APPENDIX A

PLANNING AND BUDGET PROCESS FLOW

SYSTEM PLANNING AND BUDGET PROCESS FLOW

Unitil's annual budget of system improvement projects is created through inputs of various departments. The majority of the projects entered into the capital budget are developed through the Subtransmission System and Distribution System planning processes. The loads and capability of the Subtransmission System (from System Supplies to the substations) is modeled and planned ten years into the future. The evaluation and recommended improvement projects are detailed annually in the Electric System Planning Reports. The Distribution System (from the substation to the customer) is planned five years into the future and the evaluation is detailed annually in the Distribution System Planning Studies. The planning process is worked throughout each year and the flow of the process is displayed in the Diagram 1 below.

Load forecasting:

The planning process starts with forecasting the total system loads as well as the individual substation and circuit loads.

A) The total system load is forecasted out ten years for the System Planning Study using a linear trend regression model that correlates a ten-year history of daily peak load versus daily average temperature and humidity. The annual peak system load is used with corresponding actual daily average temperature for the past ten years. The forecasting methodology is described in the main body of this report. System load projections are used to create an estimated average annual load growth rate as well as two load level projections (Peak Design Load level and Extreme Peak Load level). The load level projections are used to develop load flows for the Electric System Planning process, per Unitil's Electric System Planning Guide (Appendix B).

B) The individual substation and circuit loads are forecasted out five years by trending the past five year historic loads. Where individual customer loads can affect the trending, individual large customer loads are used in evaluating and creating the future load projections.

Load Flow Development and System Constraint Evaluation:

C) The forecasted loads are used to develop load flows and evaluate the constraints and limits of the Subtransmission System and Distribution Systems. For development of the load flows and constraints of the Subtransmission system, Siemens PSS/E planning software is used. This software creates system load flows and reports on system constraints using a balanced three-phase model of the system developed from the load forecasts, equipment ratings, system impedances, and constraint criteria per Unitil's Electric System Planning Guide (Appendix B). In developing the Subtransmission System model, each year the Unitil Energy Systems model system model is updated with system updates from the previous year and consolidate with the updated model from ISO-NE and Eversource.

Distribution System Load Flow models are created using the Minor and Minor Windmil software. This software creates load flow for each individual phase. The loads used in these models are projected loads of the individual circuits allocated with loads of individual large customers and step-down transformers. The load flows are compared to the equipment ratings and system constraint criteria specified in Unitil's Distribution Planning Guideline (Appendix E). The impedance model in the Windmil Software is developed directly from the GIS system information. Therefore changes and upgrades to the distribution system are automatically supplied to the load flow model at the beginning of each year when the circuit models are developed.

The Distribution Engineering Department then evaluates the system constraints reported by the appropriate load flow model and generates alternate system upgrades. The solutions are then modeled into the load flow model to ensure proposed system upgrades alleviate the system constraint. When all constraints for the future years are evaluated and system solutions are proposed for each constraint, the Distribution Engineering Department presents their findings and alternative solutions to the Operations Departments as well as the Energy Systems Engineering Department. During this presentation, the Operations Departments may also present system equipment concerns and other solutions may be presented to incorporate operational concerns.

Once all alternatives are scoped, the Operations Department and Energy Systems Departments will assist in generating cost estimates for each alternative. The Distribution Engineering Department will then perform cost/benefit analysis to select the overall least cost and best proposal.

<u>Planning Reports:</u>

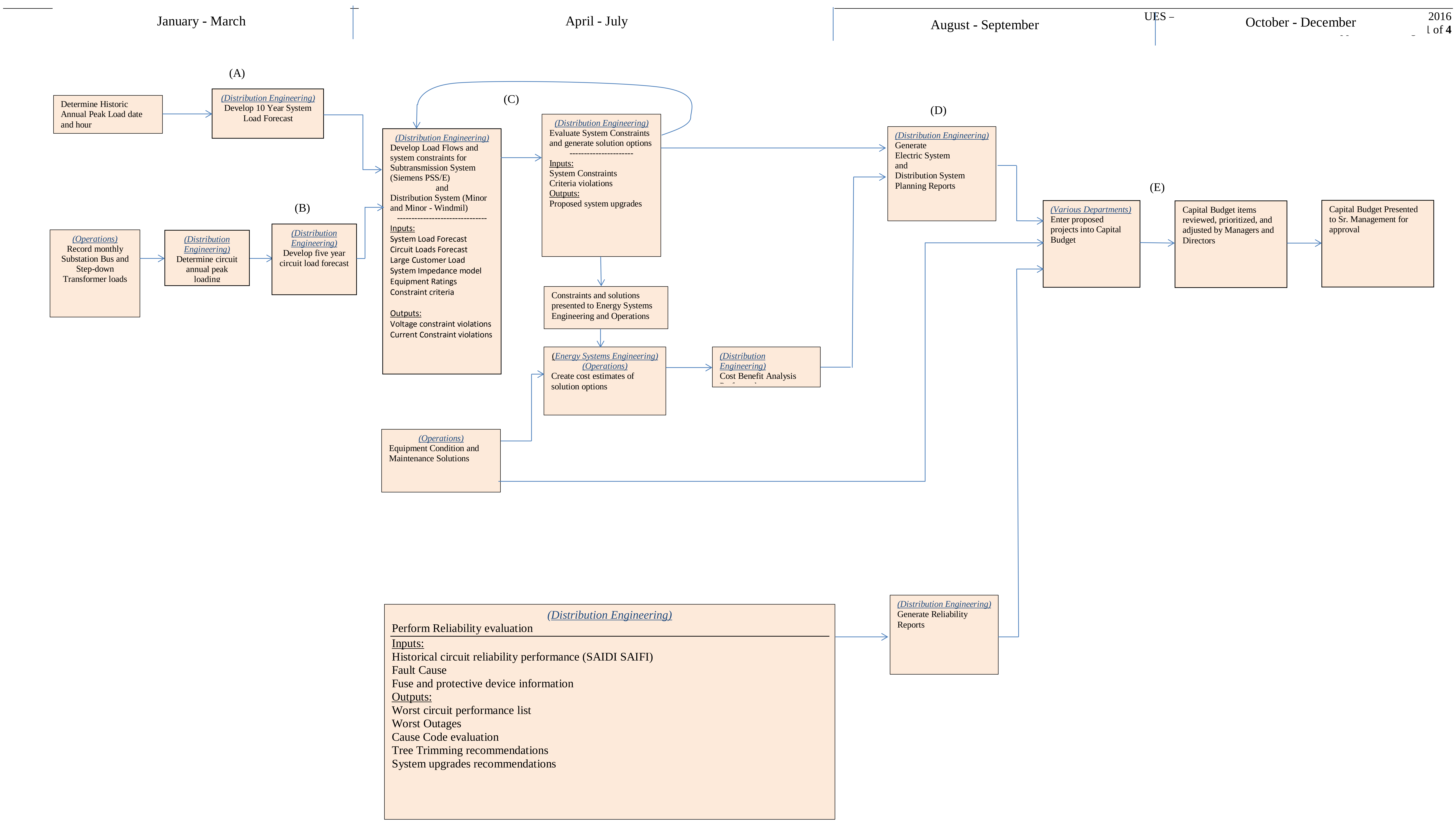
D) After all analysis is complete, including the cost benefit analysis of possible solutions, the Electric System Planning reports and the Distribution Planning reports are completed and published to Unitil stakeholders. The planning reports include a description and results of the analysis performed including, load flows, power factor analysis, with loading and voltage violations and system deficiencies. The reports also describe the scope and benefits of solutions to alleviate the deficiencies. Some line overloads and voltage violations can be solved with minor solutions with minimal cost. Where the deficiencies are not easily solved and require where a large project is proposed as a solution, multiple alternatives will be presented in the planning report with the recommended solution. When analyzing alternative solutions, operational costs and future risks are also evaluated. If the recommended solution is not simply the lowest cost solution, a justification is included with the recommended solution.

<u>Project Budgeting:</u>

E) After the planning studies are reviewed and approved by engineering management, the recommended projects entered into the capital budget with other projects entered from the reliability studies, operations personnel and other departments. When all projects are entered, each individual project is presented to the review group. System improvement projects are entered and justified individually. Unitil does not create blanket spending for system improvement projects. During the presentation of the projects, the project scope and justification is reviewed as well as the project category and priority. When all projects are accepted into the budget, engineering and operations managers and directors compare the cost reports to recommended spending level by the Engineering and Operations managers and directors provided by the Finance Department. The projects may then be revised to bring the total budget to the recommended spending level. The budget is then presented to the Sr. management team for final review prior to presenting to the board for final approval.

Diagram 1

System Improvement Planning and Budget Flow Diagram



Unitil	Guidelines	Procedure No.	GL-DT-DS-01
	Distribution Engineering	Section No.	Cover
		Page No.	1
	Electric System Planning Guide	Revision No.	4
		Revision Date	02/09/2016
		Supersedes Date:	03/13/2014

FOREWORD

The purpose of this document is to outline the study methods and design criteria used to assess the adequacy of the transmission, subtransmission, and substation systems.

Any questions or inquiries regarding information provided in this document should be referred to the Director of Engineering.

Kevin E. Sprague — Date
Director, Engineering

John J. Bonazoli — Date
Manager, Distribution Engineering

REVISION HISTORY

Annual Date of Review: January 1

Revision #	Date	Description of Changes
0	04/01/2000	Initial Issue
1	12/19/2003	Revised
2	01/12/2004	Revised
3	03/13/2014	Revised & Reformatted
4	02/09/2016	Created new document number

Table of Contents

List of Appendices

1.0 Introduction

1.1 Purpose

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.

All Unitil facilities which are considered Pool Transmission Facilities (PTF) shall be designed in accordance with the reliability standards published by ISO New England (ISO-NE), Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Corporation (NERC) as well as the criteria established within this document.

All facilities which are not considered PTF but are part of Unitil's transmission, subtransmission, and substation 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)

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".

1.2 Applicability & Scope

This document applies to the planning and design of the Unitil transmission, subtransmission, and substation systems.

1.3 Updating the Procedure

The Director, Engineering is responsible for maintaining this guideline to ensure this guideline is current with changes in the company's organization, policies or to capture good utility practices. All revisions and/or additions shall detail a revision date and number on the top right corner of each page within the header, as well as a brief description in the Revision History section on the cover.

Comments are welcomed and should be documented (using the Request for Procedure/Change Form reference in Appendix C) and addressed to the Director, Engineering. All documented comments shall be retained in a separate file and reviewed each time this procedure is revised. These comments will keep the contents of the procedure current and enhance its usefulness.

1.4 Revision Notes

This document is being issued as a new guideline and supersedes all previous revisions.

1.5 Availability

Current copies of this procedure can be found on the Hampton Shared Drive. Hard copies are not version controlled.

NOTE: Only up-to-date versions of the documents are posted on the Hampton Shared Drive. All other revisions (both electronic and hardcopy) should not be referenced.

2.0 General Information

2.1 Definitions

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 scenario for loss of an element that system adequacy is measured against.
Distribution Point	Locations on a system that are direct supply points for customer load.
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	An overhead/underground line section or device such as a generator, transformer, or circuit breaker.
Extreme Peak Load	A load forecast equating to a 96/4 probability
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 electric service to one or more customers.
Non-Distribution Point	Locations on a system that are not direct supply points for customer load.

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 — A load forecast equating to a 90/10 probability

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

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, 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.

3.0 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 Unitil's *Electrical Equipment Rating Procedures* (PR-DT-TC-01). 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. Unitil does not publish DAL ratings higher than the STE limit since loading above the STE limit requires a drastic action response.

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 contingent 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 configuration for routine operating and maintenance purposes. An acceptable alternate configuration should also satisfy normal ratings and voltages. It is not a requirement that Unitil systems be planned or designed for every possible configuration.

A Contingency Configuration describes a modified arrangement of the system in response to planned or unplanned outage of an Element. 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 is the benchmark load level that system adequacy is measured against. This load level is derived from a 90/10 forecast (a load level with a probability of being exceeded once every ten years). 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

The Extreme Peak Load is the maximum foreseeable load level that Unitil systems should be planned and designed to operate within specified equipment ratings and voltage ranges with all elements available. This load level is derived from a 96/4 forecast (a load level with a probability of being exceeded once every twenty years).

3.5 Load Power Factor

Unitil systems should be planned and designed to operate within the ISO-NE Load Power Factor Standards published for that area at Peak Design Load levels.

3.6 System Generation & Distributed Energy Resources (DER)

For planning purposes, the output of generation interconnected to the Unitil system as well as the output or load offset by other DER projects will be evaluated based on availability and reliability during peak times. 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.

The adequacy of system infrastructure to meet Unitil's end use load obligations necessitates that it be self-sufficient from generation interconnected to the Unitil system. Unitil systems are to be planned and designed to operate within specified equipment ratings and voltage ranges with at least one-half of interconnected generating facilities out of service.

3.7 Normal Conditions

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

- System in Normal Configuration;
- load levels up to Peak Design Load;
- outage of any generating plant within the immediate vicinity of the Unitil system;
- outage up to 50% of interconnected generation (cumulative output) using typical seasonal generation dispatch

3.8 Contingency Conditions

Unitil systems shall be planned and designed to meet applicable criteria for specific pre-determined contingency 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 table below describes the conditions where loss of load is allowable.

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 an external 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 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 exceed the limits described in the previous section.

3.9.3 Regional Load Shed

Unitil systems shall be designed to maintain compliance with NERC, NPCC and ISO-NE requirements for manual and automatic load shedding capabilities.

4.0 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 analysis (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 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). A circuit breaker is understood to include its associated current transformers and the bus section between the breaker bushing and its current transformer(s). Models will include two rating limits for each season's case:

Summer models	Summer Normal, Summer LTE
Winter models	Winter Normal, Winter LTE

4.3.2 Modeled Load

Peak Design and Extreme Peak forecasts should be developed annually for a period of ten years. Modeled loads for each region 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 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 interconnected 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 interconnected 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 reaffirm the necessity and in-service need date of future planned improvements or modifications and confirm that they remain the most cost-effective option available. Risks, consequences, and exposure levels should be determined in the event that projects are not completed as planned.

4.4 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.

4.5 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 will be developed and evaluated. The evaluation of alternatives and recommendations for system upgrades or modifications will be summarized within system planning studies.

4.5.1 Performance

The system performance with the proposed alternatives should meet or exceed all applicable planning criteria for the duration of the ten-year planning horizon. This does not preclude incremental system upgrades or modifications that are implemented as part of a multi-phase project to meet this overall objective.

4.5.2 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.

4.5.3 Economics

Initial and future investment cost estimates should be prepared for each alternative identified during the course of a study. These estimates shall be used to perform a Net Present Value analysis as well as a cost/benefit analysis as deemed necessary for each alternative.

4.5.4 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 years.

4.5.5 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.

4.5.6 Reporting Study Results

A system planning study report should define the modeling assumptions, study procedures, system constraints and/or violations of design criteria identified, alternatives for system upgrades or modifications considered, economic comparison, and final recommendations resulting from the study.

Appendix A – Design Guideline Summary

Design Condition	Load Level	Generation	Allowable Element Loading		Allowable Loss of Load	
			Limit[1]	Duration	Limit	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	Continuous	none	---
outage of generating plant			≤ Normal	Continuous	none	---
Contingency Configuration – loss of non-radial line			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---
loss of a Unitil system supply transformer			≤ LTE	Per transformer rating summary	none	---
loss of radial line (no backup tie)			≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
*loss of an external 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

* Loss of load up to these limits is allowed in cases where Unitil distribution service is supplied by another utility from a site without an on-site back-up transformer. This criteria is intended to facilitate the installation of a mobile transformer in order to restore load.

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

Appendix B – 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

Appendix C - Request for Procedure/Change Form

Requestor: ______________________
Title: ______________________
Department: ______________________
Location/DOC: ______________________
Date: ______________________
Procedure No.: ______________________

Item(s)/Section to be changed (if applicable):
Section: ______________________
Page: ______________________
Figure: ______________________
Appendix ______________________
Other: ______________________

For New Procedures

Description of new procedure to be developed: ______________________

Reason for new procedure: ______________________

For Changes to Existing Procedures

Description of requested change(s): ______________________

Reason for requested change(s): ______________________

Instructions: The individual requesting a new procedure or change(s) to existing procedures shall complete this form and submit it to the Director of the applicable department. For changes to procedures please attach a copy of the existing procedure with revisions marked on the copy.

Requestors Signature: ______________________ Date: ______________

For Reviewers Use Only
Change(s) Approved? YES NO If No, briefly explain ______________________
Changes Implemented? YES NO Date Implemented: ______________________
Reviewers Signature: Date:

Unitil Energy Systems - Capital

Electric System Planning Study 2016-2025

Prepared By:

J. Goudreault
Unitil Service Corp.
August 24, 2015

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 2016 through 2025.

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

Year	Project Description	Justification	Cost
2020	Re-conductor 37 Line (Penacook S/S – Maccoy St Tap)	Contingency Loading	$300,000

Note: It is assumed that Broken Ground is in service by 2017. 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 Eversource 34.5 kV subtransmission system from six interconnection points. Four of these interconnections emanate from the Eversource Garvins substation located in Bow. Two tie points originate from the Eversource Oak Hill S/S located in Concord.

The Eversource 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 C-189 connecting to the Farmwood 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 Eversource 318 Line. This radial tap serves as the normal supply into the UES-Capital Hollis S/S.

The Eversource Oak Hill S/S is served from two 115kV transmission lines; the B-15 and B-84 Lines from Farmwood S/S. Two 115 - 34.5 kV, 24/40/44.8 MVA transformers supply the Oak Hill 34.5kV bus. Two Eversource 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 2017, the new UES Broken Ground system supply located in Concord will be placed in service. Broken Ground will be supplied by two incoming 115 kV transmission lines (tapped off the C-189 Line) and consist of two 115 – 34.5 kV, 60 MVA transformers. Two 34.5 kV subtransmission lines will emanate from Broken Ground. One of these lines (288 Line) will terminate at the Hollis 34.5kV bus to supply Hollis substation. The UES 318 Line tap will be removed and UES load will no longer receive supply from Eversource's 318 Line. The second line from Broken Ground will be the 38 Line. As part of this construction, the 38 Line will be normally open at Hollis substation. The reconfigured 38 Line will be served radially from Broken Ground with a normally open tie with the 35 Line at Horseshoe Pond.

In addition to the 34.5kV interconnections with Eversource, 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 Eversource Garvins Falls hydro-generation station interconnects directly at Garvins S/S.

A system one-line diagram is included in Appendix I 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)
2016	137.9	141.3
2017	139.0	143.0
2018	140.1	144.1
2019	141.3	146.1
2020	142.3	147.2
2021	143.2	148.7
2022	143.9	149.7
2023	144.7	150.2
2024	145.7	151.3
2025	147.0	152.9

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 33.3.0) 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 2014 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 Eversource. Bus loads were compiled for the model by aggregating substation, circuit, and large customer load information for the July 2, 2014 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 2014 summer peak.

Base-case models for study of future years were developed from this 2014 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 base-cases 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 – 2016-2026 Load Power Factor Limits

Equivalent Load (% of Peak)	Minimum p.f.	Maximum p.f.
28%	n/a	0.9850, lagging
66%	0.9550, lagging	0.9725, leading
100%	0.9758, lagging	n/a

On July 2, 2014 at 14:00, the UES-Capital system reached a peak demand of 123.879 MW. The system was lagging by 11.972 MVAr during that peak hour, with a corresponding power factor of 0.9694 (lagging)[1].

In 2016 at a system peak design load of 137.9 MW, the estimated net power factor is expected to be approximately 0.9737 (lagging) as seen at the 115 kV system supply delivery points. The apparent improvement of system power factor compared to the actual LPF in 2014 is largely due to the Oak Hill 115kV capacitor bank being offline during the 2014 peak hour. The 2016 model and all future models assume this capacitor bank to be online. In addition, significant system improvements and configuration changes completed by Eversource during this period will change the supply point load share ratios thus reducing the supply losses allocated to UES-Capital.

In 2017, the Broken Ground system supply is expected to be in-service. This new supply substation will have 19.2MVAr of reactive compensation installed on the 34.5kV bus. With the new system supply and additional capacitor banks, the estimated net power factor is expected to remain above the minimum LPF standard throughout the study period.

[1] Estimated LPF at the 115kV transmission system after allocating supply losses and reactive compensation based on UES-Capital's load share ratio at each supply point.

The following table lists the estimated system power factor for select years over the ten year study period.

UES-Capital System – Anticipated Power Factor

Year	Uncorrected System Load * (MW)	(MVAr)	p.f. (115 kV)	Est. Minimum p.f. correction (MVAr)
2016	138.61	32.40	0.9737, lagging	1.4[1]
2017	139.51	17.50	0.9922, lagging	n/a
2025	147.50	20.88	0.9901, lagging	n/a

* - with no improvements, all internal system generation offline, and all existing substation capacitors switched into service. Load levels shown include UES's share of system supply transformer losses at Garvins and Oak Hill.

Note: This analysis assumes that (4) 4.8MVAr capacitor banks will be installed at Broken Ground and that the existing 3.6MVAr capacitor bank at Hollis will be removed once this system supply is in-service. It is also noted that at present load forecasts, it is anticipated that only two of the capacitor banks at Broken Ground will be needed for LPF correction in 2017 and by 2025 three will be required leaving additional margin not represented in the table above.

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
2020	142.3	Conductor Overload – 37 Line Penacook to Maccoy St Tap	Loss of Circuit 4X1

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.

[1] Although this LPF would not meet the ISO-NE LPF standard for NH, no improvements are recommended for 2016 since UES reports LPF to ISO-NE as a single entity and the aggregate LPF for UES is anticipated to meet the standard.

Constraint	Year	Circumstances	Result
Equipment Overload – 37 Line Penacook to Maccoy St Tap	2020	Loss of Circuit 4X1	Loading > 100% Normal Exposure > 12 hrs

8 SYSTEM IMPROVEMENT OPTIONS

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

8.1 37 Line Overload

A normally open tie exists between the 37 Line and circuit 4X1 out of Penacook S/S at the 37R4X1 recloser located at the Maccoy Street Tap. This tie is utilized as an alternate source following the contingent loss of either circuit 4X1 or the 37 Line. This source transfer is manual for the loss of circuit 4X1 but is implemented as an automatic source transfer for the loss of the 37 Line between Penacook and the Maccoy Street Tap. 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 137.9MW (2016), the 37 Line will be loaded above its Normal rating if all of circuit 4X1 is transferred (with 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 142.3MW (2020).

8.1.1 Re-conductor 37 Line from Penacook to Maccoy St Tap

Summary:

Prior to summer 2020, replace the 1/0ACSR phase conductor on the 37 Line from pole 8 to the Maccoy Street Tap with 556 AA conductor. This consists of approximately 1.25 pole miles in length. The 266 ACSR neutral conductor will remain.

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 its normal rating for many years beyond the study period.

8.1.2 Recommendation

Reconductoring as described in 8.1.1 is the recommended solution as there are no other viable alternatives to address this constraint.

9 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[1]. The review is completed under base-case 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 to 158 MW the following additional conditions have been identified for base-case conditions.

- Garvins transformer loading at 87% Eversource TFRAT
- Oak Hill transformer loading at 79% Eversource TFRAT
- Broken Ground transformer T1 loading at 42% of rating
- Broken Ground transformer T2 loading at 18% of rating

Modeling Assumptions:

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

Other Considerations:
Future studies and the Unitil/Eversource Joint Planning process will focus on alternatives for making use of the additional supply capacity provided by Broken Ground to relieve system constraints identified for the loss of a supply transformer at Garvins or Oak Hill detailed below.

Loss of a System Supply transformer:

- Following the loss of a Garvins transformer in 2025, the remaining transformer at Garvins will reach 87% of its Eversource TFRAT until the mobile or system spare can be installed. Oak Hill loading will approach 92% of Eversource TFRAT. If higher than expected loads are experienced, the only alternative currently available is manual load shedding.

- Following the loss of an Oak Hill transformer in 2020, the remaining unit approaches 101% of Eversource TFRAT. Eversource switching to shed load on the 317 Line reduces loading to below Eversource TFRAT. However, this Eversource load will remain isolated until the mobile is installed at Oak Hill. If additional load reduction is necessary Unitil can shift the 33 Line to Bow Junction. However, this switching only offloads Oak Hill incrementally. The Joint Planning Committee is currently evaluating system improvement alternatives to utilize the Broken Ground supply to restore all load following this contingency.

---

[1] UES-Capital loads were grown 7% and Eversource loads were grown 17% over this 10 year period with the exception of the Portsmouth area which was grown 24%.

10 FINAL RECOMMENDATIONS

The following summarizes final recommendations given in this report.

Year	Project Description	Justification	Cost
2020	Re-conductor 37 Line (Penacook S/S – Maccoy St Tap)	Contingency Loading	$300,000

Note: cost estimates do not include general construction overheads.

APPENDICES

- A Evaluation Criteria
- B UES-Capital Line Ratings
- C UES-Capital Transformer Ratings
- D System Load
- E Base Case Studies
- F Contingency Analysis
- G Contingency Switching Procedures
- H References
- I Economic Evaluation of Alternatives
- J Diagrams

APPENDIX A

EVALUATION CRITERIA

The following summarizes the application of electric system planning guidelines as used in this study. These criteria are based on Unitil's Electric System Planning Guide Rev 3 (March 13, 2014).

LOADING

Peak design conditions – all elements in service:

- All load in service
- All elements operating within Normal Limit ratings w/ half of internal, non-utility generating units out of service

Peak design conditions – loss of non-radial lines, or Unitil owned system supply transformers (after switching):

- All load restored to service
- All elements operating within LTE Limit ratings for up to 12 hours w/ half of internal, non-utility generating units out of service
- All elements operating within Normal Limit ratings after 12 hours of LTE loading w/ half of internal, non-utility generating units out of service

Peak design conditions – loss of radial lines, or external system supply transformers (after switching):

- Up to 30 MW of load left out of service for up to 24 hours
- All elements operating within LTE Limit ratings for up to 12 hours w/ half of internal, non-utility generating units out of service
- All elements operating within Normal Limit ratings after 12 hours of LTE loading w/ half of internal, non-utility generating units out of service

Extreme Peak conditions – all elements in service:

- All load in service
- All elements operating within LTE Limit ratings for up to 12 hours w/ half of internal, non-utility generating units out of service
- All elements operating within Normal Limit ratings after 12 hours of LTE loading w/ half of internal, non-utility generating units out of service

VOLTAGE

All conditions:

- For all 115 and 34.5 kV non-distribution[1] points: 90% < V < 105%
- For all 34.5, 13.8 and 4.16 kV distribution[2] points: 97.5% < V < 104.167%

1 "non-distribution" indicates only locations that are not direct supply outputs for distribution circuit loads
2 "distribution" indicates locations that are direct supply outputs for distribution circuit loads, after all transformation and/or voltage regulation

REDACTED

APPENDIX B

UES-CAPITAL LINE RATINGS

The following is a listing of the present summer and winter thermal ratings for UES-Capital 34.5 kV Lines studied in this report.

			Summer Capacity				Winter Capacity			
Line Section	**Limiting Factor**	**Nominal Voltage**	**Normal Limit (Amps)**	**LTE Limit (Amps)**	**Normal Limit (MVA)**	**LTE Limit (MVA)**	**Normal Limit (Amps)**	**LTE Limit (Amps)**	**Normal Limit (MVA)**	**LTE Limit (MVA)**
33 Line - West Concord to Pleasant St	266 ACSR	34.5 kV	463	562	27.7	33.6	605	677	36.2	40.5
33 Line - Bow Junction to Iron Works	556 AA	34.5 kV	739	902	44.2	53.9	968	1087	57.8	65.0
33 Line - Iron Works to Pleasant St	#2 CU	34.5 kV	240	289	14.3	17.3	312	348	18.6	20.8
34 Line – Bridge Street to West Concord	266 ACSR	34.5 kV	463	562	27.7	33.6	605	677	36.2	40.5
34 Line – West Concord to Penacook	266 ACSR	34.5 kV	463	562	27.7	33.6	605	677	36.2	40.5
35 Line – Bridge Street to Sewalls Falls	266 ACSR	34.5 kV	463	562	27.7	33.6	605	677	36.2	40.5
36 Line – Sewalls Falls to Peancook	266 ACSR	34.5 kV	463	562	27.7	33.6	605	677	36.2	40.5
37 Line – Peancook to Maccoy Tap	1/0 ACSR	34.5 kV	253	305	15.1	18.2	330	368	19.7	22.0
37 Line – Maccoy Tap to Boscawen	266 ACSR	34.5 kV	463	562	27.7	33.6	605	677	36.2	40.5
38 Line[1] – Broken Ground to Hollis	795 AA	34.5 kV	915	1121	54.7	67.0	1201	1351	71.8	80.7
38 Line – Hollis to Hazen Drive	Phase Trip	34.5 kV	400	400	23.9	23.9	400	400	23.9	23.9
38 Line – Horse Shoe Pond to Hazen Dr	Phase Trip	34.5 kV	480	480	28.7	28.7	480	480	28.7	28.7
374 Line - at Bridge Street	556 AA	34.5 kV	730	891	43.6	53.2	956	1074	57.1	64.2
374 Line - at Garvins	556 AA	34.5 kV	730	891	43.6	53.2	956	1074	57.1	64.2
375 Line - at Bridge Street	556 AA	34.5 kV	730	891	43.6	53.2	956	1074	57.1	64.2
375 Line - at Garvins	556 ACSR	34.5 kV	739	902	44.2	53.9	968	1087	57.8	65.0
288 Line[1] – Broken Ground to Hollis	795 AA	34.5 kV	915	1121	54.7	67.0	1201	1351	71.8	80.7
396 Line - Garvins to 396X1 Tap	795 AA	34.5 kV	915	1121	54.7	67.0	1201	1351	71.8	80.7
396 Line - 396X1 Tap to Bow Junction	795 Spacer	34.5 kV	860	1072	51.4	64.1	860	1072	51.4	64.1

[1] This line will be constructed as part of the Broken Ground system supply project.

APPENDIX C

UES-CAPITAL TRANSFORMER RATINGS

The following is a listing of the present summer and winter thermal ratings for UES-Capital Substation Power Transformers.

Distribution Substation Transformers		Voltage	Summer Capacity		Winter Capacity	
			Normal (MVA)	LTE (MVA)	Normal (MVA)	LTE (MVA)
13T1	Boscawen	34.5-13.8 kV	6.20	6.32	6.98	7.26
13T2	Boscawen	34.5-13.8 kV	8.19	8.44	9.17	9.63
18T2	Bow Bog	34.5-13.8 kV	3.33	3.38	3.78	3.98
7T1	Bow Junction	34.5-13.8 kV	12.45	12.65	13.65	14.34
1T1	Bridge St.	34.5-4.16 kV	8.19	8.44	9.24	9.70
1T2	Bridge St.	34.5-4.16 kV	8.19	8.44	8.44	8.44
3T1	Gulf St.	34.5-4.16 kV	5.06	5.16	5.75	6.04
3T2	Gulf St.	34.5-4.16 kV	4.13	4.23	4.66	4.89
24T1	Hazen Drive	34.5-4.16 kV	2.71	2.76	3.07	3.24
24T2	Hazen Drive	34.5-4.16 kV	3.84	3.92	4.34	4.58
8T1	Hollis	34.5-4.16 kV	3.81	3.89	4.31	4.57
22T1	Iron Works Rd.	34.5-13.8 kV	12.45	12.66	13.91	14.61
14T1	Langdon	34.5-4.16 kV	5.06	5.16	5.75	6.04
23T1	Montgomery St.	34.5-13.8 kV	9.00	9.27	10.28	10.79
4T1	Penacook	34.5-13.8 kV	12.45	12.66	13.97	13.97
21T1	Storrs St.	34.5-13.8 kV	9.00	9.27	10.35	10.97
16T1	Terrill Park	34.5-4.16 kV	6.20	6.32	6.93	7.21
2T1	West Concord	34.5-13.8 kV	5.67	5.84	6.56	6.92
15T1	West Portsmouth	34.5-4.16 kV	12.44	12.63	13.97	14.59
15T2	West Portsmouth	34.5-4.16 kV	1.86	1.93	2.18	2.31

System Supply Transformers	Voltage	Summer Capacity		Winter Capacity	
		Normal (MVA)	Thermal Limit	Normal (MVA)	Thermal Limit
TB-39 Garvins[1]	115 – 34.5 kV	60	69	60	69
TB-51 Garvins[1]	115 – 34.5 kV	60	70	60	70
TB-15 Oak Hill[1]	115 – 34.5 kV	45	50	45	50
TB-84 Oak Hill[1]	115 – 34.5kV	45	52	45	52
Broken Ground T1[2]	115 – 34.5kV	60	72	60	72
Broken Ground T2[2]	115 – 34.5kV	60	72	60	72

[1] Garvins and Oak Hill system supply transformers listed are property of Eversource.
[2] In 2017, the new Broken Ground system supply will be in service with two 60 MVA transformers with a Thermal Limit of 72 MVA each.

Unitil
Unitil Service Corp.

APPENDIX D

Ten-Year System Load Forecasts
Summer 2016 – 2025

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.

The UES Capital system reached a peak load for the summer of 2014 of 123.879 MW on July 2, 2014 at 2:00 PM. The daily average temperature was 80°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 daily average temperature for this day was 88°F. The historical mean of annual highest daily average temperatures for the past ten years is 83.1°F. The linear trend of the 83°F mean point estimates from annual load-versus-temperature models for the UES Capital system is -0.25 MW per year with an average standard deviation of ±3.4 MW among the models at this temperature.

UES-Capital Ten-Year Summer Design Forecasts

Projected Summer Season	Average Peak Load (MW)	Peak Design Load (MW)	Extreme Peak Load (MW)
2016	128.3	137.9	141.3
2017	128.5	139.0	143.0
2018	128.8	140.1	144.1
2019	129.6	141.3	146.1
2020	129.6	142.3	147.2
2021	129.8	143.2	148.7
2022	130.1	143.9	149.7
2023	130.8	144.7	150.2
2024	131.0	145.7	151.3
2025	131.5	147.0	152.9

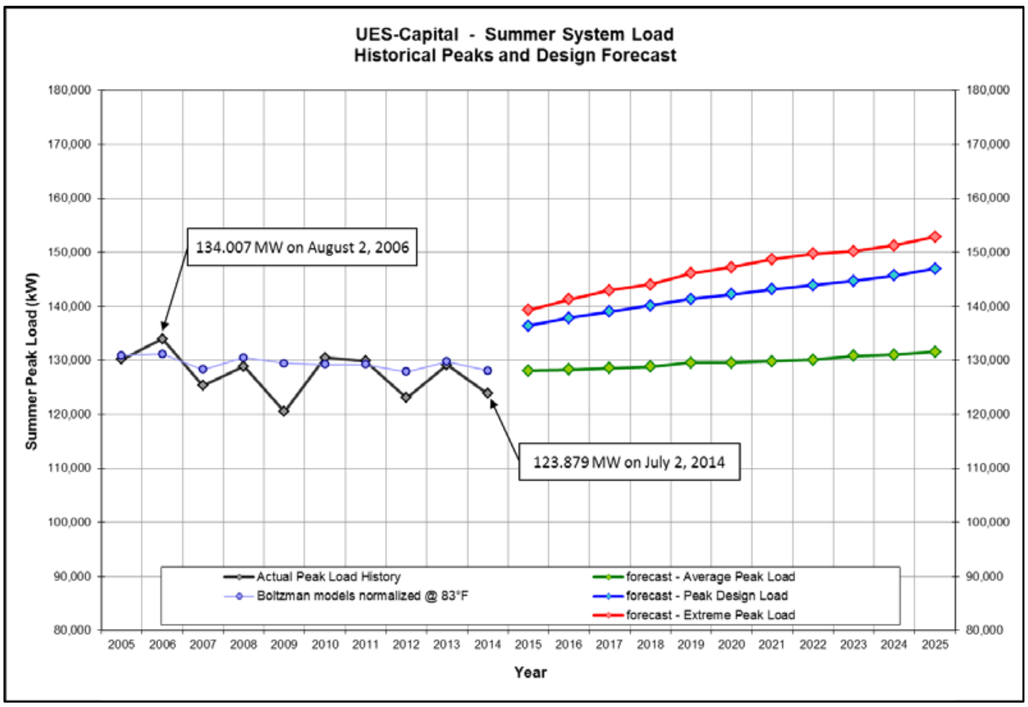


Chart 3. UES-Capital – Historical Summer System Peak Loads and Design Forecasts.

APPENDIX E

BASE CASE STUDIES

The information provided in this section describes details of power flow simulation results for year by year studies of the UES-Capital system in its normal or proposed operating configuration(s). The system is examined for deficiencies under peak design and extreme peak loading conditions with all elements in service. Details are quantified as to the adequacy of the normal system operating configuration, and substation and subtransmission system infrastructure. System voltages or equipment loadings that are approaching operational limits are noted.

Base-case conditions studied are based on the following generation dispatch conditions. Only generators interconnected internal to the UES-Capital system and local area Eversource generators are listed.

Generator	Location	Status / Output Level
SES	UES 37 Line	Offline
Lower Falls Hydro	UES 37 Line	1.66MW
Briar Hydro	UES Circuit 4X1	Offline
Upper Falls Hydro	UES Circuit 4X1	1.15MW
Concord Steam	UES Circuit 1X7P	Offline
Garvins Hydro	Eversource Garvins S/S	Offline
Amoskeag Hydro	Eversource Eddy S/S	Offline
Hooksett Hydro	Eversource 334 Line	Offline
Pembroke Hydro	Eversource 335 Line	Offline

The UES-Capital system was modeled in two base-case configurations as summarized below:

2016 (137.9MW):
- UES system looped between Garvins & Penacook with 317/3122 load shed scheme disabled
- Second transformer at Eversource Rimmon Substation in-service

2017 – 2025 (139.0MW – 147.0MW):

- Broken Ground system supply in-service
- UES system looped between Garvins & Penacook with 317/3122 load shed scheme disabled
- 38 Line fed radially from Broken Ground to Horse Shoe Pond (38 recloser open)
- Eversource's 332 Line open at J3532
- Eversource's 334 Line open at 334J15

Complete details of these system configurations are provided below:

<u>374 Line – Garvins to Bow Junction</u>
The 374 Line operates radially between Garvins and Bow Junction

- 374 breaker normally closed at Garvins
- 374J4 switch normally open
- 374J375 switch normally open at Garvins
- 396J374 switch normally open at Garvins
- 318J374 switch normally open at Garvins[1]

- Distribution loads normally supplied:
  - Bow Junction S/S circuits 7W3, 7W4 and 7X1

<u>396 Line and 374 Line – Garvins to Bridge Street</u>
The 396 Line is the supply to the 374 Line beyond the 374J4 at Bow Jct. These lines operate in parallel with 375 Line from Garvins to Bridge Street.

