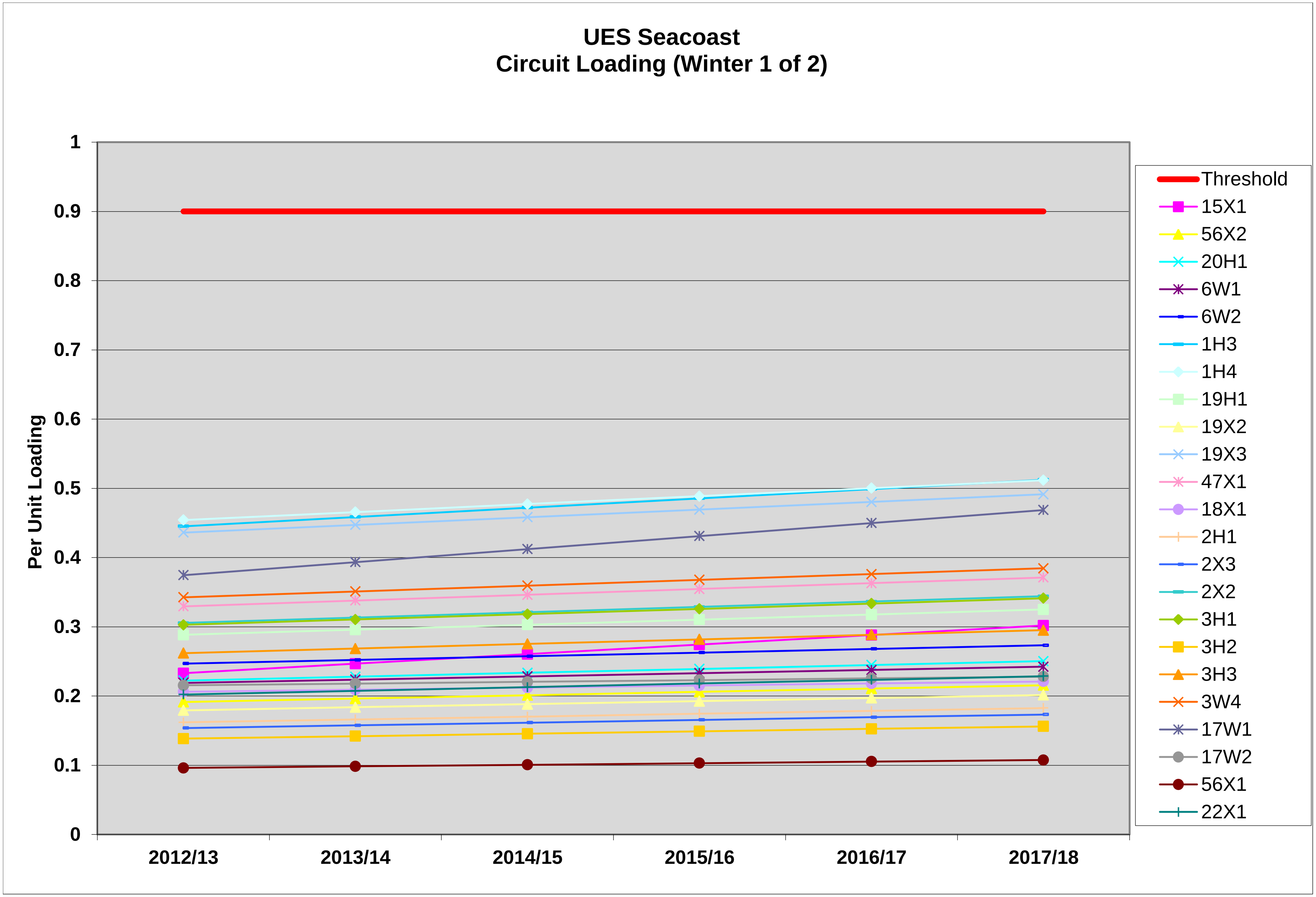
UES Seacoast
Transformer Loading (Winter)
Per Unit Loading
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Dow's Hill 20T1
East Kingston 6T1
Exeter 1T1
Exeter 1T2
Exeter Switching 19T1
Hampton 2T1
Hampton Beach 3T1
Hampton Beach 3T3
High Street 17T1
Plaistow 5T1
Seabrook 7T1
Timberlane 13T1
Westville 21T1
Threshold

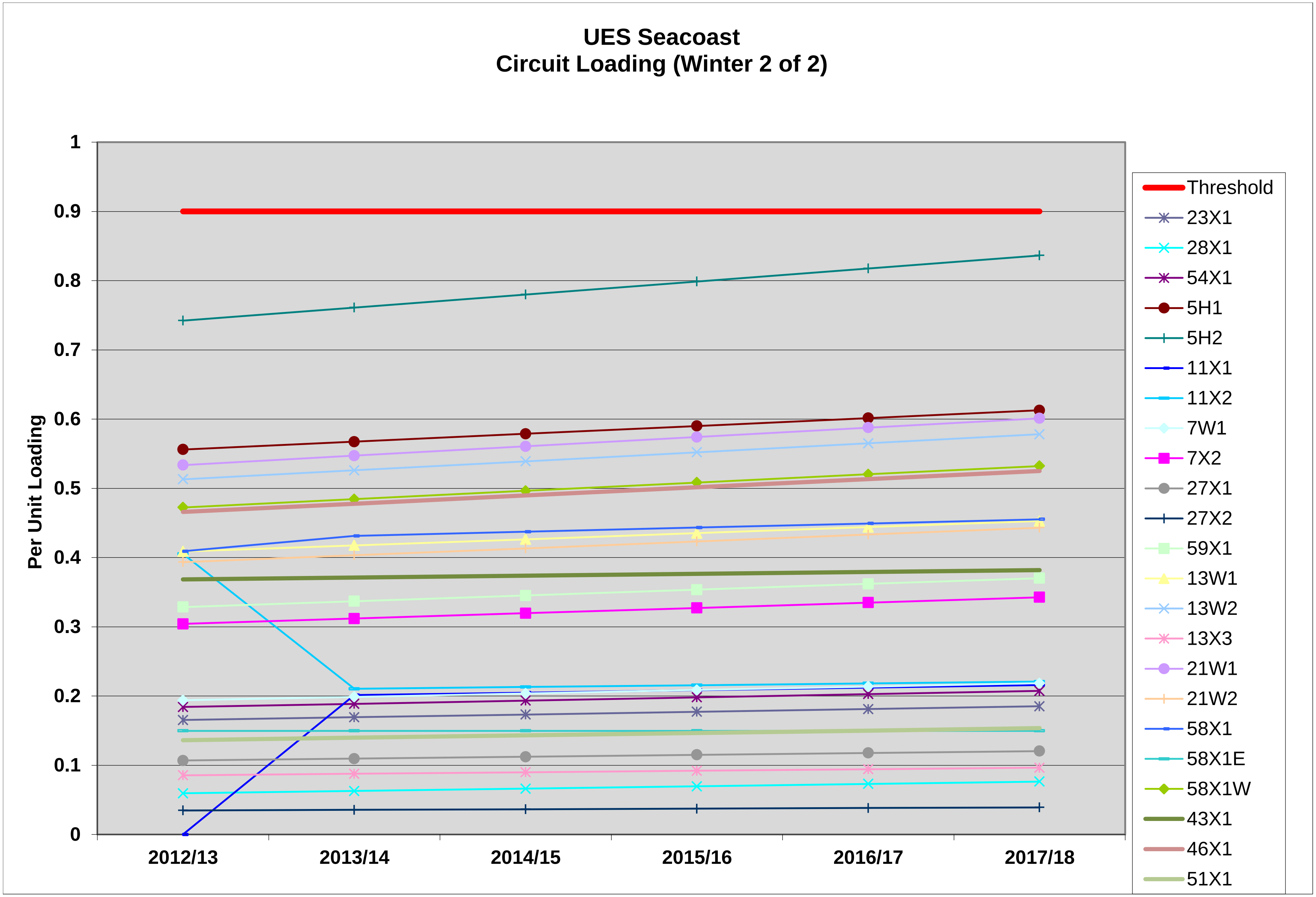
Appendix D

Circuit Loading Charts
(in Per Unit)


UES Seacoast
Circuit Loading (Summer 1 of 2)
Per Unit Loading
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2012
2013
2014
2015
Threshold
15X1
56X2
20H1
6W1
6W2
1H3
1H4
19H1
19X2
19X3
47X1
18X1
2H1
2X3
2X2
3H1
3H2
3H3
3W4
17W1
17W2
56X1
22X1


UES Seacoast Circuit
Loading (Summer 2 of 2)
Per Unit Loading
1.4
1.2
1
0.8
0.6
0.4
0.2
0
2012
2013
2014
2015
Threshold
23X1
28X1
54X1
5H1
5H2
11X1
11X2
7W1
7X2
27X1
27X2
59X1
13W1
13W2
13X3
21W1
21W2
58X1
58X1E
58X1W
43X1
46X1
51X1


UES Seacoast
Circuit Loading (Winter 1 of 2)
Per Unit Loading
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Threshold
15X1
56X2
20H1
6W1
6W2
1H3
1H4
19H1
19X2
19X3
47X1
18X1
2H1
2X3
2X2
3H1
3H2
3H3
3W4
17W1
17W2
56X1
22X1


UES Seacoast
Circuit Loading (Winter 2 of 2)
Per Unit Loading
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2012/13
2013/14
2014/15
2015/16
2016/17
2017/18
Threshold
23X1
28X1
54X1
5H1
5H2
11X1
11X2
7W1
7X2
27X1
27X2
59X1
13W1
13W2
13X3
21W1
21W2
58X1
58X1E
58X1W
43X1
46X1
51X1

Appendix E

Protection Violations

Coordination Concerns:

Circuit	Protecting (down-line) Device			Protected (up-line) Device		
	Recloser/ Fuse	Pole	Street, Town	Recloser/ Fuse	Pole	Street, Town
1H3	40 QA	27/2	Center St., Exeter	75 QA	27/5	Center St., Exeter
	50 QA	272/5	Water St. Rear Ext., Exeter	100 QA	272/1	Water St. Rear Ext., Exeter
	50 QA	203/26	Water St. Exeter	75 QA	272/25	Water St. Exeter
6W1	100 QA	14/60	North Rd., East Kingston	75 QA	14/65	North Rd., East Kingston
	150 QA	14/59	North Rd., East Kingston	100 QA	14/60	North Rd., East Kingston
	50 QA	8/24	East Rd., East Kingston	175 QA	8/26	East Rd., East Kingston
	150 QA	32/14	South Rd., Kensington	75 QA	32/7	South Rd., Kensington
	20 QA	36/6	West School Rd., Kensington	40 QA	36/2	West School Rd., Kensington
	40 QA	17/3	Stage Coach Rd., East Kingston	40 QA	23/49	South Rd., East Kingston
	100 QA	10/1	Stage Coach Rd., South Hampton	125 QA	8/1	Main St., South Hampton
11X1	Various	Various	Doe Run Ln., Stratham	25 QA	27/25	Doe Run Ln., Stratham
	100 QA	76/1	Raeder Dr., Stratham	50 QA	75/53	Portsmouth Ave., Stratham
	20 QA	17/16	Butterfield Ln., Stratham	50 QA	75/61	Portsmouth Ave., Stratham
11X2	125 QA	274/8-58	Hayes Trailer Park, Exeter	150 QA	105/6	Jady Hill Cir., Exeter
	25 QA	155/16-52	Portsmouth Ave., Exeter	10 QA	155/16	Portsmouth Ave., Exeter
	75 QA	24/2	Buzzell Ave., Exeter	125 QA	157/2	Prospect St., Exeter
	10 QA	195/4-51	Holland Way, Exeter	40 QA	195/4	Holland Way, Exeter
19X2	40 QA	190/2	Thornton Rd, Exeter	75 QA	99/34	High St., Exeter
	40 QA	209/4	Wheelwright Ave., Exeter	75 QA	99/38	High St., Exeter
19X3	125 QA	246/6	Villa Dr., Exeter	25 QA	246/5	Villa Dr., Exeter
	150 QA	234/10	Robinhood Dr., Exeter	150 QA	234/1	Robinhood Dr., Exeter
	150 QA	229/31	Newfields Rd., Exeter	100 QA	229/26	Newfields Rd., Exeter
	125 QA	288/7	Public Works Rd., Exeter	150 QA	229/31	Newfields Rd., Exeter
	75 QA	313/1	Walter's Way, Exeter	100 QA	229/26	Newfields Rd., Exeter
	100 QA	229/72-1	Newfields Rd., Exeter	100 QA	229/26	Newfields Rd., Exeter
	75 QA	202/9	Washington St., Exeter	25 QA	202/14	Washington St., Exeter
	10 QA	123/2	Little River Rd., Exeter	20 QA	21/13	Brentwood Rd., Exeter
	25 QA	225/8	Oakland Heights Rd., Exeter	60 QA	228/1	Oakland Heights Ed., Exeter
	30 QA	61/30-52	Epping Rd., Exeter	30 QA	61/30	Epping Rd., Exeter
	15 QA	215/3-51	Industrial Dr., Exeter	50 QA	215/3	Industrial Dr., Exeter
	125 QA	310/11	Continental Dr., Exeter	150 QA	61/49-1	Epping Rd., Exeter

Circuit	Protecting (down-line) Device			Protected (up-line) Device		
	Recloser/ Fuse	Pole	Street, Town	Recloser/ Fuse	Pole	Street, Town
19X3	25 QA	310/7-51	Continental Dr., Exeter	25 QA	310/7	Continental Dr., Exeter
23X1	150 QA	62/26	New Zealand Rd., Seabrook	125 QA	62/26	New Zealand Rd., Seabrook
43X1	100 QA	26/15	Willow Rd., East Kingston	10 QA	26/21	Willow Rd., East Kingston
	10 QA	72/49-51	Little River Rd. West, Kingston	30 QA	72/55	Little River Rd. West, Kingston
	10 QA	287/5	Great Hill Estates, East Kingston	20 QA	219/93	Route 111, Exeter
	10 QA	220/6	Juniper Ridge Rd., Exeter	30 QA	219/58	Route 111, Exeter
	Various	Various	Pickpocket Rd., Exeter	40 QA	148/19	Pickpocket Rd., Exeter
	25 QA	102/3	Hobart St., Exeter	50 QA	130/6	McKinley St., Exeter
58X1	30 QA	Various	Pentucket Shopping, Plaistow	75 QA	128/1	Pentucket Shopping, Plaistow
	Various	Various	Gardner Dr., Plaistow	40 QA	78/3	Gardner Dr., Plaistow
	Various	Various	Chandler St., Paistow	20 QA	78/13	Gardner Dr., Plaistow
	Various	Various	Kohl's Plaza, Plaistow	75 QA	117/8	Route 125, Plaistow
	Various	Various	Lower Maple Ave., Atkinson	50 QA	53/28	Main St., Atkinson
	20 QA	53/41-21	Main St., Atkinson	20 QA	53/41	Main St., Atkinson
	30 QA	53/60	Main St., Atkinson	40 QA	53/54	Main St., Atkinson
	Various	Various	South Main St., Plaistow	75 QA	91/51	Main St., Plaistow
	10 QA	64/6	Mankill Brook Rd., Plaistow	5 QA	81/24	Pollard Rd., Plaistow
	5 QA	130/6	Katherine Way, Plaistow	5 QA	81/29	Pollard Rd., Plaistow
	40 QA	71/5	Puzzle Way, Newton	60 QA	19/183	Main St., Newton
	Various	Various	Forest St., Plaistow	50 QA	35/67	Forest St., Plaistow

Sensitivity Concerns:

Circuit	Recloser/ Fuse	Pole	Street, Town	Sensitivity Ratio
19H1	19H1	n/a	Exeter Switching Station, Exeter	1.8:1
19X3	50 QA	46/21	Court St., Exeter	2.9:1
43X1	40 QA	219/59	Route 111, Exeter	1.9:1
58X1	50 QA	103/5	Wentworth Ave., Plaistow	1.8:1

Unprotected Laterals:

Circuit	Pole	Mainline Street, Town	Lateral Street	# Sections
1H4	178/6	South St., Exeter	South St.	1
	45/4	Court St., Exeter	Maple St.	1
	45/3	Court St., Exeter	Pole 45/3-51	1
	70/8	Front St., Exeter	Spring St.	5
	120/5	Lincoln St., Exeter	Pole 120/5-54	3
	120/3	Lincoln St., Exeter	Humble Pie Food Shop	1
	125/17	Main St., Exeter	Burnham Dry Cleaners	1
6W1	7/41	Depot Rd., East Kingston	George St.	1
6W2	38/41	Depot Rd., Kingston	Pole 38/41-3	3
	113/25	Scotland Rd., Kingston	Depot St.	6
11X1	75/35	Portsmouth Ave., Stratham	Pole 75/35-2	2
	75/41	Portsmouth Ave., Stratham	Pole 75/41-1	1
	75/68	Portsmouth Ave., Stratham	Pole 75/68-52	1
19H1	79/3	Gilman Ln., Exeter	Pole 79/3-2	1
	9/13	Drinkwater Rd., Kensington	Pole 9/13-2	2
19X2	99/3	High St., Exeter	Chestnut St.	12
	99/21	High St., Exeter	Buzzell Ave.	3

Note: The table above summarizes the unprotected laterals tapped directly off the mainline of distribution circuits identified in the UES-Unprotected Lateral Study for the third of the circuits analyzed.

For the purposes of this report, a distribution circuit main line is defined as all three phase sections of a distribution circuit that is currently protected by a substation recloser, breaker, or fuse.

Appendix F

Stepdown Replacement/Metering Projects

2013 Stepdown Replacements

None Required

2013 Stepdown Metering Installations

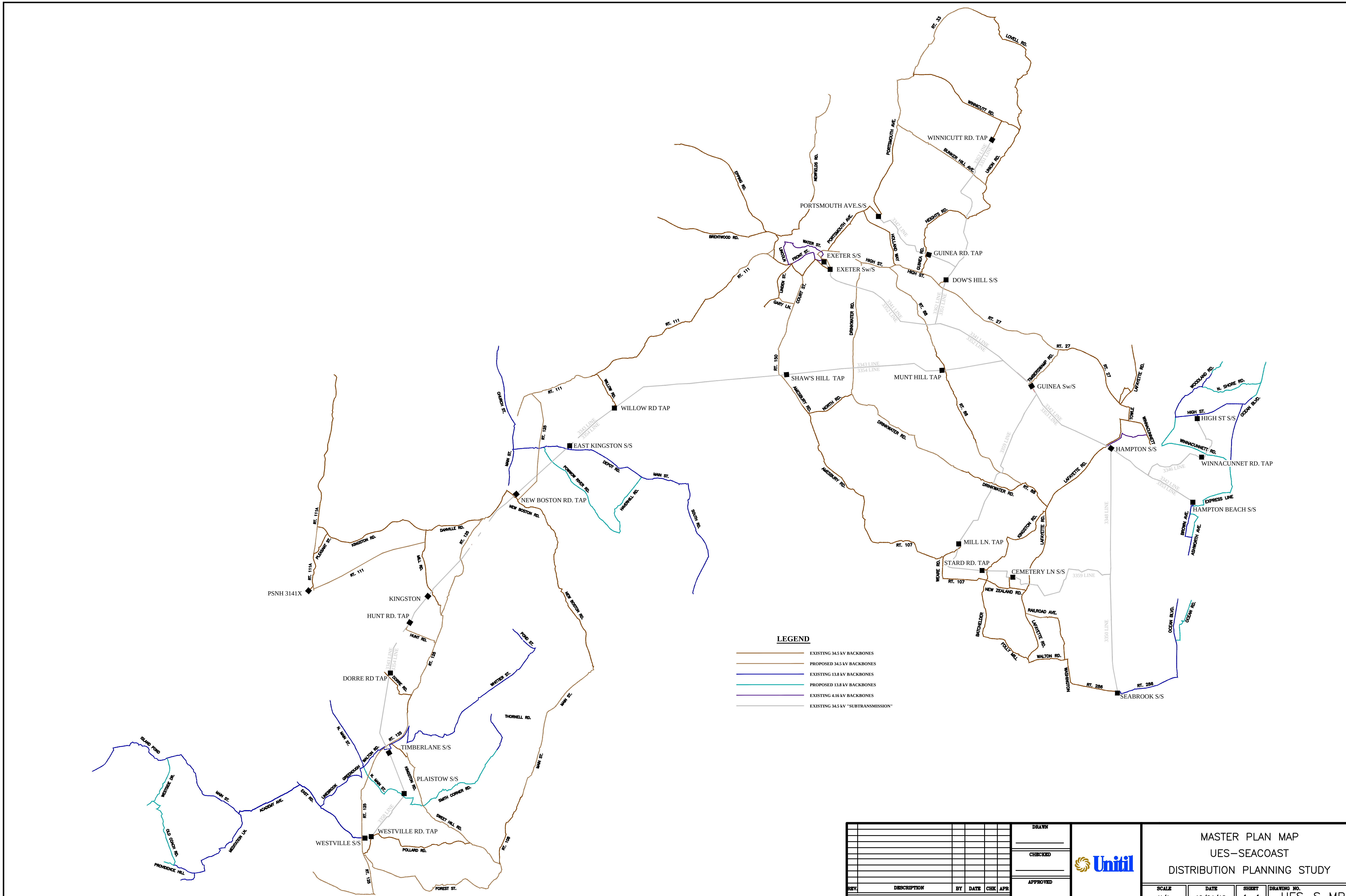
Location	Transformer Size
19X3 – Oak Street p. 138/6	3-500 kVA
19X3 – Route 85 p. 229/20	3-500 kVA
19X3 – Brentwood Road p. 21/66	1-333 kVA
19X3 – Dogtown Road p. 53/2	1-333 kVA
27X1 – Court Street p. 44/60	3-500 kVA
27X1 – Drinkwater Road p. 9/42	3-500 kVA
27X1 – Green Gate Campground p. 242/1	1-333 kVA
27X1 – Exeter Elms p. 44/63-1	1-500 kVA
2X3 – Route 88 p. 12/3	3-500 kVA
2X3 – Rocks Road p. 81/1-A	3-333 kVA
7W1 – Portsmouth Ave p. 75/23	3-500 kVA
7X2 – Tricia Street p. 121/2	1-500 kVA
58X1 – West Pine Street p. 104/2	1-500 kVA
2X2 – Lafayette Road p. 152/65	3-333 kVA

Future Stepdown Replacements

Location	Existing Size
21W1 – Meditation Lane p. 56/33	3-167 kVA
58X1 – Whitton Place p. 107/3	1-333 kVA
58X1 – Forest Street p. 35/1	1-167 kVA

Appendix G

Master Plan Map



PORTSMOUTH AVE.S/S
EXETER S/S
EXETER Sw/S
GUINEA RD. TAP
DOW'S HILL S/S
WINNICUTT RD. TAP
SHAW'S HILL TAP
MUNT HILL TAP
GUINEA Sw/S
HIGH ST S/S
HAMPTON S/S
WINNACUNNET RD. TAP
HAMPTON BEACH S/S
MILL LN. TAP
STARD RD. TAP
CEMETERY LN S/S
SEABROOK S/S
WILLOW RD TAP
EAST KINGSTON S/S
NEW BOSTON RD. TAP
PSNH 3141X
KINGSTON
HUNT RD. TAP
DORRE RD TAP
TIMBERLANE S/S
PLAISTOW S/S
WESTVILLE RD. TAP
WESTVILLE S/S
LEGEND
EXISTING 34.5 kV BACKBONES
PROPOSED 34.5 kV BACKBONES
EXISTING 13.8 kV BACKBONES
PROPOSED 13.8 kV BACKBONES
EXISTING 4.16 kV BACKBONES
EXISTING 34.5 kV "SUBTRANSMISSION"
REV.
DESCRIPTION
BY
DATE
CHK
APR
REVISIONS
DRAWN
CHECKED
APPROVED
Unitil
MASTER PLAN MAP
UES–SEACOAST
DISTRIBUTION PLANNING STUDY
SCALE
N/A
DATE
10/24/12
SHEET
1 OF 1
DRAWING NO.
UES–S MP

Unitil Service Corp.

Electric System Planning Guide

Unitil Service Corp.

Original Issue:	April 2000
Revised:	December 19, 2003
Revised:	January 12, 2004

TABLE OF CONTENTS

1 OBJECTIVE

The objective of this guide is to define study methods and design criteria used to assess the adequacy of Unitil transmission, subtransmission, and substation systems; and to provide guidance in the planning and evaluation of modifications to these systems. The purpose is to ensure appropriate and consistent planning and design practices to satisfy applicable criteria and reasonable performance expectations.

2 INTRODUCTION

All Unitil facilities which are part of the Bulk Power System (Pool Transmission Facilities, PTF) shall be designed in accordance with the latest versions of the Northeast Power Coordinating Council (NPCC) policies, the New England Power Pool (NEPOOL) standards, and all applicable Unitil policies. The fundamental guiding documents are the "Basic Criteria for Design and Operation of Interconnected Power Systems" (NPCC Document A2), the "Reliability Standards for the New England Power Pool" (NEPOOL Document PP3), and this document.

All Unitil facilities which are not considered PTF but are part of the Unitil systems shall be designed in accordance with the latest version of this document.

Detailed design of facilities may require additional guidance from industry or technical standards which are not addressed by any of the documents referenced in this guide.

Systems should be planned and designed with consideration for ease of operation. Such considerations include, but are not limited to:

- Utilization of standard components to facilitate availability of spare parts
- Minimization of post contingency switching operations
- Minimization of the use of Special Protection Systems (SPS)

Regulatory Requirements

All Unitil facilities shall be designed and operated in accordance with all applicable state regulatory requirements as specified in the State of New Hampshire's "Code of Administrative Rules" or the Commonwealth of Massachusetts "Code of Massachusetts Regulations."

3 PLANNING CRITERIA

Unitil transmission, subtransmission, and substation systems should be planned and designed for safe, economical and reliable performance, with consideration for normal and reasonably foreseeable contingency situations, load levels, and generation.

3.1 Allowable Equipment Loading

Thermal ratings for system equipment are established to obtain the maximum use of the equipment accepting some defined, limited loss of life or loss of strength. These ratings are based on the Unitil "Electrical Equipment Rating Procedures Guide". The principal variables used to derive these ratings include specific equipment physical parameters and design, maximum allowable operating temperatures, seasonal ambient weather conditions, and representative daily load cycles.

Normal ratings describe the allowable loading to which equipment can operate for normal, continuous load cycling up to peak demands at the indicated **Normal Limit**. Emergency ratings allow brief operation of equipment to higher peak demand limits for emergency situations.

The following listing summarizes Unitil equipment thermal ratings:

Rating	Allowable Duration before Relief
Summer Normal Limit	continuous
Summer Long-Time Emergency (LTE) Limit	12 hours
Summer Short-Time Emergency (STE) Limit	15 minutes
Winter Normal Limit	continuous
Winter Long-Time Emergency (LTE) Limit	4 hours
Winter Short-Time Emergency (STE) Limit	15 minutes

Equipment loaded at or below its **Normal Limit** is operating within normal loading conditions. Equipment loaded above its **Normal Limit** is operating at emergency loading conditions, and may be experiencing higher than normal loss of life or loss of strength.

Equipment loaded above its **Normal Limit** and at or below its **Long-Time Emergency Limit** is operating at a long-time emergency load level. Long-time emergency loading may be sustained for a single, non-repeating load cycle where the **Normal Limit** is exceeded for no more than the allowable duration.

Equipment loaded above its **Long-Time Emergency Limit** and at or below its **Short-Time Emergency Limit** is operating at a short-time emergency load level. Short-time emergency loading must be relieved to normal or LTE conditions within 15 minutes. Unitil systems should be planned and designed to avoid short-time emergency loading. However, it is acceptable for equipment to be loaded to short-time emergency conditions following a loss-of-element contingency, provided automatic or remote actions are in place to relieve the loading within the specified time.

Equipment loaded beyond its **Short-Time Emergency Limit** is operating at a **Drastic Action Level (DAL)**, and immediate relief is required including the shedding of load if necessary. If a facility operates at this level for more than five minutes, equipment may suffer unacceptable damage. Unitil systems shall not be planned for equipment to reach DAL loadings.

3.2 Allowable System Voltages

System voltage ranges are established to obtain adequate operating voltages for system customers, maintain proper equipment performance, avoid over-excitation of transformers or under-excitation of generators, and preserve system stability. Unitil systems should be planned and designed to sustain steady-state operating voltages at **Non-Distribution points** within a minimum limit of 90% of nominal (108 V on a 120 V base) and a maximum limit of 105% of nominal (126 V on a 120 V base). Unitil systems should be planned and designed to sustain steady-state operating voltages at **Distribution points** within a minimum limit of 97.5% of nominal (117 V on a 120 V base) and a maximum limit of 104.2% of nominal (125 V on a 120 V base).

In this context, **Non-Distribution points** indicate locations that are not direct supply outputs for distribution circuit loads. Most transmission and subtransmission lines are **Non-Distribution**, as are most substation facilities where the voltage regulation is applied after the low-side bus (i.e. at the individual distribution circuit terminals).

Correspondingly, **Distribution points** indicate locations that are direct supply outputs for distribution circuit loads. This may be, for example, at unregulated distribution circuit or customer taps off of subtransmission lines, or at substation low-side buses where voltage regulation is provided by load-tap-changing power transformers or regulators at the transformer output.

It is acceptable for steady-state voltage excursions beyond these limits to occur immediately following a contingency event and while corrective actions are in progress. However, Unitil systems should be planned and designed to limit the extent and duration of such excursions. Furthermore, Unitil systems shall not be planned to accept unchecked voltage collapse.

There are no design limits on the amount of change in operating voltages from initial pre-contingency to immediate post-contingency levels.

3.3 System Configuration

Unitil systems shall be planned and designed to meet applicable criteria utilizing specific normal and emergency configurations of system elements.

The **Normal Configuration** shall describe the intended arrangement of the system when all normally in-service elements are available. Unitil systems should be planned and designed to operate within normal equipment ratings and voltage ranges when in the **Normal Configuration** at all normally anticipated load levels.

The arrangement of system elements may be temporarily altered to a non-emergency configuration for routine operating and maintenance purposes. An acceptable non-emergency configuration should also satisfy normal ratings and voltages. It is not a requirement that Unitil systems be planned or designed for every possible non-emergency configuration.

A **Contingency Configuration** describes a modified arrangement of the system in response to emergency conditions. Unitil systems should be planned and designed to be promptly arranged into prescribed **Contingency Configurations** when necessary to attain acceptable conditions following specific contingent emergencies, and to operate within specified equipment ratings and voltage ranges when in these configurations.

3.4 System Load

Unitil systems shall be planned and designed to meet applicable criteria up to specific normal and emergency load levels.

3.4.1 Peak Design Load

The **Peak Design Load** describes the benchmark load level that system adequacy is measured against. It shall be the highest anticipated coincident, active (real) power demand of all system customers, plus associated system losses, plus adjustments deemed reasonable to address forecasting uncertainties. The **Peak Design Load** is the actual load and losses to be supplied, and not the net sum of power flows at system boundaries after being offset by internal sources. Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges at load levels up to the established **Peak Design Load**.

3.4.2 Extreme Peak Load

Load levels above the established **Peak Design Load** are considered a contingency event under which emergency conditions may be accepted. The **Extreme Peak Load** describes a maximum foreseeable load level benchmark, such as might occur during extraordinary, one-in-ten-year temperature extremes. Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges at load levels up to the established **Extreme Peak Load** with all elements available.

3.5 Load Power Factor

Load Power Factor in each area should be consistent with the limits set by the requirements developed under NEPOOL criteria, rules, and standards #30 (CRS-30) for that area.

3.6 System Generation

The operation of generating plants not directly under Unitil control may be determined by a competitive market bidding system where plant availability and dispatch may not include consideration of system support or reliability needs. Unitil systems shall be planned and designed to meet applicable criteria under reasonably foreseeable generation dispatch, taking into account uncertainties in unit status and future availability.

3.6.1 Generation Dispatch

For planning purposes, typical historical performance for each unit may be used as the initial basis for generation dispatch assumptions. These assumptions should take into account factors for seasonal variations, demonstrated forced-outage rates, operating limits, and expected performance during system disturbances.

The planning and operation of generating plants outside of Unitil systems is not typically within the scope of Unitil planning requirements unless they have a direct impact on system adequacy. The impact of generation inside or within the immediate vicinity of Unitil systems should be taken into account. Unitil systems should be planned and designed to operate within normal equipment ratings and voltage ranges during the outage of any utility-owned generating plant.

3.6.2 Non-Utility Generation

The adequacy of system infrastructure to meet Unitil's end-use load obligations necessitates that it be self-sufficient to a certain extent from internal, non-utility generation. Unitil systems are to be planned and designed to operate within specified equipment ratings and voltage ranges with at least one-half of all internal, non-utility generating facilities that presently exist being out of commission in the future.

3.6.3 Generation Rejection or Ramp Down

Generation rejection or ramp down refers to tripping or running back the output of a generating unit in response to a system disturbance. As a general practice, generation rejection or ramp down should not be included in the planning and design of the Unitil systems.

3.6.4 Priority

Serving load has priority over generation. Therefore, if there is an option to trip generation or trip load, the plan will be to trip generation.

3.7 Normal Conditions

Unitil systems shall be planned and designed to operate within normal equipment ratings and voltage ranges for the following normal conditions:

- all normally in-service elements available, and
- load levels up to the established **Peak Design Load**, and
- typical seasonal generation dispatch.

Additionally, the impact of the following generation conditions should be taken into account:

- outage of any utility-owned generating plant inside or within the immediate vicinity of the system, and
- outage of up to 50% (cumulative output) of internal non-utility generating plants.

3.8 Contingency Conditions

Unitil systems shall be planned and designed to meet applicable criteria for specific, pre-determined emergency scenarios.