- 396 breaker normally closed at Garvins
- 0374 breaker normally closed at Bridge Street
- 396J374 switch normally open
- 374J4 switch normally open

- Distribution loads normally supplied:
  - Langdon S/S circuits 14H1, 14H2, and 14X3
  - 374A (Industrial Park Tap)
  - Gulf Street S/S circuits 3H1, 3H2, and 3H3
  - Bridge Street circuits 1H1, 1H2, 1H6 and 1X7P (in parallel with 375 Line)[2]
  - Montgomery Street S/S circuits 21W1A, 21W1P, Elderly Housing, Nelson Plaza and Concord Steam

<u>375 Line – Garvins to Bridge Street</u>
The 375 Line operates in parallel with 396/374 Line from Garvins to Bridge Street

- 375 breaker normally closed at Garvins
- 0375 breaker normally closed at Bridge Street
- 374J375 switch normally open at Garvins

[1] This switch is being installed by Eversource in 2014 as part of the Garvins 115kV upgrades.
[2] These circuits are fed from the 374 Line side of the normally closed 1XBT1 bus tie switch at Bridge Street

- Distribution loads normally supplied:
  - Terrill Park S/S circuits 16H1, 16H3, 16X4, 16X5, and 16X6
  - 375X1(Flanders Tap)
  - Bridge Street S/S circuits1H3, 1H4, 1H5, 1X7A (in parallel with 374 Line) [1]
  - Storrs Street S/S circuits 21W1A, 21W1P, and Holiday Inn[1]

<u>396X1 Line – 396 Line to Bow Bog</u>

- 396X1J1 normally closed at the 396 Line tap at Garvins

- Distribution loads normally supplied:
  - 17X1 (Z-Tech Corporation)
  - Bow Bog S/S circuit 18W2

<u>33 Line – Bow Junction to West Concord</u>

The 33 Line is a double ended line between Bow Junction and West Concord that normally operates radially from each source with an open point at Pleasant Street

- 33 Recloser normally closed at Bow Jct. S/S
- 033 OCR normally closed at W. Concord S/S
- 33J1 switch normally open at Pleasant St S/S

- Distribution loads normally supplied:
  - 33X2 (State of NH Tap), 33X3 (St Paul's Tap), 33X4 (Little Pond Rd Tap), 33X5 (Jefferson Pilot Tap), 33X6 (NH Prison Tap)
  - Iron Works Road S/S circuits 22W1, 22W2 and 22W3
  - Pleasant Street S/S circuit 6X3

<u>34 Line – Bridge Street to Penacook</u>

The 34 Line operates in parallel with the 35/36 Line from Bridge Street to Penacook

- 34 breaker normally closed at Bridge St
- 034 breaker normally closed at Penacook

- Distribution loads normally supplied:
  - 34X1 Tap (alternate supply to Montgomery Street - normally open at DS-17A)
  - 34X3 Tap (alternate supply to Storrs Street - normally open at 200E cutouts)
  - 34X2 (Concord Center)
  - West Concord S/S circuits 2H1, 2H2, 2H3, and 2H4
  - 34X4 (Crowley Foods)
  - Penacook S/S circuits 4W3 and 4W4 (when operating in parallel with 35/36 Line)[2]

<u>35 and 36 Lines – Bridge Street to Penacook</u>[3]

The 35/36Line operates in parallel with the 34 Line from Bridge Street to Penacook.

---

[1] These circuits are fed from the 375 Line side of the normally closed 1XBT1 bus tie switch at Bridge Street
[2] These circuits are fed from the 34 Line side of the normally closed 4XBT1 bus tie switch at Penacook
[3] This line is designated the 35 Line on the Bridge Street side of Sewalls Falls and the 36 Line on the Penacook side.

- 35 breaker normally closed at Bridge St.
- 036 breaker normally closed at Penacook

- Distribution loads normally supplied:
  - West Portsmouth St. S/S circuits 15W1, 15W2 and 15H3
  - Penacook S/S circuit 4X1 including Briar Hydro, Upper Falls Hydro, 41A Tap, 41B Tap and Hoyt Tap (when operating in parallel with 34 Line) [1]
  - 35X1 (Locke Road Tap) and several other lateral taps in the vicinity of Locke Road (35X2, 35X3, 35X4)

<u>37 Line – Penacook to Boscawen</u>
The 37 Line operates radially from Penacook to Boscawen with normally open tie to circuit 4X1.

- 37 breaker normally closed at Penacook
- 37R4X1 recloser at Maccoy St Tap normally open (alternate supply from circuit 4X1)

- Distribution loads normally supplied:
  - Lower Falls Hydro, SES, 37X1 (37A tap)
  - Boscawen S/S circuits 13W1, 13W2, 13W3, and 13X4 (Elektrisola)

<u>38 Line – Hollis to 35 Line(Horseshoe Pond)</u>

2016:
The 38 Line is a double ended line between Hollis and the 35 Line at Horse Shoe Pond Tap that normally operates radially from each source with an open point at Hazen Drive.

- 038 breaker normally closed at Hollis
- 38 recloser normally closed at Horseshoe Pond (35 Line Tap)
- 38R1 recloser normally open at Hazen Drive

2017 – 2025:
The 38 Line operates radially from Broken Ground to Horse Shoe Pond Tap with a normally open tie with the 35 Line.

- 038 breaker normally closed at Broken Ground
- 38 recloser normally open at Horse Shoe Pond (35 Line Tap)

- Distribution loads normally supplied:
  - Hollis S/S circuits 8H1, 8H2, 8X3, and 8X5
  - 38A tap (Alton Woods)
  - Canterbury Meadows Tap (alternate supply to Canterbury Meadows – normally open at cutouts)
  - Hazen Drive S/S circuits 24H1, 24H2
  - State Tap (State of NH Campus on Hazen Drive)
  - 38B Tap (Fort Eddy)
  - Horseshoe Pond Business Park Tap

[1] These circuits are fed from the 35 Line side of the normally closed 4XBT1 bus tie switch at Penacook

- New Hampshire Technical School Tap

Additionally, the following system capacitor banks are modeled as being switched in:

• Bridge Street 34.5kV bus	7.2 MVAr (34.5 kV)
• Bridge Street 4kV bus	1.2 MVAr (4.16 kV)
• Bridge Street 4kV bus	1.2 MVAr (4.16 kV)
• 37 Line at Boscawen S/S	3.6 MVAr (34.5 kV)
• Bow Junction 34.5kV bus	3.6 MVAr (34.5 kV)
• Hollis S/S 34.5kV bus[1]	3.6 MVAr (34.5 kV)
• Hollis S/S 4kV bus	0.3 MVAr (4.16 kV)
• 38 Line at Hazen Drive S/S	3.6 MVAr (34.5 kV)
• Penacook S/S 34.5kV bus	7.2 MVAr (34.5 kV)
• 33 Line at Pleasant Street S/S	3.6 MVAr (34.5 kV)
• 33 Line at West Concord S/S	2.4 MVAr (34.5 kV)
• Iron Works 13.8kV bus	2.4 MVAr (13.8kV)
• Broken Ground 34.5kV bus	9.6 MVAr (34.5kV)
• Broken Ground 34.5kV bus	9.6 MVAr (34.5kV)

Other capacitors on distribution circuits are typically not directly modeled, but rather are included within modeled loads.

The system is examined for deficiencies under peak design and extreme peak loading conditions with all elements in service. In addition, the system is examined for deficiencies under peak design and extreme peak loading conditions with at least half of the available generation off-line. Details are quantified as to the adequacy of the normal system operating configuration, and substation and subtransmission system infrastructure

The following table is used to summarize the results of the analysis. Not all of the items identified in the table are violations of established planning guidelines. All conditions where the loading is at or above the normal rating or where voltage levels are at or below the planning criteria are identified. An asterisk (*) is used to identify the results which do not meet planning guidelines. Each condition which does not meet planning criteria is considered to be a system constraint and a system improvement alternative is required. The table is organized by year and load level. For each base-case, there may be multiple conditions that result.

[1] This capacitor bank will be removed in 2017 as part of the Broken Ground project.

Base-case (Peak Design Load) Planning Flags

Year	Load Level (MW)	*	Location/Element	Condition	Planning Criteria or Rating
2016	137.9		Garvins Transformer TB-39 Loading[1]	Loading > 88% Eversource TFRAT	Loading > Eversource TFRAT
			Garvins Transformer TB-51 Loading[1]	Loading > 87% Eversource TFRAT	Loading > Eversource TFRAT

Basecase peak loading constraints eliminated in 2017 with Broken Ground in-service

Extreme (Extreme Peak Load) Planning Flags

Year	Load Level (MW)	*	Location/Element	Condition	Planning Criteria or Rating
2016	141.3		Garvins Transformer TB-39 Loading[1]	Loading > 89% Eversource TFRAT	Loading > Eversource TFRAT
			Garvins Transformer TB-51 Loading[1]	Loading > 89% Eversource TFRAT	Loading > Eversource TFRAT

Extreme peak loading constraints eliminated in 2017 with Broken Ground in-service

[1] Results with second transformer at Eversource Rimmon S/S in service, Eversource 332 & 334 Lines split, and UES system looped

APPENDIX F

CONTINGENCY ANALYSIS

The information provided in this section describes the power flow simulation results for the case by case studies of loss of system elements at peak load conditions. These details are provided to quantify the adequacy of substation and subtransmission system infrastructure under contingency circumstances, and to guide development of operating procedures to respond to these scenarios. System voltages or equipment loadings that are approaching operational limits are described for each significant switching step. Details regarding troubleshooting faults or isolation of specific components to be left out of service are not typically provided. Similarly, not all details that would be required in formal switching orders are included.

The following is a summary list of the loss-of-element contingencies studied:
1) Loss of G146 – Deerfield to Garvins
2) Loss of H137 – Merrimack Station to Garvins
3) Loss of C189 – Farmwood to Garvins[1]
4) Loss of C189 – Garvins to Curtisville[2]
5) Loss of C189 – Curtisville to Farmwood[2]
6) Loss of B15 – Farmwood to Oak Hill
7) Loss of B84 – Farmwood to Oak Hill
8A) Loss of Garvins TB39 Transformer
8B) Loss of Garvins TB51 Transformer
9A) Loss of Oak Hill TB15 Transformer
9B) Loss of Oak Hill TB84 Transformer
10) Loss of Broken Ground Transformer T1[2]
11) Loss of Broken Ground Transformer T2[2]
12) Loss of 374 Line at Garvins
13) Loss of 375 Line at Garvins
14) Loss of 374 Line at Bridge Street
15) Loss of 375 Line at Bridge Street
16) Loss of 396 Line at Garvins
17) Loss of 33 Line at Bow Junction
18) Loss of 318 Line at Garvins[1]
19) Loss of 318 Line Tap at Hollis (or Loss of Hollis Regulators)[1]
20) Loss of 317 Line, Oak Hill to Penacook
21) Loss of 3122 Line, Oak Hill to Penacook
22) Loss of 34 Line at Penacook
23) Loss of 34 Line at Bridge Street
24) Loss of 36 Line at Penacook
25) Loss of 35 Line at Bridge Street
26) Loss of 33 Line at West Concord

[1] This contingency will be eliminated from study in 2017 when Broken Ground is in-service.
[2] This contingency will be studied for the years 2017-2025 when Broken Ground and Eversource's Curtisville are in-service.

27) Loss of 1X7P Circuit at Bridge Street
28) Loss of 1X7A Circuit at Bridge Street
29) Loss of 37 Line at Penacook
30) Loss of 37 Line beyond Maccoy Tap
31) Loss of Circuit 4X1 at Penacook
32) Loss of 288 Line at Broken Ground[2]
33) Loss of the 38 Line at Hollis[1]
34) Loss of 38 Line at Horseshoe Pond Tap[1]
35) Loss of the 38 Line at Broken Ground[2]

For each element scenario, the system was reviewed only under the assumed worst circumstances for the location of the loss of equipment. Furthermore, the switching examined may in some cases set up a configuration that appears to re-energize a faulted element or ignore a lack of sectionalizing. As a study of system capabilities, the emphasis is on performance in contingency configurations, and not maintenance switching or emergency troubleshooting. Finally, the switching examined may not be the only contingency response available.

The following table is used to summarize the results of the analysis. Not all of the items identified in the table are violations of established planning guidelines. All conditions where the loading is at or above the normal rating or where voltage levels are at or below the planning criteria are identified. An asterisk (*) is used to identify the results which do not meet planning guidelines. Each condition which does not meet planning criteria is considered to be a system constraint and a system improvement alternative is required.

The table is organized by year and load level. For each contingency, there may be multiple conditions that result. For each of the conditions, an exposure calculation is completed to determine the number of individual and consecutive hours as well as the number of individual and consecutive days where the system may be exposed to this condition. The last column is used to identify which planning criteria have been surpassed. The results from this analysis are summarized in the following table.

Contingency (Peak Design Load – Generation Off) Planning Flags

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2016	137.9	Loss of Garvins TB-39 **Or** Loss of Garvins TB-51	Up to 24MW of Load Out of Service (Hollis) Loading @ 97% of Oak Hill Transformer TB-15 Loading @ 93% of Oak Hill Transformer TB-84 Loading on 317/3122 Lines @ 101% Normal Rating Voltage on 33 & 38 Lines @ 0.96 PU[1]	< 24 hrs < 12 hrs	30MW of Load Out of Service up to 24 hrs Loading > Eversource TFRAT Loading > Eversource TFRAT Loading > Normal Rating Voltage < 0.975 PU	

[1] Marginal low voltage conditions is limited to a small number of customers and is resolved with additional switching or when internal generation comes back online.

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2016	137.9	Loss of Oak Hill Transformer TB-15[1] **<u>Or</u>** Loss of Oak Hill Transformer TB-84	Up to 13MW of Load Out of Service (Eversource 317 Line) Loading @ 97% of Oak Hill Transformer TB-15 (or TB-84) Loading @ 93% of Garvins Transformer TB-39 Loading @ 92% of Garvins Transformer TB-51	< 24 hrs	30MW of Load Out of Service up to 24 hrs Loading > Eversource TFRAT Loading > Eversource TFRAT Loading > Eversource TFRAT	
		Loss of 375 Line at Bridge St	Loading @ 96% of Normal Rating on 374 Line	< 12 hrs	Loading > Normal	
		Loss of 33 Line at Bow Jct	Voltage on 33 Line 0.96 PU		Voltage < 0.975 PU	*
		Loss of 318 Line at Garvins	3025 Line @ 103% Normal (Oak Hill – Hollis) Loading on 35 Line @ 93% Normal Rating Loading on 38 Recloser at Horseshoe Pond @ 81% minimum phase pickup	< 12 hrs < 12 hrs	Loading > Normal Loading > Normal Loading > 90% pickup	

[1] Results shown are after Eversource switching to isolate Eversource 317 Line load

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2016	137.9	Loss of Hollis Tap (or Hollis Regulators)	Up to 15MW of Load Out of Service (8X3, 8H1 & 8H2) Loading on 38 Recloser at Horseshoe Pond @ 81% minimum phase pickup	< 24 hrs	30MW of Load Out of Service up to 24 hrs Loading > 90% pickup	
		Loss of 317 Line	Up to 13MW of Load Out of Service (Eversource 317 Line) Loading @ 96% of Normal Rating of 3122 Line	< 24 hrs < 12 hrs	30MW of Load Out of Service up to 24 hrs Loading > Normal	
		Loss of 3122 Line	Loading @ 115% of Normal Rating (92% LTE)of 317 Line Loading @ 92% of Garvins Transformer TB-39 Loading @ 91% of Garvins Transformer TB-51	< 12 hrs	Loading > Normal Loading > Eversource TFRAT Loading > Eversource TFRAT	

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2016	137.9	Loss of 34 Line at Penacook	Loading on 33 Line @ 96% Normal Rating	< 12 hrs	Loading > Normal	
			Loading @ 92% of Garvins Transformer TB-39		Loading > Eversource TFRAT	
			Loading @ 91% of Garvins Transformer TB-51		Loading > Eversource TFRAT	
		Loss of 34 Line at Bridge Street	Loading on 33 Line @ 96% Normal Rating	< 12 hrs	Loading > Normal	
		Loss of 35 Line at Bridge Street	Loading @ 93% of Normal Rating of 318 Line	< 12 hrs	Loading > Normal	
			Loading @ 102% of Normal Rating of 318 Tap	< 12 hrs	Loading > Normal	
		Loss of 33 Line at West Concord	Loading @ 91% of Garvins Transformer TB-39		Loading > Eversource TFRAT	
			Loading @ 90% of Garvins Transformer TB-51		Loading > Eversource TFRAT	
			Loading on 33 Line @ 96% Normal Rating	< 12 hrs	Loading > Normal	
		Loss of Circuit 4X1	Loading @ 109% of Normal Rating of 37 Line	< 12 hrs	Loading > Normal	

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2016	137.9	Loss of 38 Line @ Horse Shoe Pond	Up to 2.2MW of Load Out of Service (Horse Shoe Corp Center & Tech School)	< 24 hrs	30MW of Load Out of Service up to 24 hrs	
			Loading @ 104% of Normal Rating of 318 Line	< 12 hrs	Loading > Normal	
			Loading @ 114% of Normal Rating (94% LTE) of 318 Tap	< 12 hrs	Loading > Normal	
2020	142.3	Loss of Circuit 4X1	Loading @ 113% of Normal Rating (94% LTE) of 37 Line	> 12 hrs	Loading > Normal	*

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2025	147.0	Loss of Garvins TB-39 **<u>Or</u>** Loss of Garvins TB-51	Loading @ 87% of Garvins Transformer TB-39 (or TB-51) Loading @ 92% of Oak Hill Transformer TB-15 Loading @ 89% of Oak Hill Transformer TB-84 Voltage on 33 Line @ 0.95 PU[1]		Loading > Eversource TFRAT Loading > Eversource TFRAT Loading > Eversource TFRAT Voltage < 0.975 PU	

[1] Marginal low voltage conditions is limited to a small number of customers and is resolved with additional switching or when internal generation comes back online.

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2025	147.0	Loss of Oak Hill Transformer TB-15[1] **<u>Or</u>** Loss of Oak Hill Transformer TB-84	Up to 16MW of Load Out of Service (Eversource 317 Line) Loading @ 92% of Oak Hill Transformer TB-84 (or TB-15) Loading @ 78% of Garvins Transformer TB-39[2] Loading @ 77% of Garvins Transformer TB-51[2]	< 24 hrs	30MW of Load Out of Service up to 24 hrs Loading > Eversource TFRAT Loading > Eversource TFRAT Loading > Eversource TFRAT	
		Loss of 375 Line at Garvins	Loading @ 96% of Normal Rating on 374 Line	< 12 hrs	Loading > Normal	
		Loss of 375 Line at Bridge St	Loading @ 98% of Normal Rating on 374 Line	< 12 hrs	Loading > Normal	
		Loss of 33 Line at Bow Jct	Voltage on 33 Line 0.95 PU		Voltage < 0.975 PU	*
		Loss of 317 Line	Up to 16MW of Load Out of Service (Eversource 317 Line)	< 24 hrs	30MW of Load Out of Service up to 24 hrs	
		Loss of 3122 Line	Loading @ 101% of Normal Rating of 317 Line	< 12 hrs	Loading > Normal	

[1] Results shown are after Eversource switching to isolate Eversource 317 Line load (approx. 16MW)
[2] Loading on Garvins transformers at 100% of TFRAT rating until Eversource switching to manually shed 317 Line load is completed.

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2025	147.0	Loss of 34 Line at Penacook	Loading on 33 Line @ 103% Normal Rating	< 12 hrs	Loading > Normal	
		Loss of 34 Line at Bridge Street	Loading on 33 Line @ 103% Normal Rating	< 12 hrs	Loading > Normal	
		Loss of 33 at West Concord	Loading @ 103% of Normal Rating on 33 Line	< 12 hrs	Loading > Normal	
		Loss of 37 Line beyond Maccoy Tap	Up to 11MW of Load Out of Service	< 24 hrs	30MW of Load Out of Service up to 24 hrs	

APPENDIX G

CONTINGENCY SWITCHING PROCEDURES

The information provided in this section describes the system switching analyzed in the contingency analysis. The results of these simulations are summarized in the table in Appendix F.

The information below describes the initial event, initial load out of service, switching procedure to restore load, and system concerns. The initial event describes which devices have operated to isolate the fault. The initial load out of service is the load which has been isolated in conjunction with the initial event. The switching procedure to restore load is the approach that has been taken to restore as much load as possible while still satisfying applicable planning criteria. This is meant to be used as a guide and not as step by step switching procedures to be implemented in the field. Finally, those system concerns that have been identified by the analysis of the final configuration are listed for the 10 year study timeframe.

1) Loss of G146 Line, Deerfield to Garvins
(fault between 246 and 4629 breakers at Deerfield, and G1460 breaker at Garvins)

Initial Event:
- 246 trips to lockout at Deerfield
- 4629 trips to lockout at Deerfield
- G1460 trips to lockout at Garvins
- No load out of service

Switching Procedures:
- No switching necessary

System Concerns:
- None

2) Loss of H137 Line, Merrimack Station to Garvins
(fault between H137 breaker at Merrimack Station and H1370 breaker at Garvins)

Initial Event:
- H137 trips to lockout at Merrimack Station
- H1370 trips to lockout at Garvins
- No load out of service

Switching Procedures:
- No switching necessary

System Concerns:
None

3) Loss of C189 Line, Farmwood to Garvins (2016)
(fault between C1890 breaker at Garvins and the 189J3 switch at Farmwood)

Initial Event:
- C1890 trips to lockout at Garvins
- 892 and 8939 breakers trip to lockout at Farmwood
- No load out of service

Switching Procedures:
- No switching necessary

System Concerns:
None

4) Loss of C189 Line, Garvins to Curtisville (2017-2025)
(fault between C1890 breaker at Garvins and the C189S breaker at Curtisville)

Initial Event:
- C1890 trips to lockout at Garvins
- C189S trips to lockout at Curtisville
- No load out of service

Switching Procedures:
- No switching necessary

System Concerns:
None

5) Loss of C189 Line, Curtisville to Farmwood (2017-2025)
(fault between C189N breaker at Curtiville and the 189J3 switch at Farmwood)

Initial Event:
- C189N breaker at Curtisville trips to lockout
- 892 and 8939 breakers trip to lockout at Farmwood
- No load out of service

Switching Procedures:
- No switching necessary

System Concerns:
None

6) Loss of B15 Line, Farmwood to Oak Hill
(fault between J315 switch at Farmwood and J15 circuit switcher at Oak Hill)

Initial Event:
- 139 and 145 breakers trip to lockout out at Farmwood
- TB15 breaker trips and locks out at Oak Hill
- No load out of service

System Concerns:
This contingency is similar to the loss of TB-15. Refer to contingency 9A

7) Loss of B84 Line, Farmwood to Oak Hill
(fault between J484 switch at Farmwood and J84 circuit switcher at Oak Hill)

Initial Event:
- 892 and 8202 breakers trip to lockout out at Farmwood
- TB84 breaker trips and locks out at Oak Hill
- No load out of service

System Concerns:
This contingency is similar to the loss of TB-84. Refer to contingency 9B

8A) Loss of Garvins TB39 Transformer
(Garvins TB39 transformer fault)

Reference part 8B) Loss of Garvins TB51 transformer below. The remaining Garvins TB51 transformer for this contingency has a slightly higher thermal limit. Otherwise, details on initial event, automatic restoration, follow-on switching procedures, and associated system concerns are effectively the same.

8B) Loss of Garvins TB51 Transformer
(Garvins TB51 transformer fault)

Initial Conditions and Switching Procedures in 2016 with the 2nd Transformer at Rimmon in-service:

Initial Event:
- G1460, H1370 and C1890 trip at Garvins
- TB36, TB39, TB51, 318, 374, 375, 396, 3320 and 3340 trip at Garvins
- 34 and 35 trip at Bridge Street via transfer trip from Garvins
- J51 opens at Garvins

- Load out of service:

Hollis 8H1, 8H2, 8X3, 8X5
38 Line distribution loads (038 to 38J3)
Bow Bog 18W2
17X1 (Z-Tech Corporation)
Bow Junction 7X1, 7W3, 7W4
Langdon Street 14H1, 14H2, 14X3
374A Industrial Park Drive Tap
Gulf Street 3H1, 3H2, 3H3
Bridge Street 1H1, 1H2, 1H3, 1H4, 1H5, 1H6

Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
318X2, 318X4 (Eversource)
Garvins Hydro (Eversource)
332 Line (Eversource)
334 Line to China Mills (Eversource)
1X7A
Storrs Street 21W1A
1X7P
Montgomery Street 21W1P
33X2 (NH State Tap)
Iron Works Road 22W1, 22W2, 22W3
Concord Steam
375X1(Flanders Tap)

Automatic Restoration:
- H1370 recloses at Garvins
- TB39 recloses at Garvins
- 374, 375 and 396 reclose at Garvins

- Load restored:
  Bow Bog 18W2
  17X1 (Z-Tech Corporation)
  Bow Junction 7X1, 7W3, 7W4
  Langdon Street 14H1, 14H2, 14X3
  374A Industrial Park Drive Tap
  Gulf Street 3H1, 3H2, 3H3
  33X2 (NH State Tap)
  1X7A
  Storrs Street 21W1A
  1X7P
  Bridge Street 1H1, 1H2, 1H3, 1H4, 1H5, 1H6
  Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
  375X1(Flanders Tap)
  Iron Works Road 22W1, 22W2, 22W3
  Montgomery Street 21W1P
  Garvins Hydro (Eversource)
  Concord Steam

- Remaining load out of service:
  Hollis 8H1, 8H2, 8X3, 8X5
  38 Line distribution loads (038 to 38J3) 318X2, 318X4 (Eversource)
  332 Line (Eversource)
  334 Line to China Mills (Eversource)

Supply transformer loading at system loads of 137.9MW (2016):
- Garvins TB-39 transformer expected to reach 76% of Eversource TFRAT
- Oak Hill TB-15 transformer expected to reach 95% of Eversource TFRAT
- Oak Hill TB-84 transformer expected to reach 91% of Eversource TFRAT
- 317 & 3122 Lines at 98% of normal rating

Perform switching to restore 38 Line load:
1. Hollis – Open 038 OCR
2. Hazen Drive – Close 38R1

Eversource switching to restore load:
1. Hollis – Open DS318

2. Garvins – Close 318 OCR
3. 332/335 Line – Close J3532
4. China Mills 334 Line – Close 334J15

Load Restored:
38 Line distribution loads (038 to 38J3)
318X2, 318X4 (Eversource)
332 Line (Eversource)
334 Line to China Mills (Eversource)

System Concerns before mobile is installed at Hollis:

At system loads of 137.9 MW (2016):
- Garvins TB-39 transformer expected to reach 81% of Eversource TFRAT
- Oak Hill TB-15 transformer expected to reach 97% of Eversource TFRAT
- Oak Hill TB-84 transformer expected to reach 93% of Eversource TFRAT
- 317 & 3122 Lines at 101% of normal rating
- Marginal low voltage on 33 & 38 Lines

- Up to 24 MW of load remains out of service:
  Remaining load out of service:
  Hollis 8H1, 8H2, 8X3, 8X5

Note:
Transferring Pleasant St on the 33 Line to Bow Jct marginally improves voltages and reduces 317 & 3122 Line loading. This switching can be performed if actual conditions necessitate. However, this switching increases loading on remaining Garvins transformer to TFRAT. Consult with ESCC prior to switching.

... install* Eversource *35 MVA, 115-34.5 kV Mobile S/S at Hollis S/S to restore Hollis Load ...

Switching Procedures following Mobile installation
1. Hollis – close DS318

- Load Restored
  Hollis 8H1, 8H2, 8X3, 8X5
  - All load restored

System Concerns with Mobile S/S in-service:
- None

... install* Eversource *44.8 MVA, 115-34.5 kV spare transformer at Garvins S/S, release Mobile S/S, and restore system configuration to the extent possible...

System Concerns:

- None (assuming 34 and 35 OCB's open at Bridge Street)

Initial Conditions and Switching Procedures 2017-2025 with Broken Ground in-service:

Initial Event:

- G1460, H1370 and C1890 trip at Garvins
- TB36, TB39, TB51, 318, 374, 375, 396, 3320 and 3340 trip at Garvins
- 34 and 35 trip at Bridge Street via transfer trip from Garvins
- J51 opens at Garvins

- Load out of service:

Bow Bog 18W2
17X1 (Z-Tech Corporation)
Bow Junction 7X1, 7W3, 7W4
Langdon Street 14H1, 14H2, 14X3
374A Industrial Park Drive Tap
Gulf Street 3H1, 3H2, 3H3
Bridge Street 1H1, 1H2, 1H3, 1H4, 1H5, 1H6
Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
332 Line (Eversource)
334 Line to China Mills (Eversource)
1X7A
Storrs Street 21W1A
1X7P
Montgomery Street 21W1P
33X2 (NH State Tap)
Iron Works Road 22W1, 22W2, 22W3
318X2, 318X4 (Eversource)
Garvins Hydro (Eversource)
Concord Steam
375X1(Flanders Tap)

Automatic Restoration:

- H1370 recloses at Garvins
- TB39 recloses at Garvins
- 374, 375 and 396 reclose at Garvins

- Load restored:

Bow Bog 18W2
17X1 (Z-Tech Corporation)
Bow Junction 7X1, 7W3, 7W4
Langdon Street 14H1, 14H2, 14X3
374A Industrial Park Drive Tap
Gulf Street 3H1, 3H2, 3H3
33X2 (NH State Tap)
1X7A
Storrs Street 21W1A
1X7P
Bridge Street 1H1, 1H2, 1H3, 1H4, 1H5, 1H6
Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
375X1(Flanders Tap)
Iron Works Road 22W1, 22W2, 22W3
Montgomery Street 21W1P
Garvins Hydro (Eversource)
Concord Steam

All Unitil load Restored

- Remaining load out of service:

318X2, 318X4 (Eversource)
332 Line (Eversource)
334 Line to China Mills (Eversource)

Eversource perform switching to restore load:

1. Garvins – Close 318 OCR
2. 332/335 Line – Close J3532
3. China Mills 334 Line – Close 334J15

Load Restored:
318X2, 318X4 (Eversource)
332 Line (Eversource)
334 Line to China Mills (Eversource)

- Remaining load out of service:
None

System Concerns:
At system loads of 147.0 MW (2025):
- Garvins TB-39 at 87% TFRAT
- Oak Hill TB-15 transformer expected to reach 92% of Eversource TFRAT
- Oak Hill TB-84 transformer expected to reach 89% of Eversource TFRAT
- Marginal low voltage on 33 Line

... install* Eversource *35MVA 115-34.5 kV mobile Garvins S/S and restore system configuration to normal to the extent possible ...

9A) Loss of Oak Hill TB15 Transformer
(Oak Hill TB84 transformer fault)

Reference part 9B) Loss of Oak Hill TB15 transformer below. The remaining Oak Hill TB84 transformer for this contingency has a slightly higher thermal limit. Otherwise, details on initial event, automatic restoration, follow-on switching procedures, and associated system concerns are effectively the same.

9B) Loss of Oak Hill TB84 Transformer
(Oak Hill TB84 transformer fault)

Initial Conditions and Switching Procedures in 2016 with the 2nd Transformer at Rimmon in-service:

Initial Event:
- TB84 and J84 trip and lock out at Oak Hill
- No load out of service

System Concerns:
- Oak Hill TB15 transformer expected to reach 110% of Eversource TFRAT
- Garvins TB39 transformer expected to reach 99% of Eversource TFRAT
- Garvins TB51 transformer expected to reach 98% of Eversource TFRAT

Switching Procedures:
1. Open 317 Tap recloser (between Oak Hill and Penacook)

- Load out of service:
  Eversource 317 Line

At a system load level of 137.9MW (2016):
- Oak Hill TB15 transformer expected to reach 97% of Eversource TFRAT
- Garvins TB39 transformer expected to reach 93% of Eversource TFRAT
- Garvins TB51 transformer expected to reach 92% of Eversource TFRAT

... install Mobile S/S at Oak Hill S/S...

1. Oak Hill S/S – install Eversource 35 MVA Mobile S/S and close in to 34.5 kV bus (Eversource)
2. Oak Hill S/S – close 317 Tap reclsoer (Eversource)
   - Load restored:
     Eversource 317 Line
   - All load restored:

System Concerns:
- None

Initial Conditions and Switching Procedures 2017-2025 with Broken Ground in-service:

Initial Event:
- TB84 and J84 trip and lock out at Oak Hill
- No load out of service

System Concerns:
At a system load level of 147.0MW (2025):
- Oak Hill TB15 transformer expected to reach 107% of Eversource TFRAT
- Garvins TB39 transformer expected to reach 84% of Eversource TFRAT
- Garvins TB51 transformer expected to reach 84% of Eversource TFRAT

Switching Procedures:
1. Open 317 Tap recloser (between Oak Hill and Penacook)

- Load out of service:

Eversource 317 Line

- Oak Hill TB15 transformer expected to reach 92% of Eversource TFRAT
- Garvins TB39 transformer expected to reach 78% of Eversource TFRAT
- Garvins TB51 transformer expected to reach 77% of Eversource TFRAT

... install Mobile S/S at Oak Hill S/S...

1. Oak Hill S/S – install Eversource 35 MVA Mobile S/S and close in to 34.5 kV bus (Eversource)
2. Oak Hill S/S – close 317 Tap reclsoer (Eversource)
   - Load restored:
     Eversource 317 Line distribution
     loads
   - All load restored:

System Concerns:
- None

10) Loss of Broken Ground Transformer T1 (2017-2025)

Initial Event:
- Broken Ground – T1 115kV breaker 28T1 opens and locks out
- Broken Ground – T1 35kV breaker 28XT1 opens and locks out
- Load out of service:
  Broken Ground 28X5
  Hazen Drive 24H1, 24H2, 24H3
  38 Line distribution loads

Switching Procedures:
1. Broken Ground – Close 35kV bus tie BT28

   All Load Restored

System Concerns:
At a system load level of 147.0MW (2025):
- None

11) Loss of Broken Ground Transformer T2 (2017-2025)

Initial Event:
- Broken Ground – T2 115kV breaker 28T2 opens and locks out
- Broken Ground – T2 35kV breaker 28XT2 opens and locks out
- Load out of service:
  Broken Ground 28X5
  Hollis 8H1, 8H2

Switching Procedures:
2. Broken Ground – Close 35kV bus tie BT28

All Load Restored

System Concerns:
At a system load level of 147.0MW (2025):
- None

12) Loss of 374 Line at Garvins
(fault between 374 breaker at Garvins and 374J3 switch at Bow Junction)

Initial Event:
- 374 trips at Garvins
- Load out of service:
  Bow Junction 7X1, 7W3, 7W4 Iron Works Road 22W1, 22W2, 22W3
  33X2 (NH State Tap)

Switching Procedures:
1. Bow Junction S/S – open 374J3 switch
2. Bow Junction S/S – close the 374J4
   - Load restored:
     Bow Junction 7X1, 7W3, 7W4 Iron Works Road 22W1, 22W2, 22W3
     33X2 (NH State Tap)

   - All load restored

System Concerns:
At a system load level of 147.0MW (2025):
- None

13) Loss of 375 Line at Garvins
(fault between 375 breaker at Garvins and 375J3 switch at Terrill Park)

Initial Event:
- 375 trips to lockout at Garvins
- 0375 trips to lockout at Bridge Street
- Load out of service:
  Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
  375X1(Flanders Tap)

System Concerns:
At a system load level of 139.0MW (2016):
- 374 Line Bow Jct to Langdon Street at 99% Normal Rating

At a system load level of 147.0MW (2025):

- 374 Line Bow Jct to Langdon Street at 102% Normal Rating

Switching Procedures:
1. Terrill Park S/S – open 375J3 switch
2. Bridge Street S/S – close 0375 breaker
   - Load restored:
     Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
     375X1(Flanders Tap)
   - All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- 396 Line at 95% of Normal rating
- 374 Line Bow Jct to Langdon Street at 111% Normal Rating

At a system load level of 147.0MW (2025):
- 396 Line at 97% of Normal rating
- 374 Line Bow Jct to Langdon Street at 114% Normal Rating

… Additional Switching Procedures to Relieve Loading on 396/374 Lines …

1. Pleasant Street – Close 33J1
2. Pleasant Street – Open 033J2

System Concerns:
At a system load level of 139.0MW (2016):
- None

At a system load level of 147.0MW (2025):
- 374 Line Bow Jct to Langdon Street at 96% Normal Rating

14) Loss of 374 Line at Bridge Street
(fault between 0374 breaker at Bridge Street and 374J8 switch at Gulf Street)

Initial Event:
- 0374 trips to lockout at Bridge Street
- 396 trips to lockout at Garvins
- Load out of service:
  Langdon Street 14H1, 14H2, 14X3
  374A Industrial Park Drive Tap
  Bow Bog 18W2
  17X1 (Z-Tech Corporation)
  Gulf Street 3H1, 3H2, 3H3

Switching Procedures:
1. Gulf Street S/S – open 374J8 switch
2. Garvins S/S – close 396 breaker
   - Load restored:

Langdon Street 14H1, 14H2, 14X3
374A Industrial Park Drive Tap
Bow Bog 18W2
17X1 (Z-Tech Corporation)
Gulf Street 3H1, 3H2, 3H3
- All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- None

At a system load level of 147.0MW (2025):
- None

15) Loss of 375 Line at Bridge Street
(fault between 0375 breaker at Bridge Street and 375X1(Flanders Tap))

Initial Event:
- 0375 trips to lockout at Bridge Street
- 375 trips to lockout at Garvins
- Load out of service:
Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
375X1(Flanders Tap)

Switching Procedures:
1. Terrill Park S/S – open 375J6 in-line disconnects
2. Garvins S/S – close 375 breaker
- Load restored:
Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
375X1(Flanders Tap)

- All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- 374 Line Bow Jct to Langdon Street at 96% Normal Rating

At a system load level of 147.0MW (2025):
- 374 Line Bow Jct to Langdon Street at 98% Normal Rating

16) Loss of 396 Line at Garvins
(fault between 396 breaker and 96DX1 at Garvins)

Initial Event:
- 396 trips to lockout out at Garvins
- 0374 trips to lockout at Bridge St
- Load out of service:
Bow Bog 18W2

Langdon Street 14H1, 14H2, 14X3 — 17X1 (Z-Tech Corporation)
Gulf Street 3H1, 3H2, 3H3 — 374X1 (Industrial Park Tap)

Switching Procedures:
1. Open 96DX1 at Garvins
2. Bow Jct – close 374J4 switch

NOTE: Do Not Restore line from Bridge Street. Closing the 0374 at Bridge Street creates unacceptable loading on the 375 Line.

- Load restored:
  Bow Bog 18W2 — 17X1 (Z-Tech Corporation)
  Langdon Street 14H1, 14H2, 14X3 — 374X1 (Industrial Park Tap)
  Gulf Street 3H1, 3H2, 3H3
- All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- None

At a system load level of 147.0MW (2025):
- None

17) Loss of 33 Line at Bow Junction
(fault between 33 recloser at Bow Junction and 33J4)

Switching Procedures:
1. Iron Works Road S/S – open 33J6 switch
2. Pleasant Street S/S – close 33J1 switch
   - Load restored:
     Iron Works Road 22W1, 22W2, 22W3
3. NH State Tap 33X2 – open 33J4 switch
4. Iron Works Road S/S – close 33J6 switch
   - Load restored:
     33X2 (NH State Tap)

System Concerns:
At a system load level of 139.0MW (2016):
-Marginal low voltage on 33 Line

At a system load level of 147.0MW (2025):
- Marginal low voltage on 33 Line

18) Loss of 318 Line at Garvins
(fault between 318 breaker at Garvins and 318DX6 switches)

Initial Event:
- 318 trips to lockout at Garvins
- Load out of service:
  Hollis 8H1, 8H2, 8X3, 8X5 318X2, 318X4 (Eversource)
  38 Line distribution loads (038 to 38J3)

Switching Procedures:
1. Hollis S/S – open 038 recloser
2. Hazen Dr. – close 38R1 recloser
   - Load restored:
     38 Line distribution loads (038 to 38J2)

3. Hollis S/S – open 8BT1 bus tie switch
4. 318 Line – open 318J3 switch (Eversource)
5. 318 Line – close J2518 switch (Eversource)
   - Load restored:
     Hollis 8H1, 8H2, 8X3

6. Hollis S/S – close 038 recloser
   - Load restored:
     Hollis 8X5

7. 318 Line – open 318DX6 switch (Eversource)
8. 318 Line – close 318J3 switch (Eversource)
   - Load restored:
     318X2, 318X4 (Eversource)
   - All load restored

Additional switching to relieve loading on Horseshoe Pond 38 Recloser:
9. Confirm Hollis and Hazen Drive 3.6MVAr capacitor banks in service

At a system load level of 139.0MW (2016):
- 38 recloser at Horseshoe Pond Tap expected to exceed 81% of the equivalent 480A phase overcurrent trip setting (440A pickup with load encroachment)
- 35 Line Bridge Street to Horse Shoe Pond Tap at 93% of Normal Rating
- 3025 Line (Eversource) between Oak Hill and Hollis Tap at 103% of Normal Rating

NOTE: Broken Ground eliminates this contingency.

19) Loss of 318 Hollis Tap (or Loss of Hollis Regulators)
(fault between 318J3 switch and DS318 disconnects OR Hollis regulator failure)

Initial Event:
- 318 trips to lockout at Garvins
- Load out of service:
  Hollis 8H1, 8H2, 8X3, 8X5 318X2, 318X4 (Eversource)
  38 Line distribution loads (038 to 38J3)

Switching Procedures:
1. Hollis S/S – open 038 recloser
2. Hazen Dr. – close 38R1 recloser
   - Load restored:
     38 Line distribution loads (038 to 38J3)

5. Hollis Tap – open 318J3 switch (Eversource)
6. Garvins S/S – close 318 breaker
   - Load restored:
     318X2, 318X4 (Eversource)

7. Hollis S/S – open 803 bus-side regulator disconnect switches
8. Hollis S/S – open 8XBT1 bus tie
9. Hollis S/S – close 038 recloser
   - Load restored:
     Hollis 8X5

Additional switching to relieve loading on Horseshoe Pond 38 Recloser:
10. Confirm Hollis and Hazen Drive 3.6MVAr capacitor banks in service

System Concerns:
At a system load level of 139.0MW (2016):
- 38 recloser at Horseshoe Pond Tap expected to exceed 81% of the equivalent 480A phase overcurrent trip setting (440A pickup with load encroachment)
  - Up to 15MW of load will remain out of service until repairs are made (8X3, 8H1, 8H2).

  NOTE: This contingency details a fault on a tap consisting of 3 sections of overhead line or a regulator failure. Therefore, it is anticipated that restoration will occur in less than 12 hours of this event.

  - Consult Engineering in order to identify any distribution switching and/or sectionalizing on 8X3, 8H1, or 8H2 that may facilitate additional load restoration.

Additional switching following repairs:
11. Hollis S/S – close 803 bus-side regulator disconnect switches

12. Hollis Tap – close 318J3 switch (Eversource)
13. Hollis – close 8XBT1 bus tie
14. Hazen Dr. – open 38R1 recloser

- Load restored:
  8X3, 8H1, 8H2

  All load restored

NOTE: Broken Ground eliminates this contingency.

20) Loss of 317 Line, Oak Hill to Penacook (fault on the 317 Line)

Initial Event**:**
- 317 trips to lockout at Oak Hill
- 3170 trips to lockout at Penacook

Load out of service:
Eversource 317 Line to Davisville

System Concerns:
At a system load level of 139.0MW (2016):
- 3122 Line at 96% of Normal Rating
- Up to 13MW of load (317 Line) will remain out of service until repairs are made

At a system load level of 147.0MW (2025):
- Up to 16MW of load (317 Line) will remain out of service until repairs are made

NOTE: Broken Ground reduces 3122 loading constraint.

Switching Procedures:
1. Eversource to restore 317 Line load from Davisville (to the extent as possible)

21) Loss of 3122, Oak Hill to Penacook (fault on the 3122 Line)

Initial Event**:**
- 3122 trips to lockout at Oak Hill
- 31220 trips to lockout at Penacook

Load out of service:
None

System Concerns:
At a system load level of 139.0MW (2016):
- 317 Line @115% of its Normal Rating (92% of LTE)
- Garvins TB39 transformer expected to reach 92% of Eversource TFRAT

- Garvins TB51 transformer expected to reach 91% of Eversource TFRAT

NOTE: Broken Ground reduces 3122 loading and eliminates Garvins transformer loading constraint.

At a system load level of 147.0MW (2025):
- 3122 Line at 101% of Normal Rating

22) Loss of 34 Line at Penacook
(fault between 034 breaker at Penacook and 34J6 switch)

Initial Event:
- 034 trips to lockout at Penacook
- 34 trips to lockout at Bridge Street

- Load out of service:

34X2 (Concord Center	33X5 (Jefferson Pilot)
West Concord 2H1, 2H2, 2H3, 2H4	33X4 (Little Pond Road Tap)
34X4 (Crowley Foods)	33X3 (St Pauls)
33X6 (NH State Prison)	Pleasant Street 6X3

Switching Procedures:
1. West Concord S/S – open 033 recloser
2. Pleasant Street S/S – close 33J1 switch

- Load restored:

Pleasant Street 6X3	33X5 (Jefferson Pilot)
33X3 (St Pauls)	33X6 (NH State Prison)
33X4 (Little Pond Tap)	

3. West Concord S/S – open 34J6 switch
4. Bridge Street S/S – close 34 breaker
   - Load restored:
     34X2 (Concord Center)
     West Concord 2H1, 2H2, 2H3, 2H4
     34X4 (Crowley Foods)

- All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- 33 Line @96% of its Normal Rating
- Garvins TB39 transformer expected to reach 92% of Eversource TFRAT
- Garvins TB51 transformer expected to reach 91% of Eversource TFRAT

At a system load level of 147.0MW (2025):

- 33 Line @103% of its Normal Rating

23) Loss of 34 Line at Bridge Street
(fault between 34 breaker at Bridge Street and 34J1 switch at the 34X2 (Concord Center) Tap)

Initial Event:
- 34 trips to lockout at Bridge Street
- 034 trips to lockout at Penacook
- Load out of service:

34X2 (Concord Center)	33X5 (Jefferson Pilot)
West Concord 2H1, 2H2, 2H3, 2H4	33X4 (Little Pond Road Tap)
34X4 (Crowley Foods)	33X3 (St Pauls)
33X6 (NH State Prison)	Pleasant Street 6X3

Switching Procedures:
1. West Concord S/S – open 033 recloser
2. Pleasant Street S/S – close 33J1 switch
   - Load restored:

Pleasant Street 6X3	33X5 (Jefferson Pilot)
33X3 (St Pauls)	33X6 (NH State Prison)
33X4 (Little Pond Road Tap)	

3. West Concord S/S – open 34J3 switch
4. Penacook S/S – close 034 breaker
   - Load restored:
     West Concord 2H1, 2H2, 2H3, 2H4

5. 34X2 (Concord Center) – open 34J1 switch
6. West Concord S/S – close 34J3 switch
   - Load restored:
     34X2 (Concord Center)

   - All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- 33 Line @96% of its Normal Rating
- Garvins TB39 transformer expected to reach 90% of Eversource TFRAT
- Garvins TB51 transformer expected to reach 89% of Eversource TFRAT

At a system load level of 147.0MW (2025):
- 33 Line @103% of its Normal Rating

24) Loss of 36 Line at Penacook
(fault between 036 breaker at Penacook and 35J6A switches)

Initial Conditions and Switching Procedures in 2016 with the 2nd Transformer at Rimmon in-service:

Initial Event:
- 036 trips to lockout at Penacook
- 35 trips to lockout at Bridge Street

- Load out of service:
  West Portsmouth 15W1, 15W2, 15H3
  35X1, 35X2, 35X3, 35X4(Locke Rd)
  38 Line distribution loads (38 to 38J3)
  Hazen Drive 24H1, 24H2

Switching Procedures:
1. West Portsmouth Street S/S – open 35J4 switch
2. Bridge Street S/S – close 35 breaker

   - Load restored:
     West Portsmouth 15W1, 15W2, 15H3
     38 Line distribution loads (38 to 38J3)
     Hazen Drive 24H1, 24H2

3. 35 Line – open 35J6A switches
4. West Portsmouth Street S/S – close 35J4 switch
   - Load restored:
     35X1, 35X2, 35X3, 35X4(Locke Rd)
   - All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- Garvins TB39 transformer expected to reach 90% of Eversource TFRAT
- Garvins TB51 transformer expected to reach 89% of Eversource TFRAT

Initial Conditions and Switching Procedures in 2016 with the 2nd Transformer at Rimmon in-service:

Initial Event:
- 036 trips to lockout at Penacook
- 35 trips to lockout at Bridge Street

- Load out of service:
  West Portsmouth 15W1, 15W2, 15H3
  35X1, 35X2, 35X3, 35X4(Locke Rd)

Switching Procedures:
1. West Portsmouth Street S/S – open 35J4 switch
2. Bridge Street S/S – close 35 breaker

   - Load restored:
     West Portsmouth 15W1, 15W2, 15H3

3. 35 Line – open 35J6A switches
4. West Portsmouth Street S/S – close 35J4 switch
   - Load restored:
     35X1, 35X2, 35X3, 35X4(Locke Rd)
   - All load restored

At a system load level of 147.0MW (2025):
- None

25) Loss of 35 Line at Bridge Street
(fault between 35 breaker at Bridge Street and 35J1 switch at Horseshoe Pond)

Initial Conditions and Switching Procedures in 2016 with the 2nd Transformer at Rimmon in-service:

Initial Event:
- 35 trips to lockout at Bridge Street
- 036 trips to lockout at Penacook
- Load out of service:
  West Portsmouth 15W1, 15W2, 15H3
  Locke Rd. taps
  38 Line distribution loads (38 to 38J3)
  Hazen Drive 24H1, 24H2

Switching Procedures:
1. State Tap – open 38J2 switch
2. Hazen Dr. – close 38R1 recloser
   - Load restored:
     - Hazen Drive 24H1, 24H2
     - 38 Line distribution loads (38J3 to 38J2)

3. Horse Shoe Pond Tap – open 35J1 switch
4. Penacook S/S – close 036 breaker
   - Load restored:
     West Portsmouth 15W1, 15W2, 15H3
     Locke Rd. taps
     38 Line distribution loads (38 to 38J2)

- All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- Hollis Tap (318 Line to Hollis DS318), 336 AA conductor at 102% of Normal
- 318 Line Garvins to Hollis Tap 93% Normal

Initial Conditions and Switching Procedures 2017-2025 with Broken Ground in-service:

Initial Event:
- 35 trips to lockout at Bridge Street
- 036 trips to lockout at Penacook
- Load out of service:
  West Portsmouth 15W1, 15W2, 15H3
  Locke Rd. taps

Switching Procedures:
1. Horse Shoe Pond Tap – open 35J1 switch
2. Penacook S/S – close 036 breaker
   - Load restored:
     West Portsmouth 15W1, 15W2, 15H3
     Locke Rd. taps

   - All load restored

System Concerns:
At a system load level of 147.0MW (2025):
- None

26) Loss of 33 Line at West Concord
(fault between 033 recloser at West Concord and 33X6 (NH State Prison))

Initial Event:
- 033 trips to lockout at West Concord
- Load out of service:
  33X6 (NH State Prison)
  J33X5 (Jefferson Pilot)
  33X4 (Little Pond Road Tap)
  33X3 (St Pauls)
  Pleasant Street 6X3

1. 33X6 (NH State Prison) – open 33J12 Line GOAB
2. Pleasant Street S/S – close 33J1 switch
   - Load restored:

Pleasant Street 6X3
33X3 (St Pauls)
33X4 (Little Pond Road Tap)
33X5 (Jefferson Pilot)
33X6 (NH State Prison)

- All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- 33 Line @96% of its Normal Rating
- Garvins TB39 transformer expected to reach 91% of Eversource TFRAT
- Garvins TB51 transformer expected to reach 90% of Eversource TFRAT

System Concerns:
At a system load level of 147.0MW (2025):
- 33 Line @103% of its Normal Rating

27) Loss of 1X7P Circuit at Bridge Street
(fault between 1X7P recloser at Bridge Street and DS-17P switch at Montgomery Street)

Initial Event:
- 1X7P trips to lockout at Bridge Street
- Load out of service:
  Montgomery Street 21W1(P)
  Nelson Plaza
  Eelderly Housing
  Concord Steam

Switching Procedures:
1. Montgomery Street S/S – open DS-17P switch
2. Montgomery Street S/S – close DS-17A switch
   - Load restored:
     Montgomery Street 21W1(P)
     Nelson Plaza
     Elderly Housing
     Concord Steam
   - All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- None

At a system load level of 147.0MW (2025):
- None

28) Loss of 1X7A Circuit at Bridge Street
(fault between FA1X7 fusing at Bridge Street and incoming 1X7A switch at Storrs Street)

Initial Event:
- FA1X7 fuses operate at Bridge Street
- Load out of service:
  1X7A (Holiday Inn)
  Storrs Street 21W1A

Switching Procedures:
1. Storrs Street S/S – open switch on incoming 1X7A
2. 34 Line (p.142) – close 34X3 fused cutouts
   - Load restored:
     1X7A (Holiday Inn)
     Storrs Street 21W1A
   - All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- None

At a system load level of 147.0MW (2025):
- None

29) Loss of 37 Line at Penacook
(fault between 37 breaker at Penacook and 37J1 switch)

Initial Event:
- 37 trips to lockout at Penacook
- Penacook Lower Falls Hydro generation trips off line
- SES Concord generation trips off line

- Load out of service:
  37X1 Tap
  Boscawen 13W1, 13W2, 13W3, 13X4
  Penacook Lower Falls Hydro
  SES Concord

Maccoy Street Tap Automatic Restoration Scheme:

NOTE: ***The switching below assumes the distribution automation scheme is enabled at the Maccoy Street Tap. This switching can be performed manually if the automation scheme is disabled.***

1. Maccoy Tap –37R1 recloser opens
2. Maccoy Tap – 37R4X1 closes

- Load restored:
  - 37X1 Tap
  - Boscawen 13W1, 13W2, 13W3, 13X4
  - Penacook Lower Falls Hydro
  - SES Concord

- All load restored

At a system load level of 139.0MW (2016):
- None

At a system load level of 147.0MW (2025):
- None

30) Loss of 37 Line beyond Maccoy Tap
(fault between p.33 on 37 Line and the Penacook Lower Falls Hydro tap)

Initial Event:
- 37 trips to lockout out at Penacook
- Penacook Lower Falls Hydro generation trips off line
- SES Concord generation trips off line
- Load out of service in Summer 2013:
  - 37X1 Tap
  - Boscawen 13W1, 13W2, 13W3, 13X4
  - Penacook Lower Falls Hydro
  - SES Concord

- No switching available

System Concerns:
- Up to 11MW (2025) of load remains out of service

31) Loss of Circuit 4X1 at Penacook
(fault at 4X1 recloser)

Initial Event:
- 4X1 trips to lockout at Penacook
- Penacook Upper Falls Hydro generation trips off line
- Briar Hydro generation trips off line
- Load out of service:
  - Penacook 4X1
  - Penacook Upper Falls Hydro
  - Briar Hydro

Switching Procedures:

1. Sectionalize Circuit 4X1
2. Close the 37R4X1 at Maccoy Tap
   - Load restored:
     Penacook 4X1
     Penacook Upper Falls Hydro
     Briar Hydro
   - All load restored

System Concerns:
At a system load level of 139.0MW (2016):
- 37 Line - Penacook to Maccoy St Tap, 1/0 AA expected to reach 109% of its Normal rating

At a system load level of 142.3MW (2020):
- 37 Line - Penacook to Maccoy St Tap, 1/0 AA expected to reach 113% of its Normal Rating* (94% LTE)

* Exposure to loading above Normal exceeds 12 consecutive hours. Does not meet design guidelines.

32) Loss of 288 Line at Broken Ground

Initial Conditions and Switching Procedures 2017-2025 with Broken Ground in-service:

Initial Event**:**
- 288 trips to lockout at Broken Ground

Load out of service:
Hollis 8H1, 8H2, 8X3

Switching Procedures:
1. Broken Ground - Open 288101 DXs
2. Hollis - Close the 038 Recloser at Hollis
   - Load restored:
     Hollis 8H1, 8H2, 8X3

   - All load restored

System Concerns:
At a system load level of 147.0MW (2025):
- None

33) Loss of 38 Line at Hollis
(fault at 038 recloser)

Initial Event:

- 38 trips to lockout at Hollis
- Load out of service:
  38 Line distribution loads (038 to 38J3)

Switching Procedures:

1. Hollis S/S – open 03801 recloser line-side disconnects
2. Hazen Dr. – close 38R1 recloser
   - Load restored:
     38 Line distribution loads (038 to 38J3)
   - All load restored

At a system load level of 139.0MW (2016):

- None

NOTE: Broken Ground eliminates this contingency.

34) Loss of 38 Line at Horseshoe Pond Tap
(fault at 38 recloser)

Initial Event:

- 38 trips to lockout at Horseshoe Pond Tap
- Load out of service:
  38 Line distribution loads (38 to 38J3)
  Hazen Drive 24H1, 24H2

Switching Procedures:

1. Horseshoe Pond Tap – open 38J2 switch
2. Hazen Dr. – close 38J3 recloser
   - Load restored:
     - Hazen Drive 24H1, 24H2
     - 38 Line distribution loads (38J3 to 38J2)

3. Fort Eddy Tap – open 38J0 recloser disconnects
4. Horseshoe Pond Tap – close 38J2 switch
   - Load restored:
     - 38 Line distribution loads (38J0 to 38J2)

NOTE: ***Up to 2.2MW of load remains out of service until repairs are made if the fault is on the 38 Line.***

At a system load level of 139.0MW (2016):

- Hollis Tap (318 Line to Hollis DS318), 336 AA conductor at 114% of Normal / 94% LTE rating

- 318 Line (Garvins to Hollis tap), 477 ACSR conductor at 104% of Normal / 83% LTE rating.

NOTE: Broken Ground eliminates this contingency.

35) Loss of 38 Line at Broken Ground

Initial Conditions and Switching Procedures 2017-2025 with Broken Ground in-service:

Initial Event:
- 038 trips to lockout at Broken Ground

Load out of service:
Hazen Drive 24H1, 24H2
38 Line distribution loads

Switching Procedures:
1. Broken Ground – open 03801 DXs
2. Hollis – close 038 recloser
   - Load restored:
     Hazen Drive 24H1, 24H2
     38 Line distribution loads

   - All load restored

System Concerns:
At a system load level of 147.0MW (2025):
- None

APPENDIX H

REFERENCES

1. Electric System Planning Guide. Unitil Service Corp. Rev 3 March 13, 2014
2. Electrical Equipment Rating Procedures. Unitil Service Corp. Rev. 3 November 6, 2012

APPENDIX I
Diagrams

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

Load Flow Diagram

Redacted

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

APPENDIX D

UES-SEACOAST 2016-2025 ELECTRIC SYSTEM PLANNING STUDY

REDACTED

Unitil Energy Systems – Seacoast

Electric System Planning Study 2016-2025

Prepared By:

J. Dusling
Unitil Service Corp.
August 21, 2015

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 2016 through 2025.

The new Kingston system supply is assumed to be in service prior to the summer peak load season in 2016.

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

Year	Project Description	Justification	Cost[1]
2016	Implement Additional Switching Steps	Loading for Loss of the 3342 Line, Loss of the 3353 Line, Loss of the 3359 Line	n/a
2019	Modify 3810X and 3260X Protection Setting	Loading for Loss of the 3351 Line, Loss of 3362 Line[2]	n/a
2020	Construct a new 34.5 kV line from Guinea Switching to Hampton	Loading for Loss of the 3342 Line, Loss of the 3353 Line, Loss of the 3359 Line	$1,600,000
2022	Implement Alternate System Configuration	Loading TB141	n/a

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 subtransmission 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 single 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

[1] Cost estimates do not include general construction overheads.
[2] In 2022 after implementation of alternate configuration to address Great Bay loading.

comparison was made for the improvement plan options. Final recommendations represent the proposed system improvement plan.

3 SYSTEM DESCRIPTION AS STUDIED

The UES–Seacoast electric power system is supplied from Northeast Utilities' (NU) 345 kV and 115 kV transmission systems via three two Eversource substations, Timber Swamp, Peaslee, 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 Eversource 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.

Peeslee substation, located in central Kingston, consists of a 115 kV ring bus and supplies Unitil's Kingston substation. Kingston substation is supplied via two 115 kV lines originating at Peaslee substation and consists of two 115 – 34.5 kV, 60 MVA transformers. Four 34.5 kV subtransmission lines and two 34.5 kV distribution circuits emanate from Kingston substation.

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 transfer power to eight distribution substations and taps which serve loads in the Stratham and Exeter areas.

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)
2016	182.5	187.3
2017	185.7	191.5
2018	188.6	195.3
2019	190.6	197.9
2020	192.7	200.3
2021	195.1	204.0
2022	197.6	206.9
2023	199.3	209.5
2024	202.1	211.3
2025	203.7	214.0

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 33.3.0) 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 2014 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 and Eversource. Bus loads were compiled for the model by aggregating substation, circuit, and large customer load information for the July 23, 2014 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 2014 summer peak.

Basecase models for study of future years were developed from this 2014 peak day 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 basecase models 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 system (Seacoast and Capital) 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	0.9850, leading
66%	0.9550, lagging	0.9725, leading
100%	0.9758, lagging	n/a

On July 23, 2014 at 18:00, the UES–Seacoast system reached a peak demand of 151.382 MW. The system was lagging by 13.838 MVAr during that peak hour, with a corresponding 0.9735 (lagging)[1] power factor. This met the minimum LPF requirement of 0.9642 in effect during 2014.

In 2016 at a system peak design load of 182.5 MW, the estimated net power factor is expected to be approximately 0.9988 (lagging) as seen at the 115 kV system supply delivery points. By 2025 at a system peak design load of 203.7 MW the estimated net power factor is expected to be approximately 0.9918 (lagging).

At these loads levels, no additional capacitor installations are needed to achieve a minimum 0.9758 (lagging) UES-Seacoast system net power factor over the next ten years.

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. More details on exposure, voltage and loading values can be referenced in the contingency table in Appendix F.

[1] Estimated LPF at the transmission system after allocating losses and reactive compensation based on UES-Seacoast's load share ratio at Timber Swamp.

<table>
<tr><th>Year</th><th>Approx. Load Level (MW)</th><th>System Constraint</th><th>Circumstances</th></tr>
<tr><td rowspan="5">Prior to 2016</td><td rowspan="5">Less than 182.5</td><td>Equipment Overload – 3342 Breaker at Hampton</td><td rowspan="3">Loss of 3353 Line, Guinea to Hampton</td></tr>
<tr><td>Equipment Overload – 3342J1 Switch at Hampton</td></tr>
<tr><td>Conductor Overload – 3342 Line, Guinea to Hampton</td></tr>
<tr><td rowspan="2">Conductor Overload – 3353 Line, Guinea to Hampton</td><td>Loss of 3359 Line, Guinea to Mill Lane</td></tr>
<tr><td>Loss of 3342 Line, Guinea to Hampton</td></tr>
<tr><td>2019</td><td>190.6</td><td>Protection Setting Overload – 3810X Minimum Pick-Up Setting</td><td>Loss of 3351 Line, Great Bay to Merrill’s Pit</td></tr>
<tr><td>2022</td><td>197.6</td><td>Equipment Overload – Great Bay TB141</td><td>Basecase</td></tr>
</table>

8 SYSTEM IMPROVEMENT OPTIONS

The following sections describe details of system improvement alternatives examined to address the deficiencies identified earlier in this report. All cost estimates provided in this report are without general construction overheads and are in present year dollars.

8.1 3342 Line and 3353 Line Overload Options

The 3342 and 3353 lines are non-radial lines that are used to restore load for the loss of the 3342, 3353 or 3359 lines. The existing conductor and other associated equipment on the 3342 and 3353 lines are expected to exceed their ratings during peak conditions prior to the summer of 2016.

The following options were considered to eliminate the overload conditions associated with the 3342 and 3353 lines and associated equipment (3342 Breaker and 3342J1 Switch).

8.1.1 Perform Additional Switching to Reduce 3353 and 3342 Line Loading

Summary:

The following additional switching steps were considered for various contingencies.

- For the Loss of the 3353 Line or 3342 Line from Guinea to Hampton:
  - Seabrook Station Marsh Tap – open 48J50 switch
  - Cemetery Lane S/S – close 3359J5 switch

- For Loss of the 3359 Line from Guinea to Mill Lane:

  - Lafayette Road – close 2X3J15X1 switch
  - Cemetery Lane S/S – open 15X1 recloser
  - Hampton Beach S/S – close J042 switch
  - Hampton Beach S/S – open J053 switch

Cost Estimate: negligible (no capital investment)

Results:

Loss of the 3342 Line, Guinea to Hampton

- All elements are within planning criteria throughout the study period.

Loss of the 3353 Line, Guinea to Hampton

- All elements are within planning criteria throughout the study period.

Loss of the 3359 Line, Guinea to Mill Lane

- All elements are within planning criteria through 2020[1].

8.1.2 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. The BT-2 bus tie switch at Hampton will be upgraded to provide a rating of at least 900 amps.

Cost Estimate:

Reconductor 3342 and 3353 Lines – Guinea to Hampton	$1,850,000
Replace 3342 Breaker at Guinea	$100,000
Upgrade 3342J1 Switch at Hampton	$25,000
Upgrade BT-2 Switch at Hampton	$35,000
Total (w/o General Construction OHs)	$2,010,000

Results:

Loss of the 3342 Line, Guinea to Hampton

- From 2016 through 2025 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.

[1] Last year of the Distribution System analysis.

Loss of the 3353 Line, Guinea to Hampton

- After switching to restore all load, loading on the 3342 breaker at Guinea is expected to remain below planning guidelines.
- After switching to restore all load, loading on the 3342J1 switch at Hampton is expected to remain below planning guidelines.
- 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.

Loss of the 3359 Line, Guinea to Mill Lane

- 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.

8.1.3 Construct New 34.5 kV Line – Guinea to Hampton

Summary:

Construct a new 34.5 kV line from Guinea Switching to Hampton. Construction to include 795 AA phase conductors on separate structures from the 3342 or 3353 lines and the addition of new 34.5 kV line terminals at Guinea Switching Station and Hampton Substation. The new line will supply the bus half at Hampton that is presently supplied by the 3353 line and the 3353 line will supply the 3348 line.

Cost Estimate:

Construct new 3rd Line – Guinea to Hampton	$925,000
Construct New Line Terminal at Guinea	$300,000
Construct New Line Terminal at Hampton	$375,000
Total (w/o General Construction OHs)	$1,600,000

Results:

Loss of the 3342 Line, Guinea to Hampton (3342J1 Bus Half)

- After switching to restore all load, loading on the new line between Guinea and Hampton with the 795 AA conductor is expected to remain below planning guidelines.

Loss of the New Line, Guinea to Hampton (3353J1 Bus Half)

- 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.

Loss of the 3359 Line, Guinea to Mill Lane

- After switching to restore all load, loading on the 3353 line between Guinea and Hampton with 477 AA conductor is expected to exceed its normal limit.

Loss of the 3353 Line, Guinea to Hampton (New Bus Section)

- After switching to restore all load, loading on the new line between Guinea and Hampton with the existing 795 AA conductor is expected to remain below its normal limit.

8.1.4 Recommendation

The following system upgrades are the recommended solutions to the identified constraints associated with the 3342 and 3353 lines:

- In 2016, perform alternate switching for the loss of the 3342, 3353 and 3359 Lines.
- In 2020, construct a new 34.5 kV line from Guinea Switching to Hampton. Construction to include 795 AA phase conductors on separate structures from the 3342 or 3353 lines and the addition of new 34.5 kV line terminals at Guinea Switching Station and Hampton Substation.

8.2 3810X Protection Setting Overload Options

After switching to restore all load for loss of the 3351 line from Great Bay to Merrill's Pit the minimum pick-up settings of the 3810X circuit position are expected to exceed their LTE limit during peak conditions in 2019.

The following options were considered to eliminate the overload conditions associated with 3810X protection settings.

8.2.1 Implement New Settings

Summary:

Modify protection settings to achieve a minimum 1200 amps.

Cost Estimate: negligible (no capital investment)

Results:

Loss of the 3351 Line, Great Bay to Merrill's Pit

- All elements are within planning criteria throughout the study period.

8.2.2 Perform Alternate Switching

Summary:

Prior to restoring Dow's Hill substation and Winnicutt Road tap perform the following switching steps for the loss of the 3351line from Great Bay to Merrill's Pit:

- Exeter Switching – close BT-1A switch
- Exeter Switching – open J052 switch

Cost Estimate: negligible (no capital investment)

Results:

Loss of the 3351 Line, Great Bay to Merrill's Pit

- All elements are within planning criteria throughout the study period.

8.2.3 Recommendation

Modifying the protection settings at Great Bay is the recommended solution to address the loading concerns associated with the 3810X breaker. In the event the necessary settings cannot be achieved then alternate switching steps shall be implemented.

It is also recommended that the 3260X settings be modified at the same time as the 3810X settings. This change will be required in 2022 (See section 8.3).

8.3 Great Bay Overload Options

During summer conditions the following switching is currently performed to reduce the loading of the Great Bay transformer.

- Close J041 Switch at Exeter Switching
- Open BT-1A Switch at Exeter Switching
- Close 03341 Recloser at Wolf Hill
- Open 41J51 Switch at Merrill's Pit

In this configuration the Great Bay TB141 is expected to exceed 100% of the Eversource normal operational limit during basecase conditions in 2022. TB141 is also projected to exceed its TFRAT rating at during extreme peak conditions in 2025.

The following alternatives were considered to eliminate the overload conditions on the Great Bay TB141 transformer.

8.3.1 Alternate System Configuration A

The following alternate system configuration was considered to reduce loading of the Great Bay TB141 transformer.

Summary:

For load levels greater than 192 MW the following switching is proposed instead of the switching that is currently being performed each summer to reduce Great Bay loading:

- Close J041 Switch at Exeter Switching
- Open BT-1A Switch at Exeter Switching
- Close 3352 Recloser at Wolf Hill
- Open 52J62 Switch at Merrill's Pit

Cost Estimate: negligible (no capital investment)

Results:

Normal System Configuration and Extreme Peak

- From 2022 through 2025 and beyond after basecase and extreme peak loading on TB141 is expected to be within planning guidelines.

Loss of 3362/3352 Line

- From 2019 and beyond after switching to restore all load, loading of the 3260X protection settings are expected to exceed its normal rating without shifting load to Wolf Hill.

8.3.2 Install a 2nd Transformer at Great Bay S/S

Summary:

Purchase and install a second 115-34.5 kV, 24/32/40/44.8 MVA transformer at Great Bay. With the addition of a second transformer, Great Bay S/S will continue to normally supply the 3362 and 3351 lines, the Merrill's Pit 41J51 and 52J62 switches will be normally closed and the 03341 and 3352 breakers at Wolf Hill will be normally open.

Cost Estimate:

Purchase and install 115-34.5 kV, 24/32/40/44.8 MVA transformer	$2,500,000[1]
Total (w/o General Construction OHs)	$2,500,000

Results:

Normal System Configuration and Extreme Peak

- From the time of installation through 2025 and beyond loading each transformer at Great Bay is expected to remain below their thermal limits during peak design load and extreme peak load conditions.

Loss of Great Bay TB141 Transformer

- From time of installation through 2025 and beyond, loading on the new Great Bay transformer is expected to remain below its thermal limit without loss of load following contingency switching to shift Exeter load to Wolf Hill.

Loss of new Great Bay Transformer

- From time of installation through 2025 and beyond, loading on the new Great Bay transformer is expected to remain below its thermal limit without loss of load following contingency switching to shift Exeter load to Wolf Hill.

Loss of 3362/3352 Line

- From 2019 and beyond after switching to restore all load, loading of the 3260X protection settings are expected to exceed its normal rating without shifting load to Wolf Hill.

[1] Invest by Eversource

Loss of 3351/3341 Line

- From 2019 and beyond after switching to restore all load, loading of the 3810X protection settings are expected to exceed its normal rating without shifting load to Wolf Hill.

8.3.3 Recommendation

Switching the system into alternate system configuration A is the recommended solution to overcome loading concerns of the Great Bay TB141 transformer .

- In 2022, implement alternate system configuration A.

9 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 228 MW the following additional conditions have been identified for basecase conditions.

- Great Bay Transformer Loading
- 3358 Line Overload Plaistow to Westville Road Tap

Modeling Assumptions:

- All available capacitor banks switched in
- All 2016-2025 projects have been completed.

10 FINAL RECOMMENDATIONS

The following summarizes final recommendations given in this report.

Year	**Project Description**	**Justification**	**Cost**[1]
2016	Implement Additional Switching Steps	Loading for Loss of the 3342 Line, Loss of the 3353 Line, Loss of the 3359 Line	n/a
2019	Modify 3810X and 3260X Protection Setting	Loading for Loss of the 3351 Line, Loss of 3362 Line[2]	n/a
2020	Construct a new 34.5 kV line from Guinea Switching to Hampton	Loading for Loss of the 3342 Line, Loss of the 3353 Line, Loss of the 3359 Line	$1,600,000
2022	Implement Alternate System Configuration	Loading TB141	n/a

[1] Cost estimates do not include general construction overheads.
[2] In 2022 after implementation of alternate configuration to address Great Bay loading.

APPENDICES

A Evaluation Criteria

B UES-Seacoast Line Ratings

C UES-Seacoast Transformer Ratings

D System Load

E Base Case Studies

F Contingency Analysis

G Contingency Switching Procedures

H References

I Diagrams

APPENDIX A

EVALUATION CRITERIA

The following summarizes the application of electric system planning guidelines as used in this study. These criteria are based on Unitil's Electric System Planning Guide Rev 3 (March 13, 2014)

LOADING

Peak design conditions – all elements in service:

- All load in service
- All elements operating within Normal Limit ratings w/ half of internal, non-utility generating units out of service

Peak design conditions – loss of non-radial lines, or Unitil owned system supply transformers (after switching):

- All load restored to service
- All elements operating within LTE Limit ratings for up to 12 hours w/ half of internal, non-utility generating units out of service
- All elements operating within Normal Limit ratings after 12 hours of LTE loading w/ half of internal, non-utility generating units out of service

Peak design conditions – loss of radial lines, or external system supply transformers (after switching):

- Up to 30 MW of load left out of service for up to 24 hours
- All elements operating within LTE Limit ratings for up to 12 hours w/ half of internal, non-utility generating units out of service
- All elements operating within Normal Limit ratings after 12 hours of LTE loading w/ half of internal, non-utility generating units out of service

Extreme Peak conditions – all elements in service:

- All load in service
- All elements operating within LTE Limit ratings for up to 12 hours w/ half of internal, non-utility generating units out of service
- All elements operating within Normal Limit ratings after 12 hours of LTE loading w/ half of internal, non-utility generating units out of service

VOLTAGE

All conditions:

- For all 115, 69 and 13.8 kV non-distribution[1] points: 90% < V < 105%
- For all 13.8 and 4.16 kV distribution[2] points: 97.5% < V < 104.167%

1 "non-distribution" indicates only locations that are not direct supply outputs for distribution circuit loads
2 "distribution" indicates locations that are direct supply outputs for distribution circuit loads, after all transformation and/or voltage regulation

APPENDIX B

UES–SEACOAST LINE RATINGS

The following is a listing of the present summer and winter ratings for UES–Seacoast 34.5 kV Lines studied in this report.

			Summer Capacity				Winter Capacity			
Line Section	Limiting Factor	Nominal Voltage	Normal Limit (Amps)	LTE Limit (Amps)	Normal Limit (MVA)	LTE Limit (MVA)	Normal Limit (Amps)	LTE Limit (Amps)	Normal Limit (MVA)	LTE Limit (MVA)
3341 Wolf Hill – Merrill’s Pit	03341 CTs	34.5 kV	600		35.9		600		35.9	
3341 Merrill's Pit – Exeter Switching	795 AA 37 Arbutus	34.5 kV	915	1121	54.7	67.0	1201	1351	71.8	80.7
3341 Exeter Switching – Exeter	#1 Cu 7 str.	34.5 kV	278	335	16.6	20.0	362	403	21.6	24.1
3342 Guinea – Hampton	3342J1 switch	34.5 kV	600		35.9		600		35.9	
3342 Hampton – 3346 Line Tap	3342J2 switch	34.5 kV	400		23.9		400		23.9	
3342 3346 Line Tap – Hampton Beach	#1 Cu 7 str.	34.5 kV	278	335	16.6	20.0	362	403	21.6	24.1
3343 Guinea – Willow Road Tap	2/0 Cu str.	34.5 kV	373	451	22.3	26.9	486	543	29.0	32.4
3343 Kingston – Willow Road Tap	03343 CTs	34.5 kV	500		29.9		500		29.9	
3345 Kingston – Plaistow	477 AA 19 Cosmos	34.5 kV	663	808	39.6	48.3	868	974	51.9	58.2
3346 Line Tap – High Street	336 AA 19 Tulip	34.5 kV	531	645	31.7	38.5	694	777	41.5	46.4
3347 Line Tap – Portsmouth Avenue	336 AA 19 Tulip	34.5 kV	531	645	31.7	38.5	694	777	41.5	46.4
3348 Hampton–Seabrook Marsh Tap	336 AA 19 Tulip	34.5 kV	531	600	31.7	35.9	600		35.9	
3350 Seabrook Marsh Tap–Seabrook	#1 Cu 7 str.	34.5 kV	278	335	16.6	20.0	362	403	21.6	24.1
3351 Great Bay – Dow’s Hill	828 Amp Trip	34.5 kV	640	720	38.2	43.0	640	720	38.2	43.0

Line Section	Limiting Factor	Nominal Voltage	Summer Capacity Normal Limit (Amps)	Summer Capacity LTE Limit (Amps)	Summer Capacity Normal Limit (MVA)	Summer Capacity LTE Limit (MVA)	Winter Capacity Normal Limit (Amps)	Winter Capacity LTE Limit (Amps)	Winter Capacity Normal Limit (MVA)	Winter Capacity LTE Limit (MVA)
3352 Wolf Hill – Merrill's Pit	3352 CTs	34.5 kV	600		35.9		600		35.9	
3352 Merrill's Pit – Exeter Switching	795 AA 37 Arbutus	34.5 kV	915	1121	54.7	67.0	1201	1351	71.8	80.7
3352 Exeter Switching – Exeter	#1 Cu 7 str.	34.5 kV	278	335	16.6	20.0	362	403	21.6	24.1
3353 Guinea – Hampton	3353 CTs	34.5 kV	600		35.9		600		35.9	
3353 Hampton – 3346 Line Tap	3353J2 switch	34.5 kV	400		23.9		400		23.9	
3353 3346 Line Tap – Hampton Beach	#1 Cu 7 str.	34.5 kV	278	335	16.6	20.0	362	403	21.6	24.1
3354 Guinea – East Kingston	3354 CTs	34.5 kV	500		29.9		500		29.9	
3354 Kingston – East Kingston	03354 CTs	34.5 kV	500		29.9		500		29.9	
3356 Kingston – 3358 Line Tap	477 AA 19 Cosmos	34.5 kV	663	808	39.6	48.3	868	974	51.9	58.2
3356 3358 Line Tap – Plaistow	336 AA 19 Tulip	34.5 kV	531	645	31.7	38.5	694	777	41.5	46.4
3358 Line Tap – Westville	336 AA 19 Tulip	34.5 kV	531	645	31.7	38.5	694	777	41.5	46.4
3359 Hampton – Seabrook Marsh Tap	336 AA 19 Tulip	34.5 kV	531	645	31.7	38.5	694	777	41.5	46.4
3360 Timber Swamp – Guinea	03360 Breaker	34.5 kV	2000	2000	119.5	119.5	2000	2000	119.5	119.5
3362 Great Bay – Dow's Hill	828 Amp Trip	34.5 kV	640	720	38.2	43.0	640	720	38.2	43.0
3371 Timber Swamp – Guinea	03371 Breaker	34.5 kV	2000	2000	119.5	119.5	2000	2000	119.5	119.5
3112 Guinea – Ocean Road Tap	400 Amp Trip	34.5 kV	320	360	19.1	22.7	320	360	19.1	22.7
3165 Guinea – Ocean Road Tap	400 Amp Trip	34.5 kV	320	360	19.1	22.7	320	360	19.1	22.7
3172 Guinea – Ocean Road Tap	400 Amp Trip	34.5 kV	320	360	19.1	22.7	320	360	19.1	22.7

APPENDIX C

UES-SEACOAST TRANSFORMER RATINGS

The following is a listing of the present summer and winter thermal ratings for UES-Seacoast Substation Power Transformers.