Design Contingencies describe the pre-determined emergency scenarios that system adequacy is measured against. Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges following actions in response to the following **Design Contingencies**:

- loss of any **Non-Radial Line** element, or
- loss of any **Radial Line** element with no backup tie, or
- loss of any **System Supply Transformer**, or
- **Extreme Peak Load** with all elements available.

3.9 Allowable Loss of Load

The objective of planning and designing the system to meet **Design Contingency** criteria is to utilize system elements up to their maximum allowable capabilities to carry or restore as much load as possible. It is understood and accepted that many system fault or equipment failure events, including loss-of-element **Design Contingencies**, may result in the temporary loss of customer load until damaged components are isolated and restoration switching is performed. However, limited loss of customer load for more extended periods of time are acceptable design compromises for specific circumstances where other alternatives are not practical or economical.

3.9.1 Loss-of-Element Contingency

To provide continuity or immediate restoration of service to all portions of system load for all reasonably foreseeable contingencies requires fixed infrastructure with spare capacity or redundancy for each element. This level of design may be inefficient and cost-prohibitive to cover the contingent loss of certain major elements. The loss of limited portions of system load for limited periods of time may be tolerated under defined circumstances as part of prudent, cost-effective alternatives to fixed infrastructure. These alternatives are traditionally either of two choices: (1) the interruption of load while repairs are being made to an element that cannot be backed up; or (2) the interruption of load while mobile or spare equipment is made available from another location, transported and placed into service where needed.

The Unitil system is designed to accept loss of load during the following specifically identified **Design Contingencies**, subject to the indicated conditions and limits:

Table 3.9.1-1 Allowable Loss of Load

Design Contingency	Allowable Loss of Load	Allowable Duration
Loss of a radial line element with no backup tie	≤ 30 MW	≤ 24 hours
Loss of a system supply transformer	≤ 30 MW	≤ 24 hours

Under these contingencies, it is understood that remaining system elements will be utilized up to their maximum allowable capabilities to carry or restore as much load as possible. Allowable Loss of Load refers to a collection of customers within the system that cannot be restored after these automatic or manual actions. This load is the peak coincident demand of this collection of customers, and not the net sum of power flow that may be seen if offset by sources within the affected portions of the system. The allowable impact is limited to these affected customers, not the overall load level at any given time. If actual load at the time is not at peak conditions, it is not acceptable to extend interruptions to a wider collection of customers by summing the demands at that time up to the same numerical limit.

3.9.2 Extreme Circumstances

Widespread outages or catastrophic failures resulting from contingencies more severe than defined **Design Contingencies** may acceptably result in loss of customer load in excess of the limits given here.

3.9.3 Regional Load Shed

NEPOOL and NPCC require that each member have load shedding capability to prevent a widespread system collapse. The types of conditions that could result in these emergencies are unusually low frequencies, equipment overloads, or unacceptable voltage levels in an isolated or widespread area of New England. These conditions may require load shedding. The specific requirements associated with the load shedding are specified in NEPOOL Operating Procedure No. 7 “Action In An Emergency”.

3.10 Exceptions

These planning criteria do not apply if a customer receives service from Unitil and also has a connection to any other transmission provider regardless of whether the connection is open or closed. In this case, Unitil has the flexibility to evaluate the situation and provide interconnection facilities as deemed appropriate and economic for the service requested.

Unitil is not required to provide service with greater deterministic reliability than the customers provide for themselves. As an example, if a customer has a single transformer, Unitil does not have to provide redundant transmission supplies.

4 PLANNING STUDIES

4.1 Basic Types of Studies

System planning studies based on steady-state power flow simulation shall be routinely conducted to assess conformance with the criteria and standards cited in this guide. These studies will review present and future anticipated system conditions under normal and contingency scenarios. The scale and composition of the Unitil electric system does not typically warrant routine analysis of its dynamic behavior. Transient stability analyses (and other forms of study) are conducted as needs arise.

4.2 Study Period

The lead-time required to plan, permit, license, finance, and construct transmission, subtransmission or substation upgrades is typically between one and ten years depending on the complexity of the project. As a result, system planning studies should examine conditions at various intervals covering a period of ten-years to identify potentially long-term projects.

4.3 Modeling and Assessment for Steady-State Power Flow

The modeling representation for steady-state power flow simulation should include the impedance and admittance of lines, generators, reactive sources, and any other equipment, which can affect power flow or voltage (e.g. capacitors or reactors). The representation should include voltage or angle taps, tap ranges, and control points for fixed-tap, load-tap-changing, and phase shifting transformers.

Specific issues related to the study, which need to be addressed, are discussed below.

4.3.1 Element Ratings

Thermal ratings of each load-carrying element in the system are determined to obtain the maximum use of the equipment. The thermal ratings of each modeled system element reflect the most limiting series equipment within that element (including related station equipment such as buses, circuit breakers and switches). Models will include three (3) rating limits for each season's case:

Summer models- Summer Normal, Summer LTE, and Summer STE.
Winter models - Winter Normal, Winter LTE, and Winter STE.

4.3.2 Modeled Load

Load development is extremely important to the creation of an effective model. The summer and winter forecasted **Peak Design Loads** and **Extreme Peak Loads** should be obtained annually from the appropriate department for a period of ten years. Modeled loads for each load center should be developed in sufficient detail to distribute the active and reactive coincident loads (coincident with the system's total peak load) throughout the system such that the net effect of loads and losses matches expected power flows and the overall **Peak Design** or **Extreme Peak** load for each case.

4.3.3 Load Levels

To evaluate the sensitivity to daily and seasonal load cycles, studies may require modeling several load levels. Minimum requirements call for study of peak load levels (**Peak Design** or **Extreme Peak**). Where high voltage issues or unusual reactive power flows are a concern, or the degree of consequences and exposure to risks must be quantified, lesser load levels may be studied. The basis for the these loads can be either summer or winter conditions, whichever is the worst case scenario for the system. In some areas, both seasons should be studied.

4.3.4 Balanced Load

Balanced, three-phase, 60 Hz ac loads should be assumed at each load center unless specifically identified by an area or circuit study. Balanced loads are assumed to have the following characteristics:

- The active and reactive load of any phase is within 90% to 110% of the load of the other phases.
- The voltage unbalance between the phases, measured phase–to–phase, is less than 3%.
- Harmonic voltage distortion is within limits recommended by the current version of IEEE Std. 519.

4.3.5 Reactive Compensation

Reactive compensation should be modeled as it is designed to operate on the system and, when appropriate, located on the low voltage side of substation transformers. Reactive compensation on distribution feeders and circuits are assumed to be included within the modeled loads.

4.3.6 Generation Dispatch

Analysis of system sensitivity to variations in generation dispatch is necessary during a study. The intent is to test the adequacy of the Unitil system as much as can be reasonably anticipated against the end-use loads which it is obligated to serve.

The basis for modeling should begin with initial assumptions of generating unit outputs at their typical seasonal levels. Cases may then be modified to reflect intended criteria and assumptions for future conditions.

In modeling the system, no more than one-half of internal, non-utility generation should be considered as being in commission and operational for the future study period. This may be modeled conservatively by taking the most significant facilities for a portion of the system out of service until the sum total of internal non-utility generation has been reduced by at least fifty percent (50%) from their typical historical output. Remaining units may be modeled at their historical output. This may result in additional units being reduced or off-line if that has been their typical history (e.g. hydro generation during periods of low river flow).

4.3.7 Facility Status

Initial conditions assume all existing facilities normally connected to the system are available and operating as designed or expected.

Studies should not consider presently planned improvements or modifications to be assured to be implemented for future system models. Instead, these improvements should be updated and reaffirmed through the study process as being necessary and the most cost-effective options available. Risks, consequences, and exposure levels should be determined in the event that projects are not completed as planned.

4.4 Modeling For Stability Analysis

4.4.1 Dynamic Models

Dynamic models are required for generators and their associated equipment, HVdc terminals, and protective relays to calculate the fast acting electrical and mechanical dynamics of the power system. Dynamic model data is maintained in cooperation with NEPOOL and NPCC.

4.4.2 Load Level and Load Models

Stability studies within NEPOOL typically exhibit the most severe system response under light load conditions. Consequently, transient stability studies are typically performed with a bulk power system load level of 45% of peak system load. Other system load levels may be studied when required to stress a system interface, or to capture the response to a particular generation dispatch within a specific area or system.

System loads within NEPOOL are usually modeled as constant admittances for both active and reactive power, but other load models can be used as needed. Loads outside NEPOOL are modeled consistent with the practices of the individual areas. Appropriate load models for other areas are available through NEPOOL and NPCC.

4.4.3 Generation Dispatch

Generation dispatch for stability studies typically differs from the dispatch used in thermal and voltage analysis. Generation within the area of interest (generation behind a transmission interface or generation at an individual plant) is dispatched at full output within known system constraints. Remaining generation is dispatched economically. To minimize system inertia, generators are dispatched fully loaded to the extent possible while respecting system reserve requirements.

4.5 Addressing System Deficiencies and Constraints

System studies should clearly identify results that fail to satisfy criteria or constrain performance. To the extent that supporting information is available, these deficiencies or constraints should be quantified in terms of severity, extent of impact, duration and periods of exposure.

4.6 Development and Evaluation of Alternatives

If the performance or reliability of the forecasted system does not conform to the applicable criteria, then alternative solutions based on performance, reliability, technical preference, economics, and capacity need to be developed and evaluated. The evaluation of alternatives leads to a recommendation, which is summarized concisely in a report.

4.6.1 Performance

The system performance with the proposed alternatives should meet or exceed all applicable planning criteria.

4.6.2 Reliability

This guide assesses reliability deterministically by defining conditions which the system must be capable of withstanding. This deterministic approach is consistent with NEPOOL and NPCC practice. The system is designed to meet these deterministic criteria to promote reliability and efficiency.

The level of reliability provided through this approach may vary on the bulk system. To some degree this is acceptable due to inherent factors such as differences in local area load level, load shape, proximity to generation, interconnection voltage, accessibility of transmission resources, service requirements, and class and vintage of equipment. When the level of reliability provided to an area is significantly lower than other areas, alternatives are developed to improve the reliability.

When assessing local area reliability, the engineer compares the reliability of comparable areas at different locations on the system. This comparison considers factors such as age, condition, style, and failure rates of equipment. The cause of poor reliability also influences the recommended action. Therefore, the engineer must assess the specific conditions affecting the reliability of service to particular customer(s).

If remedial actions are taken, historical performance data over an appropriate period of time may need to be re-established prior to assessing the need for additional remedial actions.

4.6.3 Technical Preference

Technical preference should be considered when evaluating alternatives. Technical preference refers to concerns such as standard versus non-standard design or to an effort to develop a future standard. It may also refer to concerns such as age and condition of facilities, availability of spare parts, ease of maintenance, ability to accommodate future expansion, or ability to implement.

4.6.4 Economics

Initial and future investment cost estimates should be prepared for each alternative identified during the course of a study. An engineering economic analysis, as defined in the Unitil Economic Evaluation Procedures, is required to compare the total unit cost of each alternative. The analysis should include the annual charges on investments, losses, and all other expenses related to each alternative.

4.6.5 Capacity

All equipment should be sized based on economics, operating requirements, standard sizes, and engineering judgment. Engineering judgment should include recognition of realistic future constraints that may be avoided with minor incremental expense. As a rough guide, unless the equipment is part of a staged expansion, the capability of any new equipment or facilities should be sufficient to operate without constraining the system and without additional major modifications for at least ten (10) years.

4.7 Recommendation

Every study that identifies potential violations of design criteria shall propose recommended actions. The recommended actions should be based on factors such as the forecasted performance, reliability, economics, technical preference, schedule, availability of land and materials, acceptable facility designs, environmental impacts of facilities, and complexity to license and permit.

4.8 Reporting Study Results

A system planning study should culminate in a professional report clearly describing the assumptions, procedures, problems, alternatives, economic comparison, conclusions, and recommendations resulting from the study.

5 TERMINOLOGY

Bulk Power System

The interconnected electrical system comprising generation and transmission facilities on which faults or disturbances can have a significant effect outside the local area.

Contingency

An event, usually involving the loss of one or more elements, which affects the power system at least momentarily.

Contingency Configuration

A modified arrangement of the system to attain acceptable conditions following a contingency event.

Design Contingency

A pre-determined emergency scenario that system adequacy is measured against.

Distribution Point

Locations on a system that are direct supply outputs for distribution circuit loads. This may be, for example, at unregulated distribution circuit or customer taps off of subtransmission lines, or at substation low-side buses where voltage regulation is provided by load-tap-changing power transformers or regulators at the transformer output.

Drastic Action Level (DAL)

Any loading of an element above its STE limit. DAL loading requires immediate relief, including the shedding of load if necessary, to avoid the likelihood of unacceptable or catastrophic damage to equipment..

Element

Any electric device with terminals which may be connected to other electric devices, such as a generator, transformer, transmission circuit, phase angle regulating transformer, an HVdc pole, braking resistor, a series or shunt compensating device or bus section. A circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its current transformer(s).

Extreme Peak Load

A maximum foreseeable load level benchmark, such as might occur during extraordinary, one-in-ten-year temperature extremes.

Interface

A collection of transmission lines connecting two areas of the transmission system.

Load Cycle

Refers to the varying facility loading over a 24-hour period.

Long-Time Emergency (LTE) Limit, Summer or Winter

Allowable peak loading to which equipment can operate for a single, non-repeating load cycle due to emergency circumstances, accepting the possibility of higher than normal loss of life or loss of strength.

Loss of Load

Loss of service to one or more customers excluding automatic switching time.

NEPOOL

The New England Power Pool, formed in 1971, is a voluntary association of electric utilities in New England who established a single regional network to direct the operations of the major generating and transmission (bulk power system) facilities in the region.

Non-Distribution Point

Locations on a system that are not direct supply outputs for distribution circuit loads. Most transmission and subtransmission lines are non-distribution, as are most substation facilities where the voltage regulation is applied after the low-side bus (i.e. at the individual distribution circuit terminals).

Non-Radial Line

A transmission or subtransmission line, or portion of a line, with more than one possible sending end. A non-radial line may operate radially by being open at one or more ends or intermediate switching locations. However, a radially operating line is still considered non-radial if it has been designed with the intent of utilizing its alternate sending ends to carry or deliver power.

NPCC

The Northeast Power Coordinating Council is an electric regional reliability council, which was formed shortly after the 1965 Northeast Blackout to promote the reliability and efficiency of the interconnected power systems within its geographic area. The NPCC area includes the following U.S. states and Canadian provinces: Massachusetts, Connecticut, Rhode Island, New York, Vermont, New Hampshire, Maine, Ontario, Quebec, New Brunswick, and Nova Scotia.

Normal Configuration

The intended arrangement of a system when all normally in-service elements are available.

Normal Limit, Summer or Winter

Allowable peak loading to which equipment can operate during normal, continuous load cycling and prescribed seasonal conditions.

Peak Design Load

The benchmark load level that system adequacy is measured against. The **Peak Design Load** is the highest anticipated coincident, active (real) power demand of all system customers, plus associated system losses, plus adjustments deemed reasonable to address forecasting uncertainties. It is the actual load and losses to be supplied, and not the net sum of power flows at system boundaries after being offset by internal sources.

Radial Line

A transmission or subtransmission line, or portion of a line, with only one effective sending end and no back up ties to carry or deliver power.

Scheduled Switching

Any planned switching which is scheduled in advance of any work. This does not include work that occurs as a result of a contingency.

Short-Time Emergency (STE) Limit, Summer or Winter

One-time peak loading which can be sustained by equipment for up to 15 minutes while corrective actions are underway following a contingency emergency, and accepting the likelihood of higher than normal loss of life or loss of strength.

Special Protection Systems

A Special Protection System (SPS) is a protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Automatic underfrequency load shedding is not considered an SPS.

System Supply Transformer

Transformers that deliver power into a system from its external transmission supply.

System

The collection of electric transmission, subtransmission and substation elements that receive electric power supplied from internal and external sources and transport and deliver it to distribution systems. The system is generally a continuous infrastructure in a certain operating area.

Unitil owns and operates systems in three areas: Unitil Energy Systems – Capital (in the region of Concord, NH), Unitil Energy Systems – Seacoast (in the region of Exeter and Hampton, NH), and Fitchburg Gas and Electric Light (Fitchburg, MA).

Transfers

The flow of electrical power across a transmission circuit or interface.

Table 1. Design Guideline Summary

Design Condition	Load Level	Generation	Allowable Element Loading Limit[1]	Allowable Element Loading Duration	Allowable Loss of Load Limit	Allowable Loss of Load Duration
Normal Configuration – all elements in service, or non-emergency configuration	≤ Peak Design Load	typical seasonal dispatch w/ up to half of internal, non-utility generating units out of service	≤ Normal	---	none	---
Normal Configuration – outage of generating plant			≤ Normal	---	none	---
Contingency Configuration – loss of non-radial line			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---
Contingency Configuration – loss of radial line (no backup tie)			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
Contingency Configuration – loss of system supply transformer			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
Extreme Peak – all elements in service	≤ Extreme Peak Load		≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---

(S) = Summer load cycle, (W) = Winter load cycle

Table 2. Voltage Range Summary

Condition	Low Limit (p.u.)	High Limit (p.u.)
Non-Distribution points	0.90	1.05
Distribution points	0.975	1.042

[1] STE loading is acceptable following a loss-of-element contingency, provided actions are available to relieve the loading within 15 minutes.

Unitil
Unitil Service Corp.

Ten-Year System Load Forecasts
Summer 2010 - 2019

Distribution Engineering Dept.
April 6, 2009

The attached charts and tables provide the present ten-year load forecasts for the UES-Capital, and UES-Seacoast electric systems. For each system, three forecasts are established – an *Average Peak Load*, *Peak Design Load* and *Extreme Peak Load*. Each forecast is based on a linear trend of the system's temperature-adjusted ten-year load history.

Projection Methodology
The historical basis for each system is a series of yearly regression models that are developed to correlate actual daily loads to actual daily temperatures in that season. Once a model is established, an estimated peak load can be derived for that season for any given temperature. There are two dimensions of variability introduced with this modeling. First is the highest daily temperature experienced within a season, which varies with short-term weather trends from one year to another. Second is the model estimate of peak load at any specific temperature. This estimate has its own variation of possibilities due to the influence of other existent factors not incorporated into the model. These variations are characterized as randomness in making future projections. The probability distribution for annual highest temperatures is assumed to follow the discrete distribution of past historical highest temperatures. The random possibilities of peak load outcomes for any specific temperature are assumed to follow a standard probability distribution model with a mean centered on the point estimate of the peak load at that temperature and varying based on its individual standard deviation according to the fit of the seasonal model to the actual historical values.

To establish load projections, a Monte Carlo simulation is run to produce random annual highest temperatures and random peak load estimates at those temperatures from each year's seasonal model that makes up the historical basis. Each trial in the simulation is projected forward using linear trending. This results in a range of peak load possibilities for each future year assuming linear growth, and varying due to annual highest temperature possibilities and variability in loads versus temperature. The likelihood of specific peak load levels occurring in any particular future year can be estimated from an assumed probability distribution using the mean and standard deviation of the trial results for that year. The *Average Peak Load*, *Peak Design Load* and *Extreme Peak Load* forecasts are set at specific probability limits per the intent of planning guidelines.

Load Levels
The *Average Peak Load* is provided as a guide for general load growth decisions not related to system infrastructure planning. The attached *Average Peak Design Load* forecasts are set at the 50% probability limit. Based on the assumptions of the modeling

and projection methods, each year there is an equal likelihood of that year's peak demand load being either higher or lower than the *Average Peak Load* level.

For the purpose of assessing the adequacy of system infrastructure, contingency studies for the loss of major system elements are evaluated against *Peak Design Load* levels to identify where and when system constraints do not meet planning guidelines. The attached *Peak Design Load* projections are set at the 90% probability limit. This is intended to roughly equate to a 1-in-10 year likelihood that the *Peak Design Load* level will be exceeded.

It is important to recognize that with this level of study, constraints and reinforcements are not necessarily associated with major contingencies occurring only at the highest peak hour of the year. Instead, they are associated with contingencies occurring any time during broader stretches of heavy loading that may or may not encompass that one maximum peak hour. In situations when actual demand somewhat exceeds contingency design forecasts, there should be less concern that design criteria will be challenged unless a contingency condition also exists at the same time. The probability of major contingencies existing at times when loads exceed *Peak Design Load* levels should be quite small. Furthermore, the period of exposure to those unplanned conditions should be kept brief if such an event were to occur.

More demanding *Extreme Peak Load* levels are used for evaluation of system constraints under these higher conceivable load conditions, but without the loss of major equipment. The attached *Extreme Peak Load* projections are set at the 96% probability limit. This is intended to roughly equate to a 1-in-25 year likelihood that the *Extreme Peak Load* level will be exceeded. Under conditions up to these *Extreme Peak Load* levels, it is essential that the system, with all major elements in service, meet planning guidelines while serving all customers. In the event that conditions exceed these *Extreme Peak Load* levels, load shedding and/or additional loss of equipment life may be acceptable.

UES-Capital – Summer

The UES-Capital system reached a peak load for the summer of 2008 of 128.847 MW on June 10, 2008 at 4:00 PM[1]. The daily average temperature was 82°F on this peak day. The highest peak load for the UES-Capital system remains 134.007 MW, set on August 2, 2006 at 2:00 PM. The historical mean of annual highest daily average temperatures for the past twenty years[2] is 81.7°F. The linear trend of the 81°F mean point estimates from annual load-versus-temperature models for the UES-Capital system is 2.5 MW per year with an average standard deviation of ±3.1 MW among the models at this temperature.

Table 1. UES-Capital Ten-Year Summer Design Forecasts

Projected Summer Season	Average Peak Load[3] (MW)	Peak Design Load[4] (MW)	Extreme Peak Load[5] (MW)
2010	131.8	142.0	145.6
2011	133.3	144.5	148.8
2012	135.7	147.6	152.1
2013	136.9	150.3	155.2
2014	138.9	152.9	158.3
2015	141.4	155.9	161.3
2016	143.3	158.3	164.1
2017	145.1	161.3	167.5
2018	146.9	164.0	170.5
2019	149.1	166.8	173.5

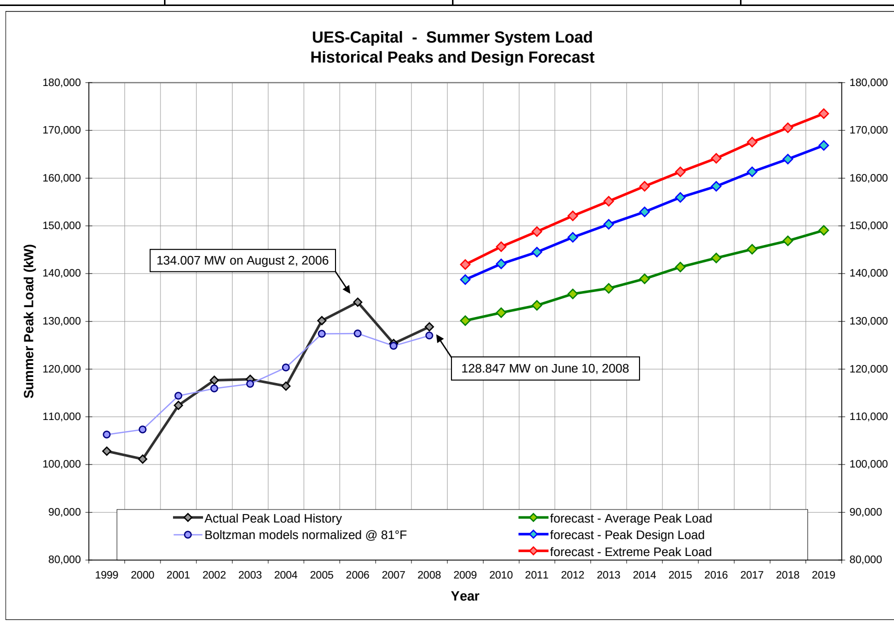


Chart 1. UES-Capital – Historical Summer System Peak Loads and Design Forecasts.

---

1 - peak hourly consumption of 128,847 kWhr
2 - with adjustments to the daily average temperatures on record for the summer peak days in 2005 and 2006 to discount drops in late afternoon temperatures due to thunderstorms on these days.
3 - est. 50% probability limit
4 - est. 90% probability limit
5 - est. 96% probability limit

UES-Seacoast System – Summer

The UES-Seacoast system reached a peak load for the summer of 2008 of 147.168 MW on July 9, 2008 at 5:00 PM[6]. The daily average temperature was 81°F on this peak day. The highest peak load for the UES-Seacoast system remains 170.548 MW, set on August 2, 2006 at 5:00 PM. The historical mean of annual highest daily average temperatures for the past twenty years[7] is 82.4°F. The linear trend of the 82°F mean point estimates from annual load-versus-temperature models for the UES-Seacoast system is 4.3 MW per year with an average standard deviation of ±4.6 MW among the models at this temperature.

Table 2. UES-Seacoast Ten-Year Summer Design Forecasts

Projected Summer Season	Average Peak Load[8] (MW)	Peak Design Load[9] (MW)	Extreme Peak Load[10] (MW)
2010	165.5	180.5	184.8
2011	169.5	185.8	190.4
2012	173.4	191.9	196.7
2013	177.0	196.4	202.7
2014	179.4	201.7	207.9
2015	183.3	206.7	213.9
2016	186.8	211.5	219.0
2017	190.3	216.3	224.5
2018	193.8	220.9	229.5
2019	196.9	225.8	235.1

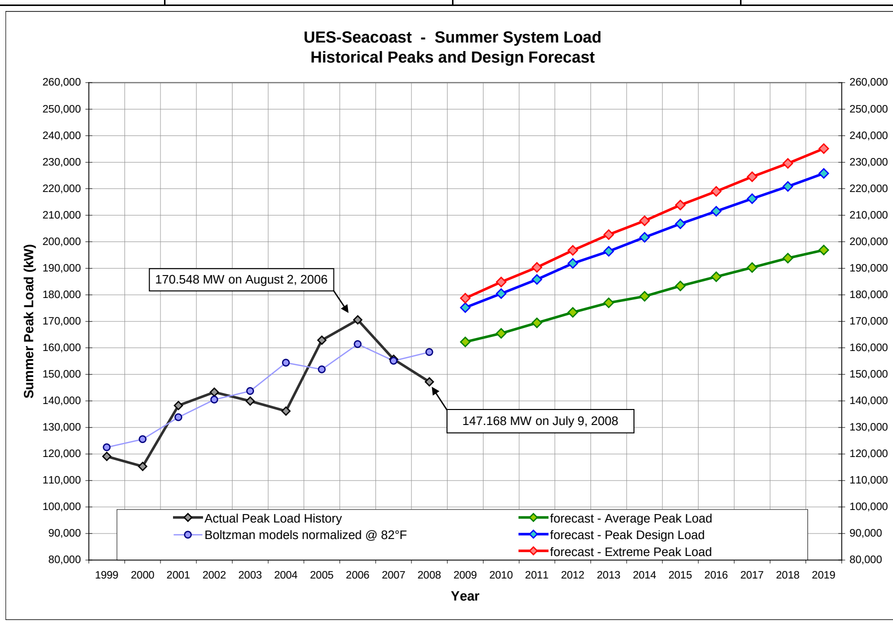


Chart 2. UES-Seacoast – Historical Summer System Peak Loads and Design Forecasts.

6 - peak hourly consumption of 147,168 kWhr.

7 - with adjustment to the daily average temperature on record for the summer peak day in 2005 to discount a drop in late afternoon temperatures due to thunderstorms on this day.

8 - est. 50% probability limit

9 - est. 90% probability limit

10 - est. 96% probability limit

Unitil Energy Systems - Capital

Electric System Planning Study
2013-2022

Prepared By:

J. Goudreault
Unitil Service Corp.
November 29, 2012

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

This study is an evaluation of the Unitil Energy Systems – Capital (UES-Capital) electric power system. Its purpose is to identify when system growth is likely to cause system supplies and main elements of the 34.5 kV subtransmission and substation systems to reach unacceptable design limits, and to provide recommendations for the most cost-effective system improvements. The study examines the UES-Capital system under summer peak load conditions in its normal operating configuration and in response to design contingencies for the loss of key system elements. The study covers the ten year period from 2013 through 2022.

The following system improvements are recommended from the results of this study:

Year	Project Description	Justification	Cost
2013	Implement Load Shed Scheme at Penacook	Basecase & Contingency Loading	Minimal
	Implement Load Encroachment Settings at Horse Shoe Pond	Contingency Loading	Minimal
	Setting Changes at 4X1 Recloser	Contingency Loading	Minimal
	Install Capacitor Bank on 33 Line at Pleasant Street	Contingency Voltage Support	$30,000
	Install Capacitor Bank on 38 Line at Hazen Drive	Contingency Voltage Support	$30,000
2014	115 – 34.5kV System Supply – Broken Ground (Phase 1 of 4)	Basecase & Contingency Loading	$175,000
2015	115 – 34.5kV System Supply – Broken Ground (Phase 2 of 4)	Basecase & Contingency Loading	$2,300,000
2016	115 – 34.5kV System Supply – Broken Ground (Phase 3 of 4)	Basecase & Contingency Loading	$6,750,000
2017	115 – 34.5kV System Supply – Broken Ground (Phase 4 of 4)	Basecase & Contingency Loading	$775,000
2021	Re-conductor 37 Line (Penacook S/S – 4X1 Tie) and Setting Changes to 37 Breaker	Contingency Loading	$300,000

Note: cost estimates do not include general construction overheads.

2 INTRODUCTION

The purpose of this study is to plan for recommended system improvements to meet system design and performance objectives. It evaluates the adequacy of the UES-Capital electric system with respect to its external system supply interconnection and internal system infrastructure throughout the study period. Conditions are examined at increasing load levels (representing expansion of electric customer load) under normal operating conditions, contingency scenarios for loss of major system elements, and extreme load levels above forecast design loads (representing load expansion plus exceptional hot weather conditions).

Detailed system models were developed for each year of design and extreme peak load levels. Power flow simulations were performed for normal and contingency configurations. From these simulations, system deficiencies were identified. System improvement alternatives were developed and tested to assess the impact they had on these deficiencies. Cost estimates were developed for each improvement alternative, and a cost-benefit comparison was made for the improvement plan options. Final recommendations represent the proposed system improvement plan.

3 SYSTEM DESCRIPTION

The UES–Capital electric power system is supplied by the Northeast Utilities – Public Service of New Hampshire (NU-PSNH) 34.5 kV subtransmission system from six interconnection points. Four of these interconnections emanate from the NU-PSNH Garvins substation located in Bow. Two tie points originate from the NU-PSNH Oak Hill S/S located in Concord.

The NU-PSNH Garvins S/S is served from three 115 kV transmission lines; the H-137 originating from Merrimack Station, the G-146 connecting to Deerfield S/S, and the V-182 connecting to the Webster S/S. Two 115 - 34.5 kV, 36/48/60/67.2 MVA transformers supply the Garvins 34.5kV bus. Three UES-Capital subtransmission lines (374, 375 & 396) are served directly from Garvins 34.5kV breaker positions. A fourth interconnection is a radial tap of the PSNH 318 Line. This radial tap serves as the normal supply into the UES-Capital Hollis S/S.

The NU-PSNH Oak Hill S/S is served from two 115kV transmission lines; the P-145 from Merrimack Station and the F-139 from Webster S/S. Two 115 - 34.5 kV, 24/40/44.8 MVA transformers supply the Oak Hill 34.5kV bus. Two NU-PSNH 34.5kV subtransmission lines emanating from Oak Hill (3122 and 317 lines) supply the UES-Capital Penacook S/S.

The UES-Capital electric system consists of seven 34.5kV subtransmission lines interconnecting sixteen distribution substations. The 374 Line operates radially between Garvins and Bow Jct S/S. The 396 Line supplies the 374 Line beyond Bow Jct S/S. From Bow Jct S/S the 374 Line operates in parallel with the 375 Line Garvins to Bridge St S/S. The 34 and 35/36 lines operate in parallel from Bridge Street S/S to Penacook S/S. The 37 line operates radially from Penacook S/S to Boscawen S/S. The 33 line interconnects Bow Junction S/S and West Concord S/S with a normally open point at Pleasant St S/S. The 38 line interconnects Hollis S/S with the 35 line at the Horse Shoe Pond Tap with a normally open point at Hazen Drive S/S.

In addition to the 34.5kV interconnections with NU-PSNH, five non-utility generating plants connect internally into the UES–Capital system. The largest, Wheelabrator Concord (SES-Concord), interconnects at 34.5 kV at the 37X1 tap off the 37 line and typically supplies 12 MW to 14 MW into the system. Three hydro-generation facilities, Penacook Upper Falls, Penacook Lower Falls and Briar Hydro, interconnect at 34.5 kV in the vicinity of Penacook substation. Concord Steam interconnects to the 13.8 kV distribution system in downtown Concord. Finally, the NU-PSNH Garvins Falls hydro-generation station interconnects directly at Garvins S/S.

A system one-line diagram is included in Appendix J for reference.

4 SYSTEM LOADS

The scheduling of system modifications is dependent on the projected timetable of system loads that trigger the need. For planning purposes, design forecasts are based on linear trend projections of a ten-year history of daily load versus temperature regression models, which account for the correlation of daily loads to actual daily temperature. This results in a range of peak load possibilities for each year, which vary due to annual highest temperature. Peak Design Load and Extreme Peak Load forecasts are set assuming specific probability limits per the intent of planning guidelines. Details of the methodology and results are given in Appendix D – Ten Year System Load Forecasts.

The resulting UES-Capital system load projections used for this study are provided in the table below.

UES-Capital System Loads Under Study

Projected Summer Season	Peak Design Load (MW)	Extreme Peak Load (MW)
2013	137.4	141.1
2014	138.8	142.6
2015	140.6	144.9
2016	142.2	146.7
2017	143.6	148.1
2018	144.8	149.7
2019	146.8	151.9
2020	148.3	154.0
2021	149.6	155.7
2022	151.3	157.1

5 SYSTEM MODELING AND ANALYSIS

Traditional load flow analysis methods were used to evaluate the UES-Capital system for this study. System modeling and power flow simulations were performed using PSS®E (version 32.0.3) software by Siemens. Because summer hot weather conditions present the greatest thermal constraints on system equipment, and UES-Capital is a historically summer peaking system, this study examines summer peak load conditions only.

An initial load flow model of the UES-Capital system was created to replicate conditions during the 2011 summer peak. Details of the UES-Capital system infrastructure were assembled using best available data on system impedances, transformer ratios, equipment ratings, etc. This model was added to a representation of the surrounding external power system from load flow cases provided by ISO-NE and PSNH. Bus loads were compiled for the model by aggregating substation, circuit, and large customer load information for the July 22, 2011 summer peak. Much of this load information is available only as non-coincident, monthly peak demands. With the operating configuration, substation and capacitors set in the model to actual conditions at the time, overall scaling adjustments were made to bus loads to reasonably match the power flow simulation results to actual recorded system flows for the peak day and hour. Once completed, this established a confident model representing the UES-Capital system as it existed during the 2011 summer peak.

Basecase models for study of future years were developed from this 2011 peak model. Anticipated system configuration and known individual load adjustments were made. Then overall bus loads were grown to set the total UES-Capital system load plus internal losses, as seen at the system supply delivery points, to the study loads (Section 4 – System Loads).

These basecases were used to analyze normal operating conditions, extreme peak conditions, and all major design contingencies for each of the ten years under study. Unacceptable system conditions were identified based on the Unitil Electric System Planning Guide. Details summarizing these criteria are given in Appendix A – Evaluation Criteria.

6 POWER FACTOR ANALYSIS

Load power factor for the UES-Capital system is subject to the guidelines of ISO-NE Operating Procedure No. 17 – Load Power Factor Correction (OP-17). The power factor limitations outlined in OP-17 are summarized in the following table for the ISO-NE New Hampshire Area.

ISO-NE New Hampshire Area – Load Power Factor Limits

Equivalent Load (% of Peak)	Minimum p.f.	Maximum p.f.
28%	n/a	0.9958, leading
31%	n/a	0.9958, leading
66%	0.9271, lagging	0.9805, leading
94%	0.9667, lagging	n/a
100%	0.9667, lagging	n/a

On July 22, 2011 at 13:00, the UES-Capital system reached a peak demand of 129.877 MW. The system was lagging by 10.187 MVAr during that peak hour, with a corresponding power factor of 0.997 (lagging).

In 2013 at a system peak design load of 137.4 MW, the estimated net power factor is expected to be approximately 0.9855 (lagging) as seen at the 115 kV system supply delivery points. By 2022 at a system peak design load of 151.3 MW, with the new Broken Ground system supply addition in service, the estimated net power factor is expected to be approximately 0.9977 (lagging). Note that the power factor analysis performed assumes all existing substation and subtransmission capacitors are available and switched into service. In addition, all generation is assumed offline since UES-Capital's responsibility to meet ISO-NE load power factor guidelines applies with or without internal generation.

At these load levels, no additional power factor correction capacitor additions are needed to achieve the ISO-NE minimum peak load power factor of 0.9667 (lagging) over the next ten years. The following table lists the estimated system power factor for select years over the ten year study period.

UES-Capital System – Anticipated Power Factor

	Uncorrected System Load *			**Est. Minimum p.f. correction**
Year	**(MW)**	**(MVAr)**	**p.f. (115 kV)**	**(MVAr)**
2013	137.9	23.7	0.9855, lagging	n/a
2016	142.8	29.4	0.9794, lagging	n/a
2017	144.8	8.2	0.9984, lagging	n/a
2021	151.5	10.3	0.9977, lagging	n/a

* - with no improvements, all existing substation capacitors switched into service. Assumes new Broken Ground system supply in service by 2017 with two 7.2 MVAr capacitor banks. Includes UES share of system supply transformer losses at Garvins, Oak Hill and Broken Ground.

7 SYSTEM CONSTRAINTS

The following summarizes the system deficiencies driving improvement proposals during the ten year study period, with the load level and projected year in which they first occur. The table is sorted by year and load level. The system constraint is listed in the year when it first violates planning criteria. Not all circumstances driving the system constraint are shown in this table.

Year	Load Level (MW)	System Constraint	Circumstances
2013	137.4	Transformer Overload – Garvins TB-39 & TB-51[1]	Loss of P145 Line
		Low Voltage – 33 Line	Loss of H137 Line Loss of V182 Line Loss of P145 Line Loss of Garvins Transformer
		Low Voltage – 38 Line	Loss of V182 Line Loss of Garvins Transformer Loss of 38 Line @ Hollis
		Equipment Overload – 317 Line	Loss of 3122 Line
		Equipment Overload – 3122 Line	Loss of 317 Line
		Protection Setting Overload – Circuit 4X1	Loss of 37 Line
		Protection Setting Overload – 38 Recloser at Horse Shoe Pond	Loss of 318 Line Loss of Hollis Tap
2014	142.6	Transformer Overload – Garvins TB-39 & TB-51[1]	Extreme Peak
2016	142.2	Transformer Overload – Garvins TB-39 & TB-51[1]	Basecase
2017	143.6	Transformer Overload – Garvins TB-39 & 51	Loss of any Supply Transformer Loss of 317 Line Loss of 3122 Line Loss of 34 Line @ Penacook Loss of 36 Line @ Penacook
		Transformer Overload – Oak Hill TB-15 & 84	Loss of any Supply Transformer
		Equipment Overload – 318 Hollis Tap Conductors	Loss of 38 Line @ Horse Shoe Pond
		Low Voltage – 33 Line	Loss of 33 Line at Bow Junction
2021	149.6	Equipment Overload – 37 Line Penacook to Maccoy Tap	LO Circuit 4X1
		Protection Setting Overload – 37 Breaker at Penacook	LO Circuit 4X1

[1] This constraint is based on the UES-Capital system operating in parallel between Garvins and Oak Hill. The constraint is eliminated by splitting the system as described in Section 8.

The table below is used to further document the system constraints as summarized in the table above. This table is sorted by constraint. All of the contingency conditions for each constraint are detailed. The result column identifies why the constraint does not meet planning criteria. More details on exposure, voltage and loading values can be referenced in the contingency table in Appendix F.

Constraint	Year	Circumstances	Result
Transformer Overload – Garvins TB-39 & TB-51	2013	Loss of P145 Line[1]	Loading > 104% PSNH TFRAT
	2014	Extreme Peak (system looped)[1]	Loading > 100% PSNH TFRAT
	2016	Basecase (system looped)[1]	Loading > 100% PSNH TFRAT
	2017	Extreme Peak	Loading > 91% of PSNH TFRAT
		Loss of any Supply Transformer	Loading > 100% of PSNH TFRAT
		Loss of 317 Line	Loading > 100% PSNH TFRAT
		Loss of 3122 Line	Loading > 100% PSNH TFRAT
		Loss of 38 Line @ Horse Shoe Pond	Loading > 95% PSNH TFRAT
		Loss of 34 Line @ Penacook	Loading > 100% PSNH TFRAT
		Loss of 36 Line @ Penacook	Loading > 100% PSNH TFRAT
Transformer Overload – Oak Hill TB-15 & 84	2017	Loss of any Supply Transformer	Loading > 96% PSNH TFRAT
Low Voltage – 33 Line	2013	Loss of H137 Line	Voltage < 96%
		Loss of V182 Line	Voltage < 96%
		Loss of P145 Line	Voltage < 96%
		Loss of Garvins Transformer	Voltage < 96%
	2017	Loss of 33 Line at Bow Junction	Voltage < 96%

[1] This constraint is based on the UES-Capital system operating in parallel between Garvins and Oak Hill. The constraint is eliminated by splitting the system as described in Section 8.

Constraint	Year	Circumstances	Result
Low Voltage – 38 Line	2013	Loss of V182 Line	Voltage < 96%
		Loss of Garvins Transformer	Voltage < 96%
		Loss of 38 Line @ Hollis	Voltage < 96%
Equipment Overload – 317 Line	2013	Loss of 3122 Line	Loading > 100% LTE
Equipment Overload – 3122 Line	2013	Loss of 317 Line	Loading > 100% LTE
Protection Setting Overload – Circuit 4X1	2013	Loss of 37 Line	Loading > 90% Trip
Protection Setting Overload – 38 Recloser at Horse Shoe Pond	2013	Loss of 318 Line	Loading > 90% Trip
		Loss of Hollis Tap	Loading > 90% Trip
Equipment Overload – 318 Hollis Tap Conductors	2017	Loss of 38 Line @ Horse Shoe Pond	Loading > 100% Normal Exposure > 12 hrs
Equipment Overload – 37 Line Penacook to Maccoy Tap	2021	Loss of Circuit 4X1	Loading > 100% Normal Exposure > 12 hrs
Protection Setting Overload – 37 Breaker at Penacook	2021	Loss of Circuit 4X1	Loading > 90% Trip

8 SYSTEM SUPPLY ADDITION OPTIONS

In last year's system planning study, *Unitil Energy Systems – Capital Electric System Planning Study 2012-2021*, several alternatives were evaluated to relieve the loading constraints at the Garvins supply transformers. It was determined from this evaluation that the addition of another 115kV-34.5kV system supply in the area of Hollis/Broken Ground was the preferred alternative with an in-service date of no later than June 1st, 2017. This in-service date is based on operating the UES-Capital system split between Garvins and Oak Hill during peak load periods to relieve these loading constraints through the summer of 2016. The emphasis of this years' study was to affirm the in-service date and to evaluate the proposed configuration of this supply relative to capacity, equipment configuration, and future expansion.

8.1 Loadflow Results

The results of this years' loadflow analysis, detailed in Section 7 of this report, confirmed that loading on the Garvins transformers is expected to reach thermal limits for many contingencies while operating at 2017 peak design load conditions. These results are predicated on operating the system split at load levels above 137MW (2013). This configuration is required due to loading constraints that occur above 137MW while the system is looped between Garvins and Oak Hill.

The following sections detail the planned operating configuration through the summer of 2016 as well as the proposed configuration of Broken Ground.

8.2 System Configuration 2013-2016

The UES-Capital system is normally operated looped between Garvins and Oak Hill. In this configuration, loading on the Garvins transformers is expected to exceed PSNH TFRAT limits at 2014 Extreme Peak and 2016 bascase load levels. In addition, some local area 115kV contingencies result in initial conditions that approach and in some cases exceed Garvins TFRAT limits as early as 2013 basecase load levels. In order to defer the need for additional supply capacity, it is recommended to split the loop between Garvins and Oak Hill internal to the UES-Capital system in order to shift load from the Garvins supply to Oak Hill.

Outlined below are two alternative configurations studied.

Open at West Concord and West Portsmouth

The first alternative studied was to open the 34 and 35/36 Lines at the 34J3 switch and the 35J3 switch located at West Concord and West Portsmouth substations respectively. This alternative reduces loading at Garvins to approximately 96% of TFRAT limits under 2016 basecase conditions. However, many contingencies (both internal and external to the UES system) result in equipment overload conditions immediately following the contingency which will require subsequent switching to reduce loading to acceptable limits.

In order to facilitate response to these conditions, the replacement of both the 34J3 and 35J3 switches is recommended to provide load break capability and remote SCADA control.

Cost Estimate:

Replace 34J3 and 35J3	$250,000
Total (w/o General Construction OHs)	$250,000

Open at Bridge Street

The second alternative studied was to open the 34 and 35/36 Lines by opening the respective breakers at Bridge Street substation. This configuration reduces loading even further at Garvins to approximately 89% of TFRAT limits under 2016 basecase conditions and eliminates the post-contingency overload concerns when operating split at the West Concord and West Portsmouth. However, this configuration will require the implementation of a load shed scheme at Penacook in order to respond to the loss of either the 317 or 3122 Line from Oak Hill to Penacook. An automatic load shed scheme is necessary since loading on the remaining line will exceed the STE limitation under 2013 peak load levels.

The proposed load shed scheme will trip the 36 breaker at Penacook reducing loading to 108% of the normal rating on the remaining supply line in 2016. The estimated maximum exposure above the normal rating of the remaining line is within planning criteria (9 hours of exposure). UES response following activation of this scheme is to restore the 35/36 Line by closing the 35 breaker at Bridge Street. The resultant loading on the Garvins transformers is expected to remain below TFRAT limits under 2016 peak load conditions.

Cost Estimate:

Implement Load Shed Scheme at Penacook	Minimal
Total (w/o General Construction OHs)	Minimal

Recommendation

Based on the results detailed above, it is recommended to split the system at Bridge Street and move forward with implementation of the load shed scheme at Penacook with an in-service date of 2013. It should also be noted that it is Unitil's intent to operate the UES-Capital system split only at load levels above 137MW or more precisely when loading on the Garvins transformers exceed 62MW (~90% of TFRAT limits). This approach will need to be mutually agreed upon with PSNH as part of the Unitil/PSNH Joint Planning process.

8.3 System Supply Configuration

Unitil/UES owns a large plot of land, dubbed Broken Ground, adjacent to a 115kV corridor in the vicinity of Hollis substation. Two NU/PSNH 115kV transmission lines currently exist within this corridor; the P145 Line and the V182 Line. The proposal presented to NU is to loop one of these 115kV lines through a Unitil owned 115kV-34.5kV substation which will include the following equipment:

- (2) 115kV line terminals and busses rated 120MVA minimum
- (1) 115kV bus tie rated 120MVA minimum
- (2) 115kV:34.5kV 30/40/50MVA transformers with LTC
- (2) 34.5kV buses and bus tie with (4) outgoing line terminals per bus
    - Transformer positions rated 120MVA
    - Bus tie position rated 120MVA
    - Line terminal positions rated 72MVA

- (2) 34.5kV, 7.2MVAr capacitor banks (2x3.6MVAr stages)

Additionally, two (2) 34.5kV supply lines will be built from Broken Ground substation into Hollis substation. Each supply line will terminate on opposite sides of the Hollis 34.5kV bus tie. The intent will be to operate the 34.5kV bus tie at Broken Ground normally closed and the bus tie at Hollis normally open. Also, all of the 38 Line will be served radially from Hollis with the open point being moved to the 38 recloser at Horse Shoe Pond. This configuration will result in approximately 40MW of load being served from Broken Ground.

A conceptual layout for this system supply is shown in Figure 1. Note: This loadflow plot shows the V182 Line being the supply to Broken Ground. This line was chosen for conceptual layout purposes only and was based solely on base case line loading. The actual 115kV line which will supply Broken Ground will be determined by NU at a later date.

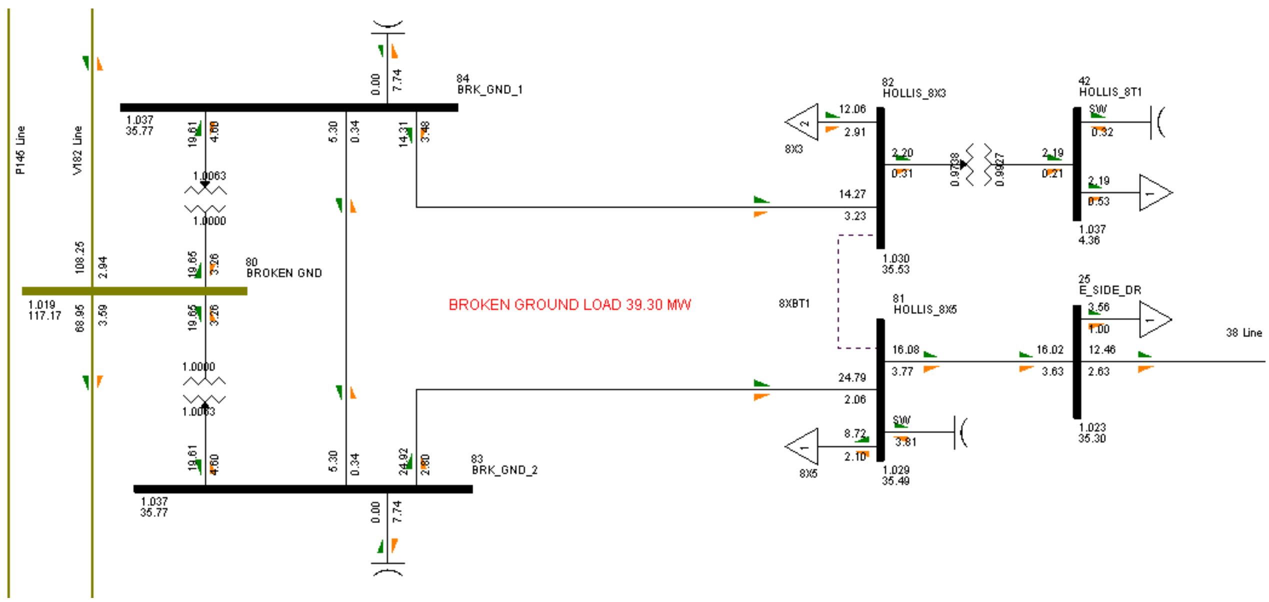


Figure 1: Broken Ground System Supply Configuration (2017)

The following construction schedule is proposed in order to meet the proposed in-service date of June 1, 2017:

Construction Schedule:

2014:

- Preliminary Design
- Survey, Soil and Geo-Tech Testing
- Permitting

Cost Estimate: $175,000

2015:

- Site Work
- Foundation Design
- Transformer Purchase

Cost Estimate: $2,300,000

2016:

- Substation Construction
- Construct (2) 35 kV subtransmission lines from Broken Ground to Hollis[1] (approx. 1 mile of 954 AA conductor and 477 AA neutral crossarm construction)
- Transformer Delivery
- Control House Delivery

Cost Estimate: $6,750,000

2017:

- Control Wiring
- Testing
- Commissioning

Cost Estimate: $775,000

Total Cost Estimate:

Construct Broken Ground S/S	$10,000,000
Total (w/o General Construction OHs)	$10,000,000

Results

The addition of Broken Ground will resolve system supply loading constraints for many years beyond the study period. It also eliminates many of the system constraints identified in this study for contingencies internal to the UES-Capital system such as loss of the 318 Line or loss of the Hollis Tap.

Basecase and Extreme Peak Loading:

- There are no system supply constraints identified for many years beyond the study period. For reference, the expected supply transformer loading conditions at the 2022 Extreme Peak load level (157MW) are listed below:
    - Garvins @ 86%
    - Oak Hill @ 45%
    - Broken Ground @ 37%

Loss of a115kV Transmission Line:

[1] The scope of this project also includes the construction of a 34.5kV distribution circuit from Broken Ground to Hollis within this same ROW. Details of the distribution circuit construction are not denoted here.

- In 2022, the loss of either the V182 or the P145 Lines result in loading on the Garvins transformers of 90% and 98% of TFRAT respectively assuming the 396/374/34 and 375/35/36 lines are looped and the entire 38 Line is fed radially from Broken Ground. Splitting the loop at the 34 and 35 breakers at Bridge Street in response to this contingency reduces loading at Garvins to less than 75% of TFRAT.

Loss of a System Supply transformer:

- Loading at Broken Ground following the loss of one transformer results in loading of 60% of the remaining unit's thermal limit in 2022 (based on a 60MVA rating).

- Following the loss of a Garvins transformer in 2022, overload concerns are identified at PSNH's Eddy & Rimmon substations. Several options will be discussed with PSNH during the Unitil/PSNH Joint Planning process to address these concerns including the following:

    - UES switching to feed the entire Bridge Street bus from the Broken Ground via the 38 Line. This solution is considered short term and would require protection setting changes on the 038 recloser at Hollis.

    - Loop the Broken Ground supply with Garvins via the 318 Line. This configuration would require terminating (or tapping) the 318 Line at the Broken Ground 35kV bus.

    - Construct additional 35kV subtransmission lines from Broken Ground to West Portmouth and/or Terrill Park.

- Following the loss of an Oak Hill transformer in 2022, the remaining unit approaches 98% of TFRAT with no load out of service (assuming the system is looped). Internal switching options are available on the UES system can reduce this loading to approximately 90% at Oak Hill. These switching scenarios will generally increase loading on the Garvins units to approximately 90% of TFRAT.

  The alternatives described to address loading constraints for loss of a Garvins transformer will also relieve future loading constraints following the loss of an Oak Hill transformer.

<u>Future Considerations:</u>
Future studies will focus on alternatives for making use of the additional supply capacity provided by Broken Ground. Some examples under consideration are listed below:

- Construct new 34.5kV subtransmission lines into West Portsmouth and/or Terrill Park.
- Construct new 34.5kV distribution circuit(s) in order to reduce the number of customers/geographical area being served by the distribution circuits out of Hollis substation.
- Construct new 34.5kV subtransmission line(s) to offload or provide back up for area PSNH subtransmission lines (e.g. 318 Line).

9 SYSTEM IMPROVEMENT OPTIONS

The following sections describe details of system improvement alternatives examined to address the deficiencies identified earlier in this report.

9.1 38 Line Protection Setting Encroachment

The 38 Line from Horse Shoe Pond is used to restore the 38 Line load beyond the normally open point (38J3) as well as and a portion of the Hollis load following the loss of either the 318 Line of for the loss of the Hollis Tap. At system load levels above 137MW (2013), the phase overcurrent element of the 38 recloser at Horse Shoe Pond will exceed 90% of the minimum trip setting.

9.1.1 Option #1: Protection Setting Change

Summary:

Prior to summer of 2013, a relay setting change will be required on the 38 recloser in order to eliminate the load encroachment on the existing phase overcurrent element.

Cost Estimate:

Protection setting change	Minimal
Total (w/o General Construction OHs)	Minimal

Results:

Encroachment on the phase overcurrent element is eliminated through 2016. This contingency is eliminated once Broken Ground is in-service.

9.1.2 Recommendation

No other viable alternatives exist for this constraint. Therefore, a protection setting change in 2013 is the recommended alternative.

9.2 4X1 Protection Setting Encroachment

Circuit 4X1 is used to restore the 37 Line load following the loss of the 37 Line between Penacook and the tie with 4X1 (37J41). At system load levels above 137MW (2013), the phase overcurrent element of the 4X1 OCB at Penacook will exceed 90% of the minimum trip setting.

9.2.1 Option #1: Protection Setting Change

Summary:

Prior to summer of 2013, a relay setting change will be required on the 4X1 OCB in order to eliminate the load encroachment on the existing phase overcurrent element.

Cost Estimate:

Protection setting change	Minimal
Total (w/o General Construction OHs)	Minimal

Results:

Encroachment on the phase overcurrent element is eliminated through the study period.

9.2.2 Recommendation

No other viable alternatives exist for this constraint. Therefore, a protection setting change in 2013 is the recommended alternative.

9.3 Low Voltage on 33 and 38 Lines

At system load levels above 137MW (2013), several internal and external contingencies result in voltages below planning criteria on the 33 and 38 Line.

9.3.1 Option #1: Install Capacitors

Summary:

Prior to summer of 2013, remove the existing 1,200kVAr at Pleasant Street S/S (33 Line) and the existing 2,400kVAr at Hazen Drive S/S (38 Line). Install new 3,600kVAr capacitor banks with local controls at each location.

Cost Estimate:

Install Capacitors at Pleasant Street	$30,000
Install Capacitors at Hazen Drive	$30,000
Total (w/o General Construction OHs)	$60,000

Results:

Low voltage concerns are eliminated throughout the study period.

9.3.2 Recommendation

Reconductoring the 33 and 38 Lines would also eliminate these low voltage concerns. However, due to the relative costs, this alternative was not considered. Therefore, the installation of additional capacitors in 2013 is the recommended alternative.

9.4 37 Line Overload and Protection Setting Encroachment

A normally open tie exists between the 37 Line and circuit 4X1 out of Penacook S/S. This tie is utilized as an alternate source following the contingent loss of either circuit 4X1 or the 37 Line. The load carrying capability of the 37 Line is limited by a section of 1/0 ACSR conductor from Penacook S/S to the 37J41 (approx. 1.25 miles).

At system load levels above 137MW (2013), the 37 Line will be loaded above its normal rating if all of circuit 4X1 is transferred (assuming all generation is off-line). Although loading is expected to be above the Normal rating at these load levels, exposure to loading above Normal for more than 12 consecutive hours is not anticipated until the system load level approaches 150MW (2021). Also at these load levels in 2021, loading on the phase overcurrent element of the 37 OCB will exceed 90% of the minimum trip setting.

9.4.1 Option #1: Protection Setting Change and Re-conductor

Summary:

Prior to summer 2021, replace the 1/0ACSR phase conductor on the 37 Line from pole 8 to pole 33 (37J41) with 336.4 AA conductor. This consists of approximately 1.25 pole miles in length. The 266 ACSR neutral conductor will remain. A relay setting change will be implemented on the 37 OCB in conjunction with this project in order to eliminate the load encroachment on the existing phase overcurrent element.

Cost Estimate:

Re-conductor 37 Line	$300,000
Total (w/o General Construction OHs)	$300,000

Results:

Loading on the 37 Line following the loss of Circuit 4X1 will remain below 65% of its normal rating throughout the study period.

9.4.2 Recommendation

No other viable alternatives exist for this constraint. Therefore, a protection setting change in 2013 and re-conductoring in 2021 is the recommended alternative.

10 MASTER PLAN ANALYSIS

A 20 year master plan review has been completed in addition to the 10 year analysis discussed in this report. This analysis reviews a system model with peak design load that has been scaled proportionately to an equivalent 20 year forecast assuming the historical growth rate. The review is completed under basecase configuration with all elements in service.

This is a high level review which identifies potential system problems which occur beyond the 10 year planning horizon. This review is used to develop a long term vision for the system which is used to guide incremental improvements. For total system loads up 167 MW the following additional conditions have been identified for basecase conditions.

- Garvins TB-39 & TB-51 loading approaching 90% TFRAT (if system looped)
- 34 Line Overload from Penacook to West Concord (if system split at Bridge St)
- 33 Line Low Voltage (if system split at Bridge St)
- 34 Line Low Voltage (if system split at Bridge St)

Modeling Assumptions:

- All available capacitor banks switched in
- All internal generation offline
- Broken Ground in Service
- 37 Line Re-conductored

Other Considerations:

Long term planning of the UES-Capital system will need to focus on utilizing the additional capacity provided by the Broken Ground system supply. Resolving the challenges that exist with the geographic location of this site relative to existing subtransmission corridors will need to be addressed in order to configure the system such that this capacity can be utilize the to its fullest extent possible.

11 FINAL RECOMMENDATIONS

The following summarizes final recommendations given in this report.

Year	Project Description	Justification	Cost
2013	Implement Load Shed Scheme at Penacook	Basecase & Contingency Loading	Minimal
	Implement Load Encroachment Settings at Horse Shoe Pond	Contingency Loading	Minimal
	Setting Changes at 4X1 Recloser	Contingency Loading	Minimal
	Install Capacitor Bank on 33 Line at Pleasant Street	Contingency Voltage Support	$30,000
	Install Capacitor Bank on 38 Line at Hazen Drive	Contingency Voltage Support	$30,000
2014	115 – 34.5kV System Supply – Broken Ground (Phase 1 of 4)	Basecase & Contingency Loading	$175,000
2015	115 – 34.5kV System Supply – Broken Ground (Phase 2 of 4)	Basecase & Contingency Loading	$2,300,000
2016	115 – 34.5kV System Supply – Broken Ground (Phase 3 of 4)	Basecase & Contingency Loading	$6,750,000
2017	115 – 34.5kV System Supply – Broken Ground (Phase 4 of 4)	Basecase & Contingency Loading	$775,000
2021	Re-conductor 37 Line (Penacook S/S – 4X1 Tie) and Setting Changes to 37 Breaker	Contingency Loading	$300,000

Note: cost estimates do not include general construction overheads.

Unitil Energy Systems – Seacoast

Electric System Planning Study 2013-2022

Prepared By:

Jake Dusling
Unitil Service Corp.
August 23, 2012

TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

This study is an evaluation of the UES–Seacoast electric power system. Its purpose is to identify when system growth is likely to cause system supplies and main elements of the 34.5 kV subtransmission and substation systems to reach unacceptable design limits, and to provide recommendations for the most cost-effective system improvements. The study examines the UES–Seacoast system under summer peak load conditions in its normal operating configuration and in response to design contingencies for the loss of key system elements. The study covers the ten year period from 2013 through 2022.

The following system improvements are recommended from the results of this study:

Year	Project Description	Justification	Cost
2013	Utilize Distribution Ties to Restore Load	Loading for Various Contingencies	n/a
	Reconductor 3360 and 3371 Lines from Timber Swamp to Guinea and Upgrade Breakers at Guinea	Loading for Various Contingencies	$300,000
2016	Construct New System Supply in Kingston, Build a 2nd Line from H141/R191 RoW to Kingston[1]	Extreme Peak and Basecase Loading Kingston TB91 and Great Bay TB141	$19,500,000
	Reconductor 3342 and 3353 Lines from Guinea to Hampton and Upgrade 3342J1, 3342 and 3353 Breakers	Loading for Various Contingencies	$750,000
2021	Reconductor 3345 and 3356 Lines from Kingston to Hunt Road Tap	Loading for Loss of the 3345 Line, Loss of 3356 Line	$600,000

[1] Subject to resolution of transmission planning issues with Northeast Utilities / Public Service of New Hampshire

[2] Portion of cost is capital investment by Northeast Utilities ($12,000,000)

Note: cost estimates do not include general construction overheads.

2 INTRODUCTION

The purpose of this study is to plan for recommended system improvements to meet system design and performance objectives. It evaluates the adequacy of the UES-Seacoast electric system with respect to its external system supply interconnection and internal system infrastructure throughout the study period. Conditions are examined at increasing load levels (representing expansion of electric customer load) under normal operating conditions, contingency scenarios for loss of major system elements, and extreme load levels above forecast design loads (representing load expansion plus exceptional hot weather conditions).

Detailed system models were developed for each year of design and extreme peak load levels. Power flow simulations were performed for normal and contingency configurations. From these simulations, system deficiencies were identified. System improvement alternatives were developed and tested to assess the impact they had on these deficiencies. Cost estimates were developed for each improvement alternative, and a cost-benefit comparison was made for the improvement plan options. Final recommendations represent the proposed system improvement plan.

3 SYSTEM DESCRIPTION

The UES–Seacoast electric power system is presently supplied from Northeast Utilities' (NU) 345 kV and 115 kV transmission systems via three Public Service Company of New Hampshire's (PSNH) substations, Timber Swamp, Kingston, and Great Bay.

Timber Swamp substation, located in northwest Hampton, presently consists of a 345 kV high-side ring bus, two 345 – 34.5 kV, 75/100/125/140 MVA transformers, and two 34.5 kV low-side buses separated by a normally open bus tie breaker. Presently, one 34.5 kV bus supplies two line terminals feeding the UES-Seacoast 3360 and 3371 lines. The second 34.5 kV bus supplies three line terminals feeding PSNH load. The 3360 and 3371 34.5 kV subtransmission lines transfer power from Timber Swamp substation to Guinea switching station serving loads in several UES-Seacoast service territory towns.

Kingston substation, located in central Kingston, consists of an incoming 115 kV radial transmission line, a single 115 – 34.5 kV, 24/32/40/44.8 MVA transformer, and an outgoing 34.5 kV line which transfers power to the adjacent UES–Seacoast Kingston Stepdown substation. Five UES–Seacoast 34.5 kV subtransmission lines emanate from here. Two of these lines supply five distribution substations to the southwest, two lines provide support to the northeast, and one line serves the remaining distribution load throughout Kingston and Danville.

The third supply point, Great Bay Substation, is located in southern Stratham. Great Bay consists of a 115 kV high-side bus, a single 115 – 34.5 kV, 24/32/40/44.8 MVA transformer, and a 34.5 kV low-side bus. Two 34.5 kV subtransmission lines exit Great Bay Substation and proceed to transfer power to eight distribution substations taps which serve loads in the Stratham and Exeter areas.

The UES-Seacoast system also has the ability to be served from the TB69 transformer at Timber Swamp using the PSNH 3112, 3165 and 3172 lines. PSNH's 3141X circuit and UES Seacoast's circuit 22X1 serve as backup supplies to each other.

4 SYSTEM LOADS

The scheduling of system modifications is dependent on the projected timetable of system loads that trigger the need. For planning purposes, design forecasts are based on linear trend projections of a ten-year history of daily load versus temperature regression models, which account for the correlation of daily loads to actual daily temperature. This results in a range of peak load possibilities for each year, which vary due to annual highest temperature. Peak Design Load and Extreme Peak Load forecasts are set assuming specific probability limits per the intent of planning guidelines. Details of the methodology and results are given in Appendix D – Load History and Design Forecasts.

The resulting UES Seacoast system load projections used for this study are provided in the table below.

UES Seacoast System Loads Under Study

Projected Summer Season	Peak Design Load (MW)	Extreme Peak Load (MW)
2013	177.7	181.9
2014	182.7	187.2
2015	188.0	192.8
2016	192.4	197.8
2017	197.0	202.4
2018	201.6	207.2
2019	206.7	212.7
2020	210.8	217.1
2021	216.3	222.6
2022	220.6	227.8

5 SYSTEM MODELING AND ANALYSIS

Traditional load flow analysis methods were used to evaluate the UES-Seacoast system for this study. System modeling and power flow simulations were performed using PSS®E (version 32.0.3) software by Siemens. Because summer hot weather conditions present the greatest thermal constraints on system equipment, and UES-Seacoast is a historically summer peaking system, this study examines summer peak load conditions only.

An initial load flow model of the UES-Seacoast system was created to replicate conditions during the 2011 summer peak. Details of the UES-Seacoast system infrastructure were assembled using best available data on system impedances, transformer ratios, equipment ratings, etc. This model was added to a representation of the surrounding external power system from load flow cases provided by ISO-NE. Bus loads were compiled for the model by aggregating substation, circuit, and large customer load information for the July 6, 2010 summer peak. Much of this load information is available only as non-coincident, monthly peak demands. With the operating configuration, substation and capacitors set in the model to actual conditions at the time, overall scaling adjustments were made to bus loads to reasonably match the power flow simulation results to actual recorded system flows for the peak day and hour. Once completed, this established a confident model representing the UES-Seacoast system as it existed during the 2011 summer peak.