Distribution Substation Transformers		Voltage	Summer Capacity		Winter Capacity	
			Normal (MVA)	LTE (MVA)	Normal (MVA)	LTE (MVA)
1T1	Exeter	4.16 – 34.5 kV	4.49	4.58	5.07	5.38
1T2	Exeter	4.16 – 34.5 kV	4.49	4.58	5.07	5.38
2T1	Hampton	4.16 – 34.5 kV	6.20	6.32	6.98	7.26
3T1	Hampton Beach	4.16 – 34.5 kV	6.22	6.33	6.88	7.22
3T3	Hampton Beach	13.8 – 34.5 kV	12.39	12.61	13.86	14.41
5T1	Plaistow	4.16 – 34.5 kV	3.83	3.90	4.38	4.38
6T1	East Kingston	13.8 – 34.5 kV	12.45	12.67	13.86	13.86
7T1	Seabrook	13.8 – 34.5 kV	6.22	6.33	6.98	7.33
13T1	Timberlane	13.8 – 34.5 kV	12.50	12.72	14.07	14.77
17T1	High St.	13.8 – 34.5 kV	12.45	12.67	13.97	14.66
19T1A	Exeter Switch	4.16 – 34.5 kV	0.63	0.65	0.73	.077
19T1B	Exeter Switch	4.16 – 34.5 kV	0.63	0.65	0.73	0.77
19T1C	Exeter Switch	4.16 – 34.5 kV	0.63	0.65	0.73	0.77
20T1	Dow's Hill	4.16 – 34.5 kV	1.86	1.93	2.18	2.31
21T1	Westville	13.8 – 34.5 kV	12.45	12.67	13.97	14.64
21T2	Westville	13.8 – 34.5 kV	12.45	12.66	13.91	14.61
46X1	Winnacunnet Rd. Steps	4.16 – 34.5 kV	3.60	3.60	3.60	3.60

Note: This study does not attempt to identify distribution substation loading concerns. Distribution substation transformer concerns are identified and addressed under the 5 year distribution planning study.

System Supply Transformers	Voltage	Summer Capacity		Winter Capacity	
		Normal (MVA)	Thermal Limit	Normal (MVA)	Thermal Limit
Great Bay[1]	115 – 34.5 kV	44.8	51[2]	53.5	63
Timber Swamp TB25[1]	345 – 34.5 kV	136	160	147	173
Timber Swamp TB69[1]	345 – 34.5 kV	136	160	147	173
Kingston 22T1	115 – 34.5kV	60	72	60	72
Kingston 22T2	115 – 34.5kV	60	72	60	72

[1] Property of Eversource
[2] Great Bay TB141 has an operation limit of 46 MVA. During the summer of 2010 the Great Bay transformer was carrying 46 MVA of load and came into alarm. The alarm set point is 90ºC top oil temperature. The trip is set at 100ºC top oil temperature.

Unitil
Unitil Service Corp.

APPENDIX D

Ten-Year System Load Forecasts
Summer 2016 - 2025

Distribution Engineering Dept.
February 11, 2015

The attached charts and tables summarize the most recent ten-year load forecasts for the UES-Capital, UES-Seacoast, and FG&E 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-Seacoast System – Summer

The UES-Seacoast system reached a peak load for the summer of 2014 of 151.382 MW on July 23, 2014 at 6:00 PM[1]. The daily average temperature was 80°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 daily average temperature for this day was 87°F. The historical mean of annual highest daily average temperatures for the past ten years[2] is 84.4°F. The linear trend of the 84°F mean point estimates from annual load-versus-temperature models for the UES-Seacoast system is +0.6 MW per year with an average standard deviation of ±5.6 MW among the models at this temperature.

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

Projected Summer Season	Average Peak Load (MW)	Peak Design Load (MW)	Extreme Peak Load (MW)
2016	167.7	182.5	187.3
2017	168.6	185.7	191.5
2018	169.7	188.6	195.3
2019	170.3	190.6	197.9
2020	171.4	192.7	200.3
2021	172.4	195.1	204.0
2022	172.9	197.6	206.9
2023	173.7	199.3	209.5
2024	174.5	202.1	211.3
2025	175.2	203.7	214.0

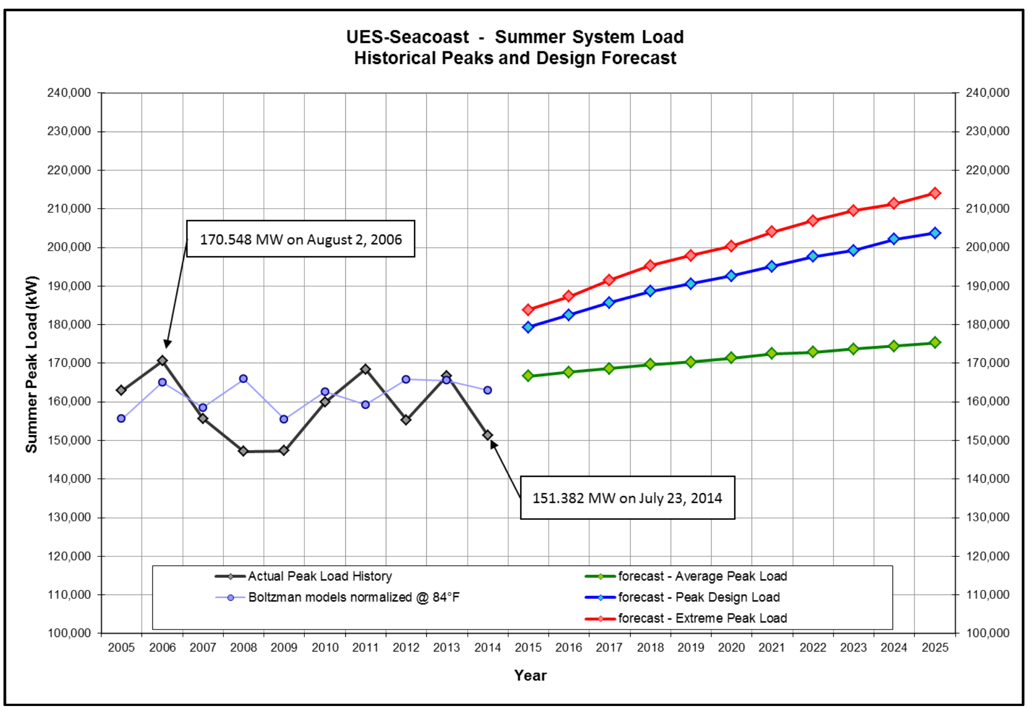


Chart 2. UES-Seacoast – Historical Summer System Peak Loads and Design Forecasts.

[1] - peak hourly consumption of 151,382 kWhr.

[2] - 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.

APPENDIX E

BASE CASE STUDIES

The information provided in this section describes details of power flow simulation results for year by year studies of the UES–Seacoast system in its normal or proposed operating configuration(s). The system is examined for deficiencies under peak design and extreme peak loading conditions with all elements in service. Details are quantified as to the adequacy of the normal system operating configuration, and substation and subtransmission system infrastructure. System voltages or equipment loadings that are approaching operational limits are noted.

Unless otherwise noted, the system is modeled in its normal “summer season” operating configuration, summarized as follows:

<u>3360 Line, Timber Swamp to Guinea</u>

- 43J60 switch normally open at Guinea

<u>3371 Line, Timber Swamp to Guinea</u>

- 54J71 switch normally open at Guinea

<u>3343 Line, Guinea to Kingston</u>

- 3343 breaker normally open at Guinea
- 43J18X1 switch normally open at the Guinea
- J643 switch normally open at East Kingston
- 43J54X1 switch normally open at the New Boston Road Tap
- Distribution loads normally supplied:
    - Willow Road Tap circuit 43X1
    - Shaw’s Hill Tap circuits 27X1 and 27X2
    - Munt Hill Tap circuit 28X1

<u>3354 Line, Guinea to Kingston</u>

- 3354 breaker normally open at Guinea
- 54J43X1 switch normally open at the Willow Road Tap
- 54J27 switch normally open at Shaw’s Hill Tap
- 54J28 switch normally open at Munt Hill Tap
- Distribution loads normally supplied:
    - East Kingston S/S circuits 6W1 and 6W2
    - New Boston Road Tap circuit 54X1

<u>3342 Line, Guinea to Hampton Beach</u>
- BT-2 switch normally open at Hampton
- J042 switch normally open at Hampton Beach
- Distribution loads normally supplied:
  - Hampton S/S circuit 2X2

<u>3353 Line, Guinea to Hampton Beach</u>
- 53J46 switch normally open at the 3346 Line Tap
- Distribution loads normally supplied:
  - Hampton S/S circuits 2H1 and 2X3
  - Hampton Beach S/S circuits 3H1, 3H2, 3H3 and 3W4

<u>3359 Line, Guinea to Seabrook Marsh Tap</u>
- 3359J5 switch normally open at the Cemetery Lane S/S
- Distribution loads normally supplied:
  - Mill Lane Tap circuit 23X1
  - Stard Road Tap circuit 59X1
  - Cemetery Lane S/S circuit 15X1

<u>3348 Line, Hampton to Seabrook Marsh Tap</u>
- Distribution loads normally supplied:
  - Seabrook Station

<u>3346 Line, 3346 Line Tap to High Street</u>
- Distribution loads normally supplied:
  - Brazonics
  - Hampton sewer treatment plant
  - Winnacunnet Road Tap circuit 46X1
  - High Street S/S circuits 17W1 and 17W2

<u>3350 Line, Seabrook Marsh Tap to Seabrook</u>
- Distribution loads normally supplied:
  - Seabrook S/S circuits 7W1 and 7X2

<u>3345 Line, Kingston to Plaistow</u>
- 45J56X1 switch normally open at the Hunt Road Tap
- 45J56X2 switch normally open at the Dorre Road Tap
- Distribution loads normally supplied:
  - Timberlane S/S circuits 13W1, 13W2, and 13X3
  - Plaistow S/S circuits 5H1 and 5H2

<u>3356 Line, Kingston to Plaistow</u>

- J1356 switch normally open at Timberlane
- J556 switch normally open at Plaistow
- Distribution loads normally supplied:
  - Hunt Road Tap circuit 56X1
  - Dorre Road Tap circuit 56X2

<u>3358 Line, Plaistow to Westville</u>

- Distribution loads normally supplied:
  - Process Engineering
  - Westville Road Tap circuit 58X1
  - Westville S/S circuits 21W1 and 21W2

<u>3351 Line, Great Bay to Merrill's Pit</u>

- Distribution loads normally supplied:
  - Winnicutt Road Tap circuit 51X1
  - Dow's Hill S/S circuit 20H1

<u>3362 Line, Great Bay to Merrill's Pit</u>

- 62J51X1 switch normally open at Winnicutt Road Tap
- 3347B recloser normally open at 3347 Line Tap
- J2062 switch normally open at Dow's Hill

<u>3347 Line, 3347 Line Tap to Portsmouth Avenue</u>

- Distribution loads normally supplied:
  - Guinea Road Tap circuit 47X1
  - Osram Sylvania
  - Portsmouth Avenue S/S circuits 11X1 and 11X2

<u>3341 Line, Wolf Hill to Exeter</u>

- 03341 recloser normally closed at Wolf Hill
- 41J51 switch normally open at Merrill's Pit
- 41J57 switch normally open at P.E.A. Tap
- J041 switch normally closed at Exeter Switching
- BT-1A switch normally open at Exeter Switching
- Distribution loads normally supplied:
  - Exeter Switching S/S circuit 19X2
  - Exeter S/S circuit 1H3

<u>3352 Line, Wolf Hill to Exeter</u>

- 3352 recloser normally open at Wolf Hill
- Distribution loads normally supplied:
  - P.E.A.
  - Exeter Switching S/S circuit 19H1 and 19X3
  - Exeter S/S circuit 1H4

Additionally, the following system capacitor banks are modeled as being switched in during summer peak conditions:

• Guinea S/S	6.6 MVAr (34.5 kV)
• Guinea S/S (2-3.6 MVAr banks)	7.2 MVAr (34.5 kV)
• Kingston S/S (4-4.8 MVAr banks)	19.2 MVAr (34.5 kV)
• 3351 Line at the 3347 Line Tap	2.4 MVAr (34.5 kV)
• 3362 Line at the 3347 Line Tap	2.4 MVAr (34.5 kV)
• Portsmouth Avenue S/S	2.4 MVAr (34.5 kV)
• 3352 Line at P.E.A. Tap	2.4 MVAr (34.5 kV)
• High Street S/S	2.4 MVAr (34.5 kV)
• Seabrook S/S	1.8 MVAr (34.5 kV)
• 3359 Line at Mill Lane Tap	2.4 MVAr (34.5 kV)
• 3343 Line at New Boston Rd. Tap	2.4 MVAr (34.5 kV)
• 3354 Line at New Boston Rd. Tap	2.4 MVAr (34.5 kV)
• 3345 Line at Plaistow S/S	2.4 MVAr (34.5 kV)
• 3356 Line at Plaistow S/S	2.4 MVAr (34.5 kV)
• East Kingston S/S 13.8kV Bus	1.2 MVAr (13.8 kV)
• 3358 Line at Westville S/S	2.4 MVAr (34.5 kV)
• Westville S/S 13.8kV Bus	1.2 MVAr (13.8 kV)
• Timberlane S/S (2-900 KVAR banks)	1.8 MVAr (13.8 kV)
• Hampton Beach S/S	1.2 MVAr (4.16 kV)
• Hampton Beach S/S	0.6 MVAr (4.16 kV)

Other capacitors on distribution circuits are typically not directly modeled, but rather are included within modeled loads.

The system is examined for deficiencies under peak design and extreme peak loading conditions with all elements in service. In addition, the system is examined for deficiencies under peak design and extreme peak loading conditions with at least half of the available generation off-line. Details are quantified as to the adequacy of the normal system operating configuration, and substation and subtransmission system infrastructure.

The following table is used to summarize the results of the analysis. Not all of the items identified in the table are violations of established planning guidelines. All conditions where the loading is at or above the normal rating or where voltage levels are at or below the planning criteria are identified. An asterisk (*) is used to identify the results which do not meet planning guidelines. Each condition which does not meet planning criteria is considered to be a system constraint and a system improvement alternative is required. The table is organized by year and load level. For each basecase, there may be multiple conditions that result.

Basecase (Peak Design Load) Planning Flags

Year	Load Level (MW)	*	Location/Element	Condition	Planning Criteria or Rating
2016	182.5		Great Bay 44.8 MVA Transformer	93% Eversource Operational Limit	Loading > Operational Limit
2022	197.6		Great Bay 44.8 MVA Transformer	91% Eversource TFRAT	Loading > TRAFT
		*	Great Bay 44.8 MVA Transformer	101% Eversource Operational Limit	Loading > Operational Limit

Extreme (Extreme Peak Load) Planning Flags

Year	Load Level (MW)	*	Location/Element	Condition	Planning Criteria or Rating
2016	187.3		Great Bay 44.8 MVA Transformer	97% Eversource Operational Limit	Loading > Operational Limit
2017	185.7		Great Bay 44.8 MVA Transformer	91% Eversource TFRAT	Loading > TRAFT
			Great Bay 44.8 MVA Transformer	101% Eversource Operational Limit	Loading > Operational Limit
2025	214.0	*	Great Bay 44.8 MVA Transformer	101% Eversource TFRAT	Loading > TRAFT

APPENDIX F

CONTINGENCY ANALYSIS

The information provided in this section describes the power flow simulation results for the case by case studies of the loss of system elements at peak load conditions. These details are provided to quantify the adequacy of substation and subtransmission system infrastructure under contingency circumstances, and to guide development of operating procedures to respond to these scenarios. System voltages or equipment loadings that are approaching operational limits are described for each significant switching step. Details regarding troubleshooting faults or isolation of specific components to be left out of service are not typically provided. Similarly, not all details that would be required in formal switching orders are included.

The following is a summary list of the loss-of-element contingencies studied:

1) Loss of Timber Swamp TB25 Transformer
2) Loss of Kingston 22T2 Transformer
3) Loss of Kingston 22T2 Transformer
4) Loss of Great Bay TB141 Transformer
5) Loss of 3360 Line, Timber Swamp to Guinea
6) Loss of 3371 Line, Timber Swamp to Guinea
7) Loss of 3343 Line, Kingston to Guinea
8) Loss of 3354 Line, Kingston to Guinea
9) Loss of 3345 Line, Kingston to Plaistow
10) Loss of 3356 Line, Kingston to Plaistow
11) Loss of 3358 Line at Plaistow
12) Loss of 3351 Line, Great Bay to Merrill's Pit
13) Loss of 3362 Line, Great Bay to Merrill's Pit
14) Loss of 3347 Line at 3347 Line Tap
15) Loss of 3341 Line at Merrill's Pit
16) Loss of 3352 Line at Merrill's Pit
17) Loss of 3342 Line, Guinea to Hampton
18) Loss of 3353 Line, Guinea to Hampton
19) Loss of 3359 Line, Guinea to Mill Lane Tap
20) Loss of 3348 Line at Hampton
21) Loss of 3342 Line, Hampton to Hampton Beach
22) Loss of 3353 Line, Hampton to Hampton Beach
23) Loss of 3346 Line at 3346 Line Tap
24) Loss of 3350 Line at Seabrook Station Marsh Tap

For each element scenario, the system was reviewed only under the assumed worst circumstances for the location of the loss of equipment. Furthermore, the switching examined may in some cases set up a configuration that appears to re-energize a faulted element or ignore a lack of sectionalizing. As a study of system capabilities, the emphasis is on performance in contingency configurations, and not maintenance switching or emergency troubleshooting. Finally, the switching examined may not be the only contingency response available.

The following table is used to summarize the results of the analysis. Not all of the items identified in the table are violations of established planning guidelines. All conditions where the loading is at or above the normal rating or where voltage levels are at or below the planning criteria are identified. An asterisk (*) is used to identify the results which do not meet planning guidelines. Each condition which does not meet planning criteria is considered to be a system constraint and a system improvement alternative is required.

The table is organized by year and load level. For each contingency, there may be multiple conditions that result. For each of the conditions, an exposure calculation is completed to determine the number of individual and consecutive hours as well as the number of individual and consecutive days where the system may be exposed to this condition. The last column is used to identify which planning criteria have been surpassed. The results from this analysis are summarized in the following table.

Contingency (Peak Design Load – Generation Off) Planning Flags

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2016	182.5	Loss of 3359 Line, Guinea to Mill Lane	3353 Line, Guinea to Hampton @ 120% of Normal	> 12 hrs	Loading > 100% Normal For more than 12 consecutive hours	*
			3348 Line, Hampton to Seabrook Station Marsh Tap @ 101% of Normal	< 12 hrs	Loading > 100% Normal	
		Loss of 3353 Line, Guinea to Hampton	3342 Breaker at Guinea @ 129% of Thermal Limit		Loading > Thermal Limit	*
			3342J1 Switch at Hampton @ 129% of Thermal Limit		Loading > Thermal Limit	*
			3342 Line, Guinea to Hampton @ 117% of Normal	> 12 hrs	Loading > 100% Normal For more than 12 consecutive hours	*
		Loss of 3342 Line, Guinea to Hampton	3353 Line, Guinea to Hampton @ 117% of Normal	> 12 hrs	Loading > 100% Normal For more than 12 consecutive hours	*
		Loss of 3351 Line, Great Bay to Merrill's Pit	3810X overcurrent protection at 86% of pick-up setting		Loading > 80% Trip Setting	
2017	185.7	Loss of 3359 Line, Guinea to Mill Lane	3353 Line, Guinea to Hampton @ 101% of LTE		Loading > 100% LTE	*
2018	188.6	Loss of 3348 Line	3359 Line, Guinea to Mill Lane @ 101% of Normal	< 12 hrs	Loading > 100% Normal	
2019	190.6	Loss of 3351 Line, Great Bay to Merrill's Pit	3810X overcurrent protection at 91% of pick-up setting		Loading > 90% Trip Setting	*
2020	192.7	Loss of 3342 Line, Guinea to Hampton	3353 Line, Guinea to Hampton @ 101% of LTE		Loading > 100% LTE	*
		Loss of 3353 Line, Guinea to Hampton	3342 Line, Guinea to Hampton @ 101% of LTE		Loading > 100% LTE	*

Year	Load Level (MW)	Contingency	Condition	Exposure	Planning Criteria or Rating	*
2023	199.3	Loss of 3345 Line, Kingston to Plaistow	3356 Line, Kingston to Hunt Road @ 101% of Normal	< 12 hrs	Loading > 100% Normal	
		Loss of 3356 Line, Kingston to Plaistow	3345 Line, Kingston to Hunt Road @ 100% of Normal	< 12 hrs	Loading > 100% Normal	

APPENDIX G

CONTINGENCY SWITCHING PROCEDURES

The information provided in this section describes the system switching analyzed in the contingency analysis. The results of these simulations are summarized in the table in Appendix F.

The information below describes the initial event, initial load out of service, switching procedure to restore load, and system concerns. The initial event describes which devices have operated to isolate the fault. The initial load out of service is the load which has been isolated in conjunction with the initial event. The switching procedure to restore load is the approach that has been taken to restore as much load as possible while still satisfying applicable planning criteria. This is meant to be used as a guide and not as step by step switching procedures to be implemented in the field. Finally, those system concerns that have been identified by the analysis of the final configuration are listed for the 10 year study timeframe.

1) Loss of Timber Swamp TB25 Transformer
(Timber Swamp TB25 transformer fault)

Initial Event:
- 6925 trips and locks out at Timber Swamp 345 kV Ring Bus
- 3135 trips and locks out at Timber Swamp 345 kV Ring Bus

- Load out of service:
  - Guinea 18X1
  - Hampton 2H1, 2X2 and 2X3
  - Hampton Beach 3H1, 3H2, 3H3, 3W4
  - Winnacunnet Road Tap 46X1
  - High Street 17W1 and 17W2
  - Brazonics
  - Hampton sewer treatment plant
  - Seabrook 7W1 and 7X2
  - Mill Lane Tap 23X1
  - Stard Road Tap 59X1
  - Cemetery Lane 15X1
  - Seabrook Station
  - Munt Hill Tap 28X1
  - Shaw's Hill Tap 27X1 and 27X2
  - Willow Road Tap 43X1
  - East Kingston 6W1 and 6W2
  - New Boston Road Tap 54X1
  - Exeter Switching 19X2

Automated Switching
- Timber Swamp S/S – TB25 opens
- Timber Swamp S/S – BT62 closes

- Load restored:

Guinea 18X1	Cemetery Lane 15X1
Hampton 2H1, 2X2 and 2X3	Seabrook Station
Hampton Beach 3H1, 3H2, 3H3, 3W4	Munt Hill Tap 28X1
Winnacunnet Road Tap 46X1	Shaw's Hill Tap 27X1 and 27X2
High Street 17W1 and 17W2	Willow Road Tap 43X1
Brazonics	East Kingston 6W1 and 6W2
Hampton sewer treatment plant	New Boston Road Tap 54X1
Seabrook 7W1 and 7X2	Exeter Switching 19X2
Mill Lane Tap 23X1	
Stard Road Tap 59X1	

- All load restored

System Comments and Concerns:

- All elements within planning criteria throughout the study period.

2) Loss of a Kingston 22T1 Transformer
(Kingston 22T1 transformer fault)

Initial Event:

- 22T1 breaker trips and locks out at Kingston
- 22XT1 low-side protection trips and locks out at Kingston

- Load out of service:

Munt Hill 28X1	Shaw's Hill 27X1, 27X2
Willow Road 43X1	Kingston 22X2
Timberlane 13W1, 13W2, 13X3	Plaistow 5H1, 5H2

Switching Procedures:

1. Kingston S/S – close BT22A breaker

- Load restored:

Munt Hill 28X1	Shaw's Hill 27X1, 27X2
Willow Road 43X1	Kingston 22X2
Timberlane 13W1, 13W2, 13X3	Plaistow 5H1, 5H2

System Comments and Concerns:

- Kingston 22T1 expected to exceed 90% of 72 MVA thermal rating at total system load levels above 180 MW (prior to 2016).
* - Kingston 22T1 expected to exceed its 72 MVA thermal rating at total system load levels above 206 MW (2020 and later).

... reconfigure system to reduce loading concerns ...

2. Guinea Sw/S – close 3354 breaker
3. Kingston S/S – open 03354 breaker

System Comments and Concerns:
- All elements within planning criteria throughout the study period.

3) Loss of a Kingston 22T2 Transformer
(Kingston 22T2 transformer fault)

Initial Event:
- 22T1 breaker trips and locks out at Kingston
- 22XT1 low-side protection trips and locks out at Kingston

- Load out of service:

East Kingston 6W1, 6W2	New Boston Road 54X1
Kingston 22X1	Hunt Road 56X1
Dorre Road 56X2	Process Engineering
Westville Road Tap 58X1	Westville 21W1, 21W2

Switching Procedures:
2. Kingston S/S – close BT22A breaker

- Load restored:

East Kingston 6W1, 6W2	New Boston Road 54X1
Kingston 22X1	Hunt Road 56X1
Dorre Road 56X2	Process Engineering
Westville Road Tap 58X1	Westville 21W1, 21W2

System Comments and Concerns:
- All elements within planning criteria throughout the study period.

4) Loss of Great Bay TB141 Transformer
(failure of TB141 transformer)

Initial Event:
- J141 trips and locks out at Great Bay
- TB141 trips and locks out at Great Bay

- Load out of service:

Winnicutt Rd. Tap 51X1	Dow’s Hill 20H1
Guinea Rd. Tap 47X1	P.E.A.
Osram/Sylvania	Exeter Switching 19H1, 19X3
Portsmouth Ave. 11X1, 11X2	Exeter 1H3 and 1H4

Switching Procedures:
1. Great Bay S/S – open 3260X breaker
2. Great Bay S/S – open 3810X breaker
3. Merrill’s Pit – close 41J51 Switch
   - Load restored:
     Winnicutt Rd. Tap 51X1
     Guinea Rd. Tap 47X1
     Osram/Sylvania
     Dow’s Hill 20H1
     Portsmouth Ave. 11X1, 11X2
4. Wolf Hill – close 3352 recloser
   - Load restored:
     Exeter Switching 19H1, 19X3
     Exeter 1H4
     P.E.A.

   - All load restored

System Comments and Concerns:
At a system load level of 203.7MW (2025)
- Wolf Hill recloser disconnect switches @98% of their Normal/LTE rating.

5) Loss of 3360 Line, Timber Swamp to Guinea
(fault between 03360 breaker at Timber Swamp and 3360 breaker at Guinea)

Initial Event:
- 03360 trips and locks out at Timber Swamp
- 3360 trips and locks out at Guinea

- Load out of service:
  Exeter Switching 19X2

1. Wolf Hill – open 03341 recloser
2. Wolf Hill – close 3352 recloser
3. Merrill’s Pit – open 52J62 switch
4. Merrill’s Pit – close 41J51 Switch
   - Load restored:
   - Exeter Switching 19X2

   - All load restored

System Comments and Concerns:
- All elements within planning criteria throughout the study period.

6) Loss of 3371 Line, Timber Swamp to Guinea
(fault between 3341 breaker at Timber Swamp and 3371 breaker at Guinea)

Initial Event:
- 03371 trips and locks out at Timber Swamp
- 3371 trips and locks out at Guinea

- No Load out of service

Switching Procedures:
No switching necessary

System Comments and Concerns:
- All elements within planning criteria throughout the study period.

7) Loss of 3343 Line, Kingston to Guinea
(fault between 3343 breaker at Guinea and 03343 breaker at Kingston)

Initial Event:
- 03343 trips and locks out at Kingston

- Load out of service:
  Willow Road Tap 43X1
  Shaw's Hill Tap 27X1, 27X2
  Munt Hill Tap 28X1

Switching Procedures:
1. Willow Rd. Tap – open 43J43X1 switch
2. Willow Rd. Tap – close 54J43X1 switch
   - Load restored:
     Willow Rd. Tap 43X1
3. Munt Hill Tap – open 43J28 switch
4. Munt Hill Tap – close 54J28 switch
   - Load restored:
     Munt Hill Tap 28X1
5. Shaw's Hill Tap – open 43J27 switch
6. Shaw's Hill Tap – close 54J27 switch
   - Load restored:
     Shaw's Hill Tap 27X1, 27X2

   - All load restored:

System Comments and Concerns:
- All elements within planning criteria throughout the study period.

8) Loss of 3354 Line at Kingston
(fault between 3354 breaker at Guinea and 3354J3 switch at East Kingston)

Initial Event:
- 03354 trips and locks out at Kingston

- Load out of service:
  New Boston Road Tap 54X1 East Kingston 6W1, 6W2

Switching Procedures:
1. New Boston Road Tap – open 54J54X1 switch
2. New Boston Road Tap – close 43J54X1 switch
   - Load restored:
     New Boston Road Tap 54X1
3. East Kingston S/S – open J654 switch
4. East Kingston S/S – close J643switch
   - Load restored:
     East Kingston 6W1, and 6W2

- All load restored

System Comments and Concerns:
- All elements within planning criteria throughout the study period.

9) Loss of 3345 Line, Kingston to Plaistow
(fault between 3345 breaker at Kingston and J545 switch at Plaistow)

Initial Event:
- 3345 trips and locks out at Kingston

- Load out of service:
  Timberlane 13W1, 13W2, 13X3
  Plaistow 5H1, 5H2

Switching Procedures:
1. Plaistow S/S – open J545 switch
2. Plaistow S/S – close J556 switch
   - Load restored:
     Plaistow 5H1, 5H2
3. Timberlane S/S – open J1345 switch
4. Timberlane S/S – close J1356 switch
   - Load restored:
     Timberlane 13W1, 13W2, 13X3

- All load restored

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- All elements within planning criteria.

At a system load level of 203.7MW (2025):
- 3356 Line @104% of its Normal Rating.

10) Loss of 3356 Line, Kingston to Plaistow
(fault between 3356 breaker at Kingston and J556 switch at Plaistow)

Initial Event:
- 3356 trips and locks out at Kingston

- Load out of service:
  - Hunt Rd. Tap 56X1
  - Dorre Rd. Tap 56X2
  - Westville Rd. Tap 58X1
  - Westville 21W1, 21W2
  - Process Engineering

Switching Procedures:
1. Plaistow S/S – open 3356J1 switch
2. Plaistow S/S – close J556 switch
   - Load restored:
     - Westville Rd. Tap 58X1
     - Westville 21W1, 21W2
     - Process Engineering
3. Hunt Rd. Tap – open 56J56X1 switch
4. Hunt Rd. Tap – close 45J56X1 switch
   - Load restored:
     - Hunt Rd. Tap 56X1
5. Dorre Rd. Tap – open 56J56X2 switch
6. Dorre Rd. S/S – close 45J56X2 switch
   - Load restored:
     - Dorre Rd. Tap 56X2

   - All load restored

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- All elements within planning criteria.

At a system load level of 203.7MW (2025):
- 3345 Line @103% of its Normal Rating.

11) Loss of 3358 Line at Plaistow
(fault between 56J58 switch at Plaistow. and DS21 at Westville)

Initial Event:
- 3356 trips and locks out at Kingston

- Load out of service:
  Hunt Rd. Tap 56X1
  Dorre Rd. Tap 56X2
  Westville Rd. Tap 58X1
  Westville 21W1, 21W2
  Process Engineering

Switching Procedures:
1. Plaistow S/S – open 56J58 switch
2. Kingston S/S – close 3356 breaker
   - Load restored:
     Hunt Rd. Tap 56X1
     Dorre Rd. Tap 56X2
   - No Additional Switching Available

   - Load remaining out of service
     Westville Rd. Tap 58X1
     Westville 21W1, 21W2
     Process Engineering

System Comments and Concerns:
At a system load level of 182.5MW (2016):
- Up to 21 MW remain out of service.

At a system load level of 203.7MW (2025):
- Up to 24 MW remain out of service.

12) Loss of 3351 Line, Great Bay to Merrill's Pit
(fault between 3260X breaker at Great Bay and 41J51 switch at Merrill's Pit)

Initial Event:
- 3260X trips and locks out at Great Bay

- Load out of service:
  Winnicutt Rd. Tap 51X1
  Guinea Rd. Tap 47X1
  Portsmouth Ave. 11X1, 11X2
  Dow's Hill 20H1
  Osram/Sylvania

Automated Switching
- 3347 Line Tap – 3347A opens
- 3347 Line Tap – 3347B closes

- Load restored:
  - Guinea Rd. Tap 47X1 — Osram/Sylvania
  - Portsmouth Ave. 11X1, 11X2

Switching Procedures:
1. Winnicutt Rd. Tap – open 51J51X1 switch
2. Winnicutt Rd. Tap – close 62J51X1 switch
   - Load restored:
     - Winnicutt Rd. Tap 51X1
3. Dow's Hill S/S – open J2051 switch
4. Dow's Hill S/S – close J2062 switch
   - Load restored:
     - Dow's Hill 20H1

   - All load restored

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- 3810X overcurrent protection at 86% of its minimum pick-up setting.

At a system load level of 203.7MW (2025):
- 3810X overcurrent protection at 97% of its minimum pick-up setting.

13) Loss of 3362 Line, Great Bay to Merrill's Pit
(fault between 3810X breaker at Great Bay and 52J62 switch at Merrill's Pit)

Initial Event:
- 3810X trips and locks out at Great Bay

- Load out of service:
  - Exeter Switching 19H1, 19X3 — P.E.A.
  - Exeter 1H4

Switching Procedures:
1. Merrill's Pit – open 52J62 switch
2. Wolf Hill – close 3352 recloser
   - Load restored:
     - Exeter Switching 19H1, 19X3 — P.E.A.
     - Exeter 1H4

   - All load restored

System Comments and Concerns:
- All elements within planning criteria throughout the study period.

14) Loss of 3347 Line at 3347 Line Tap
(fault between 3347 Line Tap and 3347J3 Switch)

Initial Event:
- 3347A trips and locks out at 3347 Line Tap
- 3347B remains open at 3347 Line Tap

- Load out of service:
  Guinea Rd. Tap 47X1 Osram/Sylvania
  Portsmouth Ave. 11X1, 11X2

Switching Procedures:
No Subtransmission switching available

... utilize distribution ties to restore as much load as possible ...

System Comments and Concerns:
At a system load level of 182.5MW (2016):
- Up to 18 MW remain out of service.

At a system load level of 203.7MW (2025):
- Up to 20 MW remain out of service.

15) Loss of 3341 Line at Merrill's Pit
(fault between 41J51 switch at Merrill's Pit and 03341 breaker at Wolf Hill)

Initial Event:
- 03341 recloser trips and locks out at Wolf Hill

- Load out of service:
Summer 2024:
  Exeter Sw/S 19X2 Exeter 1H3

Switching Procedures:
1. Wolf Hill – close 3352 recloser
2. Merrill's Pit – open 52J62 switch
3. Exeter Sw/S – open J041 switch
4. Exeter Sw/S – close BT-1A switch
   - Load restored:
     Exeter Sw/S 19X2 Exeter 1H3

   - All load restored

System Comments and Concerns:
- All elements within planning criteria throughout the study period.

16) Loss of 3352 Line at Merrill's Pit
(fault between 52J62 switch at Merrill's Pit and 3352 breaker at Wolf Hill)

Initial Event:

- 3810X trips and locks out at Great Bay

- Load out of service:
  - Exeter Switching 19H1, 19X3 — P.E.A.
  - Exeter 1H4

Switching Procedures:

1. Exeter Sw/S – open J052 switch
2. Exeter Sw/S – close BT-1A switch
   - Load restored:
     - Exeter Switching 19H1, 19X3 — Exeter 1H4
3. P.E.A. Tap – open 52J57 switch
4. P.E.A. Tap – close 41J52 switch
   - Load restored:
     - P.E.A.

- All load restored

System Comments and Concerns:

- All elements within planning criteria throughout the study period.

17) Loss of 3342, Guinea to Hampton
(fault between 3342 breaker at Guinea and 3342J1 switch at Hampton)

Initial Event:

- 3342 trips and locks out at Guinea

- Load out of service:
  - Hampton 2X2 — High Street 17W1, 17W2
  - Winnacunnet Rd. Tap 46X1 — Brazonics
  - Hampton Sewer Treatment Plant

Switching Procedures:

1. Hampton S/S – open 3342J1 switch
2. Hampton S/S – close BT-2 switch
   - Load restored:
     - Hampton 2X2 — High Street 17W1, 17W2
     - Winnacunnet Rd. Tap 46X1 — Brazonics
     - Hampton Sewer Treatment Plant

- All load restored

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- 3353 Line @117% of its Normal Rating.
- 3353 Line @96% of its LTE Rating.

At a system load level of 203.7MW (2025):
- 3353 Line @132% of its Normal Rating.
- 3353 Line @108% of its LTE Rating.

... reconfigure system as necessary to reduce loading concerns ...

3. Seabrook Station Marsh Tap – open 48J50 switch
4. Cemetery Lane S/S – close 3359J5 switch

- Load out of service:

Seabrook 7W1, 7X2	Seabrook Station

- All load restored:

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- 3359 Line @97% of its Normal Rating.