Basecase models for study of future years were developed from this 2011 peak model. Anticipated system configuration and known individual load adjustments were made. Then overall bus loads were grown to set the total UES-Seacoast system load plus internal losses, as seen at the system supply delivery points, to the study loads (Section 4 – System Loads).

These basecases were used to analyze normal operating conditions, extreme peak conditions, and all major design contingencies for each of the ten years under study. Unacceptable system conditions were identified based on the Unitil Electric System Planning Guide. Details summarizing these criteria are given in Appendix A – Evaluation Criteria.

6 POWER FACTOR ANALYSIS

Load power factor for the UES–Seacoast system is subject to the guidelines of ISO-NE Operating Procedure No. 17 – Load Power Factor Correction (OP-17). The power factor limitations outlined in OP-17 are summarized in the following table for the ISO-NE New Hampshire Area.

ISO-NE New Hampshire Area – Load Power Factor Limits

Equivalent Load (% of Peak)	Minimum p.f.	Maximum p.f.
28%	n/a	0.9958, leading
31%	n/a	0.9958, leading
66%	0.9271, lagging	0.9805, leading
94%	0.9667, lagging	n/a
100%	0.9667, lagging	n/a

On July 22, 2011 at 16:00, the UES–Seacoast system reached a peak demand of 168.431 MW. The system was lagging by 6.687 MVAr during that peak hour, with a corresponding 0.999 (lagging) power factor.

In 2013 at a system peak design load of 177.7 MW, the estimated net power factor is expected to be approximately 0.989 (lagging) as seen at the 34.5 kV system supply delivery points. By 2022 at a system peak design load of 220.6 MW, with the new Kingston area system supply in service, this estimated net power factor is expected to be approximately 0.978 (lagging). Note that these assume all existing substation and subtransmission capacitors are switched into service.

At these loads levels, no additional capacitor additions are needed to achieve a minimum of 0.967 (lagging) over the next ten years. The following table provides the estimated system power factor over the ten year study period.

UES-Seacoast System – Anticipated Power Factor

Year	Uncorrected System Load * (MW)	(MVAr)	p.f. (115 kV)	Est. Minimum p.f. correction (MVAr)
2013	178.5	26.8	0.989, lagging	n/a
2014	183.7	31.8	0.985, lagging	n/a
2015	189.0	31.8	0.981, lagging	n/a
2016	192.9	21.9	0.994, lagging	n/a
2017	197.7	26.3	0.991, lagging	n/a
2018	202.3	30.4	0.989, lagging	n/a
2019	207.5	35.7	0.986, lagging	n/a
2020	211.6	39.6	0.984, lagging	n/a
2021	217.3	43.9	0.980, lagging	n/a
2022	221.6	48.1	0.977, lagging	n/a

* With no improvements, all existing substation capacitors switched into service. Assumed new Kingston area system in service in 2016 with two 7.2 MVAr capacitor banks. Includes losses of system supply transformers at Timber Swamp, Great Bay and Kingston.

7 SYSTEM CONSTRAINTS

The following summarizes the system deficiencies driving improvement proposals during the ten year study period, with the load level and projected year in which they first occur. The table is sorted by year and load level. The system constraint is listed in the year when it first violates planning criteria. Not all circumstances driving the system constraint are shown in this table.

Year	Load Level (MW)	System Constraint	Circumstances
Prior to 2013	Approx. 147.0	Equipment Overload – 3353 Breaker CT's at Guinea	Loss of 3342 Line, Guinea to Hampton
		Equipment Overload – 3342 Breaker at Hampton	Loss of 3353 Line, Guinea to Hampton
		Equipment Overload – 3342J1 Switch at Hampton	Loss of 3353 Line, Guinea to Hampton
Prior to 2013	Approx. 158.0	Protection Setting Overload – 3112 Breaker at Guinea	Various Contingencies
		Protection Setting Overload – 3172 Breaker at Guinea	Various Contingencies
2013	177.7	Low Voltage – Seabrook Station	Loss of 3348 Line at Hampton
2014	182.7	Conductor Overload – 3353 Line, Guinea to Hampton	Loss of 3342 Line, Guinea to Hampton
		Conductor Overload – 3342 Line, Guinea to Hampton	Loss of 3353 Line, Guinea to Hampton
		Triple Ended Line Protection required on 3112, 3165 and 3172 Lines	Various Contingencies
2019	206.7	Equipment Overload – 3112 Breaker CT's at Guinea	Various Contingencies
		Equipment Overload – 3172 Breaker CT's at Guinea	Various Contingencies
		Conductor Overload – 3348 Line, Hampton to Seabrook Station Marsh Tap	Loss of 3359 Line, Guinea to Mill Lane
		Conductor Overload – 3359 Line, Guinea to Mill Lane	Loss of 3348 Line at Hampton
2020	210.8	Equipment Overload – 3359 Breaker CT's at Guinea	Loss of 3348 Line at Hampton
2021	216.3	Conductor Overload – 3356 Line, Kingston to Hunt Road	Loss of 3345 Line, Kingston to Hunt Road
		Conductor Overload – 3345 Line, Kingston to Hunt Road	Loss of 3356 Line, Kingston to Hunt Road
2022	220.6	Protection Setting Overload – 3165 Breaker at Guinea	Various Contingencies
		Conductor Overload – 3371 Line, Timber Swamp to Wolf Hill	Basecase

The table below is used to further document the system constraints as summarized in the table above. This table is sorted by constraint. All of the contingency conditions for each constraint are detailed. The result column identifies why the constraint does not meet planning criteria. More details on exposure, voltage and loading values can be referenced in the contingency table in Appendix F.

Constraint	Year	Contingency	Result
3353 Breaker CT Loading at Guinea	Prior to 2013	Loss of 3342 Line, Guinea to Hampton	Loading > 100% LTE
		Loss of 3359 Line, Guinea to Mill Lane	
	2016	Loss of 3342 Line, Hampton to Hampton Beach	
3342 Breaker Loading at Guinea	Prior to 2013	Loss of 3353, Guinea to Hampton	Loading > 100% LTE
3342J1 Switch Loading at Hampton	Prior to 2013	Loss of 3353, Guinea to Hampton	Loading > 100% LTE
3112 Trip Setting Loading at Guinea	Prior to 2013	Loss of 3360 Line, Timber Swamp to Guinea	Loading > 90% of Trip Setting
		Loss of 3371 Line, Timber Swamp to Guinea	
		Loss of 3341 Line at Merrill’s Pit	
	2015	Loss of 3362 Line, Great Bay to Merrill’s Pit	
		Loss of 3352 Line at Merrill’s Pit	
	2016	Loss of 3351 Line, Great Bay to Merrill’s Pit	
3172 Trip Setting Loading at Guinea	Prior to 2013	Loss of 3360 Line, Timber Swamp to Guinea	Loading > 90% of Trip Setting
		Loss of 3371 Line, Timber Swamp to Guinea	
		Loss of 3341 Line at Merrill’s Pit	
	2015	Loss of 3362 Line, Great Bay to Merrill’s Pit	
		Loss of 3352 Line at Merrill’s Pit	
	2016	Loss of 3351 Line, Great Bay to Merrill’s Pit	
Seabrook Station Voltage	2013	Loss of 3348 Line at Hampton	Voltage < 95%
	2016	Loss of 3359 Line, Guinea to Mill Lane	
3353 Line Loading, Guinea to Hampton	2014	Loss of 3342 Line, Guinea to Hampton	Loading > 100% Normal Exposure > 12 hrs
	2016	Loss of 3359 Line, Guinea to Mill Lane	
	2018	Loss of 3342 Line, Guinea to Hampton	Loading > 100% LTE
	2020	Loss of 3359 Line, Guinea to Mill Lane	
3342 Line Loading, Guinea to Hampton	2014	Loss of 3342 Line, Guinea to Hampton	Loading > 100% Normal Exposure > 12 hrs

Constraint	Year	Contingency	Result
3342 Line Loading, Guinea to Hampton	2018	Loss of 3342 Line, Guinea to Hampton	Loading > 100% LTE
3112 Breaker CT Loading at Guinea	2019	Loss of 3360 Line, Timber Swamp to Guinea	Loading > 100% LTE
		Loss of 3371 Line, Timber Swamp to Guinea	
		Loss of 3341 Line at Merrill's Pit	
		Loss of 3352 Line at Merrill's Pit	
		Loss of 3351 Line, Great Bay to Merrill's Pit	
3172 Breaker CT Loading at Guinea	2019	Loss of 3360 Line, Timber Swamp to Guinea	Loading > 100% LTE
		Loss of 3371 Line, Timber Swamp to Guinea	
		Loss of 3341 Line at Merrill's Pit	
		Loss of 3352 Line at Merrill's Pit	
		Loss of 3351 Line, Great Bay to Merrill's Pit	
3348 Line Loading, Hampton to Seabrook Station Marsh Tap	2019	Loss of 3359 Line, Guinea to Mill Lane	Loading > 100% Normal Exposure > 12 hrs
	2022	Loss of 3359 Line, Guinea to Mill Lane	Loading > 100% LTE
3348J1 Switch Loading at Hampton	2019	Loss of 3359 Line, Guinea to Mill Lane	Loading > 100% LTE
3359 Line Loading, Guinea to Mill Lane	2019	Loss of 3348 Line, Hampton to Seabrook Station Marsh Tap	Loading > 100% Normal Exposure > 12 hrs
3359 Breaker CT Loading at Guinea	2020	Loss of 3348 Line, Hampton to Seabrook Station Marsh Tap	Loading > 100% LTE
3356 Line Loading, Kingston to Hunt Road	2021	Loss of 3345 Line, Kingston to Hunt Road	Loading > 100% Normal Exposure > 12 hrs
3345 Line Loading, Kingston to Hunt Road	2021	Loss of 3356 Line, Kingston to Hunt Road	Loading > 100% Normal Exposure > 12 hrs
3165 Breaker CT Loading at Guinea	2022	Loss of 3360 Line, Timber Swamp to Guinea	Loading > 90% of Trip Setting
		Loss of 3371 Line, Timber Swamp to Guinea	
		Loss of 3341 Line at Merrill's Pit	
		Loss of 3352 Line at Merrill's Pit	
		Loss of 3351 Line, Great Bay to Merrill's Pit	

Constraint	Year	Contingency	Result
3371 Line Loading, Guinea to Wolf Hill	2022	Basecase	Loading > 100% Normal

8 KINGSTON AREA SYSTEM SUPPLY OPTIONS

The following sections describe two configuration options for the new Kingston area system supply.

Both options consist of building a new 115-34.5 kV substation in the Kingston/Plaistow area with the following equipment:

- New 115 kV line from Kingston Tap to the existing Kingston substation.
- Two 115 kV line terminals, buses and normally open bus tie
  - Line Terminals and bus rated minimum 120 MVA
  - Bus Tie rated minimum 120 MVA

Additionally, the existing 115 kV line from the Kingston Tap to the existing Kingston substation will need to be rebuilt with larger conductor. The existing conductor is rated for 80 MVA normal and 88 MVA LTE and the total expected load for the new substation is approximately 89 MVA (77 MVA without PSNH load) in 2022.

8.1 Construct New Supply in the Vicinity of Kingston Stepdown

This option consists of constructing the new system supply the existing Kingston stepdown property. This configuration will consist of:

- Three 115-34.5 kV power transformers with LTC
  - Transformers rated for 60 MVA each, minimum
  - One transformer to be an in-service system spare
- Three 34.5 kV buses with normally open bus ties and three outgoing line terminals per bus
  - Transformer positions rated minimum 90 MVA
  - Bus Tie rated minimum 120 MVA
  - Line Terminal rated minimum 72 MVA
- Three 34.5 kV, 7.2 MVAr (2x3.6 MVAr stages) capacitor banks, one per 34.5 kV bus.

  System Supply Bus 1 Line Terminals
  - 3343 Line to Guinea
  - 3345 Line to Plaistow
  - Spare position

System Supply Bus 2 Line Terminal:

- 3354 Line to Guinea
- 3356 Line to Plaistow
- Spare position

System Supply Bus 3 Line Terminal:

- 22X1 Distribution Circuit
- PSNH 3141X Load (Spare position w/o PSNH load)
- Spare position

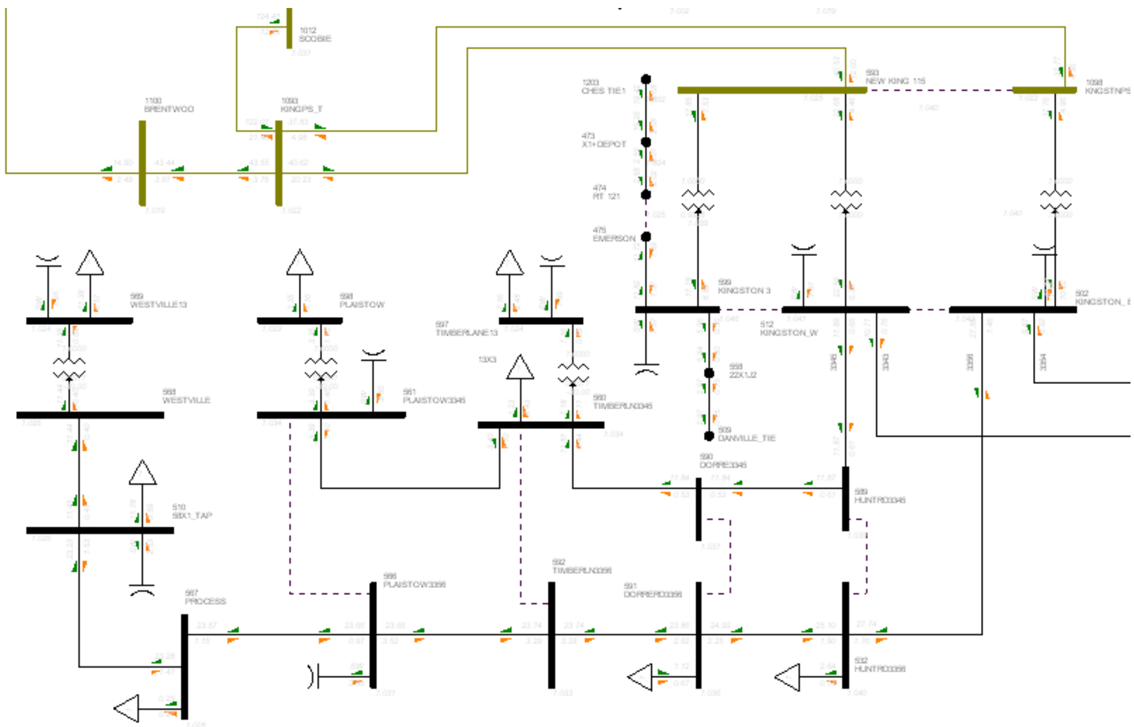


Figure 1 – New Kingston Area Supply at Kingston Stepdown

Cost Estimate:

Construct new 115 kV line and 115 kV Switch Yard	$12,000,000	(NU)
Construct new 115-34.5 kV, Substation	$6,500,000	
Purchase of System Spare Transformer	$1,000,000	
Total (w/o General Construction OHs)	$19,500,000	

Results:

Basecase

- Loading on system supply transformer 1 expected to be 25.3 MVA (includes 10 MVA of PSNH 3141X load) in 2016, increasing to as much as 28.1 MVA in 2022.
- Loading on system supply transformer 2 expected to be 38.6 MVA in 2016, increasing to as much as 43.5 MVA in 2022.

- Loading on system supply transformer 3 expected to be 16.0 MVA in 2016, increasing to as much as 17.0 MVA in 2022.

Extreme

- Loading on system supply transformer 1 expected to be 25.9 MVA (includes 10 MVA of PSNH 3141X load) in 2016, increasing to as much as 29.0 MVA in 2022.
- Loading on system supply transformer 2 expected to be 39.8 MVA in 2016, increasing to as much as 45.1 MVA in 2022.
- Loading on system supply transformer 3 expected to be 16.5 MVA in 2016, increasing to as much as 17.5 MVA in 2022.

Loss of System Supply Transformer

- Loading on the remaining system supply transformers is expected to be 39.9 MVA each (includes 10 MVA of PSNH 3141X load) in 2016, increasing to as much as 44.3 MVA each in 2022.

Loss of 115 kV Line from Kingston Tap to Kingston

- Loading on the remaining 115 kV Line expected to be 78.5 MVA (includes 10 MVA of PSNH 3141X load) in 2016, increasing to as much as 87.9 MVA in 2022.

Loss of 3141X at Chester (PSNH)

- Loading on system supply transformer 3 is expected to be 36.0 MVA in 2016, increasing to as much as 37.0 MVA in 2022.

Loss of 3343 Line at Kingston

- Loading on system supply transformer 2 expected to be 35.4 MVA in 2016, increasing to as much as 53.9 MVA in 2022.

Loss of 3354 Line at Kingston

- Loading on system supply transformer 1 expected to be 34.5 MVA (includes 10 MVA of PSNH 3141X load) in 2016, increasing to as much as 38.4 MVA in 2022.

Loss of 3345 Line at Kingston

- Loading on system supply transformer 2 expected to be 49.9 MVA in 2016, increasing to as much as 57.0 MVA in 2022.

Loss of 3356 Line at Kingston

- Loading on system supply transformer 1 expected to be 52.8 MVA (includes 10 MVA of PSNH 3141X load) in 2016, increasing to as much as 60.2 MVA in 2022.

8.2 Construct New Supply in the Vicinity of Plaistow Stepdown

This option consists of constructing the new system supply in vicinity of Plaistow substation. PSNH 3141X will be supplied from PSNH's existing Kingston substation. This configuration will consist of:

- Three 115-34.5 kV power transformers with LTC
  - Transformers rated for 90 MVA each, minimum
  - One transformer to be a system spare
- Two 34.5 kV buses with a normally open bus tie and four outgoing line terminals per bus
  - Transformer positions rated minimum 120 MVA
  - Bus Tie rated minimum 120 MVA
  - Line Terminal rated minimum 72 MVA
- Two 34.5 kV, 7.2 MVAr (2x3.6 MVAr stages) capacitor banks, one per 34.5 kV bus.

Two New 115 kV Lines from Kingston Stepdown to Plaistow

- Each line shall be rated for 120 MVA, minimum
- Lines to be constructed in 3345/3356 right-of-way
- 3345 and 3356 lines will be underbuilt with 954 AA conductor on 115 kV structures

System Supply Bus 1 Line Terminals

- 3358 Line to Westville
- 3356 Line to Kingston
- Two spare positions

System Supply Bus 2 Line Terminal:

- 3345 Line to Kingston
- Plaistow distribution substation
- Two spare position

Kingston Stepdown Configuration:

- Install normally open bus tie breaker
- Remove TB91 breaker

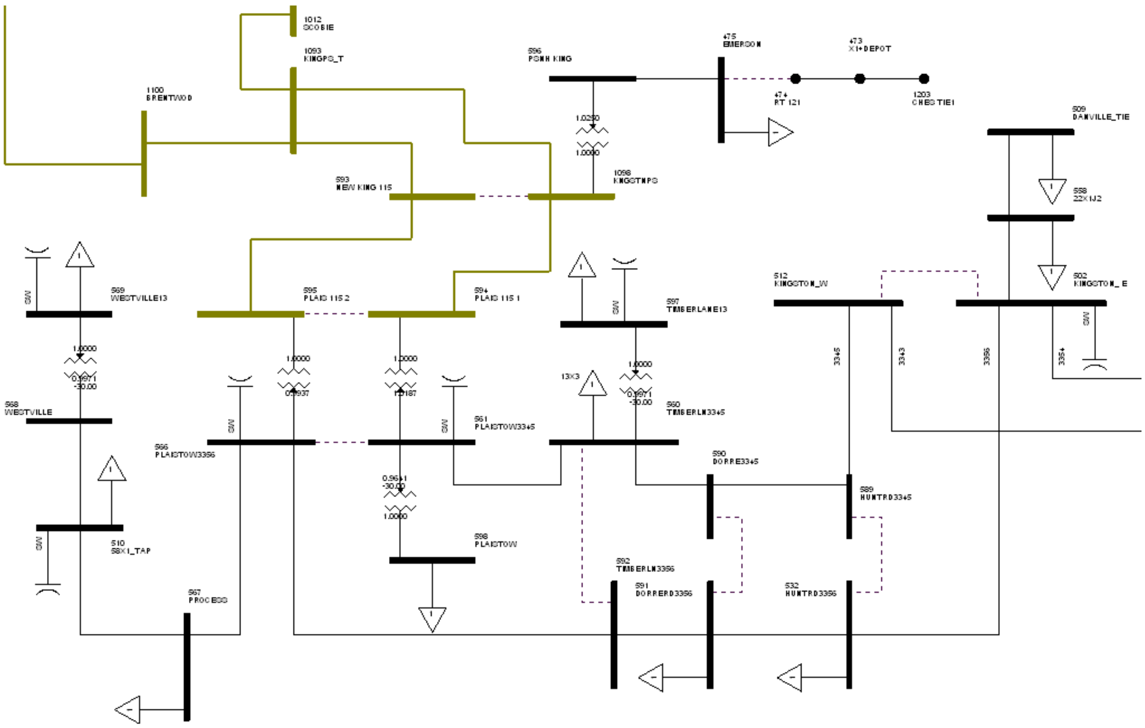


Figure 2 – New Kingston Area Supply at Plaistow

Cost Estimate (Supply Located in Plaistow):

Construct new 115 kV line and 115 kV Switch Yard	$12,000,000	(NU)
Construct new 115-34.5 kV, Substation	$6,500,000	
Purchase of System Spare Transformer	$1,000,000	
Construction of two 115 kV Lines to new Kingston Supply	$4,500,000	
Modifications at Kingston Stepdown	$250,000	
Total (w/o General Construction OHs)	$24,250,000	

Results:

Basecase

- Loading on system supply transformer 1 expected to be 45.4 MVA in 2016, increasing to as much as 51.1 MVA in 2022.
- Loading on system supply transformer 2 expected to be 22.9 in 2016, increasing to as much as 26.0 MVA in 2022.

Extreme

- Loading on system supply transformer 1 expected to be 46.5 in 2016, increasing to as much as 52.5 MVA in 2022.
- Loading on system supply transformer 1 expected to be 23.5 in 2016, increasing to as much as 26.8 MVA in 2022.

Loss of System Supply Transformer

- Loading on the remaining system supply transformer expected to be 68.3 MVA in 2016, increasing to as much as 76.7 MVA in 2022.

Loss of 115 kV Line from Kingston Tap to Kingston

- Loading on the remaining 115 kV Line expected to be 79.7 MVA (includes 10 MVA of PSNH 3141X load) in 2016, increasing to as much as 87.7 MVA in 2022.

Loss of 115 kV Line from Kingston to Plaistow

- Loading on the remaining 115 kV Line expected to be 77.5 MVA (includes 10 MVA of PSNH 3141X load) in 2016, increasing to as much as 87.3 MVA in 2022.

Loss of 3343 Line at Kingston

- Loading on system supply transformer 2 expected to be 55.1 in 2016, increasing to as much as 61.2 MVA in 2022.

Loss of 3354 Line at Kingston

- Loading on system supply transformer 1 expected to be 32.7 MVA in 2016, increasing to as much as 37.0 MVA in 2022.

Loss of 3345 Line at Kingston

- Loading on system supply transformer 2 expected to be 63.5 in 2016, increasing to as much as 72.3 MVA in 2022.

Loss of 3356 Line at Kingston

- Loading on system supply transformer 1 expected to be 43.1 MVA in 2016, increasing to as much as 49.0 MVA in 2022.

8.2.1 Recommendation

Constructing the new Kingston area supply at the existing Kingston Stepdown site is the recommended location for the new system supply. The Kingston stepdown location provides similar benefits to constructing the supply in Plaistow without the need to build 115 kV lines in the 3345/56 right-of-way. Equipment size will be finalized through joint planning the NU/PSNH. The final supply configuration will be determined once ultimate transformer capacity is finalized and distribution load supplied by the new substation will be supplied from the appropriate line to balance load between supply transformers.

9 SYSTEM IMPROVEMENT OPTIONS

The following sections describe details of system improvement alternatives examined to address the deficiencies identified earlier in this report.

9.1 3342 Line and 3353 Line Overload Options

The following alternatives were considered to eliminate the overload conditions associated with the 3342 and 3353 lines and associated equipment (3353 Breaker CT’s, 3342 Breaker, 3342J1 Switch).

9.1.1 Perform Distribution Switching to Reduce 3353 and 3342 Line Loading

Summary:

The following additional switching steps were considered for various contingencies.

- For the Loss of the 3342 Line from Guinea to Hampton and Loss of the 3353 Line from Guinea to Hampton (load levels above 147 MW):
  - Lafayette Road – close 2X3J15X1 switch
  - Hampton S/S – open 2X3 recloser
  - Hampton S/S – open 2X2 recloser
  - Route 27 – close 2X2J18X1 switch
- For Loss of the 3359 Line from Guinea to Mill Lane (load levels above 158 MW):
  - Lafayette Road – close 2X3J15X1 switch
  - Cemetery Lane S/S – open 15X1 recloser
  - Hampton Beach S/S – close BT-3A switch
  - Hampton Beach S/S – open J053 switch
- Loss of the 3342 Line from Hampton to Hampton Beach (load levels above 192 MW):
  - Lafayette Road – close 2X2J2X3 switch
  - Hampton S/S – open 2X3 recloser

Cost Estimate: negligible (no capital investment)

Results:

Loss of the 3342 Line, Guinea to Hampton

- From 2016 and beyond after switching to restore all load, various distribution concerns existing on circuit 18X1/2X2.
- From 2022 and beyond after switching to restore all load, loading on the 3353 breaker CT's at Guinea are expected to exceed their 600A thermal limit (101% at peak design load in 2022).

Loss of the 3353 Line, Guinea to Hampton

- From 2016 and beyond after switching to restore all load, various distribution concerns existing on circuit 18X1/2X2.
- From 2022 and beyond after switching to restore all load, loading on the 3342 breaker at Guinea is expected to exceed its 600A thermal limit (101% at peak design load in 2022).

- From 2022 and beyond after switching to restore all load, loading on the 3342J1 switch at Hampton is expected to exceed its 600A thermal limit (101% at peak design load in 2022).

Loss of the 3359 Line, Guinea to Mill Lane

- From 2016 through 2022 and beyond after switching to restore all load, loading on the 3353 breaker CT's at Guinea are expected to exceed their 600A thermal limit (102% at peak design load in 2016).

Loss of the 3342 Line, Hampton to Hampton Beach

- From 2022 and beyond after switching to restore all load, loading on the 3353 breaker CT's at Guinea are expected to exceed their thermal limit (101% at peak design load in 2022).

9.1.2 Reconductor 3342 and 3353 Lines – Guinea to Hampton

Summary:

Replace the existing 477 AA phase conductor with 954 AA on the 3342 line and 3353 line from Guinea Switching to Hampton S/S. Similarly, replace/upgrade any breakers, breaker CTs, in-line switches, connectors, hardware and other associated equipment with ratings less than 1200 amps.

Cost Estimate:

Reconductor 3342 Line – Guinea to Hampton	$375,000
Reconductor 3353 Line – Guinea to Hampton	$375,000
Total (w/o General Construction OHs)	$750,000

Results:

Loss of the 3342 Line, Guinea to Hampton

- From 2013 through 2022 and beyond after switching to restore all load, loading on the 3353 breaker CT's at Guinea are to remain below thermal limit (76% at peak design load in 2022).
- From 2013 through 2022 and beyond, after switching to restore all load, loading on the 3353 line between Guinea and Hampton with 954 AA is expected to remain below planning guidelines (89% of Normal Limit at peak design load in 2022).

Loss of the 3353 Line, Guinea to Hampton

- From 2013 through 2022 and beyond, after switching to restore all load, loading on the 3342 line between Guinea and Hampton with 954 AA is expected to remain below planning guidelines (89% of Normal Limit at peak design load in 2022).
- From 2013 and beyond after switching to restore all load, loading on the 3342 breaker at Guinea is expected to remain below planning guidelines (76% at peak design load in 2022).

- From 2013 and beyond after switching to restore all load, loading on the 3342J1 switch at Hampton is expected to remain below planning guidelines (76% at peak design load in 2022).

Loss of the 3359 Line, Guinea to Mill Lane

- From 2013 through 2022 and beyond after switching to restore all load, loading on the 3353 breaker CT's at Guinea are to remain below thermal limit (70% at peak design load in 2022).
- From 2013 through 2022 and beyond, after switching to restore all load, loading on the 3353 line between Guinea and Hampton with 954 AA is expected to remain below planning guidelines (82% of Normal Limit at peak design load in 2022).

Loss of the 3342 Line, Hampton to Hampton Beach

- From 2013 through 2022 and beyond after switching to restore all load, loading on the 3353 breaker CT's at Guinea are to remain below thermal limit (58% at peak design load in 2022).

9.1.3 Construct New 34.5 kV Line – Guinea to Hampton

Summary:

Construct a new 34.5 kV line from Guinea Switching to the 3348 line tap at Hampton. Construction to include 954 AA phase conductors on separate structures from the 3342 or 3353 lines and the addition of a new 34.5 kV line terminals at Guinea Switching Station and Hampton Substation.

Cost Estimate:

Construct new 3rd Line – Guinea to Hampton (Substation Work)	$110,000
Construct new 3rd Line – Guinea to Hampton (Line Work)	$390,000
Total (w/o General Construction OHs)	$500,000

Challenges:

This option would require the use of the last available breaker position at Guinea S/S. This position may provide more benefit being used for an additional line from Guinea to Seabrook.

Results:

Loss of the 3342 Line, Guinea to Hampton

- In 2016 after switching to restore all load, loading on the 3353 breaker CT's at Guinea are expected to exceed their 600A thermal limit (114% at peak design load in 2022).
- In 2022 after switching to restore all load, loading on the 3353 line between Guinea and Hampton with the existing 477 AA conductor is expected to exceed their its normal rating (103% of normal rating at peak design load in 2022).

Loss of the 3353 Line, Guinea to Hampton

- From 2013 through 2022 and beyond, after switching to restore all load, loading on the new line between Guinea and Hampton with 954 AA is expected to remain below planning guidelines (41% of Normal Limit at peak design load in 2022).
- From 2013 and beyond after switching to restore all load, loading on the 3342 breaker at Guinea is expected to remain below planning guidelines (78% at peak design load in 2022).
- From 2013 and beyond after switching to restore all load, loading on the 3342J1 switch at Hampton is expected to remain below planning guidelines (78% at peak design load in 2022).

Loss of the 3359 Line, Guinea to Mill Lane

- From 2013 through 2022 and beyond after switching to restore all load, loading on the 3353 breaker CT's at Guinea are to remain below thermal limit (50% at peak design load in 2022).
- From 2013 through 2022 and beyond, after switching to restore all load, loading on the new line between Guinea and Hampton with 954 AA conductor is expected to remain below its normal limit (59% of normal Limit at peak design load in 2022).

Loss of the 3342 Line, Hampton to Hampton Beach

- From 2013 through 2022 and beyond after switching to restore all load, loading on the 3353 breaker CT's at Guinea are expected to remain below their thermal limit (79% at peak design load in 2022).

Loss of the New Line, Guinea to Hampton

- From 2013 through 2022 and beyond after switching to restore all load, loading on the new line terminal at Guinea is expected to remain below its thermal limit (% at peak design load in 2022).
- From 2013 through 2022 and beyond, after switching to restore all load, loading on the 3353 line between Guinea and Hampton with the existing 477 AA conductor is expected to remain below its normal limit (63% of normal Limit at peak design load in 2022).

9.1.4 Recommendation

Utilizing distribution switching from 2013 through 2015 and reconductoring the 3342 and 3353 Lines from Guinea to Hampton in 2016 are the recommended solutions to the identified constraints associated with the 3342 and 3353 lines. Reconductoring the 3342 and 3353 lines is the more costly option, but the existing condition of the 3342 and 3353 lines as they are today will require the lines to be rebuilt in the future and this solution does not utilize the final line terminal position at Guinea.

- In 2013, utilize distribution ties.
- In 2016, reconductor the 3342 and 3353 lines from Guinea to Hampton with 954 AA phase conductors and 477 AA neutral wire. Upgrade the 3342 and 3353 breakers at Guinea and replace the 3342J1 Switch at Hampton.

9.2 3112, 3165 and 3172 Equipment Overload Options

The following solutions were examined to avoid overloads of the 3112, 3165 and 3172 protection settings and breaker CT's.

9.2.1 Reconductor 3360 and 3371 Lines – Timber Swamp to Guinea

Summary:

Replace the existing 954 AA phase conductor with 2000 AA (or equivalent for 2000 amp contingency rating) on the 3360 line and 3371 line from Timber Swamp to Guinea Switching. Similarly, replace/upgrade any breakers, breaker CTs, in-line switches, connectors, hardware and other associated equipment with ratings less than 2,000 amps.

Cost Estimate:

Reconductor 3360 Line – Guinea to Hampton	$75,000
Reconductor 3371 Line – Guinea to Hampton	$75,000
Replace 3360 and 3371 Breakers at Guinea	$150,000
Total (w/o General Construction OHs)	$300,000

Results:

Various Contingencies

- From 2013 through 2022 and beyond after switching to restore all load, loading on the 3360 and 3371 lines are expected to remain below planning criteria (97% at peak design load in 2022).
- From 2018 and beyond after switching to restore all load, voltages along the 3346 line are expected to be below allowable limits.

9.2.2 Modify Protection on 3165, 3112 and 3172 Lines

9.2.2.1 Increase the 3112, 3165 and 3172 Protection Settings and CT Ratios - 2013

Summary:

Increase the 3112, 3165 and 3172 over current protection trip setting to 600 amps and change the 3112, 3165 and 3172 breaker CT ratios from 500:5A to 600:5A at Guinea.

This option is currently being reviewed to determine its feasibility.

Cost Estimate: negligible (no capital investment)

9.2.2.2 Upgrade Protection of 3112, 3165 and 3172 to Operate Triple Ended - 2014

Summary:

Modify the protection of the 3112, 3165 and 3172 lines to allow the lines to be operated triple ended.

The protection requirements to allow the 3112, 3165 and 3172 lines to operate triple ended has not been studied in detail and will require a joint effort between Unitil and PSNH.

Modify Protection Settings of 3112, 3172 and 3165	\$200,000
Total (w/o General Construction OHs)	\$200,000

Results:

Various Contingencies

- From 2013 through 2022 and beyond, loading on the 3112, 3165 and 3172 protection settings at Guinea are expected to remain below planning criteria (96% at peak design load in 2022).
- From 2013 through 2022 and beyond, loading on the 3112, 3165 and 3172 breaker CT's at Guinea are expected to remain below their thermal limit (86% at peak design load in 2022).

9.2.3 Guinea Expansion – Substation and Line Modifications – Timber Swamp to Guinea

Summary:

Build two new lines from Timber Swamp substation to Guinea switching station. Construction to include 954 AA phase conductor on separate structures from the 3360 and 3371 lines. This will also involve the installation of two new breaker positions at Timber Swamp, the installation of a bus tie breaker at Guinea and the upgrade of the 3354 and 3343 breakers and associated equipment to achieve at least a 1200 amp rating. Several relays at Guinea will need to be upgraded to accommodate this work. Two additional reclosers will be installed on the 3343 and 3354 lines at Wolf Hill as part of this project.

Cost Estimate:

Build 3rd and 4th Lines – Timber Swamp to Guinea	\$300,000	
Recloser Additions – Wolf Hill	\$200,000	
Substation Modifications at Guinea	\$2,500,000	
Breaker Additions – Timber Swamp	\$750,000	(PSNH)
Total (w/o General Construction OHs)	\$3,750,000	

Results:

Various Contingencies

- From 2013 through 2022 and beyond, the 3112, 3172 and 3165 lines will no longer be utilized to restore UES load for any single element contingencies.

Loss of TB141 Transformer at Great Bay

- In 2022 with all load restored loading of the TB25 transformer at Timber Swamp is expected to exceed 90% of its PSNH thermal limit of 160 MVA (92% of its thermal limit at peak design load in 2022).

9.2.4 Recommendation

The recommendation to overcome loading concerns of the 3112, 3165 and 3172 protection settings is to construct reconductor the 3360 and 3371 lines from Timber Swamp to Guinea. This option is the more costly project, however it provides more operational flexibility and reduces the reliance on PSNH equipment to overcome deficiencies on the UES system. Voltages along the 3346 line will continue to be studied in the future and voltage regulation will be installed as needed.

- In 2013, reconductor the 3360 and 3371 lines from Timber Swamp to Guinea and make the required upgrades Guinea switching station.

9.3 3348 Line and 3359 Line Overload Options

The following were examined to avoid conductor and equipment overloads identified along the 3348 and 3359 Lines. These options also address the Seabrook Station voltage concerns.

9.3.1 Perform Distribution Switching to Reduce 3348 and 3359 Line Loading

Summary:

The following additional switching steps were considered for loss of the 3348 line and loss of the 3359 line.

- For the loss of the 3348 Line at Hampton and loss of the 3359 line from Guinea to Mill Lane (load levels above 205 MW):
    - Lafayette Road – close 2X3J15X1 switch
    - Cemetery Lane S/S – open 15X1 recloser

Cost Estimate: negligible (no capital investment)

Results:

Loss of the 3348 Line at Hampton

- From 2019 through 2022 and beyond after switching to restore all load for loss of the 3348 line, all elements are expected to be with planning guidelines.

Loss of the 3359 Line, Guinea to Mill Lane

- From 2019 through 2022 and beyond after switching to restore all load for loss of the 3359 line and assuming a project has been completed to address 3353 line loading concerns, all elements are expected to be within planning guidelines.

9.3.2 Recommendation

The recommendation with the respect to the overloads of the 3348 and 3359 lines is to utilize the 15X1/2X3 distribution tie to transfer 15X1 to 2X3 prior to restoring additional load.

- In 2019, utilize the 15X1/2X3 distribution tie.

Other projects such as, reconductoring the 3348 and 3359 lines or building a 2nd line from Guinea to Cemetery Lane in the 3359 right-of-way were considered as alternatives to the recommendation.

9.4 3356 and 3345 Lines Conductor Overload Options

The following alternatives were examined to avoid conductor overloads identified on the 3345 and 3356 Lines between Kingston and Hunt Road. These options assume the new Kingston area supply is constructed on the existing Kingston Stepdown property.

9.4.1 Reconductor 3356 and 3345 Lines – Kingston to Hunt Road Tap

Summary:

Replace the existing 477 AA phase conductors with 954 AA on the 3356 line and the 3345 line from Kingston to Hunt Road Tap in 2021.

Cost Estimate:

Reconductor 3356 Line – Kingston to Hunt Road Tap	$300,000
Reconductor 3345 Line – Kingston to Hunt Road Tap	$300,000
Total (w/o General Construction OHs)	$600,000

Results:

Loss of 3345 Line, Kingston to Plaistow

- From 2021 through 2022 and beyond, loading on the 3356 line with 954 AA is expected to remain below its 1025 A normal limit (74% of normal limit at peak design load in 2021).

Loss of 3356 Line, Kingston to Plaistow

- From 2021 through 2021 and beyond, loading on the 3345 line with 954 AA is expected to remain well below its 1025 A normal limit (74% of normal limit at peak design load in 2021).

9.4.2 Construct New 34.5 kV Line – Kingston to 3358 Line Tap

Summary:

Construct a new 34.5 kV line from Kingston S/S to the 3358 Line Tap. Construction to include 954 AA phase conductors on separate structures from the 3356 of 3345 lines, the addition of a new 34.5 kV line terminal at Kingston, and tie switch additions at the 3358 Line Tap. The proposed new configuration would have the new line carrying the 3358 Line, the 3356 Line and the 3345 Line feeding Plaistow, Timberlane, Hunt Road Tap and Dorre Road Tap.

Cost Estimate:

Kingston Stepdown Modification to Accommodate 3rd Line	$300,000
Construct new 3rd Line – Kingston to 3358 Line Tap (Line)	$1,100,000
Total (w/o General Construction OHs)	$1,400,000

Results:

Loss of 3345 Line, Kingston to Plaistow

- From 2021 through 2022 and beyond, loading on the 3356 line with 477 AA conductor is expected to remain well below its 663 A normal limit (45% of normal limit at peak design load in 2022).

Loss of the New Line, Kingston to the 3358 Line Tap

- From 2021 through 2022 and beyond, loading on the 3345 and 3356 lines with 477 AA conductor are expected to remain below their normal limits (81% on the 3356 line and 35% on the 3345 line at peak design load in 2022).

Loss of 3356 Line, Kingston to Plaistow

- From 2021 through 2022 and beyond, loading on the 3345 line with 477 AA conductor is expected to remain well below its 663 A normal limit (45% of normal limit at peak design load in 2022).

9.4.3 Recommendation

Reconductoring the 3345 and 3356 lines is the recommended solution to the identified conductor constraints. It is the more costly option, but the existing condition of the 3345 and 3356 lines as they exist today will require the lines to be rebuilt in the foreseeable future.

- In 2021, reconductor the 3345 and 3356 lines with 954 AA between Kingston S/S and Hunt Road Tap.

  If the recommended system supply for the Kingston area is built at Plaistow these lines will be rebuilt as part of the 115 kV supply line construction in 2016.

10 MASTER PLAN ANALYSIS

A 20 year master plan review has been completed in addition to the 10 year analysis discussed in this report. This analysis reviews a system model with peak design load that has been scaled proportionately to an equivalent 20 year forecast assuming the historical growth rate. The review is completed under basecase configuration with all elements in service.

This is a high level review which identifies potential system problems which occur beyond the 10 year planning horizon. This review is used to develop a long term vision for the system which is used to guide incremental improvements. For total system loads up 270 MW the following additional conditions have been identified for basecase conditions.

- Timber Swamp Substation Loading
- Great Bay Transformer Loading
- 3360 Line Overload from Timber Swamp to Guinea
- 3371 Line Overload from Timber Swamp to Guinea
- 3359 Line Overload from Guinea to Mill Lane Tap
- 3342 Line Overload from Guinea to Hampton

- 3353 Line Overload from Guinea to Hampton
- 3358 Line Overload Plaistow to Westville Road Tap
- 46X1 Low Voltage

Modeling Assumptions:

- All available capacitor banks switched in
- Capacitor Banks at Guinea Expanded
- 3345 and 3356 Reconductored

11 FINAL RECOMMENDATIONS

The following summarizes final recommendations given in this report.

Year	Project Description	Justification	Cost
2013	Utilize Distribution Ties to Restore Load	Loading for Various Contingencies	n/a
	Reconductor 3360 and 3371 Lines from Timber Swamp to Guinea and Upgrade Breakers at Guinea	Loading for Various Contingencies	$300,000
2016	Construct New System Supply in Kingston, Build a 2nd Line from H141/R191 RoW to Kingston[1]	Extreme Peak and Basecase Loading Kingston TB91 and Great Bay TB141	$19,500,000
	Reconductor 3342 and 3353 Lines from Guinea to Hampton and Upgrade 3342J1, 3342 and 3353 Breakers	Loading for Various Contingencies	$750,000
2021	Reconductor 3345 and 3356 Lines from Kingston to Hunt Road Tap	Loading for Loss of the 3345 Line, Loss of 3356 Line	$600,000

1 Subject to resolution of transmission planning issues with Northeast Utilities / Public Service of New Hampshire

2 Portion of cost is capital investment by Northeast Utilities ($12,000,000)

Note: cost estimates do not include general construction overheads.

Unitil Electric System - Capital

Reliability Study 2012

Prepared By:
Cyrus Esmaeili
Unitil Service Corp.
September 27, 2012

UES - Capital Reliability Analysis and Recommendations 2012

September 27,2012

1. Executive Summary

The purpose of this document is to report on the overall reliability performance of the UES-Capital system January 1, 2011 through December 31, 2011. The scope of this report will also evaluate individual circuit reliability performance over the same time period. The reliability data presented in this report does not include Hurricane Irene (8/28/11 3:25 to 8/30/11 18:40) or the October Nor'easter (10/29/11 17:35 to 11/2/11 9:24).

The following projects are proposed from the results of this study and are focused on improving the worst performing circuits as well as the overall UES-Capital system reliability. These recommendations are provided for consideration and will be further developed with the intention to be incorporated into the 2013 budget development process.

Circuit/Line/ Substation	Proposed Project	Cost
13W2/13W3	REBUILD SPACER CABLE ON HIGH STREET & KING STREET	417,860
3H3	RECLOSER REPLACEMENT AT GULF ST S/S	19,307
18W2	UPGRADE AND SPLIT 22W3, CREATING 18W2 TIE	247,729
8X3	CREATE ALTERNATE MAINLINE	2,750,592
4W4	HYDRAULIC RECLOSER INSTALLATION ON LAKE VIEW DR	7,238

2. Reliability Goals

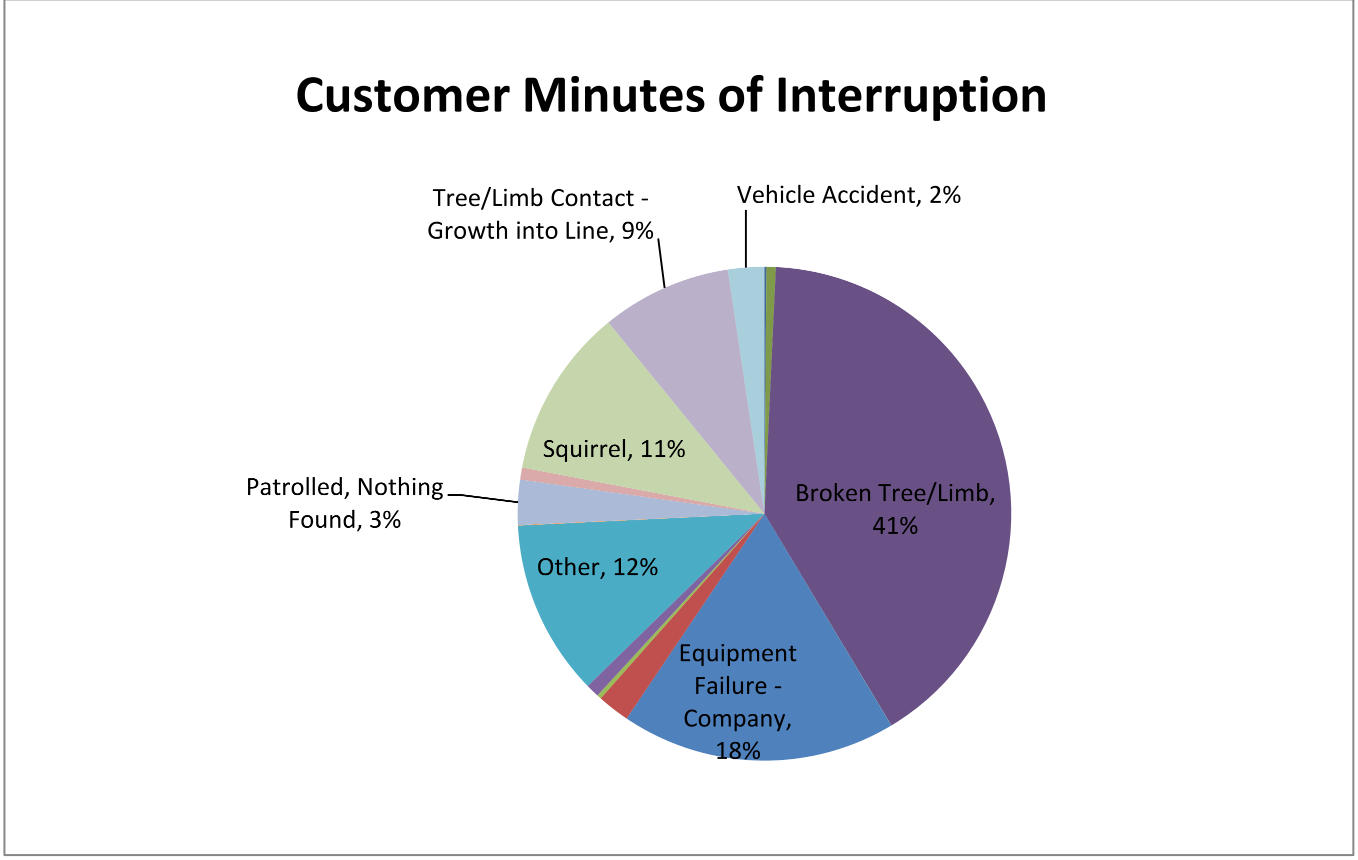
The annual corporate system reliability goals for 2012 have been set at 191-156-121 SAIDI minutes. These were developed through benchmarking Unitil system performance with surrounding utilities.

Individual circuits will be analyzed based upon circuit SAIDI, SAIFI, and CAIDI. Analysis of individual circuits along with analysis of the entire Capital system is used to identify future capital improvement projects and/or operational enhancements which may be required in order to achieve and maintain these goals.

3. Outages by Cause

The following chart provides a breakdown of outage by cause and the corresponding percentage of customer-minutes of interruption from January 1, 2011 to December 31, 2011.

Chart 1
Percent of Customer-Minutes of Interruption by Cause



Note: 98% of the cause “other” is due to one single event during the micro-burst on 9/5/11.

4. 10 Worst Distribution Outages

The ten worst distribution outages ranked by customer-minutes of interruption during the time period from January 1, 2011 through December 31, 2011 are summarized in Table 1 below.

Table 1

Worst Ten Distribution Outages

Circuit	Description Date/Cause	No. of Customers Affected	No. of Customer Minutes	Effect on UES-Capital SAIDI	Effect on UES-Capital SAIFI
7W3	9/5/11 Other (Wind Microburst)	1,838	424,779	14.24	.062
13W3	3/20/11 Equipment Failure – Company (Insulator)	2,197	197,040	6.61	.073
13W2	7/11/11 Equipment Failure – Company (Tie wire)	1,297	182,440	6.11	.043
17X1	6/20/11 Equipment Failure – Customer (lightning arrester)	1,023	156,551	5.25	.034
13W2	12/8/11 Broken Tree/Limb	563	142,275	4.77	.019
3H1	6/14/2011 Tree/Limb Contact – Growth into Line	600	117,000	3.92	.020
13W2	7/21/2011 Tree/Limb Contact – Growth into Line	1,287	106,784	3.58	.043
4W4	1/15/2011 Equipment Failure – Company (Cutout)	2,156	105,920	3.55	.072
21W1A	9/23/2011 Equipment Failure – Company (Cable)	714	101,633	3.41	.024
22W3	2/25/2011 Broken Tree/Limb	837	99,603	3.34	.028

Note: This table does not include substation, sub-transmission or scheduled planned work outages.

5. Contribution of Sub-transmission Line Outages

This section describes the contribution of sub-transmission line and substation outages on the UES-Capital system from January 1, 2011 through December 31, 2011.

All substation and sub-transmission outages ranked by customer-minutes of interruption during the time period from January 1, 2011 through December 31, 2011 are summarized in Table 2 below.

Table 3 shows the circuits that have been affected by sub-transmission line outages. The table illustrates the contribution of customer minutes of interruption for each circuit affected by a sub-transmission outage. In aggregate, sub-transmission line and substation outages accounted for 31% of the total customer-minutes for UES-Capital, excluding Hurricane Irene and the October Nor'easter.

Table 2
Sub-transmission and Substation Outages

Trouble Location	Description (Date/Cause)	No. of Customers Affected	No. of Customer Minutes	UES Capital SAIDI (min.)	UES Capital SAIFI
37 Line	8/21/2011 Broken Tree/Limb	3,088	413,792	13.88	.104
396X1 Line	9/5/2011 Other – Microburst Storm	1,056	409,728	13.72	.035
34 Line	3/9/2011 Equipment Failure – Company (Insulator)	2,675	358,517	12.02	.090
Ironworks S/S	7/11/2011 Squirrel	2,069	267,525	8.97	.069
West Portsmouth S/S	11/10/2011 Squirrel	1,315	231,166	7.75	.044
37 Line	6/3/2011 Broken Tree/Limb	3,173	120,574	4.04	.106
37 Line	7/6/2011 Broken Tree/Limb	3,171	117,327	3.93	.106
0375 Line	2/25/2011 Broken Tree/Limb	1,498	49,778	1.66	.050
[1]Terrill Park S/S	3/30/2011 Equipment Failure – Company (Insulator)	300	45,600	1.53	.010
Gulf St S/S	6/22/2011 Equipment Failure – Company (Insulator)	604	42,280	1.42	.020

[1] Unscheduled outage to replace insulator before it failed.

Table 3
Contribution of Sub-transmission and Substation Outages

Circuit	Subtransmission Line Or Substation Location	Circuit SAIDI Contribution	Customer-Minutes of Interruption	% of Total Circuit Outage Minutes	Number of Events
16H1	Line 0375	29.00	8,758	88.91%	1
16H3	Line 0375	96.33	19,343	96.03%	2
16X4	Line 0375	41.06	21,648	49.75%	1
16X5	Line 0375	6.44	29	100.00%	1
6X3	Line 34	134.41	131,186	61.81%	1
34X2	Line 34	22.33	201	100.00%	1
33X3	Line 34	134.00	134	100.00%	1
33X4	Line 34	140.62	11,390	100.00%	1
33X5	Line 34	44.67	134	100.00%	1
33X6	Line 34	134.00	134	100.00%	1
2H1	Line 34	135.73	62,042	99.55%	1
2H2	Line 34	133.97	140,700	56.96%	1
2H4	Line 34	134.00	12,596	90.20%	1
37X1	Line 37	206.61	40,353	25.92%	3
13W1	Line 37	180.66	80,618	20.37%	3
13W2	Line 37	209.15	270,377	25.03%	3
13W3	Line 37	233.64	260,136	35.40%	3
13X4	Line 37	209.00	209	56.64%	3
17X1	Line 396X1	388.00	776	100.00%	1
18W2	Line 396X1	393.82	408952	66.33%	1
22W1	Iron Works	121.40	59,901	68.90%	1
22W2	Iron Works	16.02	5,177	4.47%	1
22W3	Iron Works	126.69	202,447	30.03%	1
3H1	Gulf	70.50	42,280	23.14%	1
15W2	West Portsmouth	177.83	61,766	62.80%	1
15W1	West Portsmouth	173.12	169,400	71.37%	1

6. Worst Performing Circuits

This section compares the reliability of the worst performing circuits using various performance measures. Circuits having one outage contributing more than 75% of the customer-minutes of interruption were excluded from this analysis.

6.1. Worst Performing Circuits in Past Year

A summary of the worst performing circuits during the year of 2011 is included in the tables below. *Table 4* shows the ten worst circuits ranked by the total number of Customer-Minutes of interruption. The SAIFI and CAIDI for each circuit are also listed in this table.

Table 5 provides detail on the major causes of the outages on each of these circuits. Customer-minutes of interruption are given for the six most prevalent causes.

Table 4
Worst Performing Circuits by Customer-Minutes

Circuit	No. of Customers Interruptions	Worst Event (% of Total Cust Int.)	Customer-Minutes of Interruption	Worst Event (% of Total Minutes)	Circuit SAIDI	Circuit SAIFI	Circuit CAIDI
13W2	11,560	11.17%	1,080,312	16.89%	835.67	8.94	93.45
13W3	11,556	19.07%	734,938	26.81%	660.07	10.38	63.60
22W3	10,291	13.28%	674,182	30.03%	421.91	6.44	65.51
18W2	2,597	40.59%	616,579	66.33%	593.77	2.50	237.42
4X1	6,170	32.24%	452,801	39.53%	227.51	3.10	73.39
13W1	3,347	13.33%	395,864	20.05%	887.09	7.50	118.27
8X3	3,253	2.15%	380,731	10.76%	137.70	1.18	117.04
4W4	5,092	42.34%	303,149	34.94%	138.88	2.33	59.53
2H2	2,486	42.24%	247,020	56.96%	235.20	2.37	99.36
4W3	2,149	6.14%	243,951	13.58%	185.69	1.64	113.52

Table 5
Circuit Interruption Analysis by Cause

Circuit	Customer – Minutes of Interruption					
	Broken Tree Limb	[1]Animal	Patrolled, Nothing Found	Vehicle Accident	Company Equipment Failure	Tree Growth into Line
13W2	674,148	28,574	24,380	3,989	214,769	128,948
13W3	337,777	9,844	33,248	544	300,766	52,759
22W3	259,533	337,380	11,800	340	1,131	13,068
18W2	28,318	14,518	7,230	378	439	0
4X1	373,142	33,618	6,840	3,036	4,934	0
13W1	373,142	3,537	0	64,105	63,400	15,148
8X3	143,583	51,000	27,777	13,694	2,097	108,179
4W4	141,757	16,136	3,545	12,348	106,002	20,828
2H2	4,165	0	38,850	62,225	141,750	0
4W3	152,376	31,889	0	0	0	58,267
Total	2,487,941	526,496	153,670	160,659	835,288	397,197

[1]This category includes bird, squirrel and other animals combined

6.2. Worst Performing Circuits of the Past Five Years (2007 – 2011)

The annual performance of the ten worst circuits for the past five years has been ranked in the tables below. *Table 6* lists the ten worst circuits ranked by SAIDI performance. *Table 7* lists the ten worst performing circuits ranked by SAIFI.

Table 6
Circuit SAIDI

Circuit Ranking	2011		2010		2009		2008		2007	
	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI
1	13W1	887.09	8X3	1,037.0	13W1	797.86	211A	1,655.4	13W2	1,116.9
2	13W2	835.67	211A	650.29	13X4	444.00	13W2	1,071.9	13W1	1,108.9
3	37X1	797.25	13W1	648.23	13W2	443.03	13W1	575.6	13W3	988.0
4	13W3	660.07	13W2	487.15	18W2	369.36	22W3	434.3	15W2	949.0
5	18W2	593.77	13W3	417.67	13W3	349.28	4W3	396.1	22W3	777.4
6	22W3	421.91	2H4	414.01	211A	330.29	1H3	351.1	7W3	764.3
7	17X1	388.00	2H2	353.25	37A	269.61	22W2	291.3	4W3	744.3
8	13X4	369.00	37X1	304.57	22W3	246.30	15W1	288.9	22W1	674.9
9	21W1A	361.90	3H2	298.00	4W3	245.64	13W3	233.1	15W1	642.4
10	38W	359.61	18W2	293.13	15W1	210.10	1H4	194.0	13X4	572.0

Table 7
Circuit SAIFI

Circuit Ranking	2011		2010		2009		2008		2007	
	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI
1	13W3	10.379	13W1	5.956	211A	8.614	13W2	9.98	7W3	7.38
2	13W2	8.942	8X3	5.847	13W1	6.091	211A	7.01	16X4	6.75
3	37X1	7.660	13W3	5.561	13W2	3.881	13W1	6.28	13W2	6.49
4	13W1	7.500	13W2	4.638	22W1	3.240	22W2	5.04	22W3	6.37
5	22W3	6.440	37X1	4.391	4W3	3.051	14X3	5.00	22W1	6.08
6	38W	5.428	211A	4.365	13W3	2.748	22W3	4.58	13W1	4.90
7	13X4	5.000	1H5	4.235	22W2	2.720	15W1	3.08	1H4	4.83
8	22W2	4.881	1H3	4.135	15W1	2.277	1H3	3.00	2H2	4.51
9	3H1	3.245	1H4	4.127	18W2	2.004	4W3	2.88	6X3	4.50
10	4X1	3.100	3H2	4.000	37A	1.702	22W1	2.36	16H3	4.33

7. Animal Related outages in the Past Year (1/1/11-12/31/11)

This section summarizes the worst performing circuit and street by animal related outages during 2011.

Table 8 shows these roads with >2 animal related outages. This table identifies roads that should be reviewed for existing wildlife guards. This work would be in addition to Unitil's current practice of installing Wildlife guards when responding to outages caused by animal contact, or doing other work, at existing service transformers where no animal guard is presently installed.

Table 8
Animal Related Outages by Street

Circuit	Road	# of Animal Outages
8X3	Lane Rd	3
8X3	Horse Corner Rd	3
22W3	Fernwood Place	3

8. Tree Related Outages in the Past Year (1/1/11-12/31/11)

This section summarizes the worst ten performing circuits by tree related outages during 2011. This section is used by the forestry department to help come up with future tree trimming plans.

Table 9 shows the ten worst circuits ranked by the total number of Customer-Minutes of interruption. The number of customer-interruptions and number of outages are also listed in this table. Circuits having less than 3 outages were excluded from this table.

All streets on the Capital System with 4 or more tree related outages are shown in Table 10 below. The table is sorted by number of outages and customer-minutes of interruption.

Table 9
Worst Performing Circuits – Tree Related Outages

Circuit	Customer Minutes of Interruption	Customer Interruptions	No. of interruptions
[1]13W2	803,096.00	8,304.00	72
13W3	390,536.00	5,620.00	20
4X1	373,142.00	3,418.00	15
22W3	272,601.00	3,931.00	21
13W1	264,722.00	2,340.00	36
8X3	251,762.00	1,605.00	68
4W3	210,643.00	1,688.00	17
4W4	162,585.00	2,529.00	9
37X1	124,466.00	1,214.00	16
7W3	93,512.00	1,521.00	11

[1]13W2 has hazard tree mitigation planned in 2012 and full trimming in 2013

Table 10

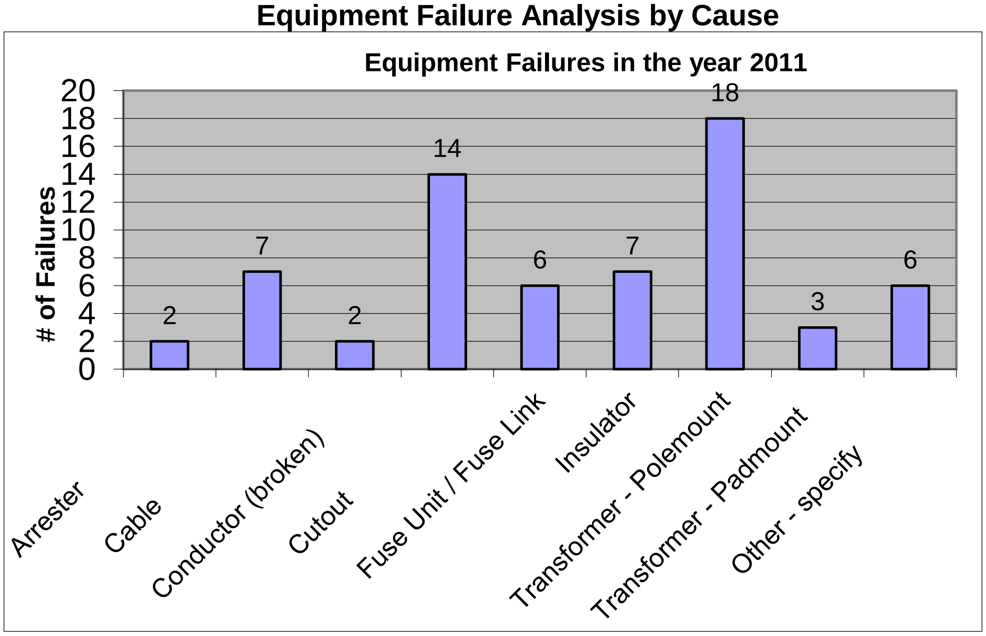
Tree Related Outages by Street

Circuit	Street	# of Outages	Customer Interruptions	Customer Mins of Interruptions
8X3	Mountain Rd	6	232	39380
13W2	West Salisbury Rd	6	310	32096
37X1	South West Rd	6	171	30813
13W2	Old Turnpike Rd	6	354	23404
4W4	Lakeview Dr	5	219	34278
13W1	Morrill Rd	5	59	17189
13W2	Warner Rd	5	150	15502
13W1	West Rd	4	522	89747
4W3	Sewalls Falls Rd	4	633	63235
8X3	Horse Corner Rd	4	210	52368
13W2	Pleasant St	4	233	40681
13W2	Franklin Rd	4	127	18282
15W1	Shaker Rd	4	283	17197
13W2	Little Hill Rd	4	75	14973
6X3	Hopkinton Rd	4	114	13453
8X3	Center Rd	4	22	2050
8X3	Wing Rd	4	30	1992
8X3	Monroe Rd	4	4	324

9. Failed Equipment

This section is intended to clearly show all equipment failures throughout the study period from January 2011 through December 2011. It is important to track these failures so that trends, if any exist, can be observed and corrected in an effort to reduce failures of a specific type of equipment in the future. *Figure 2*, shown below, shows all equipment failures throughout the study period. In addition, *Figure 3* shows each equipment failure as a percentage of the total failures within this same study period. Finally, *Figure 4* shows the top three types of failed equipment within the study period.

Chart 2
Equipment Failure Analysis by Cause



Note: Other is composed mostly of tie wire failures, and Jumper wire failures

Chart 3
Equipment Failure Analysis by Percentage of Total Failures

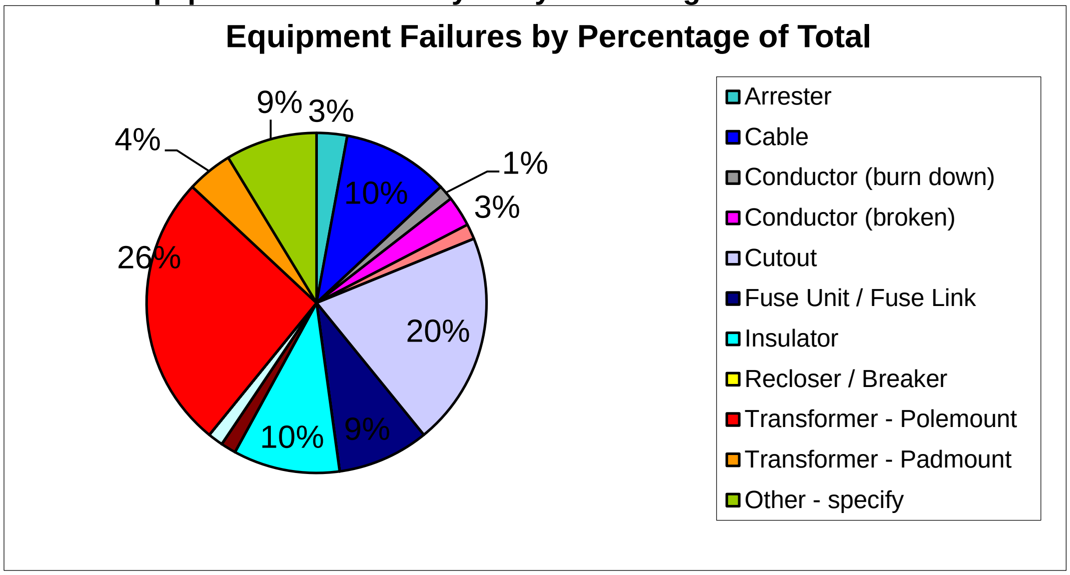


Chart 4
Annual equipment failures by category (top three)

10. Multiple Device Operations in the Past Year (1/1/11-12/31/11)

Table 11 below is a summary of the devices that have operated four or more times in 2011.