At a system load level of 203.7MW (2025):
- 3359 Line @110% of its Normal Rating.
- 3359 Line @98% of its LTE Rating.

18) Loss of 3353, Guinea to Hampton
(fault between 3353 breaker at Guinea and 3353J1 switch at Hampton)

Initial Event:
- 3353 trips and locks out at Guinea

- Load out of service:

Hampton 2H1, 2X3	Seabrook 7W1, 7X2
Hampton Beach 3H1, 3H2, 3H3, 3W4	Seabrook Station

Switching Procedures:
1. Hampton S/S – open 3353J1 switch
2. Hampton S/S – close BT-2 switch
   - Load restored:

Hampton 2H1, 2X3 — Seabrook 7W1, 7X2
Hampton Beach 3H1, 3H2, 3H3, 3W4 — Seabrook Station

- All load restored

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- 3342 Breaker at Guinea @129% of its Thermal Limit.
- 3342J1 Switch at Hampton @129% of its Thermal Limit.
- 3342 Line @117% of its Normal Rating.
- 3342 Line @96% of its LTE Rating.

At a system load level of 203.7MW (2025):
- 3342 Breaker at Guinea @146% of its Thermal Limit.
- 3342J1 Switch at Hampton @146% of its Thermal Limit.
- 3342 Line @132% of its Normal Rating.
- 3342 Line @108% of its LTE Rating.

... reconfigure system as necessary to reduce loading concerns ...

3. Seabrook Station Marsh Tap – open 48J50 switch
4. Cemetery Lane S/S – close 3359J5 switch

- Load out of service:

Seabrook 7W1, 7X2 — Seabrook Station

- All load restored:

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- 3359 Line @97% of its Normal Rating.

At a system load level of 203.7MW (2025):
- 3359 Line @110% of its Normal Rating.
- 3359 Line @98% of its LTE Rating.

19) Loss of 3359 Line, Guinea to Mill Lane Tap
(fault between 3359 breaker at Guinea and 3359J8 switch at Mill Road Tap)

Initial Event:
- 3359 trips and locks out at Guinea

- Load out of service:

Mill Lane Tap 23X1 — Cemetery Lane 15X1
Stard Road Tap 59X1

Switching Procedures:
1. Mill Lane Tap – open 3359J8 switch
2. Cemetery Lane S/S – close 3359J5 switch
   - Load restored:
     Mill Lane Tap 23X1 Cemetery Lane 15W1
     Stard Road Tap 59X1

   - All load restored:

System Comments and Concerns:
At a system load level of 182.5MW (2016):
- 3353 Line @120% of its Normal Rating.
- 3353 Line @98% of its LTE Rating.
- 3348 Line @100% of its Normal Rating.

At a system load level of 203.7MW (2025):
- 3353 Line @135% of its Normal Rating.
- 3353 Line @111% of its LTE Rating.
- 3348 Line @112% of its Normal Rating.
- 3348 Line @99% of its LTE Rating.

... reconfigure system as necessary to reduce loading concerns ...

3. Lafayette Road – close 2X3J15X1 switch
4. Cemetery Lane S/S – open 15X1 recloser
5. Hampton S/S Beach – close J042 switch
6. Hampton Beach S/S – open J053 Switch

System Comments and Concerns:
At a system load level of 203.7MW (2025):
- 3353 Line @104% of its Normal Rating.

20) Loss of 3348 Line at Hampton
(fault between 3348 breaker at Hampton and 48J50 switch at Seabrook Station Marsh Tap)

Initial Event:
- 3348 trips and locks out at Hampton

- Load out of service:
  Seabrook 7W1, 7X2 Seabrook Station

Switching Procedures:
1. Seabrook Station Marsh Tap – open 48J50 switch
2. Cemetery Lane S/S – close 3359J5 switch

- Load out of service:

  Seabrook 7W1, 7X2 — Seabrook Station

- All load restored:

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- 3359 Line @97% of its Normal Rating.

At a system load level of 203.7MW (2025):
- 3359 Line @110% of its Normal Rating.
- 3359 Line @98% of its LTE Rating.

21) Loss of 3342 Line, Hampton to Hampton Beach
(fault between 3342R1 breaker at Hampton and J042 switch at Hampton Beach)

Initial Event:
- 3342R1 trips and locks out at Hampton

- Load out of service:

Winnacunnet Rd. Tap 46X1	Brazonics
High Street 17W1, 17W2	Hampton Sewer Treatment Plant

Switching Procedures:
1. 3346 Line Tap – open 42J46 switch
2. 3346 Line Tap – close 53J46 switch
   - Load restored:

Winnacunnet Rd. Tap 46X1	Brazonics
High Street 17W1, 17W2	Hampton Sewer Treatment Plant

- All load restored:

System Comments and Concerns:
- All elements within planning criteria throughout the study period.

22) Loss of 3353 Line, Hampton to Hampton Beach
(fault between 3353R1 breaker at Hampton and J053 switch at Hampton Beach)

Initial Event:
- 3353R1 trips and locks out at Hampton

- Load out of service:

Summer 2024:

Hampton Beach 3H1, 3H2, 3H3, 3W4

Switching Procedures:

1. Hampton Beach S/S – open J053 switch
2. Hampton Beach S/S – close J042 switch
   - Load restored:

     Hampton Beach 3H1, 3H2, 3H3, 3W4
   - All load restored:

System Comments and Concerns:

- All elements within planning criteria throughout the study period.

23) Loss of 3346 Line at 3346 Line Tap
(fault between Hampton Tap and High Street S/S)

Initial Event:

- 3342R1 trips and locks out at Hampton

- Load out of service:

Winnacunnet Rd. Tap 46X1	Brazonics
High Street 17W1, 17W2	Hampton Sewer Treatment Plant

Switching Procedures:

No Subtransmission switching available

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- Up to 9 MW remain out of service.

At a system load level of 203.7MW (2025):
- Up to 10 MW remain out of service.

24) Loss of 3350 Line at Seabrook Station Marsh Tap
(fault between 3350 Line Tap at Seabrook Station Marsh Tap and 3350J1 switch at Seabrook)

Initial Event:

- 3348 trips and locks out at Hampton

- Load out of service:

Seabrook 7W1, 7X2	Seabrook Station

Switching Procedures:

1. Seabrook Station Marsh Tap – open 50J59 switch
2. Cemetery Lane S/S – close 3359J5 switch
   - Load restored:
     Seabrook Station

   - Load remaining out of service
     Seabrook 7W1, 7X2

... utilize distribution ties to restore as much load as possible ...

System Comments and Concerns:

At a system load level of 182.5MW (2016):
- Up to 10 MW remain out of service.

At a system load level of 203.7MW (2025):
- Up to 12 MW remain out of service.

APPENDIX H

REFERENCES

1. Electric System Planning Guide – Rev. 3 Unitil Service Corp. March 13, 2014

2. Electrical Equipment Rating Procedures – Rev. 3 Unitil Service Corp. November 6, 2012

APPENDIX I

DIAGRAMS

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

Load Flow Diagram

Redacted

LOAD FLOW DIAGRAM

REDACTED

LOAD FLOW DIAGRAM

REDACTED

Unitil	Guidelines	Procedure No.	GL-DT-DS-02
	Distribution Engineering	Section No.	Cover
		Page No.	1
	Distribution Planning and Design Guidelines	Revision No.	3
		Revision Date	02/09/16
		Supersedes Date:	12/10/15

FOREWORD

The purpose of this document is to outline the distribution planning process and design criteria.

Any questions or inquiries regarding information provided in this document should be referred to the Director of Engineering.

K E Sprague — 2/9/2016

Kevin E. Sprague
Director, Engineering

Date

J Bonazoli — 2/9/16

John J. Bonazoli
Manager, Distribution Engineering

Date

REVISION HISTORY

Date of Review:

Revision #	Date	Description of Changes
0	03/10/2014	Initial Issue
1	12/29/2014	Revised DG/DER Planning Guidelines (Sec 3.2)
2	12/10/2015	Revisions to Sections 3.3, 3.4 & 3.5
3	2/9/2016	Created new document number

	Guidelines	Procedure No.	GL-DT-DS-02
Unitil	Distribution Engineering	Section No.	TOC
		Page No.	2
	Distribution Planning and Design Guidelines	Revision No.	3
		Revision Date	02/09/16
		Supersedes Date:	12/10/15

Table of Contents

List of Appendices

1.0 Introduction

1.1 Purpose

The intent of this guideline is to outline the distribution planning process and design criteria that will; ensure adequate supply capacity of distribution system elements under peak load conditions, define acceptable standards of service, and to assist distribution engineers in designing a reliable and efficient distribution system in and economically prudent manner**.**

1.2 Applicability & Scope

This document applies to the planning and design of distribution circuits operating at nominal primary voltages of 34.5Y/19.92kV or less. This guideline does not apply to the design and planning of subtransmission systems and/or substations design.

1.3 Updating the Guideline

The Director, Engineering is responsible for maintaining this guideline to ensure this guideline is current with changes in the company's organization, policies or to capture good utility practices. All revisions and/or additions shall detail a revision date and number on the top right corner of each page within the header, as well as a brief description in the *Revision History* section on the cover.

Comments are welcomed and should be documented (using the *Request for Procedure/Change Form* reference in Appendix A) and addressed to the Director, Engineering. All documented comments shall be retained in a separate file and reviewed each time this procedure is revised. These comments will keep the contents of the procedure current and enhance its usefulness.

1.4 Revision Notes

This document is being issued as a new guideline and supersedes all previous revisions of *Distribution Voltage Guidelines.*

1.5 Availability

Current copies of this procedure can be found on the Hampton Shared Drive. Hard copies are not version controlled.

NOTE: Only up-to-date versions of the documents are posted on the Hampton Shared Drive. All other revisions (both electronic and hardcopy) should not be referenced.

2.0 General Information

2.1 Acronyms

DG Distributed Generation
DER Distributed Energy Resources

3.0 Distribution Planning and Design Guidelines

3.1 Planning of Distribution Systems

The goal of distribution planning is to forecast projected peak loads at the circuit level over a 5-year planning horizon and to perform circuit analysis on a regular basis in order to ensure the overall objective of this guideline is met. The distribution planning process is outline below:

- Distribution circuit load forecast shall be completed annually in accordance with *Distribution Load Projections Guideline.*
- Circuit analysis shall be completed on 1/3 of all distribution circuits annually for each operating area. Distribution circuit analysis shall be in accordance with the *Distribution Circuit Analysis Procedures* (Procedure #PR-DT-TC-02).
- Distribution Planning Studies shall be completed on an annual basis for each operating area. These studies shall be based on the distribution circuit analysis results and shall identify all equipment loading concerns or unacceptable system voltage regulation conditions.
- System modifications alternatives should be evaluated when any of the following planning thresholds are reached:
    - Loading on substation transformers and other distribution circuit elements are anticipated to reach 90% of their respective limits outlined within this guideline.
    - Loading on distribution stepdown transformers is anticipated to reach 120% of their nameplate rating.
    - Current imbalance at the distribution circuit supply point is recorded to be greater than 20%.
    - Loading on any protective device is anticipated to reach 70% of its pickup or minimum melting current.
    - Steady state primary voltage levels cannot be maintained within the limits outlined within this guideline.
    - Steady state primary voltage imbalance is anticipated to exceed the limits outlined within this guideline.
    - Protective device sensitivity does not meet the requirements set forth in the *Distribution Protection Guideline* (Guideline #GL-DT-TC-09).

3.2 Large Interconnected Distribution Generating Facilities and Distributed Energy Resources

The distribution planning process shall include the impact of interconnected large scale Distributed Generation (DG) facilities as well as the output or load offset by other DER projects. These facilities will be evaluated based on availability and reliability during peak times. DG facilities that are proposed for installation are studied under a separate effort and procedure. For the purposes of this guideline, a large DG facility shall be considered to be any facility where the aggregate nameplate generation at the point of interconnection is ≥ 500kW.

The procedure for developing load projections of circuits with large DG facilities shall follow the guidelines outlined below:

- The hourly interval circuit peak demand at the substation circuit position shall be obtained from monthly substation inspection records, SCADA, or relay interrogation.

- The hourly interval peak DG output shall be obtained from EMIS data, SCADA or relay interrogation.

- The hourly interval data obtained at the circuit position and at the DG interconnection shall be correlated to calculate an estimated aggregate peak load on the circuit. Note that hourly interval data is required in order to accurately estimate the overall circuit peak load. Monthly peak demand values obtained from substation thermal metering is not adequate to determine circuit peak load since there is no way to correlate the timing of the circuit peak with the output of the generator nor is it possible to determine if the status of the generator (online/offline) at the time of the circuit peak.

- The basis for seasonal circuit load projections shall be based on the maximum value for the summer and winter seasons estimated from the procedure described above. Load projections shall follow the process described in the Distribution Load Projections Guideline dated 5/22/09.

When performing circuit analysis of any circuit with only one large DG interconnection, it is not necessary to model the DG interconnection. This analysis was completed during the impact study. Therefore, modeling of this DG at higher load levels is not necessary. In addition, due to the uncertainty of the availability of a single DG site, the circuit must be planned in order to provide electric service to all customers that meets planning criteria with or without the DG online.

When performing circuit analysis of any circuit with 2 or more large DG sites, the following parameters and generation output scenarios shall be studied:

- Load allocation shall be performed with all DG sites disconnected from the system
- All DG facilities shall be modeled at 100% of its AC rating at the point of interconnection

- Voltage drop analysis shall be performed with all combinations of possible DG site status (online/offline)
- Substation equipment loading constraints shall be analyzed with at least 50% of the cumulative output of all DG interconnections offline. DG output shall not be scaled to meet this requirement. Rather, each site shall be considered either online of offline.

3.3 Distribution System Design Criteria

The follow design criteria shall be used as a guide for the planning and design of the distribution system.

3.3.1 Loading of Distribution Equipment

Distribution systems shall be designed using the following constraints and equipment loading limitations under peak load operating conditions:

- Loading on distribution circuit conductors and other elements not otherwise specified below should not exceed their Normal rating.
- Loading on substation transformers should not exceed their Normal rating.
- Loading on distribution stepdown transformers should not exceed 120% of their nameplate rating.
- Loading on protective devices (reclosers, sectionalizers, cutouts/fuse holders, CTs, etc.) should not exceed their nameplate rating.
- Loading on fuse links should not exceed their continuous current rating.
- ANSI/IEEE C57.95-1984 is used as a guide for determining the maximum allowable loading of regulators for normal loss of life. Loading on regulators during summer months should not exceed 120% of the nameplate rating for the set regulation range. Winter loading is limited 145% of nameplate using the same principals. Higher loading may be allowed on a short term contingency basis (LTE) or as indicated on the nameplate when the regulation range is temporarily limited (load bonus). In no case shall loading exceed the maximum load amps indicated on the nameplate.
- Loading on switches and isolating devices shall not exceed their nameplate rating.

3.3.2 Distribution Voltages and Regulation

The following outlines the required ranges for steady state RMS nominal system voltages. In all cases where system voltages are found to be outside of these limits, a detailed engineering analysis shall be performed in order to determine corrective measures.

Low Voltage Services

Electric distribution systems should be designed and constructed such that low voltage services (600 V and below) supplied to customers 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 (A) lower 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 (B) lower 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

Steady state service voltages operating below the (B) lower 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 (A) upper limit or below the (B) lower 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 Voltage Regulation

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 104%) and above 117 V (on 120 V base, or roughly 97.5%) shall be considered adequate to support all service voltage objectives. 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 necessary to remedy low service voltages if the primary system operates within this range.

Steady state primary voltages operating below 115 V (on 120 V base, or roughly 96%) are unacceptable under normal conditions. Steady state primary voltages operating as low as 115 V (on 120 V base, or roughly 96%) are tolerable if they do not result in extensive, frequent, or long lasting service voltage concerns. Primary system improvements may be necessary to resolve lengthy, recurring, widespread low service voltages.

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.

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

Transient Voltage Fluctuations (Flicker)

One of the most common sources of voltage flicker on the primary distribution system is switched customer load such as starting of large motors. The following shall be used as a general guideline for acceptable levels of voltage flicker. When the calculated voltage fluctuation exceeds these limits, remedial actions must be taken to reduce flicker to within acceptable levels in order to mitigate nuisance lamp flicker or other potential adverse effects experienced by the customer or other Unitil customers.

Voltage Flicker Criteria

The table below prescribes the acceptable voltage fluctuation due to the starting of a single motor. Unitil's ideal philosophy is to maintain flicker at a level below the Border Line of Visibility[1] but will accept levels above this limit but below the Border Line of Irritation as long as the resultant system conditions do not adversely affect other customers.

Maximum Acceptable %Voltage Fluctuation

Typical Motor Load Type/Description	Frequency of Motor Starts	Max % Fluctuation At Customer XFMR	Max % Fluctuation on Primary System
Fire Pumps	1 Start per Month	5%	4%
Pumps, air conditioning equipment, compressors, elevators, etc.	Multiple starts per hour	3%	2%

Note that the table above does not address all types of switched loads such as arc furnaces, welding equipment, etc. This type of equipment may cause multiple fluctuations per minute or even second. Prior to connecting customer load fluctuating at these rates, a detailed engineering evaluation shall be performed to determine the effects to the distribution system.

In cases where voltage flicker exceeds the prescribed limitations above, remedial actions must be taken. As a first step, the customer's service transformer may be increased by no more than one standard size. If the resulting condition still violates this guideline, the customer must employ some type of soft-starting method. In extreme cases where one or both of these measures still result in unacceptable conditions, a detailed engineering analysis should be performed to develop alternatives for the most economical solution such as re-conductoring, voltage conversion, static VAR compensation, etc. The cost of such measures, in most cases, will be entirely borne by the customer.

3.4 Standards of Construction

The purpose of this section is to provide a uniform guideline for distribution engineers when designing circuit modifications to address loading or voltage violations, support new customer load, and to improve reliability performance.

[1] IEEE Std 241-193 (Gray Book)

3.4.1 Line Extensions

The preferred construction standard for line extensions and reconductoring is open wire on crossarms. Three phase mainline backbone construction should be 336.4AA Tulip and 4/0 ACSR Penguin neutral. Larger conductors may be used when the anticipated load growth necessitates. New line extensions shall not introduce loading constraints lower than existing circuit mainline limitations. The standard wire size for overhead open wire lateral construction should be 1/0 ACSR Raven and 1/0 ACSR Raven neutral. Consideration should be given to installing 336.4AA and 4/0 ACSR neutral when the anticipated load dictates and in areas designated as a future mainline backbone within the distribution system Master Plan.

3.4.2 Single Phase Construction

Single phase laterals should be limited to residential areas serving no more than 75 amps of load. Additional phases are required for new construction applications where the lateral is anticipated to serve greater than 75 amps.

3.4.3 URD Design

All applicable Unitil Construction Standards shall be referenced when designing URD infrastructure. In addition, the following design guidelines shall be considered:

- URD developments (residential and commercial) shall be designed in a loop configuration such that a single cable fault can be isolated by manual switching whenever more than one customer will be served. Radial feed to a single URD customer is allowed.
- The impact of circuit load and voltage imbalance shall be considered during the initial design/layout phase of all single phase URD developments. Additional phases should be considered when load/voltage imbalance or protection concerns exist.
- The maximum single phase pad mount transformer size shall be limited to 75kVA.
- The maximum number of secondary and/or service runs terminated at the transformer shall be limited to four. Secondary splice boxes shall be used when more than four secondary and/or service runs are required.
- Primary cable pulling distances should be limited to 500’ in most cases for straight runs. Pull boxes, manholes, or sectionalizing cabinets shall be installed when longer distances exist between equipment or when the total bends in the duct bank exceed 180 degrees (not including sweeps at risers). Changes in direction shall be made gradually without the use of manufactured sweeps or conduit fittings that exceed 5 degrees.
- Spare conduits shall be installed under all paved surfaces.
- Secondary and service cable distances shall be considered when selecting transformer size and determining placement of equipment. Design shall maintain the service voltage requirements described in Section 3.3.2.
- Unless actual load data exists, 7.5kVA per household shall be used to determine transformer loading and secondary/service voltage drop.

3.5 Distribution Reliability

The purpose of this section is to define design options to address system reliability that should be considered as part of Distribution Planning in order to enhance the reliability of the distribution system.

3.5.1 Fault Isolating Devices

The installation of protective isolating devices should be considered in the planning process as listed below. Distribution protection design is detailed in the *Distribution Protection Guideline* (Guideline #GL-DT-TC-09).

3.5.2 Cutouts

Cutouts should be installed on the mainline pole feeding all lateral taps. The first pole in on the lateral is acceptable in cases where equipment of other space constraints do not allow the installation of a cutout on the mainline pole.

3.5.3 Reclosers

Reclosers should be considered in lieu of cutouts on laterals serving more than 200 customers.

3.5.4 Mainline Sectionalizing Devices

Sectionalizing devices, preferable gang operated load-break switches, should be considered on the mainline backbones of circuits in order to enable sectionalizing at approximately 4 MVA intervals or 500 customers.

3.5.5 Distribution Tap Wire

Covered wire should be used for all primary taps to overhead distribution transformers as it provides resistance to vegetation and animal contact.

3.5.6 Spacer Cable

Spacer cable construction or covered wire should be considered as an alternative to open wire construction in areas that are heavily treed, have a documented history of tree related outages or where a higher standard of reliability is desired. Spacer cable is also the preferred standard design when installing multiple circuits on a single pole line.

Unitil	Guidelines	Procedure No.	GL-DT-DS-02
	Distribution Engineering	Section No.	A-A
		Page No.	A-1
	Distribution Planning and Design Guidelines	Revision No.	3
		Revision Date	02/09/16
		Supersedes Date:	12/10/15

Appendix A - Request for Procedure/Change Form

Requestor: ____________________
Title: ____________________
Department: ____________________
Location/DOC: ____________________
Date: ____________________
Procedure No.: ____________________

Item(s)/Section to be changed (if applicable):
Section: ____________________
Page: ____________________
Figure: ____________________
Appendix ____________________
Other: ____________________

For New Procedures

Description of new procedure to be developed: ____________________

Reason for new procedure: ____________________

For Changes to Existing Procedures

Description of requested change(s): ____________________

Reason for requested change(s): ____________________

Instructions: The individual requesting a new procedure or change(s) to existing procedures shall complete this form and submit it to the Director of the applicable department. For changes to procedures please attach a copy of the existing procedure with revisions marked on the copy.

Requestors Signature: ____________________ Date: ____________________

For Reviewers Use Only
Change(s) Approved? YES NO If No, briefly explain ____________________
Changes Implemented? YES NO Date Implemented: ____________________   Reviewers Signature: Date:

APPENDIX F

UES CAPITAL DISTRIBUTION SYSTEM PLANNING EVALUATION 2016-2020

Unitil Energy Systems - Capital

Distribution System Planning Study
2016-2020

Prepared By:

Cyrus Esmaeili
Unitil Service Corp.
8/24/2015

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 2016 through the summer of 2020.

Projects currently under construction that are expected to be completed in 2015 are assumed to be in service for the beginning year of this study.

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($)
2016	Circuit 16H1: Transfer load to 1H4	Voltage 116.3V	Minimal
2017	Circuit 4X1: Convert a Small Portion of River Road	Voltage 116.4V	$45,000
2018	Circuit 18W2: Transfer load to 7W3 and Install Regulation on 7W3	Load at 90%	$67,000

2. System Configuration

The UES-Capital operating system takes service from the Eversource Energy. 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 Eversource Energy's 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.

This methodology does not directly forecast future DG interconnections or other DER projects/initiatives such as energy efficiency programs. Rather the impact of DG and other DER programs are inherent in the historical regression analysis by offsetting most recent peak loads thereby reducing projected growth rates at the circuit level. It is recognized that the reduction in circuit growth rates will lag DG interconnections and other DER projects implemented in a given year. However, since load forecasts are completed annually, the timing of projects identified in the planning process is continually reviewed and updated. In addition, during the annual capital budget development process a more detailed review of the most recent circuit peak loads, known load additions and interconnection applications either in study or recently processed is performed in order to ensure the timing of investments in system improvement projects is appropriate.

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

Ranking	Circuit	Average Growth Rate 2016-2020	Loading Increase 2016-2020 (KVA)
1	16H1	3.1%	184
2	8H2	2.3%	105
3	1H6	2.1%	115
4	13W3	2.0%	340
5	2H4	1.7%	58

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 transformers (CT), protection device settings, switches, circuit exit conductors, regulators, and transformers. Overall circuit ratings are based upon the most restrictive of these limiting elements. The distribution system circuit limitations can be referenced in Appendix B. Summer and winter peak load projections for the five year study period, listed in Appendix A, were compared to these circuit ratings.

Projected loads reaching certain thresholds prompted a closer assessment of the conditions. Shading, as shown below, has been added to the projection analysis to provide a visual representation of potential problem areas. The analysis of circuits and transformers reaching 90% or higher of the normal rating is described in the following section.

Legend

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

6. Transformer and Circuit Loading Analysis

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 loading reaches 90% of its seasonal rating are listed below. Summer and winter transformer loading graphs are included in Appendix C.

Bow Bog 18T2:
Peak demand loading for the Bow Bog 18T2 transformer is projected to reach as much as 3,000 kVA (90% of the transformer's summer normal rating) in 2018 and increase to as much as 3,066 kVA (92% of the summer normal rating) in 2020.

6.2. Distribution Circuit Loadings

There is no distribution substation equipment where the projected load will reach 90% or more of their rating during this study period. The summer and winter circuit loading graphs are included in Appendix D.

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).

There are no distribution stepdown transformers that are projected to exceed their normal rating during the study period.

6.4. Phase Imbalances

All of the circuits within the UES-Capital service territory were reviewed for phase balance. 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 Engineering Work Requests (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**	**Expected % imbalance**
1H4	37%	Transfer 40 kVA from phase A to phase B and phase C, equally split	<5%

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. The circuit analysis performed includes voltage drop, load flow, and protection analysis. Milsoft Windmil software is used to model the system impedances and loads to identify potential problems 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 2015. Other circuits not shown on this listing were reviewed for planning purposes. However, those circuits were not part of the three year cycle.

<table>
<tr><th>Substation</th><th>Circuit</th><th>Substation</th><th>Circuit</th></tr>
<tr><td rowspan="6">Bridge St S/S</td><td>1H1</td><td rowspan="3">West Concord S/S</td><td>2H1</td></tr>
<tr><td>1H2</td><td>2H2</td></tr>
<tr><td>1H3</td><td>2H4</td></tr>
<tr><td>1H4</td><td rowspan="3">Gulf St S/S</td><td>3H1</td></tr>
<tr><td>1H5</td><td>3H2</td></tr>
<tr><td>1H6</td><td>3H3</td></tr>
<tr><td rowspan="2">Hollis S/S</td><td>8X3</td><td rowspan="3">Boscawen S/S</td><td>13W1</td></tr>
<tr><td>8X5</td><td>13W2</td></tr>
<tr><td rowspan="2">Langdon St S/S</td><td>14H1</td><td>13W3</td></tr>
<tr><td>14H2</td><td></td><td></td></tr>
</table>

7.1. Voltage Concerns

Voltage drop analysis is performed to identify areas where the primary voltage on the circuit may be outside of a pre-determined acceptable range. The acceptable range used for this analysis is 117-125 V on a 120 V base on the circuit primary conductor. The following table summarizes the areas where voltage is expected to be outside of this range. The table is sorted by circuit and year.

Circuit	Year	Voltage	Location
4X1	2016	116.4 V	River Rd (P.18), Concord
16H1	2016	116.3 V	Canton Circle, Concord
16H1	2016	116.8 V	Gully Hill Rd, Concord

7.2. Overload Conditions

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

Circuit	Year	Percent Loading	Distribution Equipment (summer normal limit)	Location
3H1	2016	96%	95N Fuse (105 Amps)	P.34 Perley St, Concord
4W3	2016	92%	30N Fuse (38 Amps)	P.23 Sewalls Falls Rd
3H1	2018	90%	75N Fuse (80 Amps)	P.4 Concord St, Concord
8H2	2019	90%	50N Fuse (54 Amps)	P.26 Pembroke Road, Concord

7.3. Protection Concerns

Analysis is performed on the circuits to identify protective devices that violate Unitil's distribution protection sensitivity and coordination criteria. EWR's or capital budget projects are issued to address the concerns identified.

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. Circuit 16H1: Transfer load to 1H4 – (2016)

Circuit analysis has identified that the primary voltage on Canton Circle may become as low as 116.3V in 2016 and as low as 114.6V in 2020.

An AMI voltage recording meter recorded a minimum service voltage of 116V on Canton Street, on June, 30th 2015

This project will consist of transferring the 16H1 load between pole 40, on Gully Hill Road, and pole 30, on Gully Hill Road, to circuit 1H4. Pad 7 on Canton Circle will also be transferred to the shorter lateral.

The primary voltage on Canton Circle is expected to increase to approximately 117.5V in 2020, due to implementation of this project.

Project Cost (without construction overheads): Minimal

8.2. Circuit 4X1: Convert a Small Portion of River Road – (2017)

Circuit analysis has identified that the primary voltage on pole 18, River Road, may become as low as 116.4V, in 2016. There are no AMI voltage meters in this area. Where possible, recorded maximum regulator tap positions were used to better calculate voltages actually experienced.

Data for the voltage regulator bank on, River Road, spanning pole 19 through pole 21, indicates a maximum rise of 8 taps for any regulator in this bank. This maximum rise indicates a minimum primary voltage on the source side of any regulator of approximately 118V. This data was collected on 5/1/15.

This project consists of converting three phase 4.16kV to 34.5kV, from pole 39 on Washington Street to pole 12 on River Road (~2000ft). The step-down transformers and reclosers will be moved to the Pole 12 vicinity and AMI metering will be installed at the step-down transformers.

Although the circuit model indicates low voltage in 2016, it is recommended to defer the implementation of this solution until 2017, because of the analysis of actual voltage regulator taps.

The primary voltage on pole 18, River Road, is expected to increase to approximately 118.3V in 2020, after implementation of this project.

Project Cost (without construction overheads): $45,000

8.3. Circuit 18W2: Transfer load to 7W3 and Install Regulation on 7W3 – (2018)

Loading on 18T2 is expected to reach 90% of summer normal rating in 2018 and will increase to 92% in 2020. The thermal readings from 2014 indicate 18W2 loading had reached 82% of the summer normal rating. Additionally, the 1/0 Al underground circuit exit, is projected to approach 90% loading in 2020.

<u>Proposed,</u>
This project consists of transferring approximately 800kVA from 18W2 to 7W3 via the circuit tie at pole 67 on Bow Bog Road. This will require three regulators to be installed on Bow Bog Road, in the vicinity of pole 69.

Loading on the 18T2 transformer at Bow Bog is expected to decrease to 68% of its summer normal rating in 2020, but adversely increase loading on the 7T1 transformer high side fusing to 87% of its summer normal rating in 2020.

Project Cost (without construction overheads): $67,000

Transferring load from Bow Bog to Bow Junction Substation is the preferred option because it delays significant substation upgrades, although, this will impact tie capability between Iron Works, Bow Junction and Montgomery Street substations. After the contingency restoration switching of the underground circuit 21W1P, during summer peak, loading on 7T1 high side fusing will reach 90% of its summer normal rating, using 2014 summer loads, and is expected to reach 100% of that rating by 2019.

Alternative 1, Add capacity at Bow Bog Substation: This project consists of adding a 7.5MVA, 34.4/19.9kV to 13.8/7.9kV, padmount transformer (to be 18T1), pole mounted regulation, and circuit exits at Bow Bog Substation.

Loading of the new 18T1 transformer is expected to be 41% of its nameplate rating in 2020, after implementation of this project. Additionally, this project will improve tie capability among Iron Works, Bow Junction and Montgomery.

Project Cost (without construction overheads): $550,000

This alternative prevents the contingency loading concerns described in the preferred solution, has a positive effect on reliability and is consistent with the system master plan to improve this area's 13.8kV capacity. In addition, this provides a backup for a transformer which was originally purchased in 1980 and doesn't have a spare.

9. Circuit Tie Analysis

A detailed analysis was performed on ten mainline distribution circuit ties in the UES-Capital System. The circuit ties were evaluated using 2016 projected summer peak loads and were evaluated for loading and voltage violations. It is understood that marginal low voltage, coordination and protection sensitivity concerns may exist while circuits are tied. For the purpose of this review all elements were allowed to operate up to their long term emergency ratings while circuits are tied.

Detailed results of this analysis can be found in appendix F.

Projects to create additional circuit ties or increase circuit tie capability will be identified and justified as part of the UES-Capital Reliability Study.

10. 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.

10.1. 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 should be constructed to 336.4 AA open wire conductor or equivalent and the appropriate insulation level should be used, even if conditions do not require it at the time of construction.

10.2. Future Considerations

10.2.1. Bow Junction, Ironworks and Bow Bog Substation area

When load levels grow beyond this areas transformation capacity, upgrade options include adding step-down transformers, capacity at Bow Bog Substation or capacity at Ironworks Substation.

North Spring Street 4.16kV on circuit 3H1 will be converted to 13.8kV, providing a tie between 21W1P and 7W4.

Silk Farm Road, Logging Hill Road and Bow Center Road will be upgraded to mainline, improving tie capability between 22W3 and 18W2.

Robinson Road will be upgraded to mainline, improving tie capability between 7W3 and 18W2.

Clinton Street will be upgraded to mainline, improving tie capability between 22W1 and 21W1P

10.2.2. Hollis Substation area

Build a new 34.5 kV circuit out of a new substation, Broken Ground. This would be the first step toward resolving the issue of increasing size of 8X3 and 8X5. A new 34.5 kV circuit will eventually allow Hollis area loads to be re-distributed, after additional improvements are completed.

Old Loudon Road and Horse Corner Road will be converted from 13.8kV to 34.5kV, allowing for a new circuit out of Hollis Substation to feed Chichester and Epsom.

Circuit 8X5 will be extended along Sheep Davis Road to create another tie with 8X3.

4.16kV circuits along Loudon Road and East Side Drive will be upgraded to mainline, improving tie capability between circuits 8H1, 8H2, 24H1 and 24H2.

10.2.3. North Western part of Concord

Mountain Road, circuit 15W1, will be upgraded to mainline, improving tie capability with 4W3.

Fisherville Road and North State Street, circuit 4W4, will be upgraded to mainline, to eventually allow tie capability with the future 13.8kV West Concord Substation.

10.2.4. Penacook and Boscawen

Convert the 4.16kV along River Rd, Penacook, to 34.5kV. This would improve voltages in the area and provide future tie capabilities with 4W4.

Convert North Main Street, circuit 13W2, to 34.5kV, creating backup for the 37 Line.

10.2.5. Downtown Concord Overhead System

Upgrade West Concord Substation's circuits to 13.8kV. This will provide capacity to the downtown area allowing for any unexpected load additions and eventually provide additional 13.8kV tie capability.

10.2.6. Downtown Concord Underground System

The first portion of this system which may need upgrading is the 13.8kV circuits. These upgrades would most likely be mainline conductor replacement with 350 kcmil Cu cable and mainline connections upgraded to 600A.