Table11
Multiple Device Operations

Circuit	Number of Operations	Device	Customer-Minutes	Customer-Interruptions
13W2	8	Fuse, Pole 1, West Salisbury Rd	53,680	479
4W4	6	Fuse, Pole 1, Lakeview Dr	34,558	256
37X1	6	Fuse, Pole 11, South West Rd	19,765	223
8X3	6	Fuse, Pole 118, Dover Rd	10,304	143
13W2	5	Fuse, Pole 33, Winnepocket Lake Rd	7,949	54
4W3	4	Fuse, Pole 40, Hoit Rd	44,084	373
8X3	4	Fuse, Pole 1, Mountain Rd	37,968	224
13W2	4	Fuse, Pole 2, Franklin Rd	14,824	127
13W2	4	Fuse, Pole 69, Battle St	15,301	135
13W2	4	Fuse, Pole 1, Warner Rd	16,845	182

11. Other Concerns

11.1. Grey Spacer Cable Insulation

Grey spacer cable and spacers on the Unitil System manufactured prior to1975 have been identified by the manufacturer to have reached the end of its useful life. Samples of failed sections of this cable show significant “ringing” due to the dielectric breakdown of the insulation. This is an industry known problem recognized by the manufacturer due to the UV inhibitor compound in this vintage cable. This problem raises concerns with the insulations’ effectiveness, increased probability of conductor burn down, and mechanical strength of the spacers. Locations where this type of cable is installed have been identified and a replacement schedule is planned to be budgeted over the next 5 years.

11.2. Recloser Replacement

Through power factor testing it appears that the solid dielectric material used for the poles on a specific type/vintage recloser degrades over time leading to premature failure. The manufacturer has confirmed this concern. Unitil has experienced two (UES-Seacoast and FG&E) failures of type/vintage of recloser in 2011 and removed a third from service due to the appearance of tracking.

11.3. 13.8kV Underground Electric System Degradation

The 13.8kV underground electric system has been experiencing connector and conductor failures at an average rate of 2 per year for the last 10 years. (This does not include scheduled replacement of hot terminations identified by inspection) This could be due to the age of the underground system, the amount of non-continuous conductor, and/or the number of tee connectors stringed together in some locations. A study will be done next year to identify the best strategy for dealing with these concerns.

12. Recommended Reliability Improvement Projects

This following section describes recommendations on circuits, sub-transmission lines and substations to improve overall system reliability. The recommendations listed below will be compared to the other proposed reliability projects on a system-wide basis. A cost benefit analysis will determine the priority ranking of projects for the 2013 capital budget. All project costs are shown without general construction overheads

12.1. Circuits 13W2 & 13W3: Rebuild Spacer Cable on High Street & King Street

12.1.1. Identified Concerns

One outage on King Street in Boscawen within the study period has resulted in a total of 182,440 customer minutes and 1,291 customer interruptions on circuit 13W2. The existing spacer cable on 13W2 and 13W3 was manufactured in the early 1970's with the ineffective grey cable UV inhibitor. This spacer cable exposes 1,300 customers to a possible fault.

12.1.2. Recommendations

Replace the existing spacer cable on King Street and High Street with new construction. Circuits 13W2 and 13W3 shall be combined in the vicinity of pole 169 King Street. The existing spacer cable currently serving circuit 13W3 shall be removed.

- Reconductor from pole 135 to pole 169 on King Street and from pole 1 to pole 37 on High Street in Boscawen (approximately 8,000 feet) with 336 AAC spacer cable.

- Install a Gang Operated Switches on Goodue Rd P.10 and on High St P. 26.

Estimated Project Cost: $417,860
Estimated Annual Savings - Customer Minutes: 153,013, Customer Interruptions: 1,700
Customer Exposure: 1,300

12.2. Circuit 3H3: Recloser replacement at Gulf St S/S

12.2.1. Identified Concerns

Unitil has experienced premature failures of a specific type/vintage of reclosers due to insulation breakdown of the poles.

12.2.2. Recommendations

Replace this recloser.

Estimated Project Cost: $19,307
Estimated Annual Savings - Customer Minutes: 1,249, Customer Interruptions: 14
Customer Exposure: 111

12.3. Circuit 18W2: Upgrade and Split 22W3, Creating 18W2 Tie

12.3.1. Identified Concerns

There have been 7 outages affecting all of 18W2 in the last 8 years that have an average duration of over 1 1/2 hours (not including the microburst for this average). There have been 4 outages affecting all of 22W3 in the last 8 years. Also, 22W3 exposure will be reduced from 1,538 to 619 (load towards Logging Hill Road) customers. This project was analyzed considering the 18W2 load transfer to 7W3 distribution loading project had been completed, which reduces loading on 18W2 and reduces customer exposure to 773 customers.

12.3.2. Recommendations

Split and upgrade circuit 22W3 to allow circuit 18W2 to be carried by Iron Works S/S and install Gang Operated Switches strategically.

- Add a three phase circuit, built double circuited with existing infrastructure, from P.32 on Iron Works Rd to P.55 on Lewis Lane (3000ft). Install 336 AAC spacer cable using existing neutral. This will cross over I-89 highway. The 22W2 position will feed the original circuit line and the Clinton Street load. The 22W3 position will feed the new circuit line and the load towards Logging Hill Road.
- Move the existing reclosers at P.52 and P.49
- Remove fuses at P.44 Logging Hill Road.
- Install (3) Regulators in the vicinity of P.1, Albin Rd
- Install Gang Operated Switches at P. 79 Bow Center Rd, P.1 Bow Bog Rd, and P.32 Iron Works Rd

Estimated Project Cost: $247,728
Estimated Annual Savings – Customer Minutes of Interruption: 69,015, Customer Interruptions: 1,150
Customer Exposure: 773(18W2), 1547(22W3)

12.4. Circuit 8X3: Create Alternate Mainline

12.4.1. Identified Concerns

Circuit 8X3 has the largest customer exposure on the capital system at 2,764 customers. This circuit has no alternative feeds to restore customers during mainline outages. Horse Corner Rd has had 4 outages in 2011 making up 13% of the customer minutes of interruption on 8X3.

12.4.2. Recommendations

Build an alternate mainline that can be used to divert some customer exposure permanently and allow an alternate circuit feed during contingency scenarios. Three alternatives where looked at one involved crossing over PSNH territory, one involved double circuiting, and the final involved rebuilding Horse Corner Rd. The Horse Corner Road was selected because it will have the added benefit of improving reliability on this road and does not involve PSNH.

- Rebuilding 18,000ft of Horse Corner Rd from single phase 13.8kV to three phase 34.5kV spacer construction.
- Installing three 201A, 19.9kV, regulators on Horse Corner Rd in the vicinity of Dover Rd.
- Installing 19 step down transformers, metering would be needed on 1 of these stepdowns.
- Rebuilding 5,000ft of Old Loudon Rd from 13.8kV to 34.5kV open wire construction.
- Cross I-393 and double circuit mainline for 2000ft.

Estimated Project Cost: $2,750,592
Estimated Annual Savings – Customer Minutes of Interruption: 791,000, Customer Interruptions: 8,788
Customer Exposure: 2800

12.5. Circuit 4W4: Hydraulic Recloser Installation on Lakeview Dr.

12.5.1. Identified Concerns

Six outages caused the fuses on P.1 Lakeview Drive to operate which has resulted in a total of 34,558 customer minutes and 256 customer interruptions on circuit 4W4. These outages break down into the following cause categories: four broken tree limbs, one action by other and one patrolled, nothing found.

12.5.2. Recommendations

Install a 100A V4L Recloser at P.1 on Lake View Dr. with Curves A/B Trips 2/2

Estimated Project Cost: $7,238
Estimated Annual Savings – Customer Minutes of Interruption: 4,350, Customer Interruptions: 48
Customer Exposure: 36

13. Conclusion

During 2011, the Capital System has been greatly affected by interruptions involving tree contact. Enhanced tree trimming efforts are beginning to be implemented, due to increased funding. These efforts will be monitored and evaluated to assure the most effective mitigation of tree related concerns. Projects developed from this study focused on areas of tree related outages as well as other types of outages and ways to prevent or minimize the reliability impact of these outages. In addition, new ideas and solutions to reliability problems are always being explored in an attempt to provide the most reliable service possible.

Although the Boscawen area circuits have been identified as worst performing circuits multiple years running, several significant reliability improvement projects are currently under construction. These projects include: 2011 – Extensive squirrel guard installation effort on 13W3, 2012 – 37X1 load transfer, 2012 – 37 Line auto transfer scheme, 2012 – 13W2 re-coordination and installation of additional protection devices, 2012 – Transfer 13W3 load to 4X1, 2012 – Boscawen Getaway Rebuild and 2012 – Hazard Tree Mitigation. Unitil is investing over 1 million dollars in reliability enhancements for this area.

Unitil Energy Systems – Seacoast

Reliability Study
2012

Prepared By:

Jake Dusling
Unitil Service Corp.
September 18, 2012

UES – Seacoast 2012 Reliability Study

Reliability Analysis and Recommendations

September 6, 2012

1 Executive Summary

The purpose of this document is to report on the overall reliability performance of the UES-Seacoast system from January 1, 2011 through December 31, 2011. The scope of this report will also evaluate individual circuit reliability performance over the same time period. The reliability data presented in this report does not include Hurricane Irene (8/28/11 03:25 to 8/30/11 18:40) or the October Snow Storm (10/29/11 17:35 to 11/2/11 9:24).

The following projects are proposed from the results of this study and are focused on improving the worst performing circuits as well as the overall UES-Seacoast system reliability. These recommendations are provided for consideration and will be further developed with the intention to be incorporated into the 2013 budget development process.

Circuit / Line / Substation	Proposed Project	Cost ($)
22X1	Relocate Main Line to Route 111	$600,000
13W2	Transfer Portion to 5W2	$125,000[1]
Hampton S/S	Install Breakers on 3342, 3353 and 3348 Lines	$365,000
3348 / 3359	Recloser Installation and Distribution Automation Scheme	$295,000
3359	Install Wireless Fault Indicators	$168,000
3348 / 3350	Rebuild Line off the Salt Marsh	$3,000,000
Portsmouth Ave S/S	Install Reclosers	$160,000
Various	Recloser Replacements	$90,000[2]
6W1 / 6W2	Install Animal Guards Pole 48 Depot Road and Pole 94 Main Street Laterals	Minimal
Plaistow S/S	Rebuild to 15 kV	$1,250,000
Hampton Beach S/S	Add 15 kV Circuit Positions and Remove 4 kV Equipment	$1,400,000

[1] Price does not include the reconstruction of Plaistow substation and Smith Corner Road (reference 2013-2017 Distribution Planning Study for additional information).

[2] Price Assumes manufacturer discounted pricing and that the existing relays will remain.

2 Reliability Goals

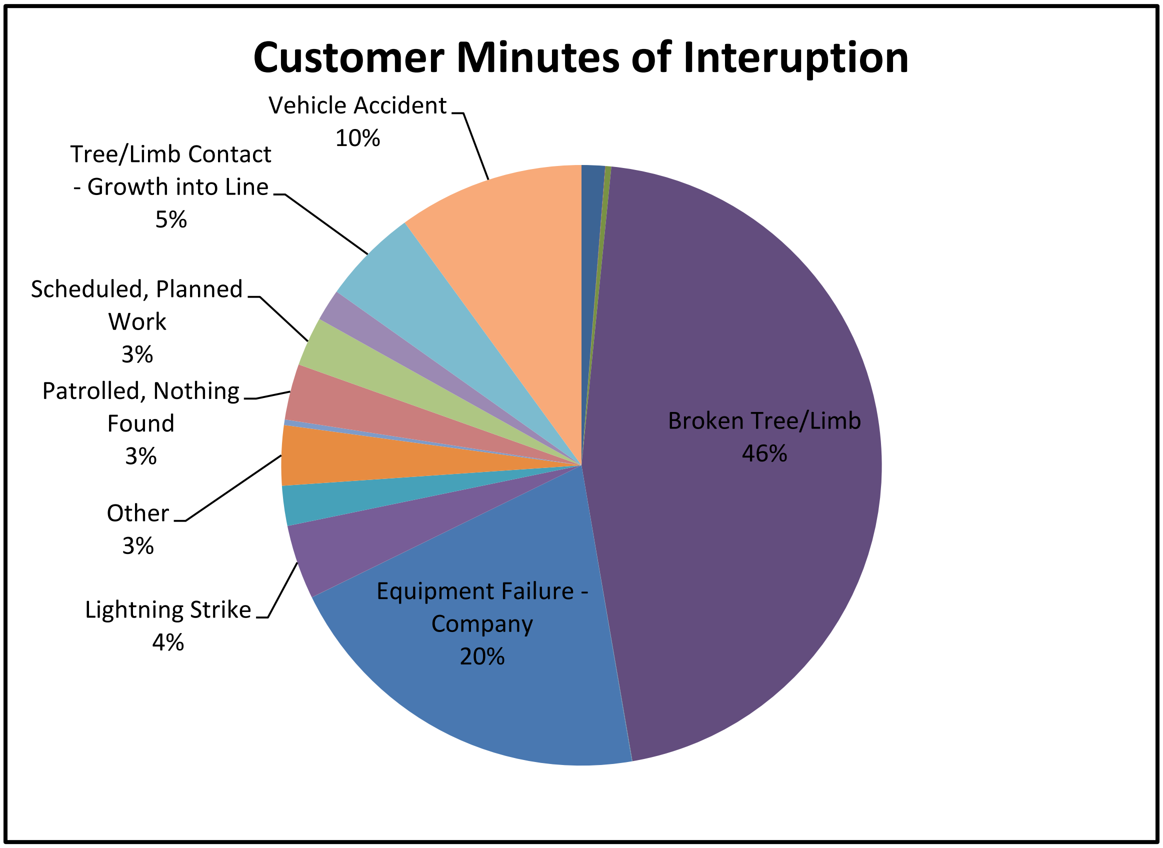
The annual corporate system reliability goals for 2012 have been set at 191-156-121 SAIDI minutes. These were developed through benchmarking Unitil system performance with surrounding utilities.

Individual circuits will be analyzed based upon circuit SAIDI, SAIFI, and CAIDI. Analysis of individual circuits along with analysis of the entire Seacoast system is used to identify future capital improvement projects and/or operational enhancements which may be required in order to achieve and maintain these goals.

3 Outages by Cause

The following chart provides a breakdown of outages by cause and the corresponding percentage of customer-minutes of interruption from January 1, 2011 to December 31, 2011.

Chart 1
Percent of Customer-Minutes of Interruption by Cause



4 10 Worst Distribution Outages

The ten worst distribution outages ranked by customer-minutes of interruption during the time period from January 1, 2011 through December 31, 2011 are summarized in Table 1 below.

Table 1
Worst Ten Distribution Outages

Trouble Location	Description (Date/Cause)	No. of Customers Affected	No. of Customer Minutes	UES Seacoast SAIDI (min.)	UES Seacoast SAIFI
7X2	6/16/11 Vehicle Accident	1,720	269,384	5.96	0.038
54X1	10/27/11 Broken Tree / Limb	1,403	252,540	5.59	0.031
22X1	2/18/11 Broken Tree / Limb	2,008	228,912	5.06	0.044
43X1	7/7/11 Vehicle Accident	1,035	224,255	4.96	0.023
7W1	1/26/11 Equipment Failure-Company (Guy / Anchor)	1,223	220,140	4.87	0.027
54X1	9/24/11 Tree/Limb Contact - Growth into Line	1,406	208,088	4.60	0.031
18X1	4/9/11 Equipment Failure-Company (Insulator)	2,611	180,159	3.99	0.058
22X1	1/27/11 Vehicle Accident	1,225	158,185	3.50	0.027
22X1	4/13/11 Equipment Failure-Company (Insulator)	2,007	148,455	3.28	0.076
19X3	6/23/11 Equipment Failure-Company (Insulator)	875	128,280	2.84	0.019

Note: This table does not include substation, sub-transmission or scheduled planned work outages.

5 Sub-transmission and Substation Outages

This section describes the contribution of sub-transmission line and substation outages on the UES-Seacoast system from January 1, 2011 through December 31, 2011.

All substation and subtransmission outages ranked by customer-minutes of interruption during the time period from January 1, 2011 through December 31, 2011 are summarized in Table 2 below.

Table 3 shows the circuits that have been affected by sub-transmission line and substation outages. The table illustrates the contribution of customer minutes of interruption for each circuit affected.

In aggregate, sub-transmission line and substation outages accounted for 29% of the total customer-minutes of interruption for UES-Seacoast, excluding Hurricane Irene and the October Nor'easter.

Table 2
Sub-transmission and Substation Outages

Trouble Location	Description (Date/Cause)	No. of Customers Affected	No. of Customer Minutes	UES Seacoast SAIDI (min.)	UES Seacoast SAIFI
3346 Line	10/13/11 Broken Tree / Limb	5,830	1,398,900	30.94	0.129
Timberlane S/S	5/16/11 Equipment Failure-Company (Insulator)	2,532	644,822	14.26	0.056
3354 Line	2/25/11 Equipment Failure-Company (Insulator)	3,122	189,040	5.96	0.038
3347 Line	6/30/11 Power Supply Interruption / Disturbance	3,015	96,480	2.13	0.067

Table 3
Contribution of Sub-transmission and Substation Outages

Circuit	Transmission Line Outage	Customer-Minutes of Interruption	% of Total Circuit Minutes	Circuit SAIDI Contribution	Number of events
47X1	Line 3347	46,240	23.62%	32.21	1
11X2	Line 3347	31,264	43.97%	31.92	1
11W1	Line 3347	18,976	14.15%	32.10	1
17W1	Line 3346	661,044	97.47%	371.56	1
17W2	Line 3346	226,920	86.95%	373.38	1
46X1	Line 3346	410,316	99.95%	378.20	1
2X2	Line 3346	33,884	69.79%	18.90	1
3W4	Line 3346	66,736	59.33%	43.32	1
54X1	Line 3354	84.120	10.74%	59.91	1
6W1	Line 3354	104.920	45.96%	60.90	1
13W1	Timberlane S/S	104,275	35.02%	96.48	1
13W2	Timberlane S/S	540,547	52.96%	396.96	1

6 Worst Performing Circuits

This section compares the reliability of the worst performing circuits using various performance measures.

6.1 Worst Performing Circuits in Past Year (1/1/11 – 12/31/11)

A summary of the worst performing circuits during the time period between January 1, 2011 and December 31, 2011 is included in the tables below.

Table 4 shows the ten worst circuits ranked by the total number of Customer-Minutes of interruption. The SAIFI and CAIDI for each circuit are also listed in this table.

Table 5 provides detail on the major causes of the outages on each of these circuits. Customer-minutes of interruption are given for the six most prevalent causes.

Circuits having one outage contributing more than 75% of the customer-minutes of interruption were excluded from this analysis.

Table 4
Worst Performing Circuits Ranked by Customer-Minutes

Circuit	No. of Customers Interruptions	Worst Event (% of Total Cust. Int.)	Customer-Minutes of Interruption	Worst Event (% of Total Minutes)	Circuit SAIDI	Circuit SAIFI	Circuit CAIDI
13W2	6,620	22%	1,020,734	53%	698.61	4.53	154.19
22X1	9,949	20%	822,506	28%	407.92	4.93	82.67
54X1	7,372	19%	783,332	32%	557.90	5.25	106.26
19X3	4,877	18%	501,316	26%	152.894	1.49	102.79
18X1	4,638	56%	387,204	47%	161.74	1.94	83.49
21W2	2,631	35%	326,939	31%	239.71	1.93	124.26
13W1	3,034	36%	297,720	36%	275.45	2.81	98.13
6W1	3,043	57%	228,280	46%	132.50	1.77	75.02
51X1	1,884	30%	197,367	28%	106.12	1.01	104.76
47X1	2,859	51%	195,806	24%	136.41	1.99	68.49

Circuits 19X3 and 22X1 are scheduled for hazard tree mitigation and circuit 13W1 is scheduled for mid-cycle review in 2012. Additionally, circuits 13W2, 21W2 and 58X1 are being trimmed as part of a storm resiliency pilot (ground to sky and hazard tree removal) in 2012. Reliability projects completed in

2012 include the installation of reclosers on circuit 13W2 and sectionalizers on circuit 19X3.

Table 5
Circuit Interruption Analysis by Cause

Circuit	Customer – Minutes of Interruption					
	Broken Tree Limb	Animal	Lightning Strike	Vehicle Accident	Company Equipment Failure	Tree Growth into Line
13W2	428,517	1,940	27,999	1,600	542,080	4,535
22X1	356,429	198	38,090	240,186	149,310	809
54X1	368,070	85,467	6,504	0	89,264	228,555
19X3[3]	38,929	6,028	28,781	390	179,162	8,501
18X1[4]	40,210	1,575	4,700	0	191,716	1,683
21W2	195,053	4,194	6,716	10,310	22,921	6,940
13W1	132,845	315	0	291	104,275	29,820
6W1	24,123	13,286	32,137	920	112,765	24,763
51X1	147,944	28,960	1,119	0	519	8,450
47X1	54,137	910	79,533	0	11,113	0
Total	**2,231,899**	**106,297**	**112,790**	**542,017**	**1,281,877**	**280,963**

[3] Loose/failed connection accounted for 126,795 customer-minutes of interruption on circuit 19X3.
[4] Scheduled planned work accounted for 141,755 customer-minutes of interruption on circuit 18X1.

6.2 Worst Performing Circuits of the Past Five Years (2007 – 2011)

The annual performance of the ten worst circuits for the past five years have been ranked in the tables below. Table 6 lists the ten worst circuits ranked by SAIDI performance. Table 7 lists the ten worst performing circuits ranked by SAIFI.

Outages accounting for more than 75% of the customer-interruptions, sub-transmission line outages and substation outages were included when calculating the indices below.

Table 6
Circuit SAIDI

Circuit Ranking (1 = worst)	2011		2010		2009		2008		2007	
	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI
1	13W2	698.61	51X1	582.06	15X1	526.90	6W1	1033.5	21W1	1082.1
2	54X1	557.90	3H2	575.51	22X1	526.47	21W1	580.27	13W2	1031.4
3	17W2	429.40	22X1	518.07	5H2	444.34	5H2	442.97	27X1	974.02
4	22X1	407.92	59X1	509.53	56X2	430.31	51X1	438.66	22X1	697.94
5	17W1	381.20	15X1	387.88	13W2	414.30	20H1	360.47	13W1	613.90
6	46X1	372.37	23X1	378.56	13W1	365.14	21W2	350.88	11W1	592.79
7	13W1	275.45	17W2	361.53	23X1	339.98	7X2	347.68	18X1	521.24
8	21W2	239.71	58X1	308.72	18X1	323.54	56X2	323.79	47X1	517.21
9	11W1	226.92	46X1	306.30	3H1	260.91	58X1	308.38	6W1	480.12
10	7X2	213.44	21W1	291.33	21W2	260.71	23X1	284.28	7W1	465.33

Circuit 22X1 is the only circuit that has been on the worst performing SAIDI circuits list for four of the last five years and circuits 13W1, 13W2, 21W1, 21W2 and 23X1 have been on the list for three of the past five years. Circuit 17W2 and 46X1 have been on the worst performing SAIDI circuits list the past two years, primarily due to subtransmission line outages.

Table 7
Circuit SAIFI

Circuit Ranking (1 = worst)	2011		2010		2009		2008		2007	
	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI
1	54X1	5.25	51X1	6.65	22X1	6.10	21W1	5.35	27X1	9.573
2	22X1	4.93	3H2	6.01	18X1	5.23	51X1	4.41	13W2	9.565
3	13W2	4.53	22X1	5.21	5H2	5.06	6W1	2.83	21W1	8.570
4	13W1	2.81	15X1	4.38	15X1	4.96	20H1	2.46	22X1	7.889
5	7X2	2.48	23X1	3.77	13W2	4.70	56X2	2.33	18X1	5.156
6	11W1	2.42	59X1	3.43	56X2	4.52	21W2	2.33	13W1	4.673
7	47X1	1.99	11W1	3.29	3H1	4.06	23X1	2.31	47X1	4.639
8	18X1	1.94	13W2	3.21	13W1	3.91	7X2	2.17	11W1	4.615
9	21W2	1.93	28X1	3.07	21W2	3.91	59X1	2.14	6W1	4.235
10	6W1	1.77	20H1	3.01	21W1	3.89	5H2	1.94	43X1	4.057

Circuit 22X1 and circuit 13W2 have been on the worst performing SAIFI circuits list for four of the last five years and circuits 11W1, 18X1, 21W1 and have been on the list for three of the past five years.

Circuit 6W1 has also been on the worst performing SAIFI worst performer circuit list three of the past five years. This circuit was split into two distribution circuits, circuit 6W1 and circuit 6W2, in September of 2011.

7 Tree Related Outages in Past Year (1/1/11 – 12/31/11)

This section summarizes the worst performing circuits by tree related outage during the time period between January 1, 2011 and December 31, 2011.

Table 8 shows these circuits ranked by the total number of Customer-Minutes of interruption. The number of customer-interruptions and number of outages are also listed in this table. Circuits having two or less tree related outages were excluded from this table.

All streets on the Seacoast system with two or more tree related outage are shown in table 9 below. The table is sorted by number of outages and customer-minutes of interruption.

Table 8
Worst Performing Circuits – Tree Related Outages

Circuit	Customer-Minutes of Interruption	Number of Customers Interrupted	No. of Interruptions
54X1	487,191.00	3,137.00	13
13W2	433,052.00	4,753.00	18
22X1	357,238.00	3,129.00	15
21W2	201,993.00	1,731.00	13
13W1	162,665.00	1,555.00	11
51X1	156,394.00	1,447.00	21
58X1	137,990.00	1,311.00	16
23X1	110,197.00	1,460.00	15
56X1	83,261.00	623.00	11
19X3	47,342.00	563.00	22

Circuits 54X1 and 56X1 are scheduled for cycle pruning in 2012.

Circuits 19X3 and 22X1 are scheduled for hazard tree mitigation and circuit 13W1 is scheduled for mid-cycle review in 2012. Additionally, circuits 13W2, 21W2 and 58X1 are being trimmed as part of a storm resiliency pilot (ground to sky and hazard tree removal) in 2012.

Table 9
Tree Related Outages by Street

Circuit	Street	# Outages	Customer-Minutes of Interruption	No. of Customer Interruptions
21W2	Main St	5	187251	1650
51X1	Winnicut Rd	5	60957	576
56X1	Hunt Rd	5	28534	354
13W2	Whittier St	4	114195	783
13W1	North Main St	4	38047	313
22X1	Main St	3	86504	674
58X1	Forest St	3	32854	326
58X1	Sawyer Ave	3	19856	127
19X3	Brentwood Rd	3	1175	4
13W1	Main St	2	111455	1130
13W2	Main St	2	70842	650
51X1	Portsmouth Ave	2	65577	639
23X1	Wild Pasture Rd	2	41140	88
13W2	Thornell Rd	2	30277	151
43X1	Exeter Rd	2	25842	217
58X1	Main St	2	17046	191
23X1	South Rd / Rt 107	2	13131	111
23X1	Highland St / Old Rt 150	2	12819	72
13W2	Smith's Corner Rd	2	11405	115
58X1	Harriman Rd	2	11350	92
22X1	Sandown Rd	2	11240	43
59X1	Crank Rd	2	9527	139
19X3	Beech Hill Rd	2	9312	112
23X1	Woodman Rd	2	8342	66
43X1	Heritage Way	2	8177	74
19H1	Drinkwater Rd	2	7982	41
2X2	Dearborn Ave	2	6200	124
51X1	Union Rd	2	5655	35
19X3	Newfields Rd	2	4574	21
6W1	Stumpfield Rd	2	3198	35
51X1	Squamscott Rd	2	1905	32
51X1	Birnum Woods Rd	2	1421	28
11W1	Doe Run Ln	2	766	12
51X1	Spring Creek Ln	2	622	4
23X1	Pevear Ln	2	534	4
28X1	Exeter Rd	2	460	2
54X1	New Boston Rd	2	324	4
19X3	Lary Ln	2	238	4
43X1	Willow Rd	2	229	2
21W2	Bittersweet Ln	2	114	2

8 Failed Equipment

This section is intended to clearly show all equipment failures throughout the study period from January 1, 2011 through December 31, 2011. Chart 2 shows all equipment failures throughout the study period. Chart 3 shows each equipment failure as a percentage of the total failures within this same study period. The number of equipment failures in each of the top three categories of failed equipment for the past five years are shown below in Chart 4.

Chart 2
Equipment Failure Analysis by Cause

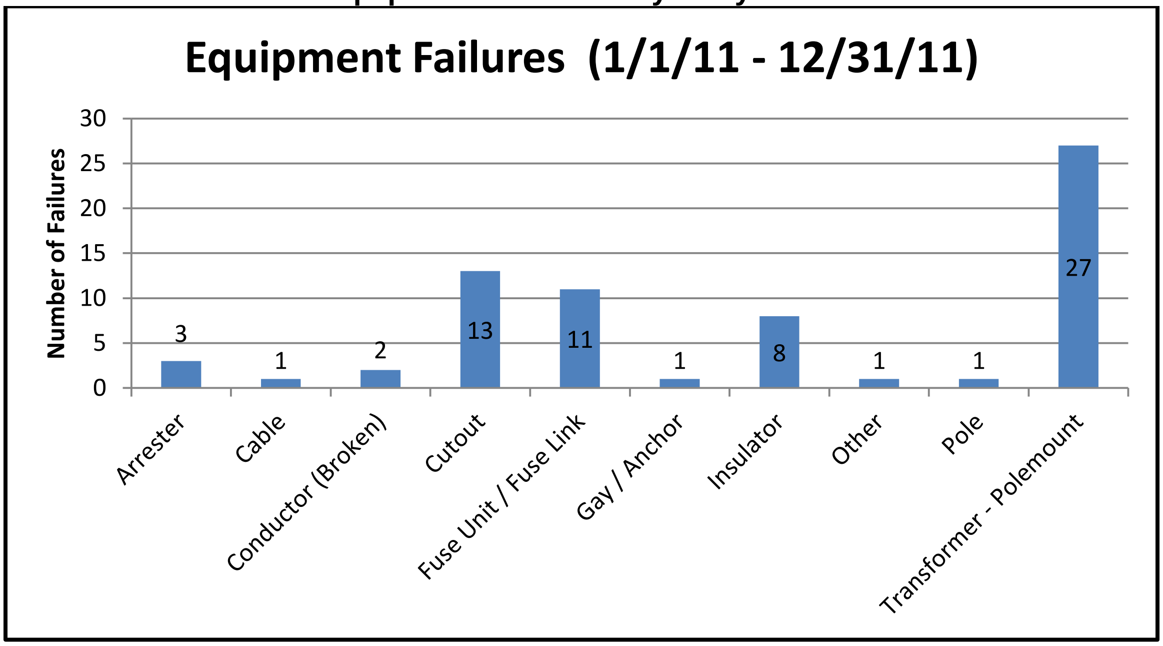


Chart 3
Equipment Failure Analysis by Percentage of Total Failures

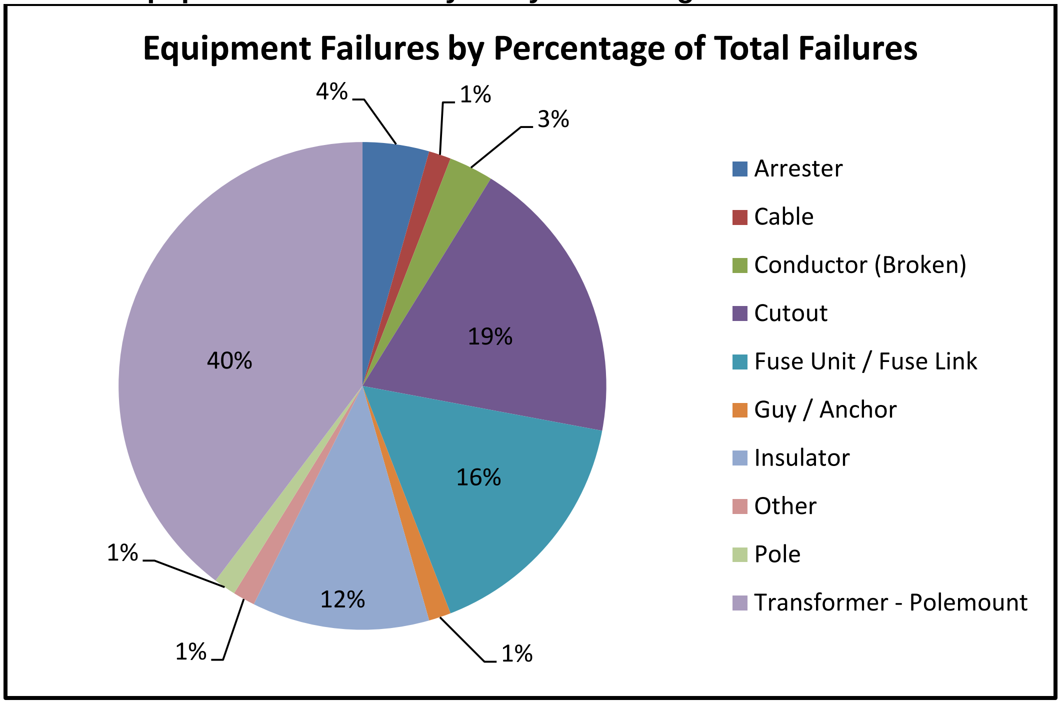
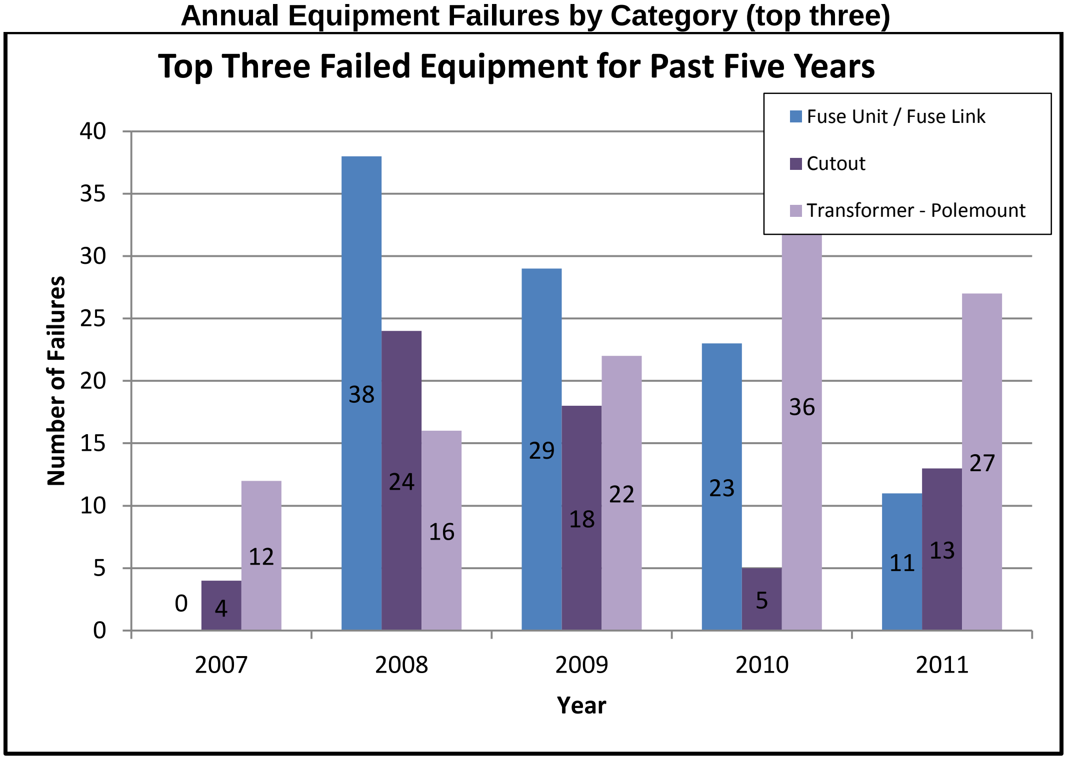


Chart 4
Annual Equipment Failures by Category (top three)



9 Multiple Device Operations in Past Year (1/1/11 – 12/31/11)

A summary of the devices that have operated three or more times from January 1, 2011 to December 31, 2011 is included in table 10 below.