11. Conclusion

The projects identified in this study attempt to 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 system reliability. 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

	Summer Peak Loads (three-phase kVA)					
	Projected					
Distribution Element	2015	2016	2017	2018	2019	2020
Boscawen 13T1 Xfmr	3,427	3,457	3,486	3,516	3,545	3,575
13W1	1,215	1,219	1,223	1,228	1,232	1,236
13W2	2,337	2,364	2,390	2,417	2,443	2,470
Boscawen 13T2 Xfmr	4,869	4,954	5,039	5,124	5,209	5,295
13W3	4,869	4,954	5,039	5,124	5,209	5,295
Boscawen 13X4	2,863	2,863	2,863	2,863	2,863	2,863
Bow Bog 18T1 Xfmr	0	0	0	0	0	0
18W1	0	0	0	0	0	0
Bow Bog 18T2 Xfmr	2,901	2,934	2,967	3,000	3,033	3,066
18W2	2,901	2,934	2,967	3,000	3,033	3,066
Bow Junction 7X1	1,672	1,691	1,710	1,730	1,749	1,768
Bow Junction 7T2 Xfmr	8,679	8,778	8,877	8,975	9,074	9,173
7W3	5,647	5,711	5,776	5,840	5,904	5,968
7W4	3,417	3,456	3,495	3,534	3,573	3,611
Bridge Street 1T1 Xfmr	4,449	4,499	4,548	4,598	4,647	4,697
1H3	1,691	1,710	1,729	1,749	1,768	1,787
1H4	1,079	1,091	1,103	1,115	1,128	1,140
1H5	1,740	1,759	1,777	1,796	1,814	1,833
Bridge Street 1T2 Xfmr	5,309	5,367	5,424	5,482	5,539	5,597
1H1	2,551	2,580	2,609	2,638	2,667	2,696
1H2	1,412	1,412	1,412	1,412	1,412	1,412
1H6	1,377	1,406	1,435	1,464	1,493	1,521
Bridge Street 1X7P	2,659	2,689	2,720	2,750	2,780	2,810
Bridge Street 1X7A	2,797	2,825	2,854	2,882	2,910	2,939
Gulf Street 3T1 Xfmr	3,548	3,575	3,602	3,629	3,656	3,683
3H1	1,882	1,905	1,928	1,950	1,973	1,995
3H2	1,666	1,670	1,674	1,679	1,683	1,688
Gulf Street 3T2 Xfmr	1,196	1,210	1,224	1,238	1,251	1,265
3H3	1,196	1,210	1,224	1,238	1,251	1,265
Hazen Drive 24T1 Xfmr	1,102	1,111	1,119	1,128	1,136	1,145
24H1	1,102	1,111	1,119	1,128	1,136	1,145
Hazen Drive 24T2 Xfmr	1,858	1,862	1,865	1,869	1,873	1,876
24H2	1,858	1,862	1,865	1,869	1,873	1,876
24H3	1,858	1,862	1,865	1,869	1,873	1,876
Hollis 8T1 Xfmr	2,316	2,355	2,395	2,434	2,473	2,512
8H1	1,276	1,290	1,305	1,319	1,334	1,348
8H2	1,144	1,170	1,197	1,223	1,250	1,276
Hollis 8X3	12,750	12,890	13,029	13,168	13,307	13,447
Hollis 8X5	8,684	8,782	8,881	8,980	9,079	9,177
Iron Works Road 22T1 Xfmr	9,024	9,125	9,225	9,325	9,426	9,526
22W1	4,423	4,471	4,519	4,567	4,615	4,663
22W2	150	152	153	155	157	159
22W3	4,546	4,597	4,649	4,701	4,752	4,804
Langdon Street 14T1 Xfmr	1,674	1,688	1,701	1,715	1,729	1,742
14H1	376	381	385	389	393	398
14H2	1,396	1,407	1,417	1,427	1,437	1,447
Langdon 14X3 (McKerly's - Harris Hall	703	711	719	727	735	743
Penacook 4X1	7,742	7,831	7,920	8,009	8,098	8,187
Penacook 4T3 Xfmr	8,749	8,814	8,878	8,943	9,007	9,072
4W3	3,624	3,630	3,636	3,643	3,649	3,656
4W4	5,125	5,184	5,242	5,300	5,358	5,417

	Summer Peak Loads (three-phase kVA)					
	Projected					
Distribution Element	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Pleasant Street 6X3	10,376	10,495	10,615	10,734	10,853	10,973
Montgomery Street 23T1 Xfmr	4,759	4,814	4,869	4,923	4,978	5,033
21W1P	2,297	2,324	2,350	2,376	2,403	2,429
21W1A	2,462	2,490	2,519	2,547	2,575	2,604
Storrs Street 21T1 Xfmr	4,759	4,814	4,869	4,923	4,978	5,033
21W1P	2,297	2,324	2,350	2,376	2,403	2,429
21W1A	2,462	2,490	2,519	2,547	2,575	2,604
Terrill Park 16T1 Xfmr	2,890	2,953	3,015	3,077	3,139	3,201
16H1	1,429	1,475	1,521	1,567	1,613	1,659
16H3	1,528	1,546	1,563	1,581	1,598	1,616
Terrill Park 16X4	2,950	2,966	2,982	2,998	3,014	3,030
Terrill Park 16X5	1,993	1,993	1,993	1,993	1,993	1,993
Terrill Park 16X6	582	582	582	582	582	582
West Concord 2T1 Xfmr	4,230	4,279	4,329	4,379	4,428	4,478
2H1	1,456	1,473	1,489	1,506	1,523	1,540
2H2	2,133	2,158	2,182	2,207	2,231	2,256
2H4	1,157	1,172	1,186	1,201	1,215	1,230
West Portsmouth 15T1 Xfmr	4,757	4,812	4,866	4,921	4,976	5,031
15W1	3,195	3,232	3,268	3,305	3,342	3,379
15W2	1,562	1,580	1,598	1,616	1,634	1,652
West Portsmouth 15T2 Xfmr	1,106	1,114	1,122	1,130	1,138	1,147
15H3	1,106	1,114	1,122	1,130	1,138	1,147
33 Line - Little Pond Tap	173	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

	Winter Peak Loads (three-phase kVA)					
	Projected					
Distribution Element	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Boscawen 13T1 Xfmr	3,137	3,173	3,209	3,245	3,281	3,317
13W1	1,219	1,233	1,247	1,261	1,275	1,289
13W2	1,918	1,940	1,962	1,984	2,006	2,028
Boscawen 13T2 Xfmr	5,303	5,364	5,425	5,486	5,547	5,608
13W3	5,303	5,364	5,425	5,486	5,547	5,608
Boscawen 13X4	3,014	3,014	3,014	3,014	3,014	3,014
Bow Bog 18T1 Xfmr	0	0	0	0	0	0
18W1	0	0	0	0	0	0
Bow Bog 18T2 Xfmr	2,694	2,708	2,722	2,737	2,751	2,765
18W2	2,694	2,708	2,722	2,737	2,751	2,765
Bow Junction 7X1	1,514	1,514	1,514	1,514	1,514	1,514
Bow Junction 7T2 Xfmr	7,576	7,641	7,706	7,771	7,836	7,901
7W3	5,235	5,262	5,290	5,317	5,344	5,371
7W4	2,341	2,379	2,416	2,454	2,492	2,530
Bridge Street 1T1 Xfmr	3,459	3,500	3,541	3,583	3,624	3,666
1H3	1,579	1,584	1,588	1,593	1,597	1,601
1H4	790	796	801	807	813	818
1H5	1,156	1,188	1,220	1,252	1,284	1,316
Bridge Street 1T2 Xfmr	3,460	3,499	3,539	3,579	3,619	3,658
1H1	1,917	1,939	1,961	1,983	2,005	2,027
1H2	807	816	826	835	844	853
1H6	865	875	885	895	905	915
Bridge Street 1X7P	1,784	1,818	1,853	1,888	1,923	1,958
Bridge Street 1X7A	1,930	1,952	1,974	1,997	2,019	2,041
Gulf Street 3T1 Xfmr	2,651	2,681	2,712	2,742	2,773	2,803
3H1	1,355	1,370	1,386	1,401	1,417	1,433
3H2	1,296	1,311	1,326	1,341	1,356	1,371
Gulf Street 3T2 Xfmr	999	1,010	1,022	1,033	1,045	1,056
3H3	999	1,010	1,022	1,033	1,045	1,056
Hazen Drive 24T1 Xfmr	1,413	1,430	1,446	1,462	1,478	1,495
24H1	1,413	1,430	1,446	1,462	1,478	1,495
Hazen Drive 24T2 Xfmr	1,729	1,757	1,784	1,812	1,840	1,867
24H2	1,729	1,757	1,784	1,812	1,840	1,867
24H3	1,729	1,757	1,784	1,812	1,840	1,867
Hollis 8T1 Xfmr	2,398	2,426	2,454	2,482	2,510	2,538
8H1	1,635	1,646	1,658	1,670	1,681	1,693
8H2	877	895	913	931	949	967
Hollis 8X3	11,072	11,291	11,511	11,730	11,949	12,168
Hollis 8X5	8,665	8,764	8,864	8,964	9,063	9,163
Iron Works Road 22T1 Xfmr	6,511	6,548	6,585	6,623	6,660	6,697
22W1	2,709	2,740	2,771	2,802	2,834	2,865
22W2	113	114	115	116	118	119
22W3	3,689	3,694	3,699	3,704	3,709	3,714
Langdon Street 14T1 Xfmr	1,489	1,529	1,568	1,608	1,648	1,687
14H1	291	294	298	301	304	308
14H2	1,295	1,334	1,372	1,411	1,450	1,489
Langdon 14X3 (McKerly's - Harris Hall	610	622	635	647	659	671
Penacook 4X1	7,290	7,374	7,458	7,542	7,626	7,710
Penacook 4T3 Xfmr	7,443	7,473	7,503	7,534	7,564	7,594
4W3	3,142	3,162	3,183	3,204	3,224	3,245
4W4	4,301	4,311	4,321	4,330	4,340	4,349

	Winter Peak Loads (three-phase kVA)					
	Projected					
Distribution Element	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Pleasant Street 6X3	7,227	7,277	7,327	7,377	7,427	7,476
Montgomery Street 23T1 Xfmr	1,458	1,484	1,511	1,537	1,564	1,590
21W1P	1,458	1,484	1,511	1,537	1,564	1,590
21W1A	1,602	1,620	1,639	1,657	1,676	1,694
Storrs Street 21T1 Xfmr	1,602	1,620	1,639	1,657	1,676	1,694
21W1P	1,458	1,484	1,511	1,537	1,564	1,590
21W1A	1,602	1,620	1,639	1,657	1,676	1,694
Terrill Park 16T1 Xfmr	1,946	1,968	1,991	2,013	2,035	2,058
16H1	1,038	1,050	1,062	1,074	1,086	1,098
16H3	1,182	1,196	1,209	1,223	1,236	1,250
Terrill Park 16X4	2,375	2,382	2,389	2,396	2,403	2,410
Terrill Park 16X5	1,737	1,737	1,737	1,737	1,737	1,737
Terrill Park 16X6	494	500	506	512	517	523
West Concord 2T1 Xfmr	3,559	3,579	3,599	3,620	3,640	3,660
2H1	1,007	1,020	1,033	1,045	1,058	1,071
2H2	2,035	2,047	2,058	2,070	2,081	2,093
2H4	1,283	1,283	1,283	1,283	1,283	1,283
West Portsmouth 15T1 Xfmr	3,824	3,865	3,906	3,948	3,989	4,030
15W1	2,693	2,724	2,755	2,786	2,817	2,848
15W2	1,131	1,141	1,151	1,162	1,172	1,182
West Portsmouth 15T2 Xfmr	804	813	822	832	841	850
15H3	804	813	822	832	841	850
33 Line - Little Pond Tap	130	136	142	148	154	159

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-Capital Summer Circuit Ratings

Distribution Element	Voltage Base (kV)	Breaker or Recloser Continuous Rating Normal	Breaker or Recloser Continuous Rating LTE	Breaker or Recloser Trip Level Normal	Breaker or Recloser Trip Level LTE	Current Transformer Present Tap Selection Normal	Current Transformer Present Tap Selection LTE	Switch Continuous Rating Normal	Switch Continuous Rating LTE	Fuse Minimum Melt Normal	Fuse Minimum Melt LTE	Regulator Rating Normal	Regulator Rating LTE	Conductor Rating Normal	Conductor Rating LTE	Transformer Rating Normal	Transformer Rating LTE	Overall Rating (kVA) Normal	Overall Rating (kVA) LTE	Overall Rating (A) Normal	Overall Rating (A) LTE	SCADA Alarm Operational High	SCADA Alarm Emergency High	Bypass: Fuse or Switch Min. Melt or Rating Normal	Bypass: Fuse or Switch Min. Melt or Rating LTE			Limiting Element Normal	Limiting Element 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	338	338			5,354	5,737	224	240	202	240			2	6	Trip	Reg
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	304	342	600	600	600	600			393.6	459.2	531	645			7,266	8,175	304	342	274	342			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			165	165			3,824	3,944	160	165	144	165			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	668	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	165	165			9,561	9,561	160	160	144	160			6	6	Reg	Reg
Bridge Street 1X7A	34.5									200	200			165	165			9,860	9,860	165	165	149	165			7	7	Wire	Wire
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	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	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			165	165			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	224	252							240	240	247	294			5,354	5,737	224	240	202	240			2	6	Trip	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	320	360	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 Ce*	34.5									40	40							2,390	2,390	40	40	36	40			5	5	Fuse	Fuse
Penacook 4X1	34.5	560	560	262.4	295.2					490	490			531	645			15,680	17,640	262	295	236	295			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					165	165			3,944	3,944	165	165	149	165			7	7	Wire	Wire
21W1A	13.8													165	165			3,944	3,944	165	165	149	165			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													165	165			3,944	3,944	165	165	149	165			7	7	Wire	Wire
21W1A	13.8	560	560											165	165			3,944	3,944	165	165	149	165			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					800	800			1211	1211					787	811	5,670	5,764	787	800	708	800			8	3	Xfmr	CT
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	480	540							480	480	475	475			3,423	3,423	475	475	428	475			7	7	Wire	Wire
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

UES-Capital Summer Circuit Ratings

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
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

UES-Capital Winter Circuit Ratings

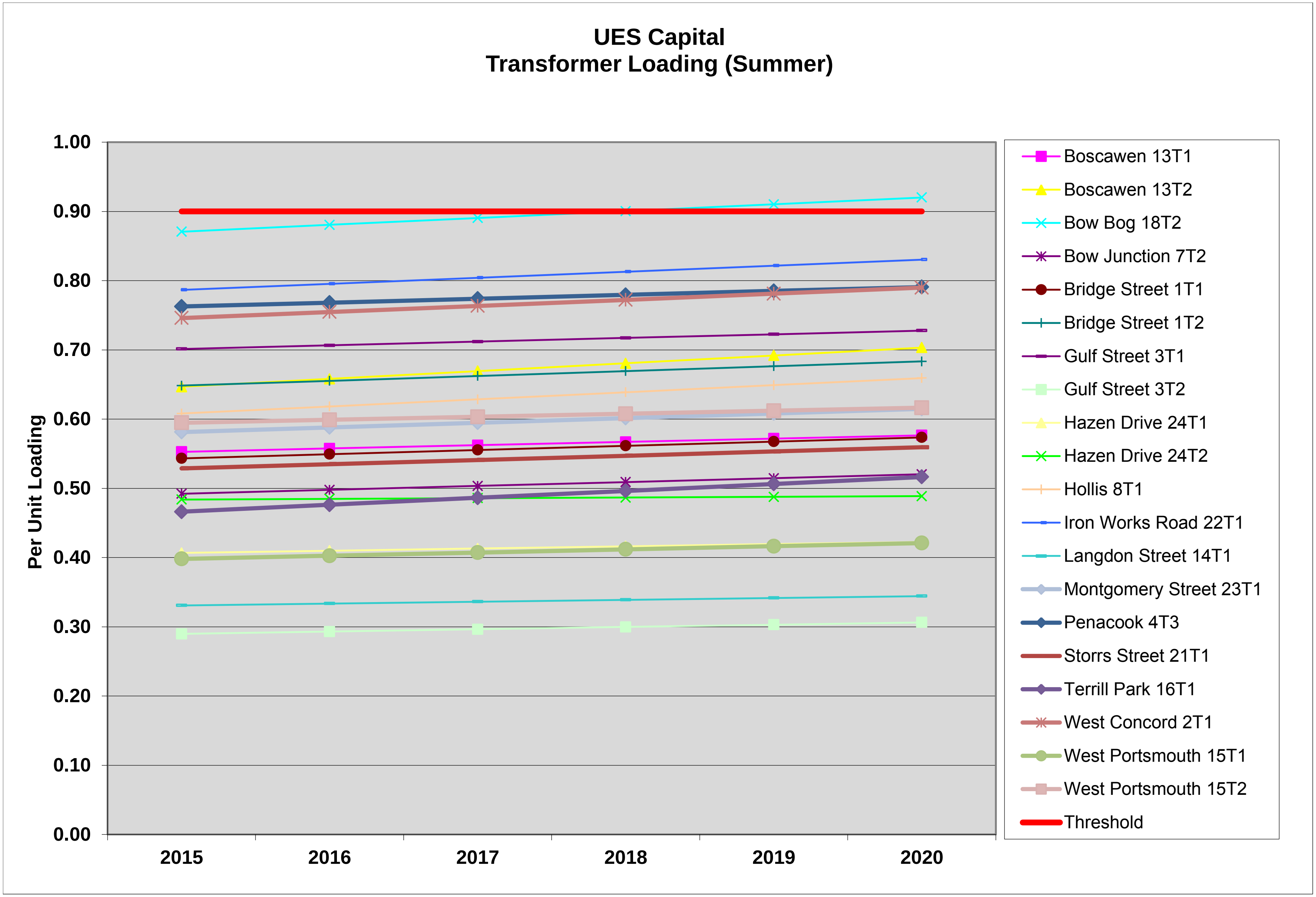
Distribution Element	Voltage Base (kV)	Breaker or Recloser Continuous Rating Normal	Breaker or Recloser Continuous Rating LTE	Breaker or Recloser Trip Level Normal	Breaker or Recloser Trip Level LTE	Current Transformer Present Tap Selection Normal	Current Transformer Present Tap Selection LTE	Switch Continuous Rating Normal	Switch Continuous Rating LTE	Fuse Minimum Melt Normal	Fuse Minimum Melt LTE	Regulator Rating Normal	Regulator Rating LTE	Conductor Rating Normal	Conductor Rating LTE	Transformer Rating Normal	Transformer Rating LTE	Overall Rating (kVA) Normal	Overall Rating (kVA) LTE	Overall Rating (A) Normal	Overall Rating (A) LTE	SCADA Alarm Operational High	SCADA Alarm Emergency High	Bypass: Fuse or Switch Min. Melt or Rating Normal	Bypass: Fuse or Switch Min. Melt or Rating LTE			Limiting Element Normal	Limiting Element LTE
Boscawen 13T1 Xfmr	13.8									365	365					292	304	6,980	7,260	292	304	263	304			8	8	Xfmr	Xfmr
13W1	13.8	560	560	224	252	300	300	600	600			240	240	338	338			5,354	5,737	224	240	202	240			2	6	Trip	Reg
13W2	13.8	560	560	224	252	300	300	600	600			240	240	483	528			5,354	5,737	224	240	202	240			2	6	Trip	Reg
Boscawen 13T2 Xfmr	13.8									315	315					384	403	7,529	7,529	315	315	284	315			5	5	Fuse	Fuse
13W3	13.8	560	560	304	342	600	600	600	600			475.6	475.6	694	777			7,266	8,175	304	342	274	342			2	2	Trip	Trip
Boscawen 13X4	34.5	560	560	272	306					202	202			322	354			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															158	167	3,780	3,980	158	167	142	167			8	8	Xfmr	Xfmr
18W2	13.8	560	560	160	180	600	600	200	200	280	280			165	165			3,824	3,944	160	165	144	165			2	7	Trip	Wire
Bow Junction 7X1	34.5	560	560	192	216	600	600							322	354			11,473	12,907	192	216	173	216			2	2	Trip	Trip
Bow Junction 7T2 Xfmr	13.8									480	480					575	575	11,473	11,473	480	480	432	480			5	5	Fuse	Fuse
7W3	13.8	800	800	384	432	600	600					475.6	475.6	694	777			9,178	10,326	384	432	346	432			2	2	Trip	Trip
7W4	13.8	800	800	480	540	600	600					668	668	694	777			11,473	12,907	480	540	432	540			2	2	Trip	Trip
Bridge Street 1T1 Xfmr	4.16									1659	1659					1282	1347	9,240	9,702	1282	1347	1154	1347			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	653	731			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					1171	1171	8,436	8,436	1171	1171	1054	1171			8	8	Xfmr	Xfmr
1H1	4.16	560	560	448	504							480	480	694	777			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	694	777			2,306	2,594	320	360	288	360			2	2	Trip	Trip
Bridge Street 1X7P	34.5	560	560									160	160	165	165			9,561	9,561	160	160	144	160			6	6	Reg	Reg
Bridge Street 1X7A	34.5									200	200			165	165			9,860	9,860	165	165	149	165			7	7	Wire	Wire
Gulf Street 3T1 Xfmr	4.16									1211	1211					798	838	5,750	6,040	798	838	718	838			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	486	543			2,421	2,724	336	378	302	378			2	2	Trip	Trip
Gulf Street 3T2 Xfmr	4.16									663	663					647	679	4,660	4,780	647	663	582	663			8	5	Xfmr	Fuse
3H3	4.16	560	560	400	450									424	464			2,882	3,242	400	450	360	450			2	2	Trip	Trip
Hazen Drive 24T1 Xfmr	4.16									647	647					426	450	3,070	3,240	426	450	383	450			8	8	Xfmr	Xfmr
24H1	4.16	560	560	384	432									322	354			2,320	2,551	322	354	290	354			7	7	Wire	Wire
Hazen Drive 24T2 Xfmr	4.16									1045	1045					602	636	4,340	4,580	602	636	542	636			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					598	634	4,310	4,570	598	634	538	634			8	8	Xfmr	Xfmr
8H1	4.16	600	600	384	432	300	300	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	300	300					694	777			2,162	2,162	300	300	270	300			3	3	CT	CT
Hollis 8X3	34.5	560	560	448	504							668.8	668.8	486	543			26,771	30,117	448	504	403	504			2	2	Trip	Trip
Hollis 8X5	34.5	560	560	400	450							668.8	668.8	486	543			23,902	26,890	400	450	360	450			2	2	Trip	Trip
Hollis - Alton Woods URD	34.5									40	40			165	165			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					582	611	11,473	11,473	480	480	432	480			5	5	Fuse	Fuse
22W1	13.8	560	560	224	252							240	240	322	354			5,354	5,737	224	240	202	240			2	6	Trip	Reg
22W2	13.8	560	560	224	252							240	240	694	777			5,354	5,737	224	240	202	240			2	6	Trip	Reg
22W3	13.8	560	560	320	360	300	300					475.6	475.6	694	777			7,171	7,171	300	300	270	300			3	3	CT	CT
Langdon Street 14T1 Xfmr	4.16									1211	1211					798	838	5,750	6,040	798	838	718	838			8	8	Xfmr	Xfmr
14H1	4.16	560	560	448	504							480	480	605	677			3,228	3,459	448	480	403	480			2	6	Trip	Reg
14H2	4.16	560	560	448	504							480	480	702	787			3,228	3,459	448	480	403	480			2	6	Trip	Reg
Langdon 14X3 (McKerly's - *Harris Hall Ce*	34.5									40	40							2,390	2,390	40	40	36	40			5	5	Fuse	Fuse
Penacook 4X1	34.5	560	560	262.4	295.2					490	490			694	777			15,680	17,640	262	295	236	295			2	2	Trip	Trip
Penacook 4T3 Xfmr	13.8					600	600			480	480					584	584	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					475.6	475.6	369	405			7,649	8,605	320	360	288	360			2	2	Trip	Trip
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									291.45	291.45					17,416	17,416	291	291	262	291			6	6	Reg	Reg
Montgomery Street 23T1 Xfmr	13.8					600	600			343	343					430	451	8,187	8,187	343	343	308	343			5	5	Fuse	Fuse
21W1P	13.8							600	600					165	165			3,944	3,944	165	165	149	165			7	7	Wire	Wire
21W1A	13.8													165	165			3,944	3,944	165	165	149	165			7	7	Wire	Wire
Storrs Street 21T1 Xfmr	13.8									490	490					433	459	10,350	10,970	433	459	390	459			8	8	Xfmr	Xfmr
21W1P	13.8													165	165			3,944	3,944	165	165	149	165			7	7	Wire	Wire
21W1A	13.8	560	560											165	165			3,944	3,944	165	165	149	165			7	7	Wire	Wire
Terrill Park 16T1 Xfmr	4.16									1211	1211					962	1001	6,930	7,210	962	1001	866	1001			8	8	Xfmr	Xfmr
16H1	4.16	560	560									480	480	443	495			3,192	3,459	443	480	399	480			7	6	Wire	Reg
16H2	4.16	560	560									480	480	694	777			3,459	3,459	480	480	432	480			6	6	Reg	Reg
16H3	4.16	560	560	448	504							480	480	694	777			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					800	800			1211	1211					910	960	5,764	5,764	800	800	720	800			3	3	CT	CT
2H1	4.16	600	600	336	378							480	480	369	405			2,421	2,724	336	378	302	378			2	2	Trip	Trip
2H2	4.16	600	600	480	540							480	480	475	475			3,423	3,423	475	475	428	475			7	7	Wire	Wire
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	486	543			2,306	2,594	320	360	288	360			2	2	Trip	Trip
West Portsmouth 15T1 Xfmr	13.8									500	500					584	610	11,951	11,951	500	500	450	500			5	5	Fuse	Fuse
15W1	13.8	600	600	248	279							240	240	312	348			5,737	5,737	240	240	216	240			6	6	Reg	Reg

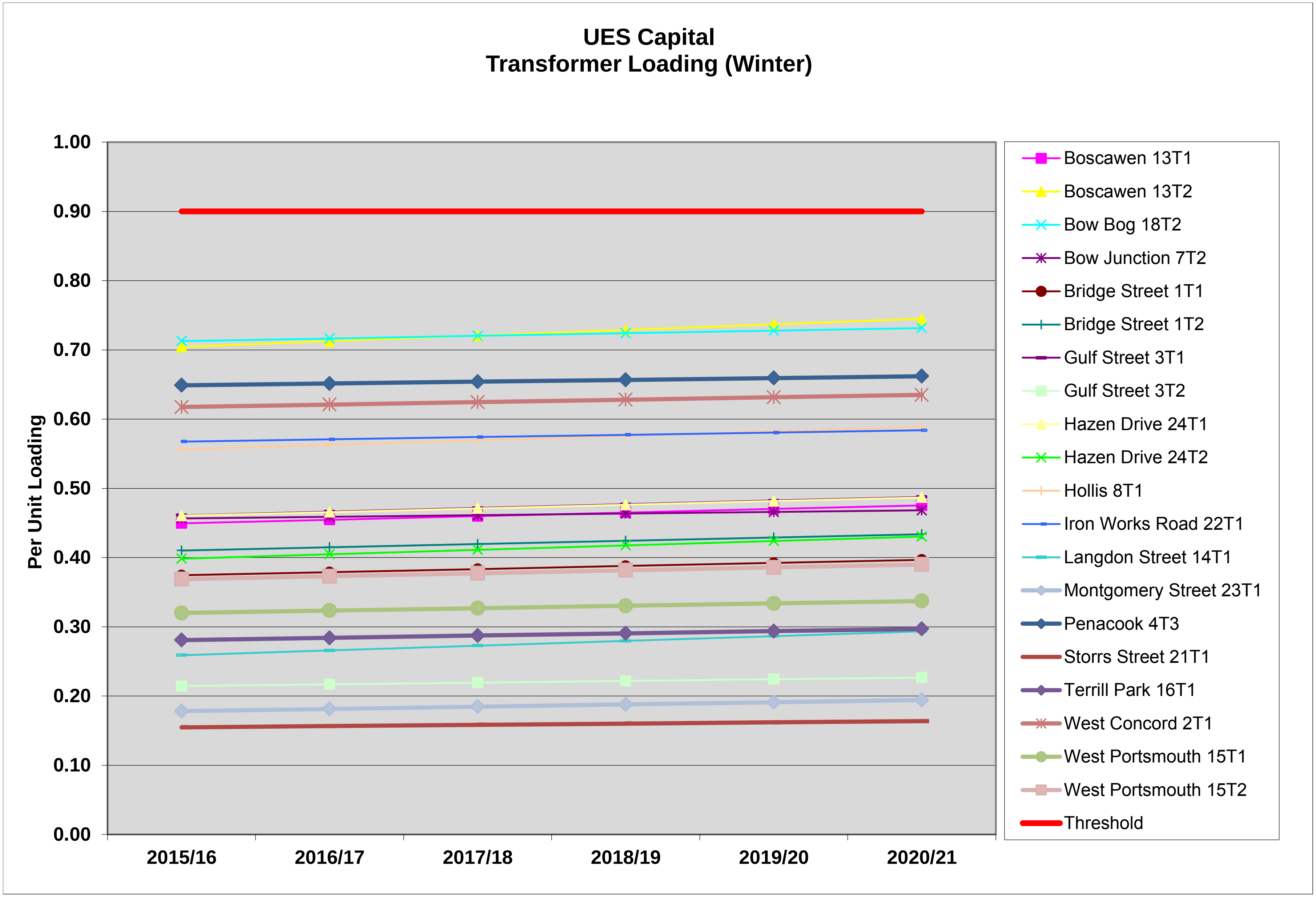
UES-Capital Winter Circuit Ratings

Distribution Element	Voltage Base (kV)	Breaker or Recloser Continuous Rating Normal	Breaker or Recloser Continuous Rating LTE	Breaker or Recloser Trip Level Normal	Breaker or Recloser Trip Level LTE	Current Transformer Present Tap Selection Normal	Current Transformer Present Tap Selection LTE	Switch Continuous Rating Normal	Switch Continuous Rating LTE	Fuse Minimum Melt Normal	Fuse Minimum Melt LTE	Regulator Rating Normal	Regulator Rating LTE	Conductor Rating Normal	Conductor Rating LTE	Transformer Rating Normal	Transformer Rating LTE	Overall Rating (kVA) Normal	Overall Rating (kVA) LTE	Overall Rating (A) Normal	Overall Rating (A) LTE	SCADA Alarm Operational High	SCADA Alarm Emergency High	Bypass: Fuse or Switch Min. Melt or Rating Normal	Bypass: Fuse or Switch Min. Melt or Rating LTE		Limiting Element Normal	Limiting Element LTE
15W2	13.8	600	600	320	360							240	240	694	777			5,737	5,737	240	240	216	240			6 6	Reg	Reg
West Portsmouth 15T2 Xfmr	4.16									403	403					303	321	2,180	2,310	303	321	272	321			8 8	Xfmr	Xfmr
15H3	4.16													312	348			2,248	2,507	312	348	281	348			7 7	Wire	Wire

Appendix C

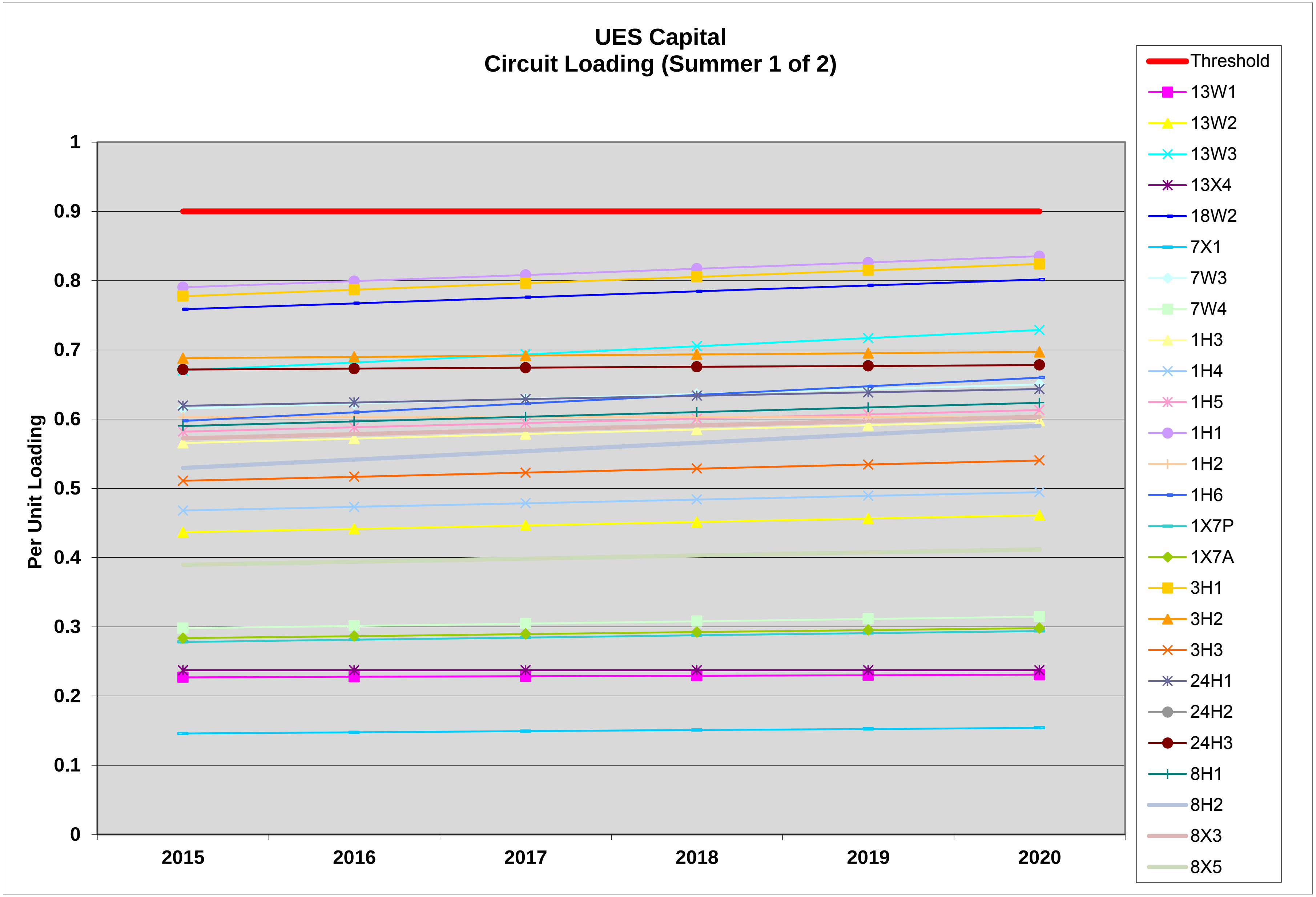
Transformer Loading Charts
(in Per Unit)

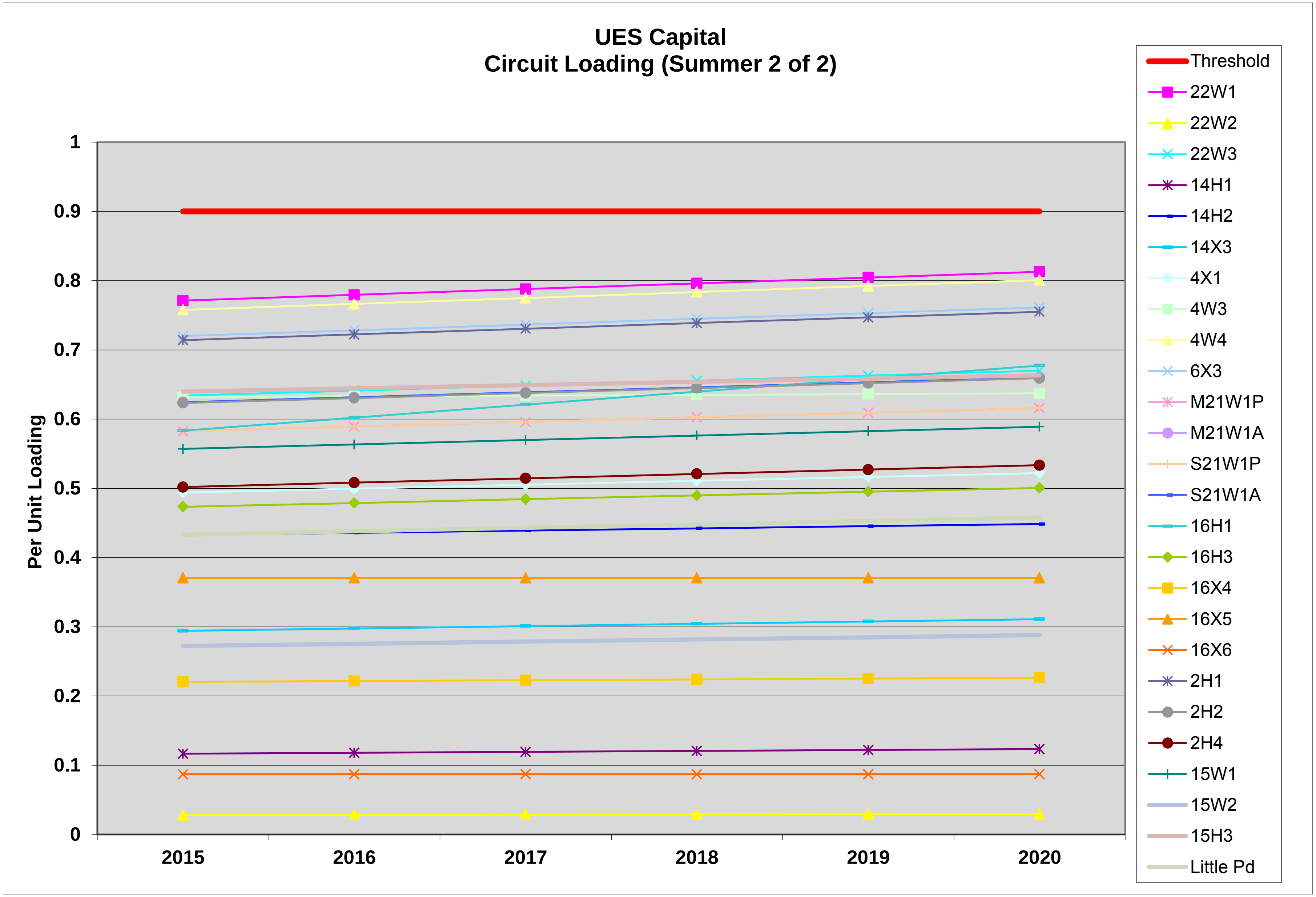

UES Capital
Transformer Loading (Summer)
Per Unit Loading
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
2015
2016
2017
2018
2019
2020
Boscawen 13T1
Boscawen 13T2
Bow Bog 18T2
Bow Junction 7T2
Bridge Street 1T1
Bridge Street 1T2
Gulf Street 3T1
Gulf Street 3T2
Hazen Drive 24T1
Hazen Drive 24T2
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

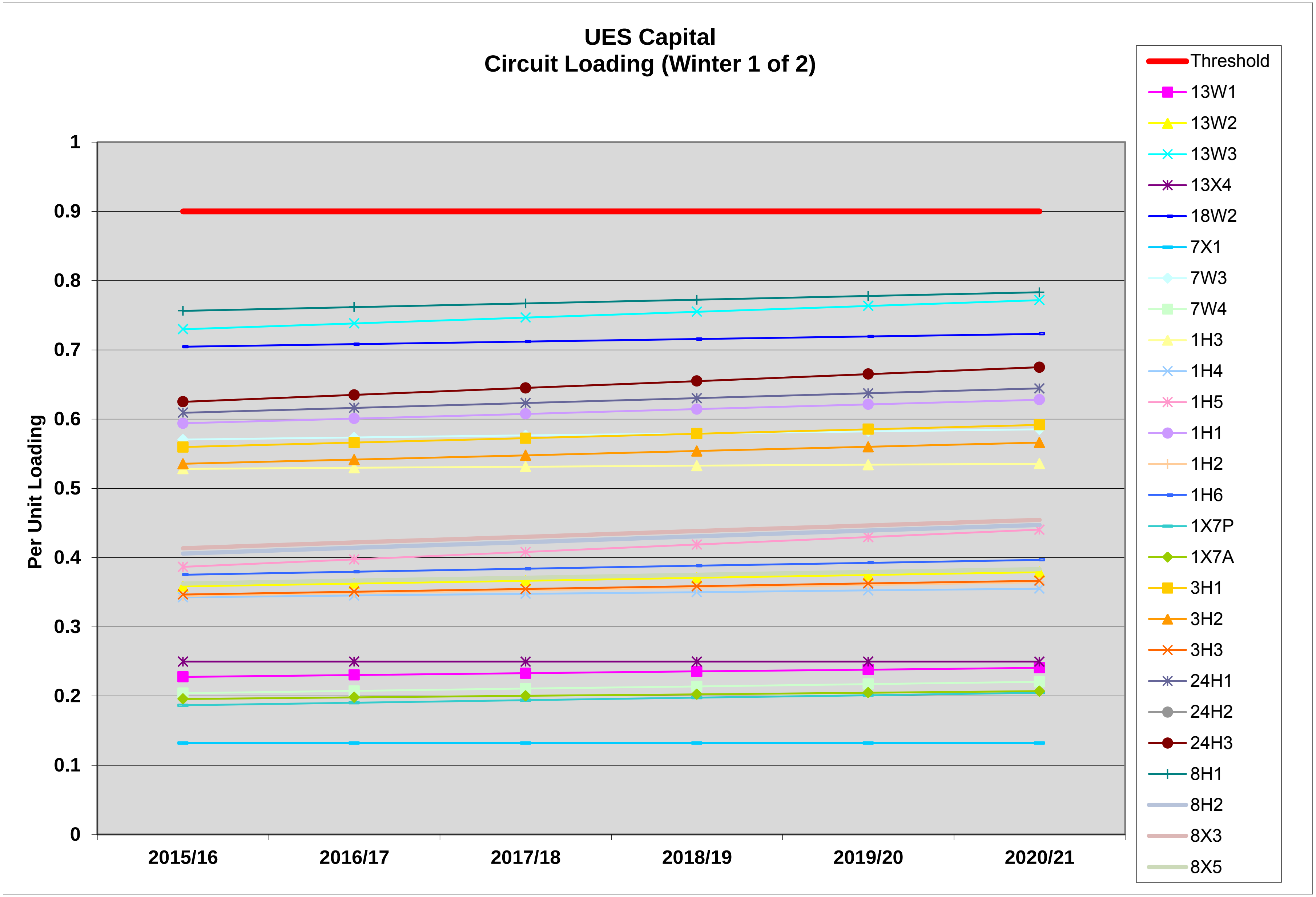

UES Capital
Transformer Loading (Winter)
Per Unit Loading
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
Boscawen 13T1
Boscawen 13T2
Bow Bog 18T2
Bow Junction 7T2
Bridge Street 1T1
Bridge Street 1T2
Gulf Street 3T1
Gulf Street 3T2
Hazen Drive 24T1
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