Table 10
Multiple Device Operations

Circuit	Number of Operations	Device	Customer-Minutes	Customer-Interruptions
22X1	4	Fuse Pole 9 Kingston Road	286,937	3,109
6W1	4	Fuse Pole 48 Depot Road	272	4
6W1	4	Fuse Pole 94 Main Street	4,042	36
21W2	3	Recloser Pole 107 Main Street	187,011	1,648
15X1	3	Fuse Pole 74 Lafayette Road	8,556	90
3H1	3	Fuse Pole 8 Kentville Terrace	7,774	78

10 Other Concerns

This section is intended to identify other reliability concerns that would not be identified from the analyses above.

10.1 Recloser Replacements

Through power factor testing it appears that the solid dielectric material used for the poles on a specific type/vintage recloser degrades over time leading to premature failure. The manufacturer has confirmed this concern. Unitil has experienced two (UES-Seacoast and FG&E) failures of type/vintage of recloser in 2011 and removed a third from service due to the appearance of tracking.

There are currently five of these reclosers in service in UES-Seacoast, two at Wolf Hill tap, two at the 3347 line tap and one at Stard Road tap.

10.2 Subtransmission Lines Across Salt Marsh

The 3348 line has been damaged several times during major events over the last four years, causing outages to the customers on all the distribution circuits supplied by the 3348, 3350 and 3353 lines. The 3348 line is constructed through salt marsh, making it very difficult to access and repair.

The 3350 line and portions of the 3342 and 3353 lines are also constructed through salt marsh. These lines have the same access concerns, but have been far more reliable than the 3348 line in the past. The 3350 line is radial line that supplies Seabrook substation, if damaged load may need to be left out of service until repairs are made.

10.3 3347 Line

The 3347 line has been damaged by trees during major events over the past four years, causing outages to customers at Guinea Road Tap and Portsmouth Ave substation until load is restored.

10.4 Hampton Beach Substation

The existing 4 kV equipment, structures and control cabinets at Hampton Beach substation are experiencing significant rusting and the foundations are cracked and crumbling. In 2009 the 3T2 transformer was removed from service and scrapped due to rusting. Additionally, a majority of the 4 kV insulators are of the brown porcelain variety that are historically prone to failure and the existing switch braids are in need of replacement.

10.5 Plaistow Substation 4 kV Foundation

The existing 5T1 transformer and switchgear foundation at Plaistow substation is in varying stages of failure. A 2005 evaluation by SW&C suggests the cause of the deterioration appears to be a chemical breakdown between the aggregate and the cement which cannot be halted by repairs or reinforcement.

The foundation failure is making it more difficult each year to rack out the breakers for maintenance, creating a concern that the breaker may no longer be able to be maintained in the future.

The breaker arc chutes are reaching the end of their useful lives and replacement units are becoming ever more difficult to purchase.

11 Recommendations

This following section describes recommendations on circuits, sub-transmission lines and substations to improve overall system reliability. The recommendations listed below will be compared to the other proposed reliability projects on a system-wide basis. A cost benefit analysis will determine the priority ranking of projects for the 2013 capital budget. All project costs are shown without general construction overheads.

11.1 Circuit 22X1 – Relocate Main Line to Route 111

11.1.1 Identified Concerns

Circuit 22X1 has been one of UES-Seacoast's worst performing circuits (top 5) four of the last five years. The fuses at pole 9

Kingston Road, feeding Route 111A have operated four times over the same period, two of which were potentially temporary in nature.

Additionally, the existing main line along Kingston Road and Pleasant Street typically sustains significant damage during major storms, requiring significant repairs to energize the mainline of 22X1.

11.1.2 Recommendation

This project will consist of building approximately 2.25 miles of new three-phase open wire construction along Route 111 from Mill Road to Danville Tie. Route 111 is a major state road-way with very little tree exposure.

Additionally, 2,500' of Route 111A will be rebuilt to three-phase construction and a new recloser will be installed along Route 111A to prevent sustained outages for potentially momentary faults.

Once complete, the new main line of 22X1 will run along Route 111 and Route 111A and Kingston/Danville Road will become protected laterals off the new mainline.

This project is expected to save approximately 1,900 customer interruptions per event for faults on Danville Road and Pleasant Street. This will also reduce damage to the mainline of 22X1 during major events.

- Estimated annual customer-minutes savings = 388,867
- Estimated annual customer-interruption savings = 4,051

Estimated Project Cost: $600,000

11.2 Hampton S/S – Install Breakers on the 3342, 3353 and 3348 Lines

11.2.1 Identified Concerns

In the present configuration, the Guinea 3353 breaker will operate for faults on the 3353 line from Hampton to Hampton Beach, the 3348 line, the 3350 line and a portion of the 3359 line causing interruptions to circuits 2H1, 2X3, 3H1, 3H2, 3H3, 7W1, 7X2 and a portion of the 3359 line, totaling approximately 5,300 customers.

For faults on the 3342 line from Hampton to Hampton Beach and the 3346 line, the Guinea 3342 breaker will operate causing interruptions to circuits 2X2, 46X1, 17W1, 17W2 and 3W4 totaling approximately 7,600 customers.

Historically, there has been at least one (1) permanent fault on one of the lines described above each year over the past five years and several momentary interruptions that could be from temporary faults on the same lines.

11.2.2 Recommendation

This project will consist of installing 1200 amp (minimum) breakers on the 3342 and 3353 lines and an 800 amp (minimum) breaker on the 3348 line at Hampton. SCADA communications and control will be installed for the new breakers.

The addition of these breakers will remove approximately 10 pole-miles of fault exposure from the 3342 and 3353 lines. This will save approximately 2,300 customer interruptions for faults on the 3348 line and a portion of the 3359 line, 4,000 customer interruptions for faults on the 3353 line from Hampton to Hampton and 2,500 customer interruptions for faults on the 3346 line and the 3342 from Hampton to Hampton Beach.

- Estimated annual customer-minutes savings = 262,957
- Estimated annual customer-interruption savings = 2,739

Estimated Project Cost: $365,000

11.3 3348/3359 Line – Distribution Automation Scheme

11.3.1 Identified Concerns

The 50J59 and 48J50 switches are located on Seabrook Station property requiring crews to pass through a security check-point to performing system switching, which adds significant time to the restoration of Seabrook substation for faults on the 3348.

11.3.2 Recommendation

This project will consist of installing two reclosers at the Seabrook Station Marsh tap, replacing the 50J59 and the 48J50 switches. The new reclosers will communicate with Hampton substation via radio.

With the addition of the new reclosers the normally open point on the 3348/59 line would be moved the 50J59 recloser. An automation scheme would be implemented to automatically restore Seabrook substation for loss of the 3348 line.

The intent is to select a scheme that is expandable to include Cemetery Lane substation, Stard Road tap and Mill Lane tap in the future.

The addition of the new reclosers and the automation scheme will allow for the automatic restoration of Seabrook substation load (approximately 3,000 customers) for the loss of the 3348 line. Additionally, the new reclosers will be set to operate for faults on the 3350 line.

- Estimated annual customer-minutes savings = 116,452
- Estimated annual customer-interruption savings = 1,213

Estimated Project Cost: $295,000

11.4 3359 Line – Wireless Fault Indicators

11.4.1 Identified Concerns

Due to the nature of the 3359 and 3348 lines, the 3359 line must be patrolled prior to performing restoration switching.

The 3359 has experience three outages since the beginning of 2010 totaling 952,013 customer-minutes of interruption and the 3359 typically sustains damage during major storm events.

11.4.2 Recommendation

This project will consist of installing six wireless fault indicators, two each at Cemetery Lane substation, Stard Road Tap and Mill Lane Tap. The indicators will be integrated into the existing RTU's at these locations to provide status via SCADA.

Prior to installation it will need to be confirmed that SCADA and communications will be able to provide status after the loss of station service.

The addition of the fault indicators will provide immediate indication of the fault location to allow crews to be dispatched to the appropriate locations for patrolling and/or restoration switching. This is expected to save approximately 275,000 customer-minutes of interruption per event for faults on the 3359 line

- Estimated annual customer-minutes savings = 167,3912
- Estimated annual customer-interruption savings = 0

Estimated Project Cost: $75,000

11.5 3348 and 3350 Line – Rebuild off the Salt Marsh

11.5.1 Identified Concerns

The 3348 line and 3350 line are constructed entirely through the salt marsh in Hampton, Hampton Falls and Seabrook, which makes them difficult to patrol and repair.

The 3350 line is a radial line to Seabrook substation. Load will remain out of service for faults on the 3350 line until the line is repaired.

These lines are concerns during all major wind events. During the 2010 wind storm several structures on the 3348 line were damaged causing the line to be out of service for several months. The line was also damaged in March of 2012 due to a failed insulator which required the line to remain out of service for a few weeks.

11.5.2 Recommendation

This project will consist of building a new 34.5 kV subtransmission line from Hampton substation to Seabrook substation. Once complete the 3348 and 3350 line will be removed from the marsh. There are several possible routes for the new line, including Route 1, the 3359 line right-of-way or along the railroad right-of-way from Hampton to Seabrook.

This project would most likely need to be a multi-year project to allow sufficient time for design and construction.

This project removes approximately 4.5 miles and 3,000 customers of exposure from lines on the salt marsh.

- Estimated annual customer-minutes savings = 112,696
- Estimated annual customer-interruption savings = 1,174

Estimated Project Cost: $3,000,000

11.6 Portsmouth Ave Substation – Install Reclosers

11.6.1 Identified Concerns

When circuit 11W1 was converted to 34.5 kV, circuit 11X2 more than doubled in size. In the new configuration faults along the Exeter portion of Portsmouth Ave will affect 11W1 customers and faults on Portsmouth Ave in Stratham will affect 11X2 customers.

This added load on the 11X2 recloser prevents 11X2 from backing up circuit 19X2 under peak conditions.

Additionally, Portsmouth Ave is supplied from the 3347 line, which is a radial line that typically experiences damage during major events.

11.6.2 Recommendation

This project will consist of installing two new reclosers at Portsmouth Ave. substation. One recloser will supply 11X1 (11W1) load and the other will supply 11X2 load. The new reclosers will be installed in locations to allow regulators to be installed on 11X1 at Portsmouth Ave substation in the future.

The recloser settings for circuit 19X2 will be modified to allow circuit 19X2 to supply circuit 11X2 and 11X1. This will require the 11X1 and 11X2 reclosers to have alternate settings while in this configuration.

Once complete circuit 11X1 will supply approximately 600 customers with 1.25 miles of main line exposure and 11X2 will supply approximately 1,000 customers with 1.25 miles of customer exposure opposed to one circuit supplying 1,600 customers with 2.5 miles of main line exposure. For loss of the 3347 line this will save roughly 200,000 customer-minutes of interruption to the customers served from Portsmouth Ave substation.

- Estimated annual customer-minutes savings = 210,481
- Estimated annual customer-interruption savings = 2,193

Estimated Project Cost: $160,000

11.7 Recloser Replacements

11.7.1 Identified Concerns

Unitil has experienced premature failures of a specific type/vintage of reclosers due to insulation breakdown of the poles.

11.7.2 Recommendation

This project will consist of replacing the remaining of these reclosers on the UES-Seacoast system. The existing relays will be re-used.

- Two (2) at Wolf Hill Tap
- Two (2) at 3347 Line Tap
- One (1) at Stard Road Tap

Below is a summary of the reliability benefit for this project:

Recloser	Customers of Exposure
03341	15,250[5]
3352	18,000[5]
3347A	5,350
3347B	7,900
59X1	3,050

[5] Assumes summer normal configuration at peak load conditions.

- Estimated annual customer-minutes savings = 120,000
- Estimated annual customer-interruption savings = 1,250

Estimated Project Cost: $90,000 (assumes special pricing from the manufacturer)

11.8 Circuit 6W1 and 6W2 – Install Animal Guards Pole 48 Depot Road and Pole 94 Main Street Laterals

11.8.1 Identified Concerns

The laterals supplied from pole 94 Main Street and pole 48 Depot Road, Kingston have each experienced four animal contact outages during 2011.

11.8.2 Recommendation

Install cone-type animal guards on all transformers (approximately 6) on the laterals supplied by pole 94 Main Street and pole 48 Depot Road, Kingston.

Once complete this mitigates animal contacts on these two laterals (approximately 15 customers).

- Estimated annual customer-minutes savings = 4,314
- Estimated annual customer-interruption savings = 40

Estimated Project Cost: Minimal

11.9 Plaistow S/S – Rebuild and Transfer Portion of 13W2 to 5W2

11.9.1 Identified Concerns

Circuit 13W2 was the worst performing circuit in 2011 and has been on UES-Seacoast's worst performing circuits three of the last five years. One substation outage at Timberlane substation resulted in approximately 540,000 customer-minutes of interruption during 2011.

The Plaistow power transformer and switchgear foundation is degrading and beyond repair causing switchgear maintenance concerns. Additionally the breaker arc chutes are reaching the end of their useful lives.

11.9.2 Recommendation

This project will consist of rebuilding Plaistow substation and converting circuits 5H1 and 5H2 to 13.8 kV operation. A portion of Smith Corner Road will be rebuilt three-phase and approximately 650 customers from circuit 13W2 will be transferred to circuit 5W2, saving interruptions to those customers for faults at Timberlane substation and along the main line of circuit 13W2.

This will also create a circuit tie between circuits 13W2 and 5W2 that will allow circuit 13W2 to be transferred to circuit 5W2 for faults at Timberlane substation and along Crane's Crossing Road, which will save approximately 90 minutes of interruption to approximately 650 customers on circuit 13W2.

Reference the UES-Seacoast 2013-2017 Distribution Planning Study for additional justification and associated costs.

11.10 Hampton Beach S/S – Add 15 kV Circuit Positions and Remove 4 kV

11.10.1 Identified Concerns

The 4 kV portion of Hampton Beach substation has several condition concerns, including the following:

- Rusting of 3T1 transformer
- Significant wear on the braids of all 4 kV switches
- Brown porcelain insulators that are prone to failure
- Significant rusting of control cabinets and structures
- Degradation of concrete foundations

11.10.2 Recommendation

This project will consist of populating the 3W5 circuit position, upgrading the existing 3W4 circuit position and installing two new 15 kV circuit positions.

Construction will include the installation of a new dual ratio power transformer and new circuit regulators and reclosers on all circuit positions.

Circuit 3H2 will be converted to 13.8 kV to accommodate this project. Circuits 3H1 and 3H3 will continue to operate at 4 kV.

Once complete this will eliminate condition concerns associated with 4 kV portion of Hampton Beach substation, which serves roughly 1,400 customers.

Estimated Project Cost: $1,400,000

12 Conclusion

The UES-Seacoast system has experienced a large number of outages caused by tree contact as well as outages affecting a large number of customers. A more aggressive tree trimming program began in 2011 and should start to reduce the number of tree related outages experienced in the future. In 2012 three circuits on the UES-Seacoast will benefit from a storm resiliency pilot, which will consist of ground to sky trimming and hazard tree removal.

The recommendations made for capital improvement projects within this report are aimed at reducing the duration and customer impact of outages, improving the reliability of the subtransmission system and mitigating damage to distribution mainlines and subtransmission lines during major events.

Demand Side Management Planning

Prepared By:

Unitil
December 2010

TABLE OF CONTENTS

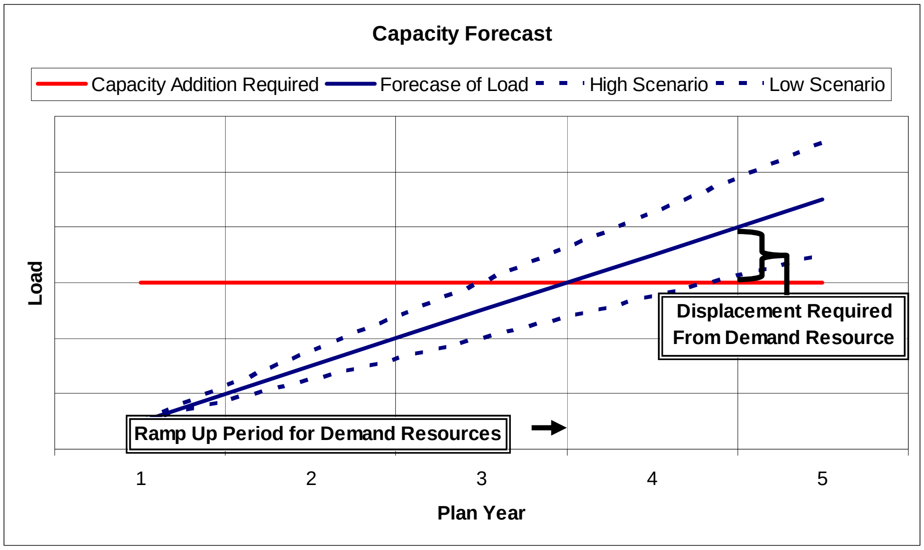
1 INTRODUCTION

Historically, the distribution system planning process focused exclusively on the capabilities of the distribution system infrastructure to satisfy the peak demands resulting from existing and projected circuit and system load requirements. To the extent that there were changes in the load characteristics of the Company or its customers over time, these factors were considered as exogenous to the plan and were presumed to be accounted for in the historical trends underlying the peak demand forecast.

In recent years, the choices and technologies by which customers can change their apparent load characteristics on the distribution system have expanded significantly. Choices made by consumers which result in increasing demand include a significantly higher penetration of air-conditioning and more recently the expansion of home entertainment and computer equipment. Customers have also made choices which have reduced demand such as energy efficiency, stimulated both by price increases and market choices, as well as by energy efficiency programs. At the same time, some customers have been inclined to install distributed generation, in response to state net metering policies and federal and state incentives.

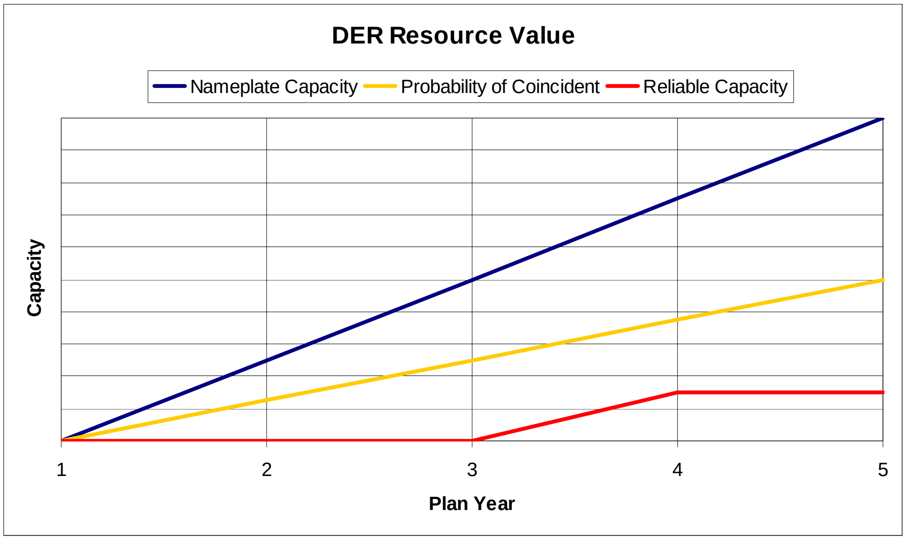
These changes have complicated the forecasting process. However, they now offer opportunities for the distribution utility, through specific programs, to directly influence consumer adoption of new technologies. As a result, these opportunities need to be factored into a utility's distribution system planning process in a more systematic way. The incremental impacts of demand-side programs and associated changes in consumer decisions in the short term may have little impact on distribution system capacity resources requirements, but in the longer term may be quite significant. Significantly changing consumer demand profiles is a radically different utility intervention than building distribution facilities to meet utility distribution planning and design criteria.

One useful tool for analyzing demand side resources is what is sometimes referred to as a "wedge analysis". In its simplest terms, this analysis seeks to factor in the impacts of demand side resources over time relative to a nominal forecast of future peak loads. Just as a distribution circuit or substation must be built in the period prior to when it is needed, demand-side options will need to be initiated and achieve specific results before the peak load increases to the point where existing distribution resources are insufficient to meet the requirements. The graph below demonstrates the concept.



In assessing any given demand-side resource, there are critical questions relative to the value of a particular resource in meeting the distribution system reliability requirements. The utility has the responsibility to the customers it serves to design a system that can serve the peak demand in a reliable manner. This has been accomplished through traditional distribution and substation system improvements that have a high level of reliability. These assets are under the control of the utility and as such are available with certainty to serve the peak demand requirements. Any resource or program relied upon to displace distribution or substation system improvements must have a similar high level of reliability.

A given resource may or may not be coincident with the Company's peak demand requirements and may or may not provide equivalent reliability to traditional distribution reliability investments. The graph below demonstrates the concept. A given demand side resource will generally have a "nameplate" capacity rating representing the maximum potential demand contribution. However, there is some probability that the maximum demand contribution will not be available at the time of the Company peak, in which case the nameplate capacity needs to be discounted. In addition there are factors that affect the degree to which the Company can count on the resource to meet peak capacity needs – for example if it involves equipment over which the Company has no contractual rights, operating control or confidence that it will operate when needed.



Unitil has previously reviewed several different distributed energy resource technologies that could be used to offset the peak loads on the system. For purposes of this analysis, the Company examined, on a preliminary basis, the current status and potential options for a variety of distributed energy resource initiatives that could contribute to meeting future peak load requirements. The analysis incorporates several existing options including Energy Efficiency Programs, Net Metering facilities and Qualifying Facility generation. It also demonstrates the potential contributions of a variety of other distributed energy resource options including enhanced energy efficiency or net metering, utility-controlled generation, demand control options under either ISO or Company control, and TOU / price induced demand changes.

These analyses are preliminary and in some cases hypothetical as the Company has not, with the exception of CORE Energy Efficiency programs, examined the options and their feasibility and cost in detail. However, the options have been selected to address a variety of technological or programmatic categories that the Company is aware of as being potentially feasible. These existing and potential distributed energy resource programs are incorporated into a preliminary hypothetical wedge analysis showing potential peak demand contributions from a variety of program and technology options. The wedge sections will then be compared to the nominal baseline system peak demand forecast discussed in Section 1.4 of this report.

2 DISTRIBUTED ENERGY RESOURCE TECHNOLOGY

Unitil analyzed several different distributed energy resource technologies that could be used to offset the peak loads on the system. The reviews included new technology which had an effect of excluding the ongoing energy efficiency and demand side management programs, which are reflected in historic peak demand trends and therefore factored indirectly into the peak demand forecast.

In the analysis, the cost of distributed energy resources were compared the costs of historical transmission and distribution projects, which ranges from about $50 per kW to $100 per kW.

In this comparison, the distributed energy resources assessed generally did not compare favorably with traditional transmission and distribution investment. However, the Company is implementing some pilot projects to continue to evaluate certain distributed energy alternatives – these are described in greater detail below. The previous review of DER technologies covered a wide range of distributed energy resources, including:

- Ice Storage (Residential and Commercial)
- Battery Storage
- Fuel Cell Generation
- Solar (Photovoltaic) Power
- Wind Power
- Landfill Generation
- Load Control with AMI
- Time of Use/Demand Response
- DER Technology Investments Pursuant to RSA 374-G

2.1 Ice Storage

Unitil's electric system demand peak is driven by air conditioning in the summer months. Ice storage technology is a potentially effective way of shifting the air conditioning peak away from the peak hours of the day. This review was focused on the Ice Energy ® Ice Bear ® system. Ice Energy's ® products shift air conditioning from "on-peak" times of the day to "off-peak" periods. This product, combined with a time-of-use rate would shift energy consumption away from the higher cost periods to periods when energy is less expensive.

Ice Energy's ® products are designed to operate in conjunction with an existing air conditioning unit. The condenser of the air conditioning unit is used to freeze water into a block of ice in the evening when electricity is less costly. During the daytime hours, the block of ice melts as it cools the coolant and provides air conditioning while reducing electric demand by 95%. This technology is rated to offset approximately 30 kWh per day. This can be related to 1 kW over 30 hours or 30 kW over 1 hour or any other ratio of 30 kWh. The Ice Bear ® product is sized to work best with a 5 ton AC unit commonly used in a residential or small commercial installation. Unitil designed and estimated several pilot project installations for the Ice Bear ® system.

Ice storage units were targeted for three separate installations at Unitil owned facilities. The designs proposed to replace the existing condensing unit and evaporator coil with an Ice Bear 30 condensing unit. The costs of these projects averaged $24,800 per located resulting in an installed cost of approximately $5,000/saved kW. Some of the challenges that Unitil identified in implementing a project such as this were:

1. Retrofitting an existing unit – addition of a cooling coil to the air handler
2. Installation of equipment on rooftops - overall weight restrictions of existing buildings.
3. Verification of assumption that annual consumption is not reduced just moved to different times of day.

Based upon the cost of this solution, Unitil decided not to continue with the pilot project recommendation.

2.2 Battery Storage:

Unitil evaluated battery storage as a means for offsetting peak load. This technology allows the batteries to be charged during off peak hours and discharged during peak hours. ZBB Energy Corporation manufactures Zinc Energy Storage Systems (ZESS) for commercial, industrial and utility storage applications in need of renewable energy power generation smoothing, peak shaving, load and/or generation shifting or load following applications.

Unitil evaluated a proposal for ZBB's ZESS regenerative fuel cell type of energy storage products. The ZESS 50 and the ZESS 500 products are complete systems which include the ZESS energy storage modules, the cooling system, overall system integration, and the Power Conversion System (PCS) for a complete integrated AC system ready for utility grid interconnect upon arrival (Minimal site preparation, minimal installation, minimal commissioning). Both the ZESS 50 and the ZESS 500 are easily dispatched over a distribution network with remote communication to allow Unitil to control the operation of each. The small foot print and high energy density make these building blocks ideal for integrating into existing infrastructure with minimal space and on site preparation work.

Unitil received an estimate for the ZESS 50 and ZESS 500 units. Based upon the pricing, the installed cost is estimated at $2,100-$2,400 per kW. Based upon the cost of this solution, Unitil decided not to continue with a pilot project recommendation.

2.3 Fuel Cell Generation:

Unitil evaluated fuel cell generator technology as a means to use an electrochemical process to produce electricity and in some cases heat. Unitil evaluated small scale fuel cell generators (1 kW - 5kW) and large scale fuel cell generators (300kW – 2.4 MW). Unitil considered fuel cell technology as an alternative to other technologies that may not be as reliable as a fuel cell (i.e. wind and solar).

Fuel cells provide clean, safe, and reliable power in a consistent manner. This is important when it comes to offsetting demand during peak load times. However, most forms of non-combustion electric generation have limitations that impact widespread use of the technology, especially as a primary source of electric power (i.e., baseload power). Fuel cell technology has advanced to the point where it is now a viable source of consistent power for baseload power applications.

Today, fuel cells are reaching their potential as the cleanest and most reliable sources of distributed power generation. Fuel cells generally have a 95% power availability, so they are generally considered very reliable. The cost evaluation, however, indicates that fuel cell generators are not an economically strong alternative. Estimates identified that for smaller applications (1 kW - 5 kW) for the installed cost is between $58,000 to $75,000 per kW.

Larger applications (300 kW – 2.4 MW) result in an installed cost between $4,000 to $5,000 per kW. Based upon the cost of this solution, Unitil decided not to continue with a pilot project recommendation.

2.4 Solar (Photovoltaic) Power:

Unitil evaluated the application of Photovoltaic (PV) systems to offset load at peak demand times. Stand alone PV is obviously reliant on the presences of sun. Therefore, it is not as reliable or as available as some of the other alternatives. PV cells are connected together to make a module. Modules are the building blocks connected together to make an array. Arrays can be added together to increase the output capacity of the system.

The PV system produces DC voltage and is interconnected to the electric grid via an inverter. The inverter changes the DC voltage to the AC voltage of the electric system. The inverter also provides protection to the electric system as it automatically disconnects the PV from the electric system during system faults. Two types of systems could be installed. The first is a typical PV system interconnected to the electric grid using an inverter. The second is a system with a back-up battery system. The battery system allows a longer output duration of the system, as the battery will be charged during high solar output, low-usage (morning) hours. When the output of the PV system diminishes in the late afternoon, high-demand hours, the battery will supplement the solar output.

Unitil designed a pilot project to produce power during the system peak by installing four typical PV systems (two in the UES Seacoast system and two in the UES Capital system) and two PV systems augmented with batteries. Unitil's evaluation indicates that PV systems are not an economically strong alternative. Unitil's estimates identified that the installed cost of PV systems at the time were between $9,000 per kW (typical system) to $14,000 per kW (battery included). Based upon the cost of this solution, Unitil decided not to continue with the pilot project.

2.5 Wind Power:

Unitil has evaluated the application of wind turbines on the distribution system. Wind turbines rely on high wind speeds to produce power and are therefore not as reliable or as available as some of the other DER alternatives, but wind turbines may produce electricity during the summer afternoon hours which could offset system peak demand. The installation of wind turbines also have additional benefits such as reduced electricity consumption and emissions associated with the majority of power generation.

Unitil currently has two Skystream 3.7, 1.8 kW-rated wind turbines in service in Hampton, NH. The Skystream 3.7 wind turbine is a completely integrated and well-built generator with proven performance for straight-forward pole top installation. The locations are fitted with anemometer and wireless monitors that can gather the data to verify that the turbine is operating properly and download wind speed and turbine output data using Zigbee RF communications to a computer. The wind speed records at the site of the wind turbine show a direct correlation with the published power curve of the Skystream 3.7 wind turbine. The two

Skystream 3.7 wind turbines, one on a Unitil owned utility pole and one on a steel monopole tower at Winnacunnet High School, cost $48,550 (> $13,000 per installed kW).

Unitil also completed an analysis of the ARE110 wind turbine and determined that it could produce roughly 25% more energy production than the Skystream 3.7 at our locations but at a price four times higher. The Company is also evaluating a Proven 15 kW) wind turbine installed by a customer at 152 Drinkwater Road in Kensington. The Proven 15 wind turbine is a well-regarded medium size wind turbine that has been installed in extreme locations such as a Shell oil platform and in Antarctica. The Company installed an interval meter and anemometer with wireless wind monitor at a cost of $1,450.

Unitil has gained valuable information about the wind turbines and their performance. However it has been found from these installations that the wind resource is not as abundant as expected. At the preset time, Unitil is still evaluating the wind turbine installations to determine if further application of the units is cost effective and if larger units, with installed costs ranging from $5,000 per kW to $25,000 per kW, might be more cost-effective.

2.6 Landfill Generation:

Unitil has several municipal landfills, which produce quantities of methane gas, located within its service territories. Unitil hired an external consultant to review the landfill located in Kingston, NH. The Kingston Municipal Landfill is a 30 acre municipal solid waste disposal site that operated from the 1920’s through December 2003. It is capped with a geomembrane cover. The landfill currently has a number of vents installed into the waste, but there is little obvious evidence of significant gas production.

The purpose of the evaluation was to determine if landfill gas (LFG) is still being generated by the landfill in recoverable quantities and if so to confirm whether there is any potential for commercial utilization of the gas as a source of energy. The evaluation included 1) an on-site inspection of the landfill, 2) an estimate of the LFG production based upon the data collected and a brief overview of other factors that would impact a development decision. Specific calculations made for the Kingston Landfill result in a total of approximately 1,500,000 tons of refuse in place when the site was filled to capacity in December 2003.

Empirical estimates based upon the observed ranges of gas generations rates for typical sites indicate that the range of gas generation from Kingston may run from a low of approximately 329,000 scfd to a high of 822,000 scfd. The probable midrange levels are 493,000 scfd or 342 scfm. However, since there is no evidence of gas escaping from the vents or through the cover, it is likely that the decomposition process, and hence the gas generation rate, is extremely slow.

Due to the small size and low gas generation rate of the Kingston landfill, it would be technically possible, but economically risky to install a gas collection system and the conversion facilities necessary to produce electric power. The procedure would entail negotiating a contract for gas rights with the town of Kingston, designing and installing a gas collection system, purchasing microturbines and erecting an enclosed facility to house them, install necessary facilities to connect with the electric grid, and providing for ongoing operations and maintenance. By the time this project was completed, the landfill would be two years older and would have less gas production capability remaining. Unless the price of energy is certain to rise and remain at extreme highs, the development of the Kingston Landfill's methane as a usable energy source is not likely to be economically feasible.