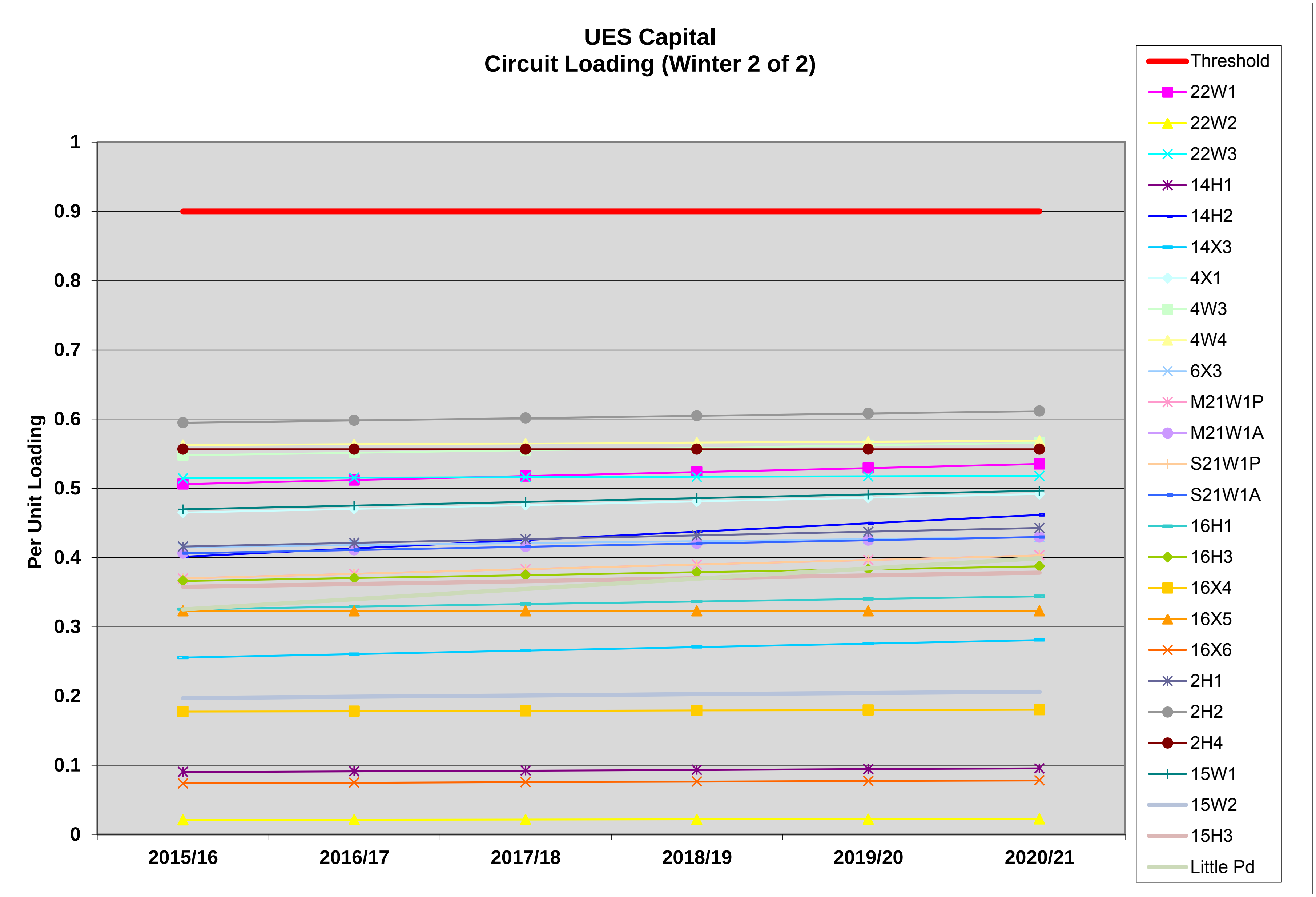
Appendix D

Circuit Loading Charts
(in Per Unit)


UES Capital
Circuit Loading (Summer 1 of 2)
Per Unit Loading
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2015
2016
2017
2018
2019
2020
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
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2015
2016
2017
2018
2019
2020
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
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
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
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
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

Circuit Tie Analysis

Circuit Tie Limitations for the 13.8kV circuits in the Southern Region of the UES-Capital Electric System

Including circuits out of the Montgomery St, Storrs St, Bow Junction, Bow Bog and Ironworks Substations

Circuit Tie	Restoring Circuit	Restored Circuit	Limit of Restoration	Planning Violations	Limitations
21W1PJ22W1 (Switch at P.36 Pleasant St)	22W1	21W1P	Switch at P.17 Pleasant St	None	None
			Full Circuit	1/0 AL 117% of Rating, S/S Equipment Overloads	Can be used up to 5.5 MVA /235 A combined load (80% of summer peak loading)
	21W1P	22W1	P.36 Pleasant St	1/0 AL UG 170% of Rating	Can be used up to 3.2 MVA /140A combined load (50% of summer peak loading)
7W4J22W1 (Solids at P.12 Clinton St)	7W4	22W1	Switch at P.23 Clinton St	95N fuse 200% of Rating 45N fuse 300% of Rating 7T1 120% of Rating	After installing solids in place of: 95N's at pole 80, on South St 45N's at pole 5, on Clinton St Can be used up to 5.5 MVA /230A combined load (80% of summer peak loading)
	22W1	7W4	Fuse at P.80 South St	45N fuse 170% of Rating 1/0 AL 110% of Rating S/S Equipment Overloads	After installing solids in place of: 45N's at pole 5, Clinton St Can be used up to 5.2 MVA /220A combined load (80% of summer peak loading)
7W4J22W2 (Switch at P.3 Ironworks Rd)	7W4	22W2	Ironworks S/S	None	None
	22W2	7W4	Switch at P.3 Ironworks Rd	22T1 110% of Rating	Can be used up to 3 MVA /130A combined load (80% of summer peak loading)
22W1J22W3-2 (Solids at P.73 Clinton St)	22W1	22W3	Switch at P.41 Silk Farm Rd	S/S Equipment Overloads (Trip Flag 108% of LTE, Regulator 113% of LTE, 1/0 AL 92% of LTE)	Can be used up to 5.4 MVA /230A combined load (85% of summer peak loading)

Circuit Tie	Restoring Circuit	Restored Circuit	Limit of Restoration	Planning Violations	Limitations
	22W3	22W1	Solids at P.23 Clinton St	1/0 AL 98% of Rating	Can be used up to 5.5 MVA /240 combined load (no limitations)
22W1J22W2-1 (Solids at P.32-B Ironworks Rd)	22W2	22W1	Ironworks S/S	None	None
	22W1	22W2	Ironworks S/S	None	None
22W2J22W3 (Solids at P.32-A Ironworks St)	22W3	22W2	Ironworks S/S	None	None
	22W2	22W3	Ironworks S/S	None	None
7W3J7W4 (Switch at P.105X S. Main St)	7W4	7W3	Bow Junction S/S	None	None
	7W3	7W4	P.105X S. Main St	S/S Equipment Overloads (Trip Flag 98% of LTE, Regulator 92% of LTE)	Can be used up to 8.6 MVA /360A combined load (85% of summer peak loading) Can be used at full combined load load in emergency situations.
7W3J22W3 (Solids at P.28 Logging Hill Rd)	22W3	7W3	Recloser at P.1 Carriage Rd	None	None
	7W3	22W3	Solids at P.1 Albin Rd	7T2 110% of Rating	Can be used up to 7.2 MVA /305A combined load (85% of summer peak loading)
18W2J22W3 (Solids at P.78 Bow Center Rd)	18W2	22W3	Solids at P.1 Albin Rd	S/S Equipment Overloads	Can be used up to 2.8 MVA /117A combined load (50% of summer peak loading)
	22W3	18W2	Solids at P.2 Bow Bog Getaway (western load)	Voltages as low as 108V S/S Equipment Overloads 1/0 AL 110% of LTE Recloser 116% of Rating	Can be used up to 5.5 MVA /235 A combined load (75% of summer peak loading), excepting voltages as low as112V Can be use up to 6.4 MVA /270 A combined load (85% of summer peak loading) in emergency situations, excepting voltages as low as 110V
7W3J18W2 (Solids at P.67	7W3	18W2	Solids at P.2 Bow Bog Getaway (eastern load)	None	None

Circuit Tie	Restoring Circuit	Restored Circuit	Limit of Restoration	Planning Violations	Limitations
Bow Bog Rd)	18W2	7W3	Solids at P.98 3A (South Main St)	S/S Equipment Overloads	Can be used up to 2.5 MVA /110 A combined load (50% of the summer peak loading)

Note: Tie capability are based on 2016 projected summer peak loads and assumes circuits are in their normal configurations prior to use. For substations with more than three loading violations the statement "S/S Equipment Overloads" is used. Marginal low voltage, coordination and sensitivity may exist when circuits are tied. All circuits on a transformer were scaled down equally to derive acceptable transformer loading.

Appendix F

Master Plan Map

LEGEND

- EXISTING 34.5 kV OVERHEAD BACKBONES
- PROPOSED 34.5 kV OVERHEAD BACKBONES
- EXISTING 13.8 kV OVERHEAD BACKBONES
- PROPOSED 13.8 kV OVERHEAD BACKBONES
- EXISTING 4.16 kV OVERHEAD BACKBONES
- PROPOSED 13.8KV OVERHEAD BACKBONES TO OPERATE AT 4KV
- EXISTING 34.5 kV "SUBTRANSMISSION"
- EXISTING 34.5 kV UNDERGROUND BACKBONE
- PROPOSED 13.8 kV UNDERGROUND BACKBONE

REV.	DESCRIPTION	BY	DATE	CHK	APR

REVISIONS

DRAWN C.E.
CHECKED
APPROVED

Unitil

MASTER PLAN MAP
UES–CAPITAL
DISTRIBUTION PLANNING STUDY

SCALE	DATE	SHEET	DRAWING NO.
N/A	5/24/13	1 OF 1	CDYDM003

APPENDIX G

UES SEACOAST DISTRIBUTION SYSTEM PLANNING STUDY 2016-2020

Unitil Energy Systems – Seacoast

Distribution System Planning Study
2016-2020

Prepared By:

J. Dusling
Unitil Service Corp.
August 24, 2015

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 2016 through the summer of 2020.

Projects currently under construction that are expected to be completed in 2015 are assumed to be in service for the beginning year of this study.

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
2017/2018	Hampton Beach 4 kV – Convert to 13.8 kV	Loading 95% Condition	$2,570,000
2019	Circuit 3W4 – Convert O Street to 13.8 kV	Voltage 116.7 V Loading 109%	$90,000

2. System Configuration

The UES–Seacoast distribution system is comprised of 45 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 subtransmission system consist of 18 lines and is presently supplied from Eversource Energy's 345 kV and 115 kV transmission systems via three Eversource Energy substations, Timber Swamp, Peaslee, 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 and 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.

Peaslee substation, located in central Kingston is a 5 terminal 115 kV switching station with two outgoing 115 kV lines that transfer power to the adjacent UES–Seacoast Kingston substation with two 115 – 34.5 kV, 60 MVA transformers. Five UES–Seacoast 34.5 kV 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 distribution load throughout Kingston and Danville.

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 transfer power to eight distribution substations and taps which serve loads in the Stratham and Exeter areas.

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 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.

This methodology does not directly forecast future DG interconnections or other DER projects/initiatives such as energy efficiency programs. Rather the impact of DG and other DER programs are inherent in the historical regression analysis by offsetting most recent peak loads thereby reducing projected growth rates at the circuit level. It is recognized that the reduction in circuit growth rates will lag DG interconnections and other DER projects implemented in a given year. However, since load forecasts are completed annually, the timing of projects identified in the planning process is continually reviewed and updated. In addition, during the annual capital budget development process a more detailed review of the most recent circuit peak loads, known load additions and interconnection applications either in study or recently processed is performed in order to ensure the timing of investments in system improvement projects is appropriate.

The following table shows the five circuits with the highest annual growth rates.

Ranking	Circuit	Average Annual Load Growth	Total Load Growth 2016-2020 (kVA)
1	3H1	3.4%	339
2	3W4	3.3%	665
3	43X1	2.8%	833
4	2X3	2.5%	566
5	2X2	2.3%	889

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 include current transformers (CT), switches, circuit exit conductors, regulators, power transformers and protective device settings. Overall circuit ratings are based upon the most restrictive of these limiting elements. The distribution system circuit limitations can be referenced in Appendix B. Summer and winter peak load projections for the five year study period, listed in Appendix A, were compared to these circuit ratings.

Projected loads reaching certain thresholds prompted a closer assessment of the conditions. Shading, as shown below, has been added to the projection analysis to provide a visual representation of potential problem areas. The analysis of circuits and transformers reaching 90% or higher of their normal ratings are described in the following section.

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

6. Transformer and Circuit Loading Analysis

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. Distribution Substation Transformer Loadings

Distribution substation 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.

Hampton Beach 4.16 kV Substation Transformer
Peak demand loading for the Hampton Beach 3T1 transformer is projected to reach as much as 5,672 kVA, 91% of its summer normal rating in 2016. It is projected to reach 6,204 kVA, 99% of its summer normal rating by the summer of 2020.

6.2. Distribution Substation Equipment Loadings

There are no distribution substation equipment that the projected load will reach 90% or more of their rating during the study period. Summer and winter transformer loading graphs are included in Appendix D.

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 are projected to exceed their Summer Normal limit during the study period. Shading has been added to the projections to provide a visual representation of potential overloads.

Legend

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

			Year Expected to Exceed 90%/100% of Rating	TRANSFORMER SIZE (kVA)			2016 Projected % Loading of Summer Limit			
CIRCUIT / LOCATION	TOWN	POLE #		A	B	C	A	B	C	BANK
15X1 Perkins Avenue	Seabrook	73/2	2016/2016	250			122%			122%
3W4 O Street	Hampton	196/1	2016/2016	333	333	333	75%	44%	109%	76%
21W1 Meditation Lane	Atkinson	55/33	2016/2017	167	167	167	64%	94%	98%	85%

6.4. Phase Imbalances

All of the circuits within the UES-Seacoast service territory were reviewed for phase balance. 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 Engineering Work Requests (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	Expected % Imbalance
5H2	30%	Transfer 100 kVA from Phase A to Phase B Transfer 650 kVA from Phase C to Phase B	<5%
20H1	27%	Transfer 150 kVA from Phase A to Phase B Transfer 450 kVA from Phase C to Phase B	<5%

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. Milsoft Windmil software is used to model the system impedances and loads to identify potential problems areas. The circuit analysis performed includes voltage drop, load flow, and protection analysis. 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 2015. 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	1H3	Shaw's Hill Tap	27X1
	1H4		27X2
East Kingston	6W1	Exeter Switching	19H1
	6W2		19X2
Portsmouth Avenue	11X1		19X3
	11X2	Westville Road Tap	58X1
Willow Road Tap	43X1		

7.1. Voltage Concerns

Voltage drop analysis is performed to identify areas where the primary voltage on the circuit may be outside of a pre-determined acceptable range. The acceptable range used for this analysis is 117-125 V on a 120 V base on the circuit primary conductor. The following table summarizes the areas where voltage is expected to be outside of this range. The table is sorted by circuit and year.

Circuit	Year	Voltage	Location
3W4	2016	116.7V	River Avenue, Hampton

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
3H1	2018	91%	#2 Cu Conductor (240 Amps)	Express Line, Hampton
3W4	2018	90%	#6 Cu Conductor (130 Amps)	River Avenue, Hampton
3H2	2020	91%	Solid Blades (300 Amps)	Ashworth Avenue, Hampton

7.3. Protection Concerns

Analysis is performed on the circuits analyzed to identifies protective devices that violate Unitil's distribution protection sensitivity and coordination criteria. As violations are identified EWR's are issued as needed to address the concerns.

8. Detailed Recommendations

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

8.1. Hampton Beach 4 kV: Convert to 13.8 kV – (2017/2018)

Distribution load projections indicate that the 3T1 transformer at Hampton Beach substation is expected to exceed 90% of its summer normal rating during summer peak conditions in 2016. Circuit models have identified that the #2 copper conductor along the Express Line in Hampton is expected to reach 91% of its rating during summer peak conditions in 2018.

Additionally, there are several condition concerns associated with the 4 kV portion of Hampton Beach substation, including breakers, regulators, station batteries, capacitor banks, foundations and relays that will require repairs and/or replacement in the near future.

This project will consist of converting circuits 3H1, 3H2 and 3H3 in their entirety to 13.8 kV operation. The existing 4 kV portion of Hampton Beach will be rebuilt to 15 kV and consist of a new 7.5/10.5 MVA transformers and two outgoing 13.8 kV circuits. This will create circuit ties between the Hampton Beach circuits and works towards the master plan of creating a circuit tie between circuit 3H(W)1 and 17W1.

Once this project is complete loading of the new substation equipment and along the Express Line are expected to be within normal limits throughout the study period.

Distribution Cost (3H1):	$ 760,000
Distribution Cost (3H2 & 3H3):	$ 95,000
Substation Cost:	$1,715,000
Total Cost:	$2,570,000

Converting circuit 46X1 along Ocean Boulevard in Hampton to 34.5 kV operation and transferring a majority of circuit 3H1 to 46X1 was considered as an alternative to the above project. This will introduce of 34.5 kV distribution along the coastline and will not address the condition concerns associated with Hampton Beach substation.

Converting circuit 46X1 to 13.8 kV along Ocean Boulevard and transferring the Ocean Boulevard portion of circuit 46X1 and a majority of circuit 3H1 to circuit 17W1 was also considered as an alternative to the this project. This project alternative does not address the condition concerns associated with Hampton Beach substation and would approximately double the size of circuit 17W1.

8.2. Circuit 3W4: Convert O Street to 13.8 kV – (2019)

Circuit analysis has indicated that the primary voltage along River Avenue will be as low as 116.7 V and the phase C 333 kVA stepdown transformer in expected to exceed its normal rating during summer conditions in 2016. Circuit models have also identified that the #6 Cu conductor along River Ave is expected to exceed 90% of its normal rating during summer conditions in 2018.

An AMI voltage recording meter recorded a minimum service voltage of 117.2 V at 40 River Avenue, Hampton on August 2, 2015. Since recorded voltages at the meter during 2015 were within acceptable ranges, the decision has been made to accept marginal risk and defer this project until 2019.

Loading balancing was considered as an alternative to this project, but did not achieve adequate results.

This project will consist of rebuilding from the O Street stepdown transformers to the end of the line to 25 kV class construction and converting to 13.8 kV operation.

Once this project is complete, voltage and loading along O Street and River Avenue are expected to be within normal limits throughout the study period.

Total Project Cost: $90,000

8.3. Stepdown Upgrades

The following locations could require stepdown replacements during the five year study period. Loading of these stepdown transformers will continue to be monitored and budget items will be entered into the capital budget model when needed.

Location	Existing Size	Proposed Size	Proposed Year
15X1 Perkins Avenue, Seabrook p. 73/2	Phase B: 250 kVA	Phase B: 500 kVA	2016
21W1 Meditation Lane, Atkinson p. 55/33	Phase A: 167 kVA Phase B: 167 kVA Phase C: 167 kVA	Phase A: 333 kVA Phase B: 333 kVA Phase C: 333 kVA	2017

9. Circuit Tie Analysis

Analysis is performed on all mainline distribution circuit ties in the UES-Seacoast system. Each year circuit tie capability is reviewed by comparing projected loads against the maximum load each circuit tie can support. The circuit tie map is updated accordingly for all newly identified circuit tie limitations.

10. 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.

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.

10.1. 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.

10.1.1 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.

10.1.2 Kingston, East Kingston, Kensington, and Hampton Falls

The Shaw's Hill 34.5 kV distribution tap is comprised of 2 circuit positions. Portions of circuits 19X3, 23X1 and 19H1 will be transferred to these circuits over time. 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 a create tie between 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.

10.1.3 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. The eastern portion of circuit 46X1 will be converted to 13.8 kV and transferred to circuits 17W1 and 3H1.

Winnacunnet Road Tap and the western portion of circuit 46X1 and the 2X2 portion of Winnacunnet Road will be convert to 34.5 kV operation, allowing portions of 2X2 to be transferred to 46X1.

10.1.4 Atkinson, Plaistow and Newton

Plaistow S/S will be converted to 34.5 kV including all of circuits 5H1 and 5H2. This will create future circuit ties with circuits 58X1 and 56X1 and provide a future distribution backup to the radial 3358 line.

11. 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, increasing capacity and creating additional distribution circuit ties that will improve overall system reliability . 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
2016-2020

Distribution Element	Summer Peak Loads (three-phase kVA)					
			Projected			
	2015	2016	2017	2018	2019	2020
Cemetery Lane 15X1	8,323	8,505	8,688	8,870	9,053	9,235
Dorre Road Tap 56X2	2,051	2,097	2,142	2,188	2,234	2,280
Dow's Hill 20T1	1,388	1,422	1,455	1,489	1,522	1,556
20H1	1,388	1,422	1,455	1,489	1,522	1,556
East Kingston 6T1	5,429	5,560	5,691	5,821	5,952	6,083
6W1	2,506	2,567	2,627	2,688	2,748	2,808
6W2	2,922	2,993	3,063	3,134	3,204	3,275
Exeter 1T1	1,629	1,669	1,708	1,747	1,786	1,826
Exeter 1T2	1,573	1,611	1,649	1,687	1,725	1,762
1H3	1,629	1,669	1,708	1,747	1,786	1,826
1H4	1,573	1,611	1,649	1,687	1,725	1,762
Exeter Switching 19T1	664	680	696	712	728	744
19H1	664	680	696	712	728	744
Exeter Switching 19X2	4,783	4,896	5,008	5,121	5,233	5,346
Exeter Switching 19X3	12,886	12,925	12,964	13,003	13,043	13,082
Guinea Road Tap 47X1	5,307	5,435	5,563	5,691	5,819	5,947
Guinea Switching 18X1	8,021	8,059	8,098	8,137	8,175	8,214
Hampton 2T1	962	985	1,008	1,030	1,053	1,076
2H1	962	985	1,008	1,030	1,053	1,076
Hampton 2X3	5,303	5,445	5,586	5,728	5,869	6,011
Hampton 2X2	9,225	9,448	9,670	9,892	10,115	10,337
Hampton Beach 3T1	5,539	5,672	5,805	5,938	6,071	6,204
3H1	2,302	2,387	2,472	2,557	2,642	2,726
3H2	1,979	2,026	2,074	2,122	2,169	2,217
3H3	1,481	1,487	1,493	1,499	1,505	1,511
Hampton Beach 3T3	4,617	4,783	4,950	5,116	5,282	5,448
3W4	4,617	4,783	4,950	5,116	5,282	5,448
High Street 17T1	5,470	5,555	5,641	5,726	5,811	5,896
17W1	3,610	3,679	3,748	3,818	3,887	3,956
17W2	2,014	2,032	2,050	2,069	2,087	2,106
Hunt Rd Tap 56X1	2,236	2,289	2,342	2,394	2,447	2,499
Kingston 22X1	5,891	5,993	6,094	6,196	6,298	6,399
Mill Lane Tap 23X1	3,219	3,295	3,371	3,446	3,522	3,598
Munt Hill 28X1	1,589	1,626	1,664	1,701	1,738	1,776
New Boston Rd. 54X1	4,244	4,290	4,335	4,381	4,427	4,472
Plaistow 5T1	2,523	2,582	2,641	2,701	2,760	2,820
5H1	1,293	1,323	1,354	1,384	1,415	1,445
5H2	1,552	1,589	1,625	1,662	1,698	1,735
Portsmouth Ave. Substation	9,844	10,076	10,308	10,540	10,771	11,003
11X1	5,100	5,220	5,340	5,460	5,580	5,700
11X2	4,744	4,856	4,968	5,079	5,191	5,303
Seabrook 7T1	4,547	4,566	4,585	4,605	4,624	4,643
7W1	4,547	4,566	4,585	4,605	4,624	4,643
Seabrook 7X2	5,715	5,757	5,799	5,840	5,882	5,923
Shaw's Hill Tap	2,696	3,360	3,420	3,480	3,540	3,600
27X1	1,777	1,818	1,860	1,902	1,944	1,986
27X2	919	941	963	984	1,006	1,027
Stard Road Tap 59X1	9,419	9,582	9,744	9,907	10,070	10,233
Timberlane 13T1	7,664	7,725	7,786	7,848	7,909	7,970
13W1	3,816	3,821	3,826	3,831	3,835	3,840
13W2	3,954	4,011	4,068	4,126	4,183	4,240
Timberlane 13X3	1,235	1,239	1,243	1,247	1,251	1,255

Distribution Element	Summer Peak Loads (three-phase kVA)					
	Projected					
	2015	**2016**	**2017**	**2018**	**2019**	**2020**
Westville 21T1	6,120	6,422	6,574	6,725	6,876	7,027
21W1	6,120	6,264	6,408	6,552	6,696	6,840
Westville 21T2	4,904	4,984	5,064	5,144	5,224	5,304
21W2	4,904	4,984	5,064	5,144	5,224	5,304
Westville Tap 58X1	11,325	11,493	11,661	11,828	11,996	12,164
58X1E	5,472	5,587	5,703	5,819	5,934	6,050
58X1W	6,377	6,437	6,497	6,557	6,617	6,677
Willow Road Tap 43X1	7,055	7,264	7,472	7,680	7,888	8,096
Winnacunnet Road Tap 46X1	2,759	2,774	2,788	2,802	2,816	2,831
Winnicutt Road Tap 51X1	6,154	6,294	6,433	6,572	6,711	6,851

Legend

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

Distribution Element	Winter Peak Loads (three-phase kVA)					
	Projected					
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Cemetery Lane 15X1	5,511	5,644	5,777	5,909	6,042	6,175
Dorre Road Tap 56X2	1,397	1,429	1,460	1,491	1,522	1,554
Dow's Hill 20T1	926	967	1,007	1,047	1,088	1,128
20H1	926	967	1,007	1,047	1,088	1,128
East Kingston 6T1	4,670	4,782	4,895	5,007	5,120	5,232
6W1	2,400	2,458	2,516	2,573	2,631	2,689
6W2	2,270	2,324	2,379	2,434	2,489	2,543
Exeter 1T1	1,378	1,411	1,445	1,478	1,511	1,544
Exeter 1T2	1,368	1,401	1,434	1,467	1,500	1,533
1H3	1,378	1,411	1,445	1,478	1,511	1,544
1H4	1,368	1,401	1,434	1,467	1,500	1,533
Exeter Switching 19T1	443	453	464	475	485	496
19H1	443	453	464	475	485	496
Exeter Switching 19X2	2,383	2,439	2,495	2,551	2,607	2,663
Exeter Switching 19X3	9,987	10,139	10,290	10,442	10,593	10,744
Guinea Road Tap 47X1	4,041	4,139	4,236	4,334	4,431	4,529
Guinea Switching 18X1	6,351	6,382	6,412	6,443	6,474	6,504
Hampton 2T1	672	693	714	734	755	776
2H1	672	693	714	734	755	776
Hampton 2X3	4,107	4,285	4,462	4,639	4,816	4,993
Hampton 2X2	6,429	6,271	6,419	6,566	6,714	6,862
Hampton Beach 3T1	2,528	2,577	2,626	2,675	2,723	2,772
3H1	1,255	1,286	1,316	1,346	1,376	1,407
3H2	435	446	456	467	477	488
3H3	837	845	853	861	869	877
Hampton Beach 3T3	1,510	1,547	1,583	1,620	1,656	1,692
3W4	1,510	1,547	1,583	1,620	1,656	1,692
High Street 17T1	3,786	3,817	3,847	3,878	3,908	3,939
17W1	2,651	2,652	2,653	2,653	2,654	2,655
17W2	1,290	1,321	1,352	1,383	1,414	1,446
Hunt Rd Tap 56X1	1,551	1,589	1,626	1,664	1,701	1,738
Kingston 22X1	3,429	3,511	3,594	3,677	3,759	3,842
Mill Lane Tap 23X1	1,795	1,839	1,882	1,925	1,968	2,012
Munt Hill 28X1	820	832	844	856	868	880
New Boston Rd. 54X1	3,478	3,536	3,593	3,651	3,709	3,767
Plaistow 5T1	2,168	2,220	2,272	2,325	2,377	2,429
5H1	1,103	1,129	1,156	1,182	1,209	1,235
5H2	1,108	1,134	1,161	1,188	1,215	1,241
Portsmouth Ave. Substation	6,960	7,128	7,295	7,463	7,631	7,799
11X1	3,449	3,532	3,615	3,699	3,782	3,865
11X2	3,511	3,595	3,680	3,764	3,849	3,934
Seabrook 7T1	1,387	1,421	1,454	1,488	1,521	1,555
7W1	1,387	1,421	1,454	1,488	1,521	1,555
Seabrook 7X2	4,070	4,128	4,186	4,244	4,302	4,360
Shaw's Hill Tap	2,103	2,418	2,473	2,529	2,585	2,640
27X1	1,551	1,589	1,626	1,664	1,701	1,738
27X2	551	565	578	591	604	618
Stard Road Tap 59X1	8,438	8,590	8,741	8,893	9,044	9,196
Timberlane 13T1	4,869	4,983	5,097	5,211	5,325	5,439
13W1	2,939	3,010	3,081	3,151	3,222	3,293
13W2	3,170	3,242	3,315	3,387	3,459	3,532
Timberlane 13X3	877	898	919	941	962	983

UES-Seacoast
5-Year Load Forecast
2016-2020

Distribution Element	Winter Peak Loads (three-phase kVA)					
	Projected					
	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Westville 21T1	3,866	3,959	4,053	4,146	4,239	4,332
21W1	3,866	3,959	4,053	4,146	4,239	4,332
Westville 21T2	2,827	2,830	2,833	2,836	2,839	2,842
21W2	2,827	2,830	2,833	2,836	2,839	2,842
Westville Tap 58X1	7,144	6,689	6,846	7,004	7,161	7,319
58X1E	3,572	3,344	3,423	3,502	3,581	3,659
58X1W	3,858	3,951	4,044	4,137	4,230	4,323
Willow Road Tap 43X1	4,894	4,977	5,059	5,142	5,225	5,308
Winnacunnet Road Tap 46X1	1,868	1,877	1,886	1,895	1,904	1,913
Winnicutt Road Tap 51X1	4,348	4,453	4,557	4,662	4,767	4,872

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

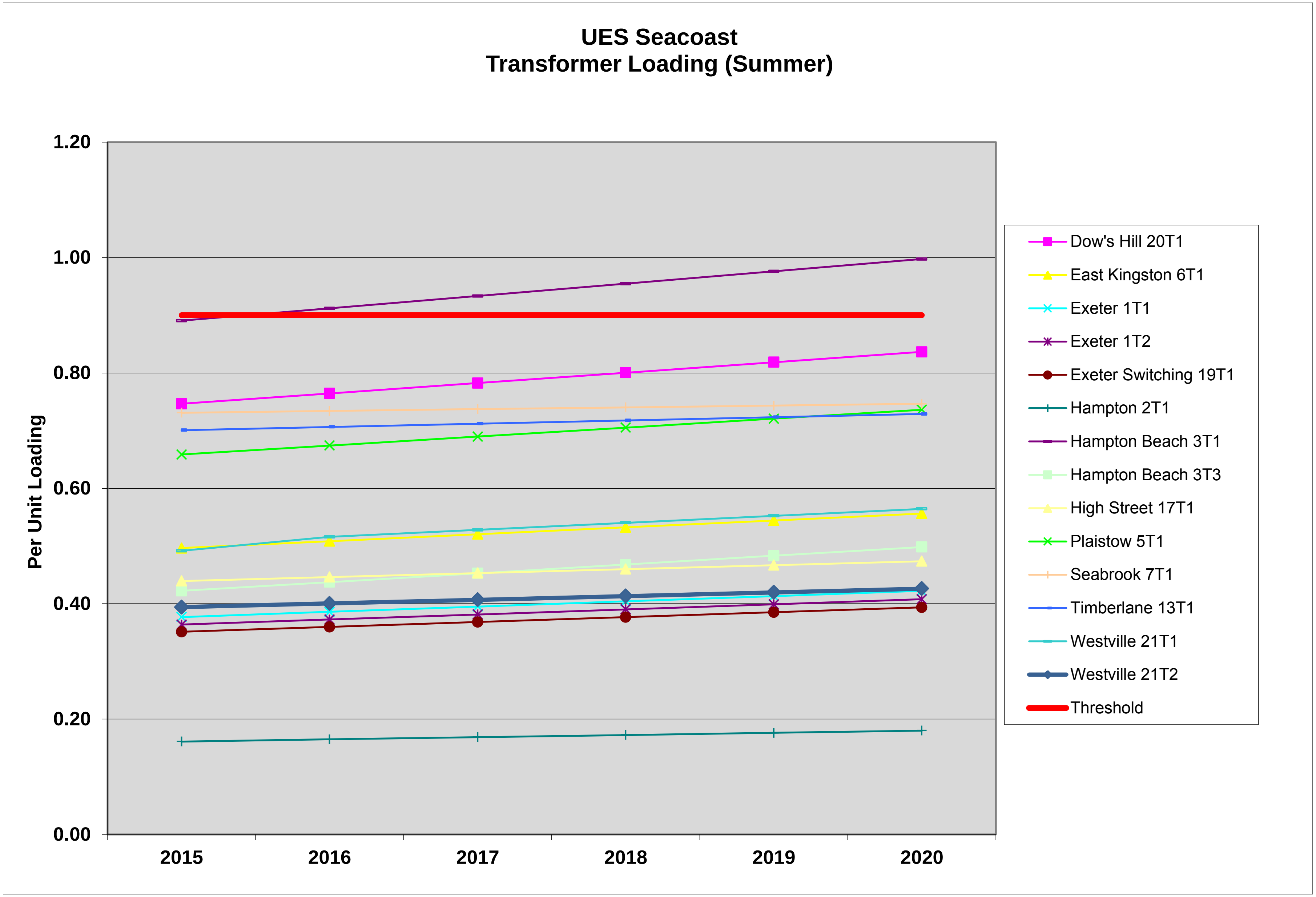
Distribution Element	Voltage Base (kV)	Breaker or Recloser Continuous Rating		Breaker or Recloser Trip Level		Current Transformer Present Tap Selection		Switch Continuous Rating		Fuse Continuous Rating		Regulator Rating		Conductor Rating		Transformer Rating		Overall Rating (kVA)		Overall Rating (A)		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			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	384	432	600	600	600	600			480	560	531	645			2,767	3,113	384	432	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	668	531	645			9,943	11,186	416	468	Trip	Trip
6W2	13.8	800	800	416	468							589	668	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					262	271	1,890	1,950	262	271	Xfmr	Xfmr
19H1	4.16	560	560	224	252	600	600	400	400			480	560	340	411			1,614	1,816	224	252	Trip	Trip
Exeter Switching 19X2	34.5	400	400	480	540	600	600	600	600			450	525	448	448			23,902	23,902	400	400	Brkr/Rclsr	Brkr/Rclsr
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	1536	1728					1037	1037					863	879	6,220	6,330	863	879	Xfmr	Xfmr
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	668	531	645			7,649	8,605	320	360	Trip	Trip
17W2	13.8	800	800	320	360	600	600	600	600			589	668	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	384	432	300	300							470	470			2,162	2,162	300	300	CT	CT
5H2	4.16	1200	1200	384	432	300	300							470	470			2,162	2,162	300	300	CT	CT
Portsmouth Ave Substation	34.5	800	800	376	423	400	400					450	525	531	645			22,468	23,902	376	400	Trip	CT
Portsmouth Ave 11X1	34.5	800	800	256	288	600	600	600	600					531	645			15,297	17,210	256	288	Trip	Trip
Portsmouth Ave 11X2	34.5	800	800	256	288	600	600	600	600					531	645			15,297	17,210	256	288	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	288	324	600	600	600	600			450	525	531	645			17,210	19,361	288	324	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									521	530	12,450	12,670	521	530	Xfmr	Xfmr
21W1	13.8	560	560	448	504	600	600	600	600			589	668	531	448			10,708	10,708	448	448	Trip	Wire
Westville 21T2	13.8					600	600									521	530	12,450	12,670	521	530	Xfmr	Xfmr
21W2	13.8	560	560	304	342	300	300	600	600			589	668	554	554			7,171	7,171	300	300	CT	CT
Westville Tap 58X1	34.5					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			270	315	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