2.7 Load Control with AMI:

Unitil has an AMI system that allows two-way communications with its endpoints. The L&G Hunt load control switch can be used to remotely control customer A/C loads during these periods to reduce customer peaks.

Unitil evaluated a project that would investigate the functionality, cost, and system impact of the Hunt load control switch if applied to customer central A/C systems. It is proposed to install 10 of these units at selected Unitil employee/customer homes during the summer and perform a variety of functional and system impact tests. Data systems and controls will also be evaluated for consideration of a full program deployment.

Unitil's estimates identified that the installed cost is approximately $600 per kW. However, Unitil believes that any type of load control must be done in conjunction with a rate mechanism which modifies customer behavior and provide incentive for reducing load during peak times. This project proposal has been deferred in lieu of the Company's proposed TOU pilot project.

2.8 Time of Use/Demand Response:

In 2009, the Company proposed a two-state Smart Grid Time-of-Use Pilot Program to evaluate the potential benefits of TOU rates in conjunction with Demand Response technologies. The Pilot Program has been approved by the NH and MA regulatory Commissions and is being implemented for the summer peak months of June-July and August 2011. The Pilot will test three different treatment options. Two will investigate TOU rates incorporating on-peak and off-peak prices and a critical peak price (CPP) that can be initiated during periods of extreme electricity demand. The third option entails a utility controlled thermostat that requires no intervention from the customer and does not involve TOU pricing.

- Simple TOU Program – Enrolled customers will receive basic educational materials, with no technology enhancement. CPP notification will be handled via email or a phone call.

- Enhanced Technology Program – Enrolled customers will receive the same educational materials, but will also receive an in-home wireless control system with a suite of energy management tools, a utility integration portal, and flexible control devices (smart thermostats and outlets). This package will allow for both utility and customer automated load control and demand response.

- Smart Thermostat Program – Enrolled customers will receive a utility controllable thermostat that offers digital programming features and customer feedback. The utility will have the ability to either cycle the customer's heating and cooling load, or change the temperature on the thermostat during periods of extreme electricity demand. This change in thermostat setting will not be accompanied with specific customer notification, but customers will be able to override the changed setting.

The total cost for the pilot project was originally estimated at $526,560, with the share for New Hampshire estimated at $312,136. This excludes internal personnel costs or overheads. The overall load savings benefit will not be known until the pilot project is completed. Customer recruitment is planned to begin in January 2011.

As an add-on to the residential TOU Pilot Program, the Company will be proposing in January 2011 to implement a smaller scale TOU evaluation for a sample of commercial and industrial customers in its NH service territories.

2.9 DER Technology Investments Pursuant to RSA374-G:

In 2008, the NH Legislature passes RSA374-G that provides an opportunity for distribution utilities to invest in DER technologies pursuant to approvals by the Public Utilities Commission. In August 2009, the Company filed the first utility proposal under RSA 374-G, proposing investments in four DER projects along with an evaluation model and cost recovery process.

One of the projects, the Smart Grid TOU Pilot Project was separated from the other three and has moved forward independently. The other three projects included a solar hot water heating project with a public housing authority, a solar PV project with a municipality and a joint microturbine and solar PV proposal for the Exeter School System (SAU16). The solar hot water heating project was withdrawn based on difficulty validating the avoided fuel source, and the stand-alone solar PV project was rejected by the Commission on the grounds that if failed cost-effectiveness testing.

The SAU16 proposal was approved and is now in commercial operation. The Company has invested $200,000 in a project estimated to cost a total of $760,000. The units include a 65kW microturbine, which produces both heat and power from natural gas and which is available for dispatch by the Company during summer peak periods, and a 100kW solar PV array. The SAU16 project passed cost-effectiveness screening based on estimates of production and output over the 20 year life of the project. The benefits of the project include distribution system peak reduction as well as a variety of energy and environmental benefits. These estimates will be validated over time through the actual production of the generating facilities.

3 ASSESSMENT OF DER CATEGORIES FOR ANALYSIS

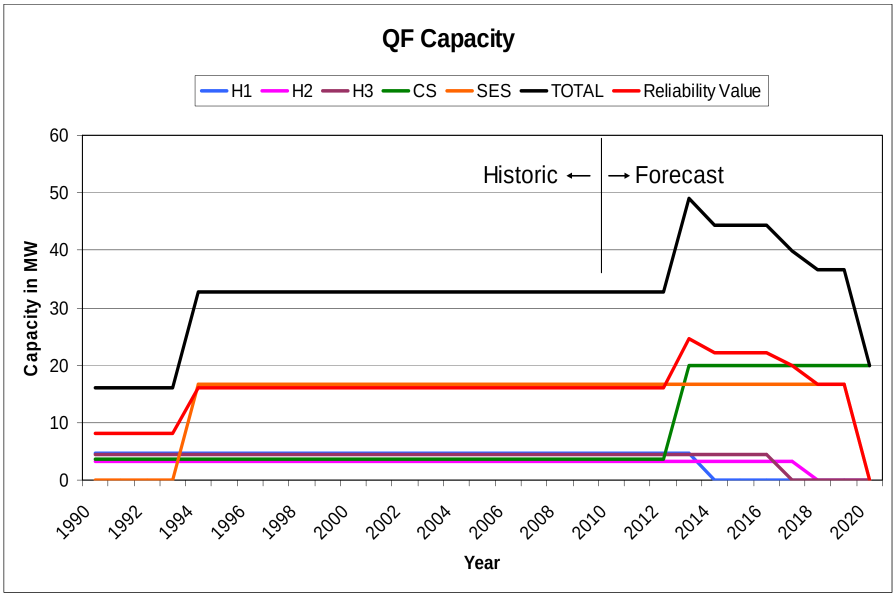
3.1 Commercial scale generation (Business As Usual)

This category includes larger, commercial scale generation installations in the Company's service territory. Such installations may be for purposes of 1) export, 2) customer self-supply or 3) sale of power under Qualifying Facility (QF) status. Since the early 1980's, the Company has needed to address the potential impacts of such commercial scale generation facilities on the distribution system, specifically in the UES-Capital service area. These installations are generally subject to federal regulatory provisions that require the Company to provide interconnection, transmission and back-up/supplemental services. The costs of these services, potentially including the costs of system modifications necessary for the continued reliability and safety of the distribution system, are attributable to the customer/generator.

In this context the Company has developed and uses planning standards which factor in the potential impact and/or value of such resources on the Company's obligation to meet peak demand requirements – these standards, and the impact of the specific resources, are considered directly in the Company's system planning process. In the planning process, these resources are not reflected as demand reductions for purposes of forecasting the Company's peak demand forecast – they are considered as exogenous to the Company's distribution loads and directly factored into the Company's capacity plan for the UES-Capital region.

Since the Company does not control the operation or dispatch of these resources, the capacity value of these resources is limited. The Company includes the resources only to the extent of its contractual relationships (e.g. as reflected in Interconnection and/or Transmission Agreements). In addition, the Company assumes for planning purposes a capacity value equal to the total of all such resources minus the size of the single largest resources, or 50% of the total generation capacity of all such resources, whichever is less. This is based upon historical operating knowledge regarding the operation of these non-utility generation assets.

The capacity resources included in this category are represented in the graph below. The resources include three hydro units, a biomass generator and a waste-to-energy generator, all of which are located in the UES-Capital service area. The graph shows the historical status of these projects and a projection based on exiting contractual agreements.



The biomass generator has proposed an increase in size from 3.6MW to 20MW – this increase is reflected in 2013. As noted this only increases the reliability value by a small amount due to the planning standard referred to above. In addition, the chart shows the end of the contractual obligations for the hydro and waste units prior to the end of the planning period. While continued operation at some level under new contracts is likely, that decision is not one the Company controls. At this time we have no definite information about the future of those resources.

In the future, the Company may need to factor in consideration of other such generation facilities, including larger generators intended primarily for customer self-supply. The Company is aware of one such possibility currently under consideration in the Seacoast area. This would include the possible interconnection of a 5MW generation unit primarily for self-supply by an industrial customer. Such installations would be incorporated into the Company's plans in a similar manner to that discussed above.

3.2 Current CORE EE programs (Business As Usual)

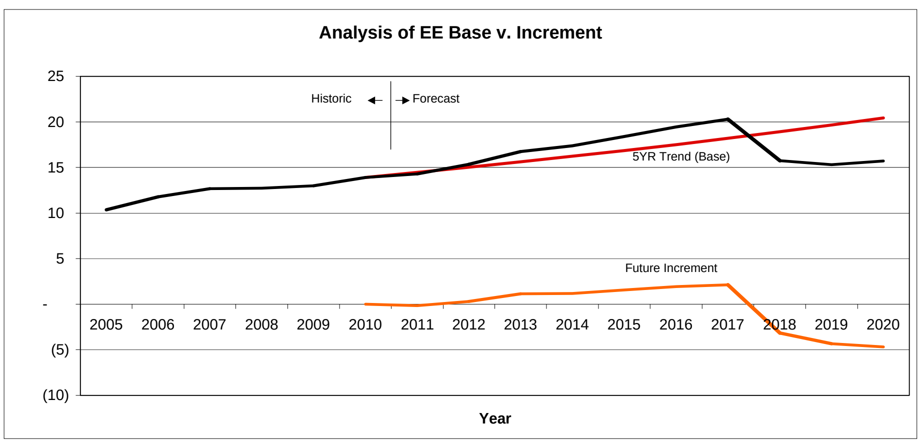
Since the early 1990's, the Company has implemented rate-funded energy efficiency (EE) programs designed to assist customers to reduce their energy consumption. In 2003, these programs expanded under the current collaborative statewide planning process. These "CORE" programs provide a comprehensive set of opportunities for residential and commercial/industrial customers to identify and implement energy saving measures. Some of the measures include reductions in peak demand.

As part of its assessment process for these programs, the Company conducts evaluation, monitoring and verification studies to determine the savings being achieved with the EE expenditures being made, and these results are reported to the Commission. In addition, the

Company participates in the regional forward capacity market (FCM), operated by the New England Independent System Operator (ISO), by submitting the capacity contribution of its EE programs to the FCM as an "other demand resource" (ODR). The revenues secured from the FCM are reinvested into the CORE EE programs.

In support of these efforts, the Company has a database that provides estimates of the peak demand contributions achieved through its EE programs. The database includes the expected end-dates when the measures installed would be retired or replaced. As a result, the EE savings show increases due to new spending as well as decreases due to measures from previous spending reaching the end of their measured life. In terms of the relative costs of these peak demand reductions, the EE programs are principally valued for energy reductions. The Company does not maintain estimates of the costs specific to achieving peak demand savings, although there are estimates of the peak demand reduction value (avoided demand costs) to customers.

The chart below shows the estimated peak demand reductions from the CORE EE programs. This projection assumes a continuation of the current level of spending and estimated savings through the planning period. In addition, however, since EE has been contributing to peak demand reductions in the past, those "Base" contributions are already reflected in the Company's peak demand forecast. The Chart shows the EE Trendline (5yr CAGR) and the resulting projection of the incremental / additional peak demand reductions from EE program spending. Notably, the incremental savings is negative in some years, particularly at the end of the planning period when high savings levels achieved in certain years reach the end of the expected measure lives for the measures which achieved those savings.



3.3 Net Metering installations (Business as Usual)

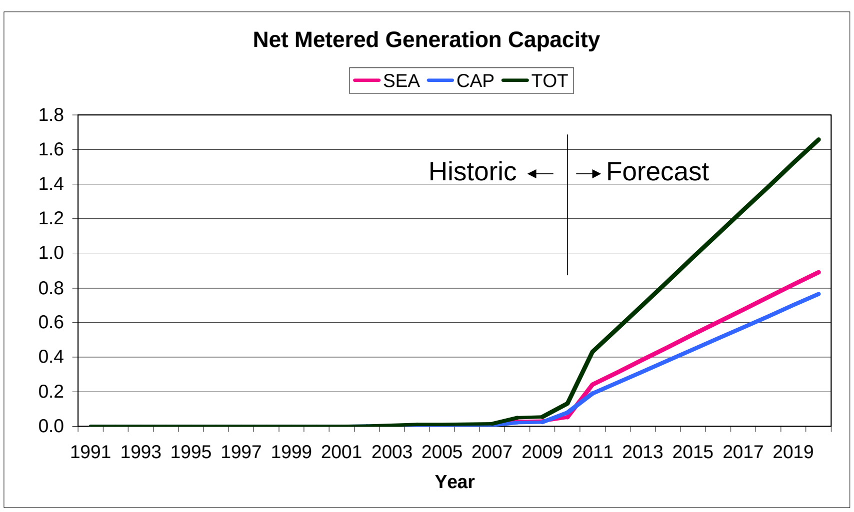
Under state regulations (PUC Rule 900), the Company is required to interconnect small scale generators on customer premises and to bill such customers on the basis of net energy metering. Effectively, this insures that the output of the generator, no matter when it is produced is credited to offset the customer's own internal loads. The allowable level of net metering is currently limited to 1% of the Company system peak load, so the potential contributions from net metered facilities are limited. However, legislation has been considered that would increase this limit – and any projects developed pursuant to RSA374-

G are excluded from that limit. In addition, the Company would consider in this category any small customer-sited generation over which it has no control.

Measuring the contribution of net metering facilities to meeting peak demand is problematic, since the arrangements do not require the generator to be separately metered. Indeed, under net metering, the Company has no information about either the time periods when customer demand is imposed on the system or when the generator is providing excess power. For purposes of current analysis, the only data which the Company does have is the nominal nameplate capacity of the installation. We have used this data for purposes of the current analysis, although we know that this likely overstates the capacity value significantly. The database does include fuel source (e.g. solar or wind), so one refinement of this analysis would be to calculate presumed peak coincidence from generic wind and solar data – however unless the generators are directly monitored we will continue to have no information about the actual status and production of the installed equipment.

The peak contributions from net metering installations are reflected in the historic load data, and therefore included in the peak demand forecast in the same way that EE programs are included. However, the number of installations historically has been very low, with a very significant ramp-up beginning in 2009. For purposes of our analysis, we have assumed that the historic peak demand forecast does not include any effect from net metering, and therefore net metering capacity is assumed to be fully incremental. In addition, the Company has no basis for a detailed estimate of the pace of future net metering applications as that will be a function of state and federal subsidies and relative economics. It is simply assumed for this analysis that the number of kW installed in 2011 and future years will equal the average of the kW installed in the proceeding five year period. The SAU16 Solar PV installation went into service in 2010 and is included in the 2011 data.

The resulting forecast of net metered generation capacity is shown in the graph below. As indicated and based on the assumptions noted above, the graph shows a steep ramp-up in capacity over the coming decade. Under these extremely favorable assumptions, net metered installations would contribute approximately 1.6MW in aggregate peak demand reductions in 2020.



3.4 Other Demand Resources (Not Business as Usual)

For purposes of the current analysis, the Company has included six different categories of other demand resources that could potentially be utilized for purposes of addressing future distribution peak load requirements. These include:

3.4.1 Expanded complement of EE programs:

The Company could increase expenditures for energy efficiency program measures, particularly those resulting in peak demand reductions. Examples could include measures to reduce the peak demands of air-conditioning equipment through ice storage or improved efficiency ratings, or increased weatherization of air conditioned homes. The Company has not assessed the market feasibility or cost of any such enhanced EE programs. For purposes of this analysis, it is simply assumed that we could achieve a doubling of the peak demand contribution from energy efficiency measure installations, relative to CORE EE (Business as Usual) by 2013.

3.4.2 Enhanced net metering (and other customer generation):

The Company could increase customer adoption of net metering or other self-generation options, for examples by offering rebates for installation of qualifying generation equipment or through direct investment such as that provided for under RSA374-G. We have not assessed the market feasibility or cost of any such program. For purposes of this analysis, it is simply assumed that we could achieve a doubling of net metering installations relative to the annual growth in Net Metering (Business as Usual) beginning in 2014.

3.4.3 Utility-controlled generation:

The Company could pursue is to invest in dispatchable generation resources, either owned and/or operated by the Company. This could potentially be located on customer premises. The SAU16 Microturbine project is an example of a dispatchable generator on customer premises – this 65 KW unit went into service in 2010 and is reflected in this category as of 2011. The Company has not assessed the market feasibility or cost of expanding initiatives in this area. However one of the simple options in this category would be for the Company to design and install local generating facilities within its system. For purposes of this analysis we have assumed the Company installs 5MW of such generation by 2016.

3.4.4 ISO / Market based demand control:

Most of the Company’s large G1 commercial and industrial customers have procured their own competitive electricity supply in the New England retail market, and we are aware of a growing trend for competitive suppliers to submit customer demand control features into the ISO Demand Reduction program. While we do not currently have data on the number or volume of such arrangements by our customers, this is a matter we are investigating with the ISO. To the extent the ISO calls on these DR resources during the Company's distribution system peak, these resources would contribute to meeting distribution system requirements. For purposes of this analysis, we have assumed that the penetration of such ISO / Market based DR gradually increases to a point where the effective peak demand of the G1 class on the Company's peak demand is reduced by 2% in 2020.

3.4.5 Utility demand control:

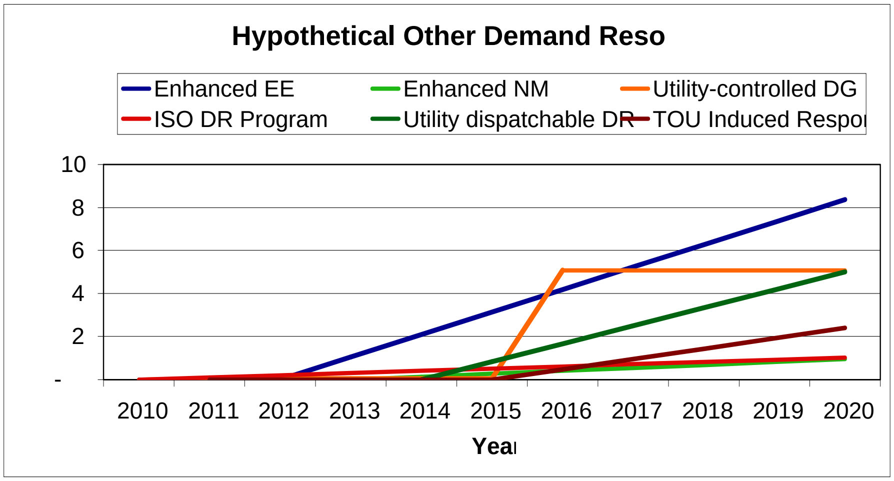
In addition to the market options for DR, the Company is investigating options for direct load control under its Smart Grid Time-of-Use pilot program. In the summer of 2011, we will be assessing certain TOU, Critical Peak Prices and DR options with a sample of customers. The Company will evaluate the results of the pilot to determine if implementing such DR options on a broader basis is warranted. For purposes of this analysis, the Company has assume that it would be feasible to deploy 5,000 one kilowatt peak load control devices within the residential and small commercial (non-G1) customer classes by 2020, beginning in 2015. The Company has not assessed the market feasibility or cost of such an option.

3.4.6 TOU / price induced demand changes:

As noted, the company is investigating TOU pricing options in its pilot program in 2011. The Company will evaluate the results of the pilot to determine if expanding TOU pricing options for its customers is warranted. For purposes of this analysis, the Company has assumed that it could deploy some form of mandatory TOU in 2016, and that such a pricing approach could result in a reduction of peak loads for non-G1 customers reaching 1% by 2020. The Company has not assessed the market feasibility or cost of such an option.

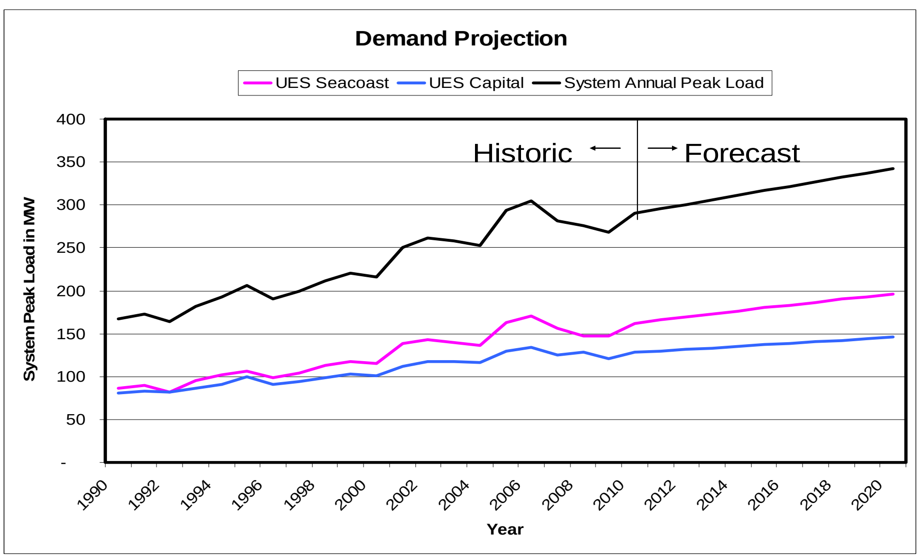
3.4.7 Summary

Given the many assumptions itemized above, the hypothetical peak demand contributions from each of these six other demand resources are shown in the chart to the right. As noted above, the assumptions relative to each of the options are potentially quite optimistic. In addition, it is not likely that all of the options will prove economically or technically feasible. Some options may in fact, provide no value in offsetting either circuit or system peak demands. Additional challenges are identified in the following sections.



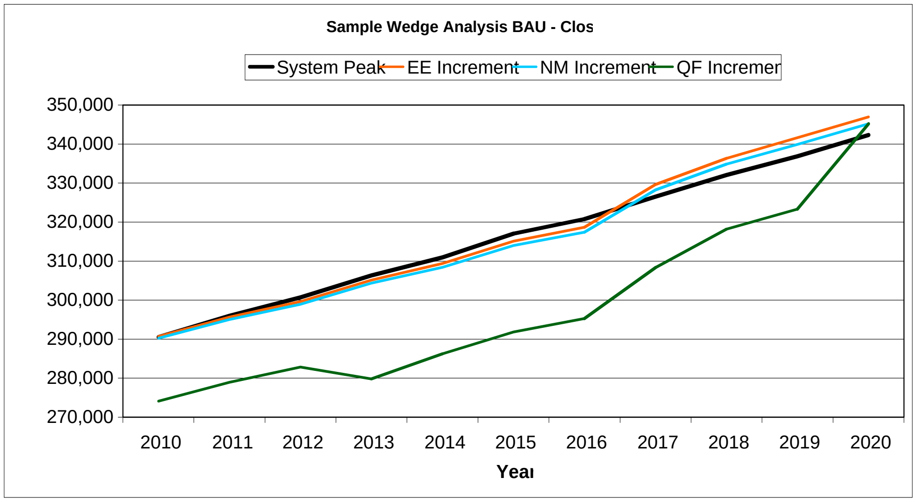
4 DISCUSSION OF DEMAND RESOURCE CONTRIBUTION TO PEAK

This chart below shows the historic and forecast peak loads for the Company as referenced in Section 1.4. While the Company maintains peak forecasts by division and at the total level, for purposes of this analysis the non-coincident peak loads have summed for UES-Seacoast and UES-Capital. This results in a slight overstatement of Company's actual system peak load because UES-Seacoast and UES-Capital peak demands are not 100% coincident. On the other hand, for distribution system planning purposes, the two service areas are planned for independently as they do not share any distribution facilities in common.

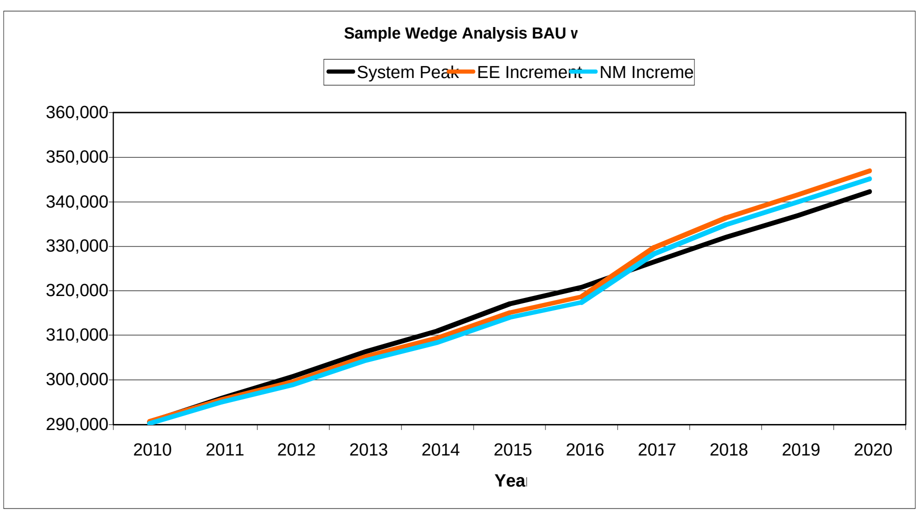


The next chart shows the projected contribution of the Business As Usual demand resources to meeting the total peak load requirements for the forecast period of 2010 to 2020. This chart begins by decrementing from the system peak the expected contributions of the CORE EE incremental savings, followed by the Net Metering savings, followed by the QF contributions. As noted the QF capacity value is significantly larger in its impacts that the

EE and NM categories of resource. However as noted above, the QF resources are not reflected in the historic peak demand data – and they are addressed in the Company's electric system planning directly, rather than as a decrement to load. It is therefore appropriate to remove the QF resources from the decremental wedge analysis.

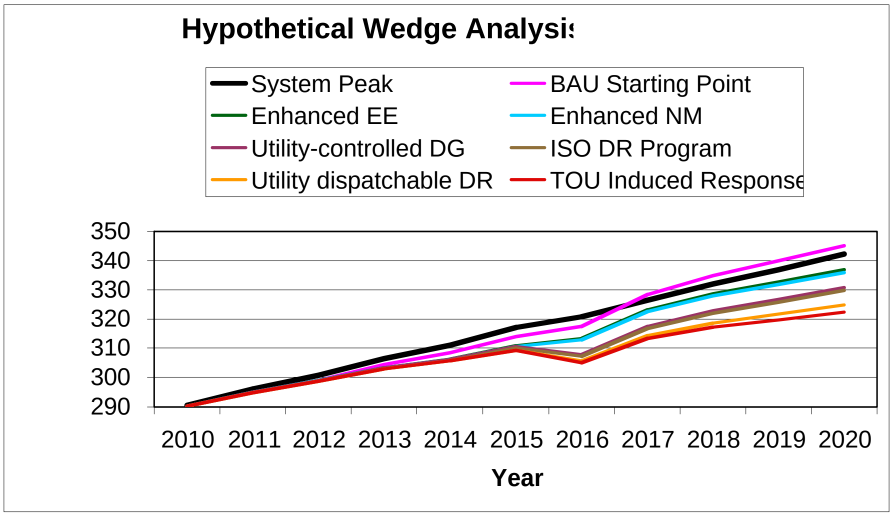


The resulting chart below, showing just the net decremental value of the EE and NM resources, is, in effect, a forecast of what the measured system peak demands would be in the Business As Usual case assuming the EE measure and NM facilities are deployed as predicted and assuming that the system peak forecast is accurate. The Sample Wedge Analysis in the Business As Usual Case (excluding QFs) shows a small but consistent decrement to system peak loads in most years. However, by 2017 the decremental value actually exceeds the base forecast value due to the EE measure retirements discussed above.



The inclusion of the EE and NM resource categories provides a "baseline" projection for the Business as Usual case. In the final chart, the Baseline decrement is presented against the System Peak forecast for the period 2010 to 2020, and then each of the additional demand resource options are factored in. For purposes of the presentation, we have accumulated the resource contributions in the following order:

Enhanced EE
Enhanced NM
Utility-controlled DG
ISO DR Program
Utility dispatchable DR
TOU Induced Response



As the chart indicates, through the accumulated contributions of all of these resources through the forecast period, it is conceivable that the peak demand curve could be effectively depressed or flattened. In other words, at a hypothetical level on a system-wide basis it is possible for implementation of multiple demand resources to provide sufficient capacity to offset future growth in peak demand on the distribution system.

Given the high degree of uncertainty in any of the estimates and the lack of information relative to the feasibility, cost and reliability of the demand side options, this hypothetical presentation is probably best characterized as a "best case". As the Company begins to develop more and better information through its pilot programs and based on continued trends in the options it does not control, this analysis will be subject to considerable refinement.

5 ISSUES FOR FURTHER CONSIDERATION

Taking the hypothetical finding that demand resources could offset future growth in system peak demand at the system level from concept to implementation faces a number of challenges. For purposes of this discussion, those challenges have divided into three categories: Validating Estimates; Resource Dependability; and Cost Recovery.

5.1 Validating Estimates:

The demand resource options reviewed in the previous sections are diverse and in some cases highly uncertain. For the most part, data on the cost and effectiveness of the resource option in meeting peak load requirements is not available. Therefore, in order to pursue any of these options, the Company faces an initial and significant hurdle in developing and executing planning studies that will provide specific cost and savings estimates for each of the options. In general this is going to involve significant cost. For example, in order to collect reliable production data on Net Metering generation, meters would have to be installed on each generator, or on a large enough sample of generators to provide statistically reliable estimates of demand output for the population as a whole. In addition to the meter investment costs, this would require consent from customers, rewiring on customer premises and a significant ongoing commitment to meter data accumulation and analysis.

Reliable cost data is also a challenge. A given energy efficiency measure installed under the CORE EE programs provides both energy and demand benefits –the corresponding costs would need to be allocated to energy or demand in order to calculate the cost associated with the peak demand savings. There are various methods for doing so – with a wide variation in the possible results.

Relative to the TOU and utility-controlled DR options, the Company is implementing a Pilot Program in 2011 designed to yield data on costs and potential savings that will provide a base for future planning purposes. This initial and very preliminary step will cost in excess of $300,000.

In addition to the lack of hard data on costs and peak savings contributions, demand options will generally require some estimation and forecasting of market behaviors by consumers or developers. What will the market response be to the introduction of additional NM rebates, or to DR incentives, or to various program and pricing options? Each demand resource option entails different questions and uncertainties relative to market response, and determining reliable answers to those questions will be necessary to the design and implementation of cost-effective implementation plans for demand resource options.

5.2 Resource Dependability:

As noted in the introduction to this section, demand resource options may have very different capabilities relative to providing reliable capacity resources. From a distribution planning standpoint, being able to rely on a demand resource option depends on determining the probability of its coincidence with system peak, and the certainty of its operating characteristics. The standard against which these resource options need to be judged is the reliability of the distribution equipment which they are presumably replacing. Determining the dependability of a demand resource will require data, as discussed above, and sophisticated assessments of probability and reliability for each option and potentially each measure or project within that option.

In addition, significant questions about the dependability of a demand resource option relates to timing. As noted in the introduction to this section, a demand resource option will need to be ramped up over a period of time – in advance of when the full capacity displacement is going to be needed. While demand resources may have some flexibility in terms of ramping up through design of rebates, marketing or spending levels, the concern here is that the success of a program launch may not be known in advance – and yet the demand resource option, once launched, is being counted on in the distribution resource plan. If a demand resource option falls short, traditional distribution investments will need to be deployed. These traditional distribution investment decisions also have a lead time, but at least the decision to deploy such a resource has a high degree of dependability. In effect, it is less risky for the Company to depend on completing construction of distribution equipment than on securing affirmative investment decisions on the part of thousands of customers.

5.3 Cost Recovery:

From a cost recovery standpoint, pursuing demand side options is significantly different from traditional distribution system investments. As noted above, the investigation and assessment of demand resource options may involve considerable expense and investment. The options as they are developed and implemented may result in investments in utility and/or customer equipment, changes in rates and prices, or in expenditures for marketing, education and customer rebates. The cost of implementing demand resource options thus may be reflected in a variety of ways – as reduced revenues, increased expenses or new investments. In contrast, traditional distribution system planning activities are an element of the Company's overall capital program and result in capital investment in distribution system plant and equipment which is clearly recoverable in rate base – this mechanism provides certainty with respect to the recovery of costs.

The treatment of demand resource options in rates does not have the same clarity as traditional distribution system peak demand options due to the diversity and complexity of the options, and the lack of defined mechanisms to deal with consequences relative to changes in revenue, changes in expense and new investments. Uncertainty about cost recovery is a key impediment to demand resource development and implementation. This uncertainty is aggravated by the fact that demand side options may result in decreases in future distribution system investments, the benefits of which will flow directly to customers in the form of lower rates. Rate mechanisms which resolve this uncertainty and provide clarity that options designed and implemented for the benefit of customers will be paid for by customers are essential.

6 CONCLUSIONS

In recent years, new demand side options have begun to emerge that distribution companies need to consider in distribution system reliability planning. These options may provide feasible and cost-effective resources which distribution companies can deploy to reduce the growth in peak demands and thereby avoid required investments in traditional distribution system plant and equipment.

The hypothetical analysis provided above shows that a combination of demand side resources could result in the reduction or flattening of system peak demand growth. These options will need considerable further study to address the concerns and questions raised in the sections above.

Among the key challenges to be addressed are the need to develop and validate estimates of cost and capacity value of the various demand side resource options, the difficulty of assuring the timing and dependability of the demand resource options being considered and implemented, and the uncertainty associated with the recovery of costs associated with the investigation, development and implementation of demand side resource options.

The Company is also pleased to be able to report that it has made several significant steps forward in addressing these challenges, specifically including:

- Implementation of a system-wide AMI providing enhanced metering and communication capabilities
- Assessment and review of a number of DER technologies with the potential for contributing to future peak demand reductions
- Completion of the first utility investment in demand side resources pursuant to RSA 374-G, resulting in the operation of a 100KW solar PV system and a 65KW dispatchable microturbine in the Exeter School System
- Smart Grid TOU Pilot Program being implemented in the summer of 2011, investigating TOU and CPP pricing and demand control options
- Presentation of an enhanced approach to Demand Side Management planning in conjunction with its Least Cost Integrated Resources Plan.