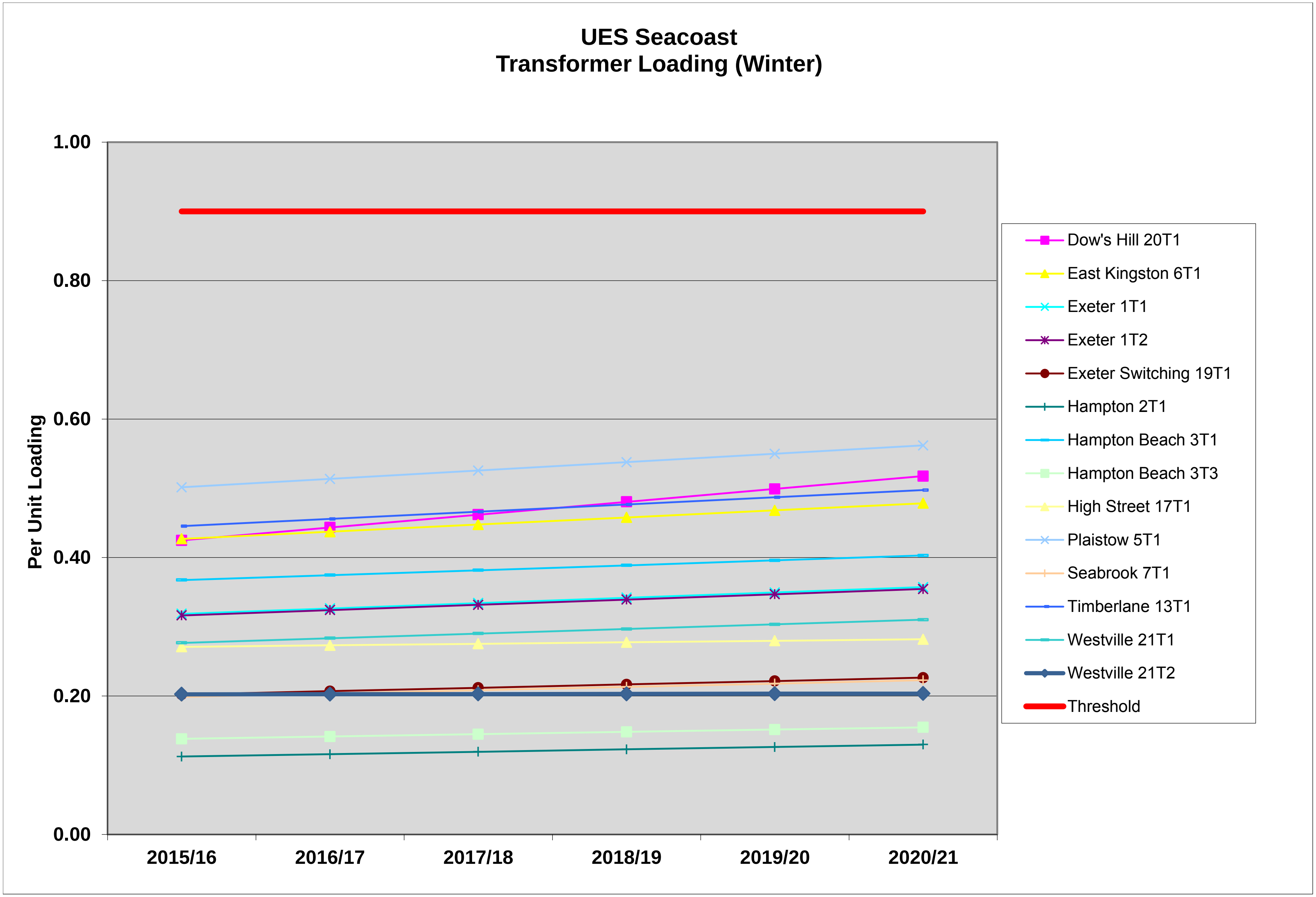
UES-Seacoast Winter Circuit Ratings

Distribution Element	Voltage Base	Breaker or Recloser				Current Transformer		Switch		Fuse		Regulator		Conductor		Transformer		Overall Rating (kVA)		Overall Rating (A)		Limiting Element	
	(kV)	Continuous Rating		Trip Level		Present Tap Selection		Continuous Rating		Minimum Melt		Rating		Rating		Rating							
		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			525	544	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	384	432	600	600	600	600			560	580	694	777			2,767	3,113	384	432	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			668	668	694	777			9,943	11,186	416	468	Trip	Trip
6W2	13.8	800	800	416	468							668	668	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					304	321	2,190	2,310	304	321	Xfmr	Xfmr
19H1	4.16	560	560	224	252	600	600	400	400			560	580	443	495			1,614	1,816	224	252	Trip	Trip
Exeter Switching 19X2	34.5	400	400	480	540	600	600	600	600			525	544	448	448			23,902	23,902	400	400	Brkr/Rclsr	Brkr/Rclsr
Exeter Switching 19X3	34.5	560	560	320	360	600	600	600	600			525	544	694	777			19,122	21,512	320	360	Trip	Trip
Guinea Road Tap 47X1	34.5	560	560	448	504	200	200	300	300			280	290	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			935	969	443	464			3,192	3,343	443	464	Wire	Wire
Hampton 2X3	34.5	800	800	336	378	600	600	900	900			525	544	694	777			20,078	22,588	336	378	Trip	Trip
Hampton 2X2	34.5	800	800	336	378	600	600	400	400			525	544	694	777			20,078	22,588	336	378	Trip	Trip
Hampton Beach 3T1	4.16	1200	1200	1536	1728					1037	1037					955	1002	6,880	7,220	955	1002	Xfmr	Xfmr
3H1	4.16	600	600	576	648	600	600	900	900			935	969	694	777			4,150	4,323	576	600	Trip	Brkr/Rclsr
3H2	4.16	600	600	576	648	600	600	900	900			420	435	694	777			3,026	3,134	420	435	Reg	Reg
3H3	4.16	600	600	576	648	600	600	900	900			420	435	694	777			3,026	3,134	420	435	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			307	318	400	400			7,328	7,590	307	318	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			668	668	694	777			7,649	8,605	320	360	Trip	Trip
17W2	13.8	800	800	320	360	600	600	600	600			668	668	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			315	326	694	777			17,927	19,495	300	326	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					280	290	694	777			16,732	17,329	280	290	Reg	Reg
Munt Hill Tap 28X1	34.5	800	800	208	234	600	600	600	600			525	544	694	777			12,429	13,983	208	234	Trip	Trip
New Boston Rd. 54X1	34.5	800	800	288	324	600	600	600	600			281	291	694	777			16,815	17,416	281	291	Reg	Reg
Plaistow 5T1	4.16					600	600			979	979					608	608	4,323	4,323	600	600	CT	CT
5H1	4.16	1200	1200	384	432	300	300							470	470			2,162	2,162	300	300	CT	CT
5H2	4.16	1200	1200	384	432	300	300							470	470			2,162	2,162	300	300	CT	CT
Portsmouth Ave Substation	34.5	800	800	376	423	400	400					525	544	694	777			22,468	23,902	376	400	Trip	CT
Portsmouth Ave 11X1	34.5	800	800	256	288	600	600	600	600					694	777			15,297	17,210	256	288	Trip	Trip
Portsmouth Ave 11X2	34.5	800	800	256	288	600	600	600	600					694	777			15,297	17,210	256	288	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			307	318	694	777			7,328	7,590	307	318	Reg	Reg
Seabrook 7X2	34.5	800	800	208	234	600	600	900	900			234	242	694	777			12,429	13,983	208	234	Trip	Trip
Shaw's Hill Tap	34.5	800	800	288	324	600	600	600	600			525	544	694	777			17,210	19,361	288	324	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			281	291	694	777			16,815	17,416	281	291	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			612	634	694	777			7,171	7,171	300	300	CT	CT
13W2	13.8	560	560	224	252	300	300	400	400			307	318	694	777			5,354	6,023	224	252	Trip	Trip
Timberlane 13X3	34.5	800	800	192	216			800	800			281	291	694	777			11,473	12,907	192	216	Trip	Trip
Westville 21T1	13.8					600	600									584	612	13,970	14,341	584	600	Xfmr	CT
21W1	13.8	560	560	448	504	600	600	600	600			668	668	694	777			10,708	12,047	448	504	Trip	Trip
Westville 21T2	13.8					600	600									584	612	13,970	14,341	584	600	Xfmr	CT
21W2	13.8	560	560	304	342	300	300	600	600			668	668	554	554			7,171	7,171	300	300	CT	CT
Westville Tap 58X1	34.5					300	300	300	300			281	291					16,815	17,416	281	291	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					315	326	694	777			11,951	11,951	200	200	CT	CT
Winnacunnet Road Tap 46X1	34.5	560	560	160	180	100	100	300	300			315	326	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

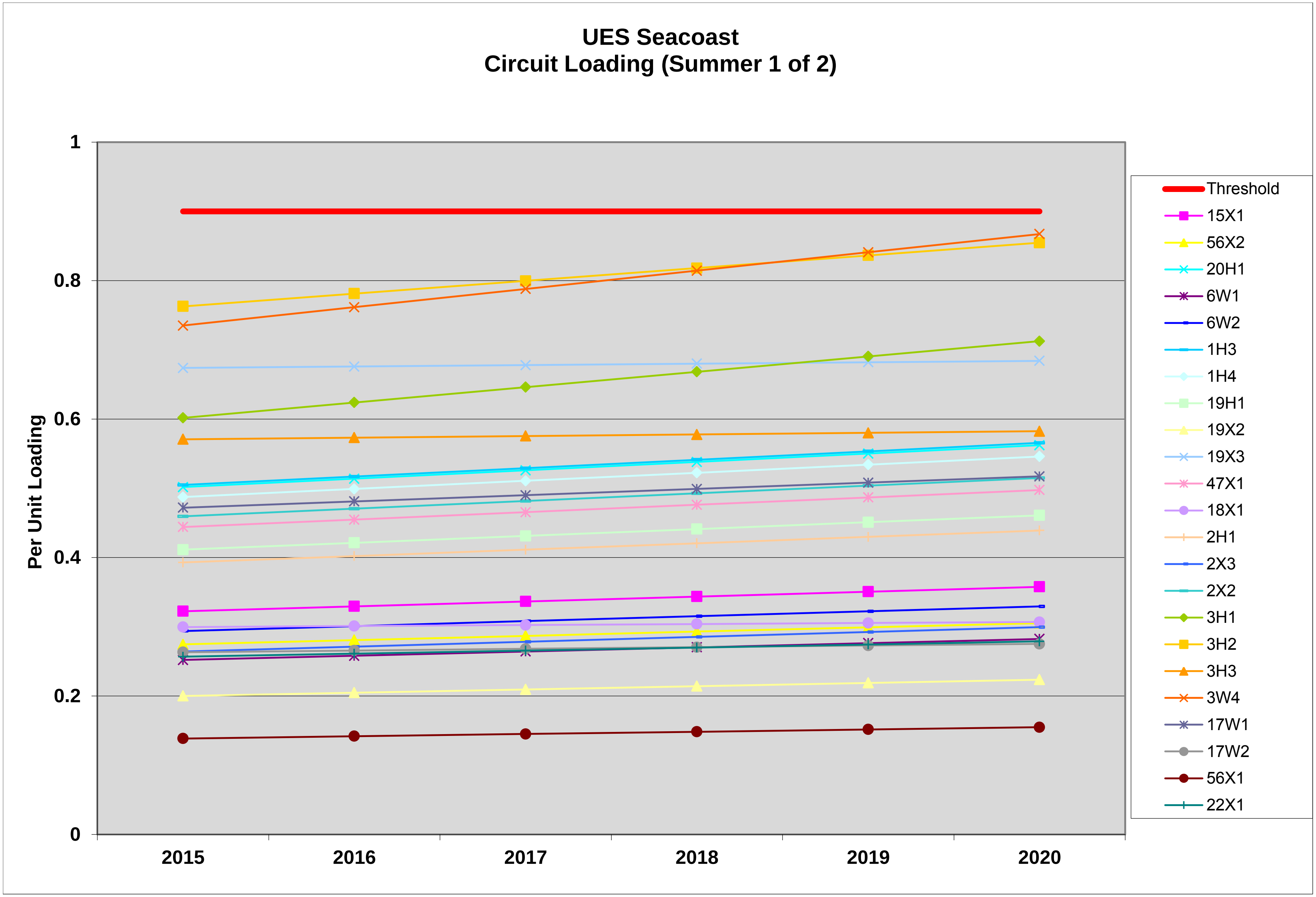
Transformer Loading Charts
(in Per Unit)

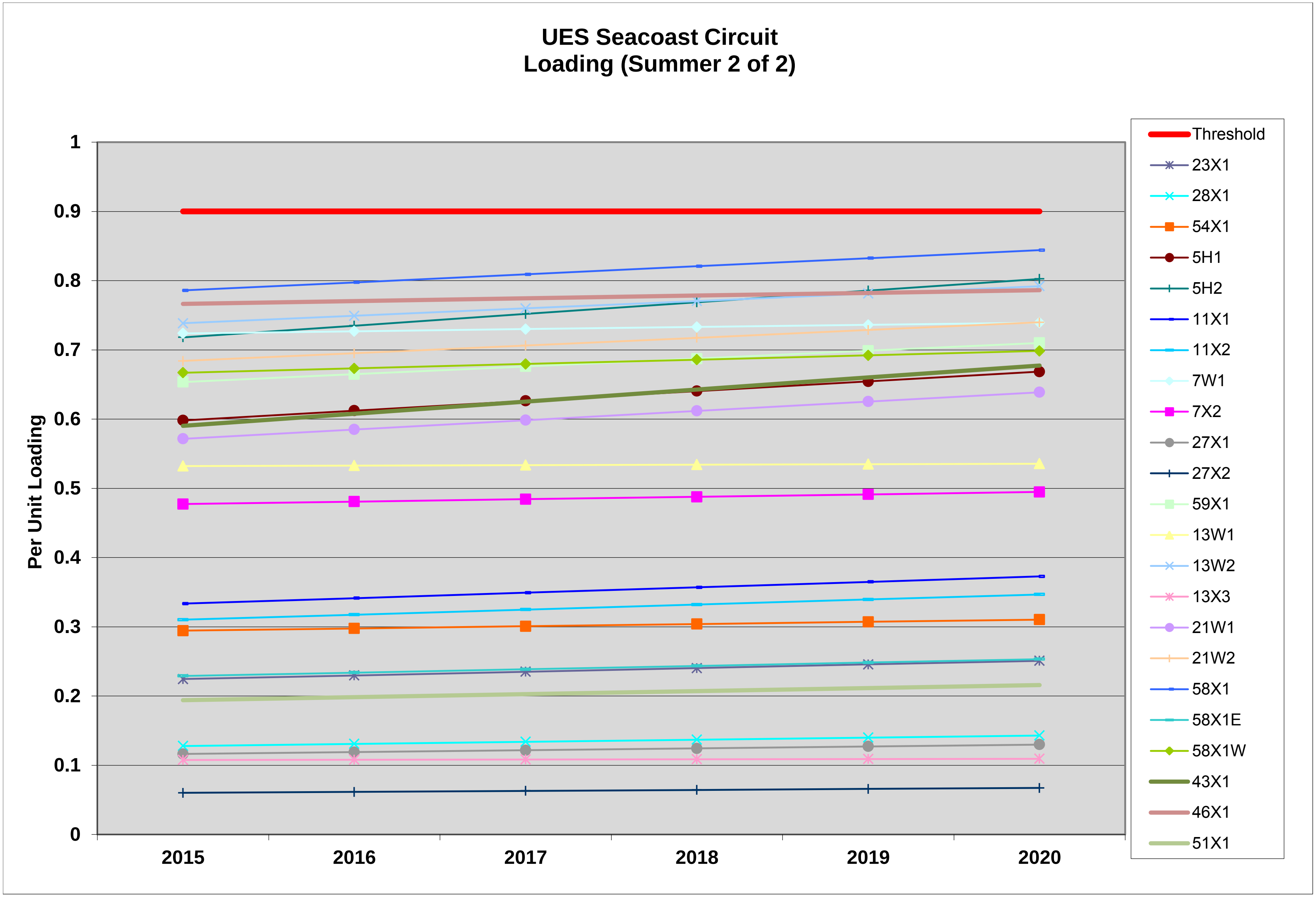

UES Seacoast
Transformer Loading (Summer)
Per Unit Loading
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2015
2016
2017
2018
2019
2020
Dow's Hill 20T1
East Kingston 6T1
Exeter 1T1
Exeter 1T2
Exeter Switching 19T1
Hampton 2T1
Hampton Beach 3T1
Hampton Beach 3T3
High Street 17T1
Plaistow 5T1
Seabrook 7T1
Timberlane 13T1
Westville 21T1
Westville 21T2
Threshold

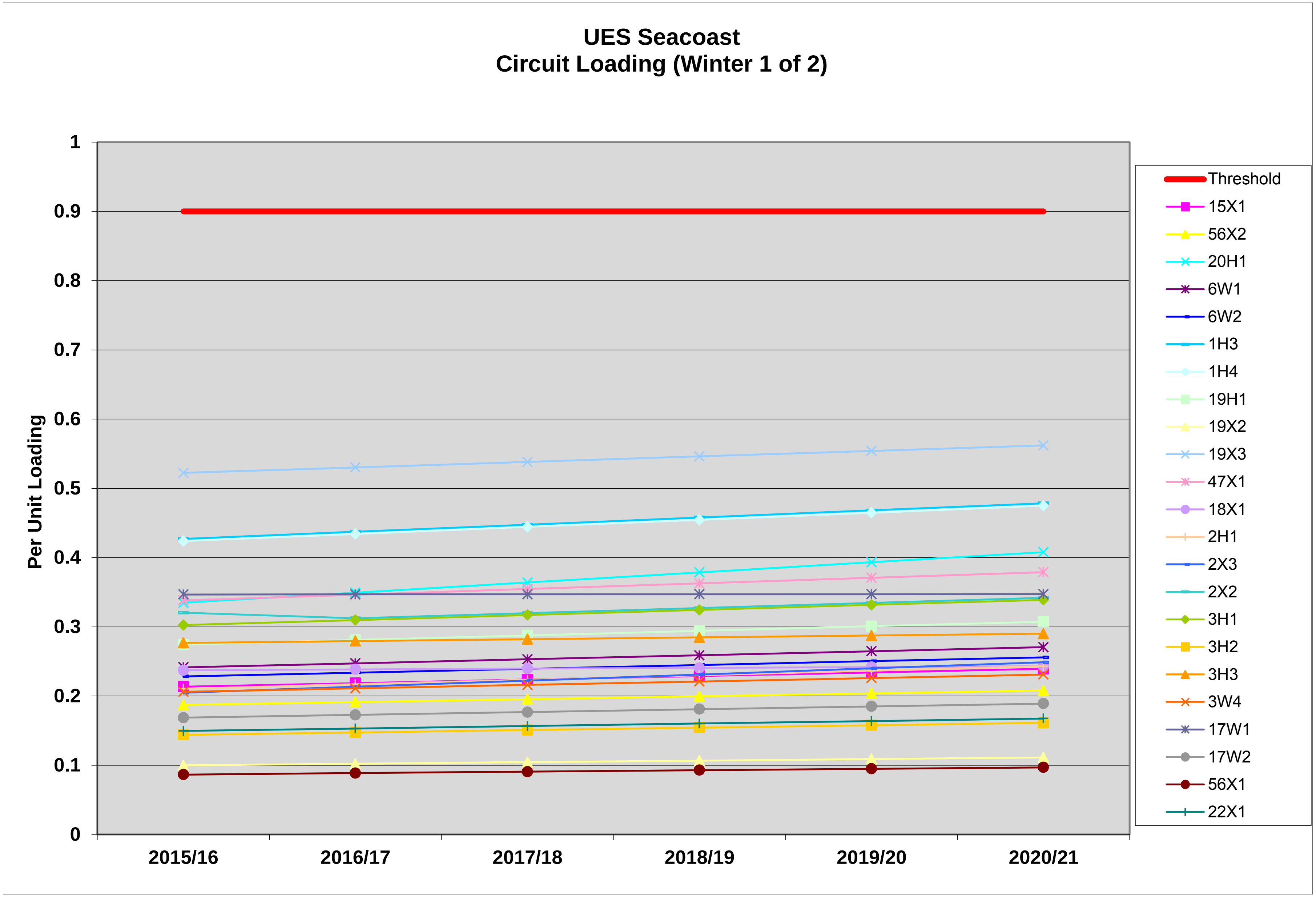

UES Seacoast
Transformer Loading (Winter)
Per Unit Loading
1.00
0.80
0.60
0.40
0.20
0.00
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
Dow's Hill 20T1
East Kingston 6T1
Exeter 1T1
Exeter 1T2
Exeter Switching 19T1
Hampton 2T1
Hampton Beach 3T1
Hampton Beach 3T3
High Street 17T1
Plaistow 5T1
Seabrook 7T1
Timberlane 13T1
Westville 21T1
Westville 21T2
Threshold

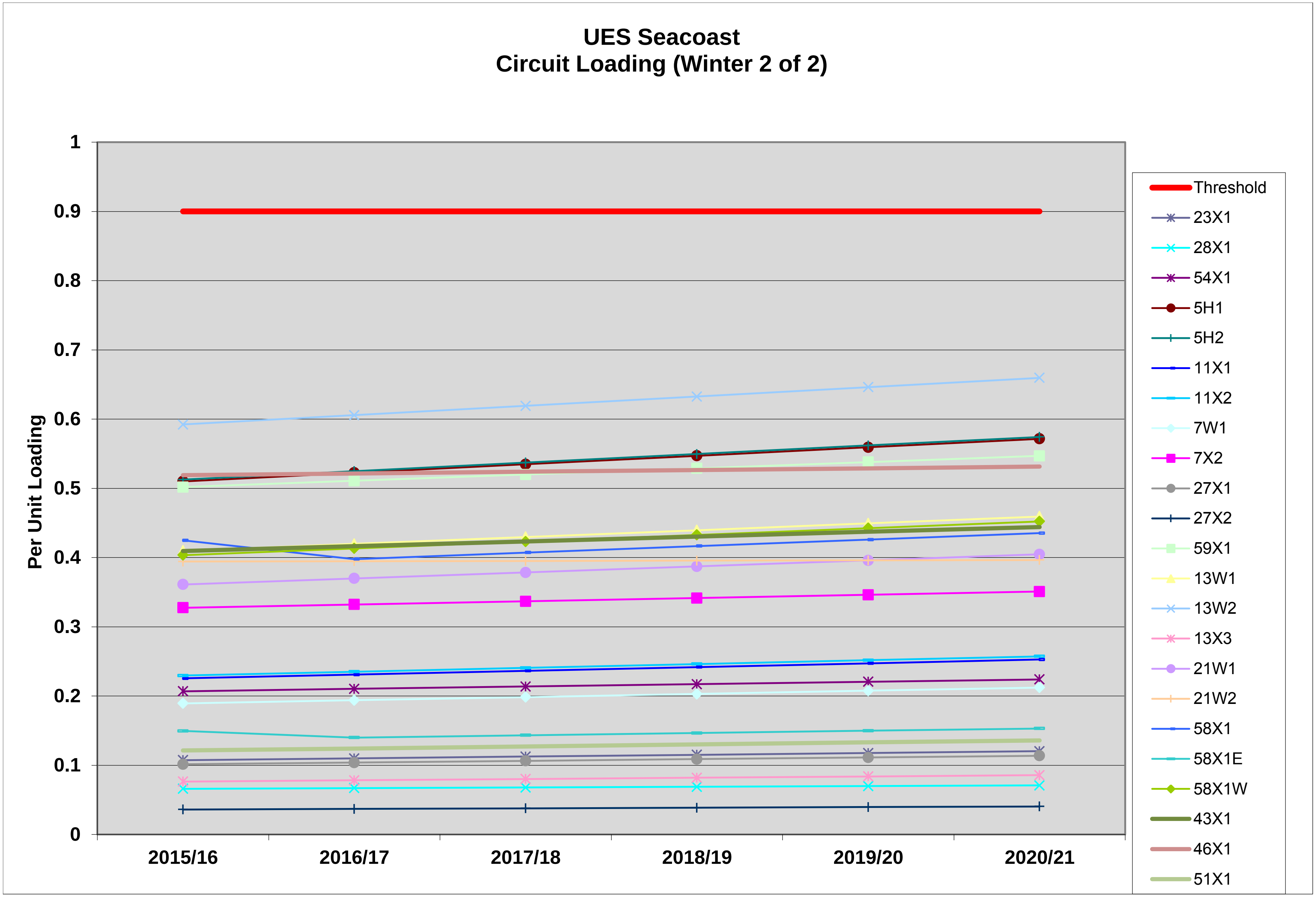
Appendix D

Circuit Loading Charts
(in Per Unit)


UES Seacoast
Circuit Loading (Summer 1 of 2)
Per Unit Loading
1
0.8
0.6
0.4
0.2
0
2015
2016
2017
2018
2019
2020
Threshold
15X1
56X2
20H1
6W1
6W2
1H3
1H4
19H1
19X2
19X3
47X1
18X1
2H1
2X3
2X2
3H1
3H2
3H3
3W4
17W1
17W2
56X1
22X1

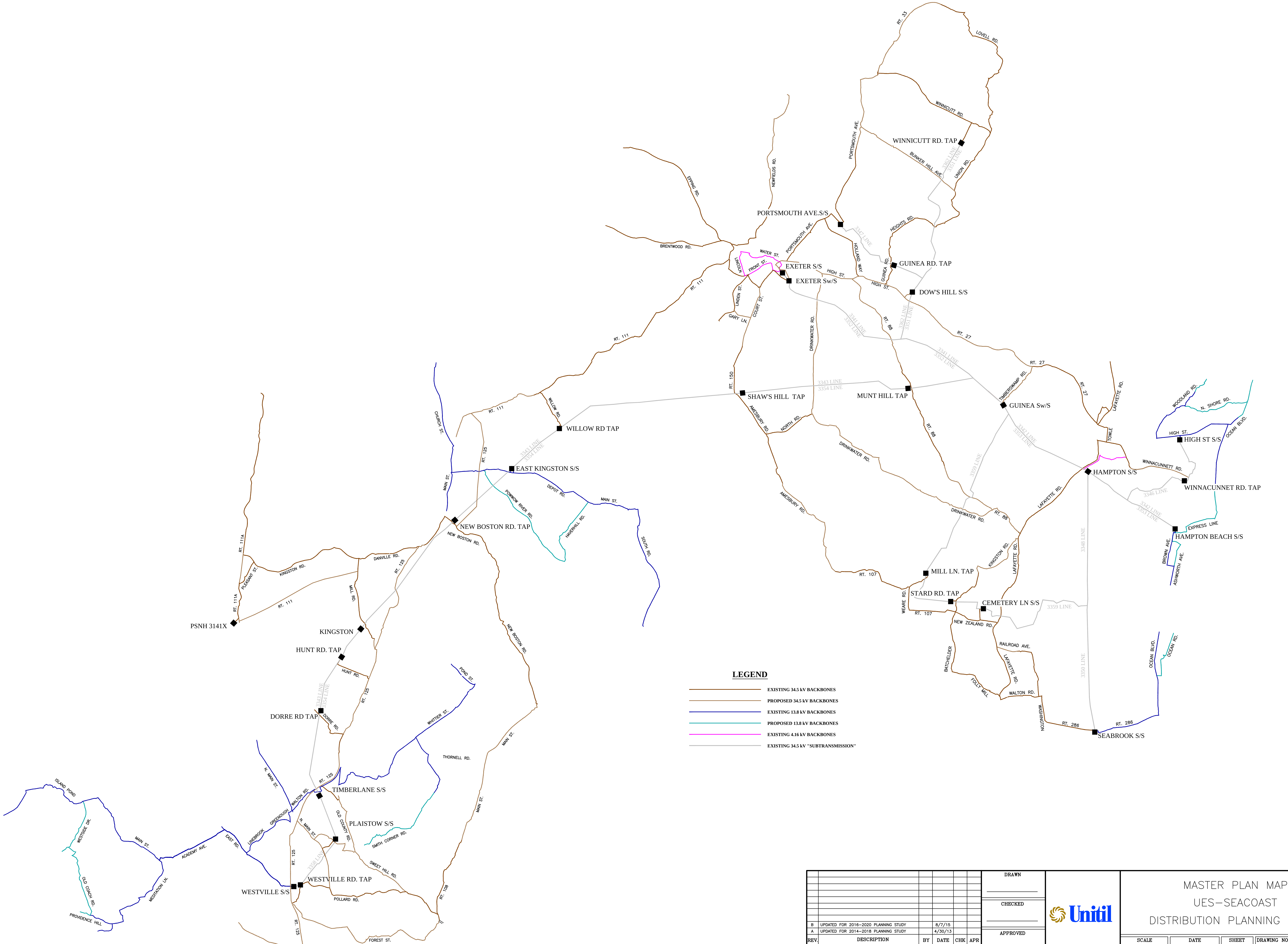

UES Seacoast Circuit
Loading (Summer 2 of 2)
Per Unit Loading
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
2015
2016
2017
2018
2019
2020
Threshold
23X1
28X1
54X1
5H1
5H2
11X1
11X2
7W1
7X2
27X1
27X2
59X1
13W1
13W2
13X3
21W1
21W2
58X1
58X1E
58X1W
43X1
46X1
51X1


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
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
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
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
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

Master Plan Map



REV.	DESCRIPTION	BY	DATE	CHK	APR
B	UPDATED FOR 2016–2020 PLANNING STUDY		8/7/15		
A	UPDATED FOR 2014–2018 PLANNING STUDY		4/30/13		

REVISIONS

DRAWN

CHECKED

APPROVED

MASTER PLAN MAP
UES–SEACOAST
DISTRIBUTION PLANNING STUDY

SCALE	DATE	SHEET	DRAWING NO.
N/A	10/24/12	1 OF 1	UES–S MP

2015 Eversource/UES JOINT PLANNING COMMITTEE RECOMMENDATION REPORT

May 19, 2015

The Joint Planning Committee has conducted the annual planning meetings in 2014 between Eversource and UES (Unitil Energy Systems). Planning departments at both companies are represented on the Joint Planning Committee. This joint planning process is a distribution planning effort and any recommendations that have transmission implications need to be reviewed by the NU Transmission Planning Department and ISO-NE.

This report summarizes the findings and recommendations of the Joint Planning Committee. The Eversource 2015-2024 Loadflow Study and the Unitil 2015-2024 Electric System Planning Studies (UES-Capital and UES-Seacoast) were used as the basis for identifying planning constraints for the years 2015-2019. Wherever feasible, alternatives are developed to resolve each planning constraint identified. Alternatives were evaluated considering several criteria including total cost in today's dollars, system benefit and technical preference. Preferred alternatives are detailed in the 5-Year Construction Plans shown below and may impact both companies. The company listed is the company responsible for the majority of the identified project's completion.

Relevant System Changes (Eversource Area / UES Area):

Relevant System changes since release of the previous Joint Planning Report are described below:

<u>Central / UES Capital</u>

1. None

<u>Eastern / Seacoast</u>

1. The 3343 and 3354 lines between Kingston S/S and Guinea S/S are now normally fed from Guinea S/S (Timber Swamp supply). The new normally open point on these lines is the 3343J5 and 3354J5 switches in the immediate vicinity of Kingston S/S. These switches do not have SCADA control.

2. In 2014, the 3360 and 3371 lines were reconductored with 1113 ACSS/TW (Avocet) and the 3360 and 3371 line positions at Guinea were upgraded with 2,000 amp breakers and 2,000 amps disconnect switches. In February of 2015, Eversource replaced breaker taps on the 03360 and 03371 breakers at Timber Swamp and implemented new protection settings for a summer normal rating of 2,000 amps.

Recommended 5 Year Construction Plan:

Eversource Area / UES Area: Central / Capital

Company	Need Date	Description
Eversource	2015	Rebuild 317 Line (see item 1)
UES/Eversource	2015-2016	Garvins 35kV bus upgrade and reconfiguration. (see item 2).
Eversource	2016	Second transformer at Rimmon (see item 3)
UES/Eversource	2015-2017	Construction of Broken Ground 115-34.5 kV system supply (see item 4).

Capital Area Item #1 – Rebuild Eversource 317 Line – 2015

<u>Planning Issue – Garvins/Oak Hill Transformer Loading</u>
Eversource is rebuilding the 317 line out of Oak Hill with an in-service date of 2015. The anticipated Eversource load to be served by this line is 12-16MW.

Note: Alternatives to this project are not a joint planning issue. Therefore, alternatives and costs relative to these upgrades are not included within this report.

Capital Area Item #2 – Garvins 35kV Bus Upgrade and Reconfiguration – 2015-2016

<u>Planning Issue – Garvins Bus Configuration</u>
Eversource is upgrading 35kV equipment and installing bus protection at their Garvins S/S. The scope of this project includes the installation of a new normally closed bus tie breaker and implementation of a bus differential scheme. This scheme will isolate a faulted bus section so that one of the Garvins transformers will remain in service.

The present line configuration at Garvins has both UES 375 and 396 lines originating from Bus #1 and the 374 line from Bus #2. This arrangement has the potential to require additional load shedding for the loss of Bus #2 since the remaining load being served from Bus #1 is anticipated to approach a single transformer TFRAT by 2017 with Broken Ground in service. This issue can be resolved by relocating either the 375 or 396 line position to Bus #2.

The following alternatives were evaluated by the Joint Planning Committee[1].

---

[1] Note that the overall scope of the Garvins 35kV upgrade project includes additional capital investment by Eversource and Unitil not detailed within this report since the justification for this project is equipment replacement and protection and control upgrades with no joint planning alternatives.

Option #1:
Construct a new 35kV bay at the end of Bus #2 for the 396 line and construct a new overhead getaway to interconnect with Unitil's 396 line.

The cost to implement this alternative is estimated to be approximately $200,000 (Eversource), $27,500 (UES) UES and Eversource will be responsible for the implementation of this project.

Option #2:
Transpose the existing 396 line position with the hydro line positions on Bus #2 and reconfigure overhead lines outside substation.

The cost to implement this alternative is estimated to be approximately $135,000 (Eversource), $27,500 (UES) UES and Eversource will be responsible for the implementation of this project.

Option #3:
Transpose the 374 and 375 lines within UES's ROW. In addition, in order to maintain the tie between 374 line and Eversource's 318 line, a new GOLB switch will be installed between the existing 375 line and Eversource's 318 line.

The cost to implement this alternative is estimated to be approximately $50,000 (Eversource), $58,300 (UES). UES and Eversource will be responsible for the implementation of this project.

Recommendation:
Option #3 is the least costly option and preferred from a technical standpoint since this option will not require any additional substation modifications within Eversource's Garvins S/S other than re-designation of equipment. The resulting worse case loading following a bus fault is 58 MW.

Capital Area Item #3 – Second Transformer at Rimmon – 2016

Planning Issue – Transformer Loading at Rimmon, Eddy and Garvins
Eversource intends to install a second transformer 44.8MVA transformer at Rimmon with an in-service date of 2016.

Note: Alternatives to this project are not a joint planning issue. Therefore, alternatives and costs relative to these upgrades are not included within this report.

Capital Area Item #4 – Broken Ground System Supply – 2017

Planning Issue – Garvins Transformer Loading
UES to construct a new 115-34.5 kV substation (Broken Ground) in Concord. This project is currently in the permitting phase with an anticipated in service date of March, 2017.

Eversource Area / UES Area: Southern / Seacoast

UES/Eversource/NU	2014-2016	Construction of Kingston 115-34.5 kV system supply substation (see item 1).
UES/Eversource/NU	2015-2016	Construction of jointly owned 35kV distribution line from Mill Rd, Kingston to Main Street, Danville (see item 2).

Seacoast Area Item #1 – Kingston System Supply – 2014-2016

Planning Issue – Kingston Transformer Loading
UES to construct a new 115-34.5 kV substation in Kingston. Eversource to construct a new 115 kV switching station (Peaslee) in Kingston. This will be the source for the new UES Kingston substation. The new UES Kingston S/S and Eversource Peaslee S/S are currently under construction with an expected in service date of April, 2016.

Seacoast Area Item #2– Construct a Jointly Owned 35kV Distribution Circuit – 2015-2016

Planning Issue – Chester 3141X Loading
Eversource plans to build a new distribution circuit (3818) from the existing Eversource Kingston S/S and tie this new line to the existing Eversource 3141X circuit in Danville. The only feasible route for this line is through the UES service territory along Rte. 111 between Main Street, Danville and Mill Road, Kingston. UES will construct a new distribution circuit from the UES Kingston S/S to Rte. 111. Eversource will construct a new distribution circuit (3818) from the Eversource Kingston S/S to Rt. 111 within the existing Eversource ROW. UES and Eversource will then construct a joint pole line along Rte. 111 from the Eversource ROW to Main Street, Danville.

Note: Alternatives to this project are not a joint planning issue. Therefore, alternatives and costs relative to these upgrades are not included within this report.

Recommended 10 Year Conceptual Plan:

Eversource Area / UES Area: Central / Capital

Company	Need Date	Description
		No identified projects at this time.

1. Unresolved issues and plans to address them:
   a. No Unresolved issues:

Eversource Area / UES Area: Eastern / Seacoast

		No identified projects at this time.

1. Unresolved issues and plans to address them:
   a) UES and Eversource need to consider timing for a second 44.8 MVA, 115-34.5 kV transformer at Great Bay Substation.

The above Joint Planning Recommendations are accepted as meeting the needs of Eversource and UES for long term planning of jointly used Distribution facilities.

James Eilenberger
Director - System Engineering, Eversource

6/1/15
Date

JAMES EILENBERGER
Print

K E S
Director of Engineering, USC

5/22/2015
Date

Kevin E Sprague
Print

Unitil Energy Systems - Capital

Reliability Study

2015

Prepared By:
Cyrus Esmaeili
Unitil Service Corp.
Oct 1, 2015

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

1. Executive Summary

The purpose of this document is to report on the overall reliability performance of the UES-Capital system January 1, 2014 through December 31, 2014. The scope of this report will also evaluate individual circuit reliability performance over the same time period. The outage data from the following storm has been excluded from these analyses: UES-CATO 11/26/2014 13:00 to 12/01/2014 19:30.

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 2015 budget development process.

Circuit / Line / Substation	Proposed Project	Cost ($)
15W1	INSTALL A RECLOSING DEVICE TO PROTECT SHAKER RD	$9000
13W1	INSTALL COVERED WIRE ALONG KIMBALL POND RD	$23,000
4W4	INSTALL COVERED WIRE ALONG LAKEVIEW RD	$99,000
BOW JUNCITON	INSTALL AN AUTO TRANSFER SCHEME	$100,000
396 LINE	INSTALL AN AUTO SECTIONALIZING SCHEME	$40,000

Note: estimates do not include general construction overheads

2. Reliability Goals

The annual corporate system reliability goals for 2015 have been set at 180-160-139 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

This section provides a breakdown of all outages by cause code experienced during 2014. Chart 1 lists the number of interruptions, and the percent of total interruptions, due to each cause. For clarity, only those causes occurring more than 5 times are labeled. Chart 2 details the percent of total customer-minutes of interruption due to each cause, only those causes contributing greater than 2% of the total are labeled.

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Chart 1
Number of Interruptions by Cause

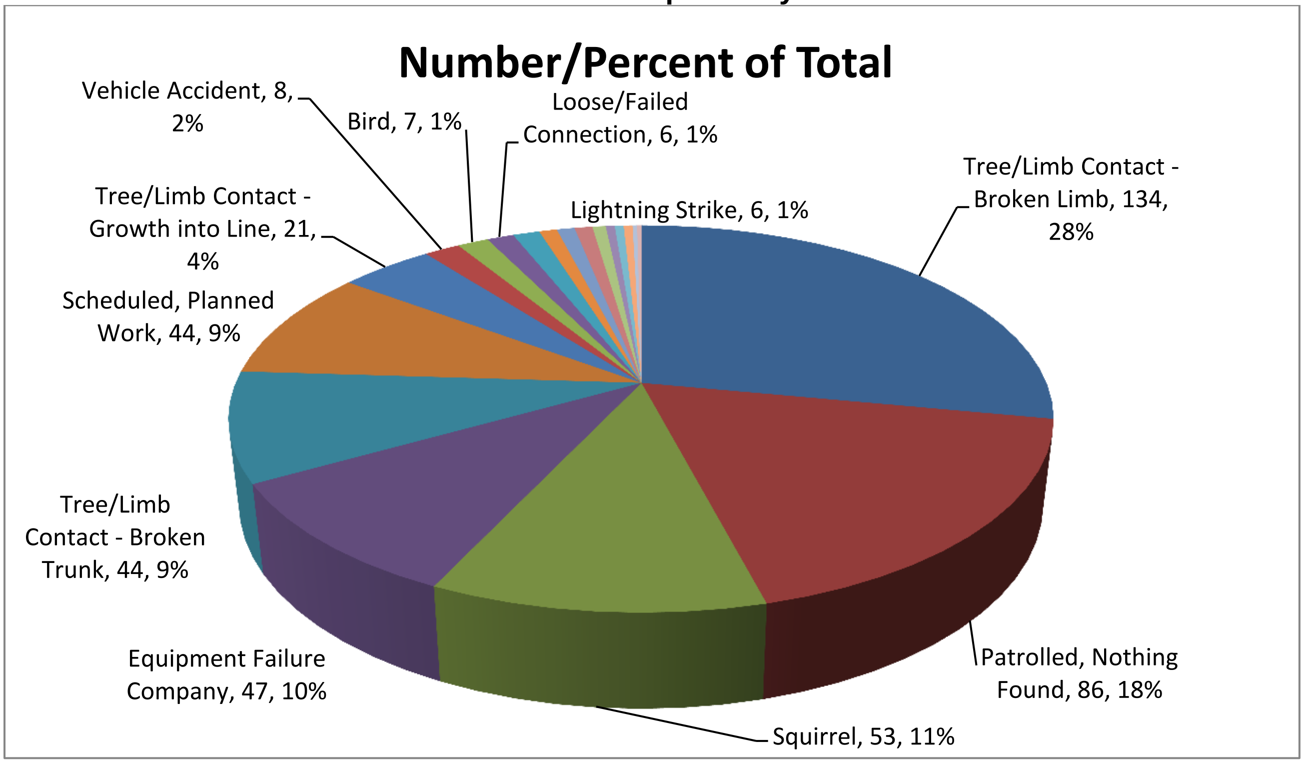
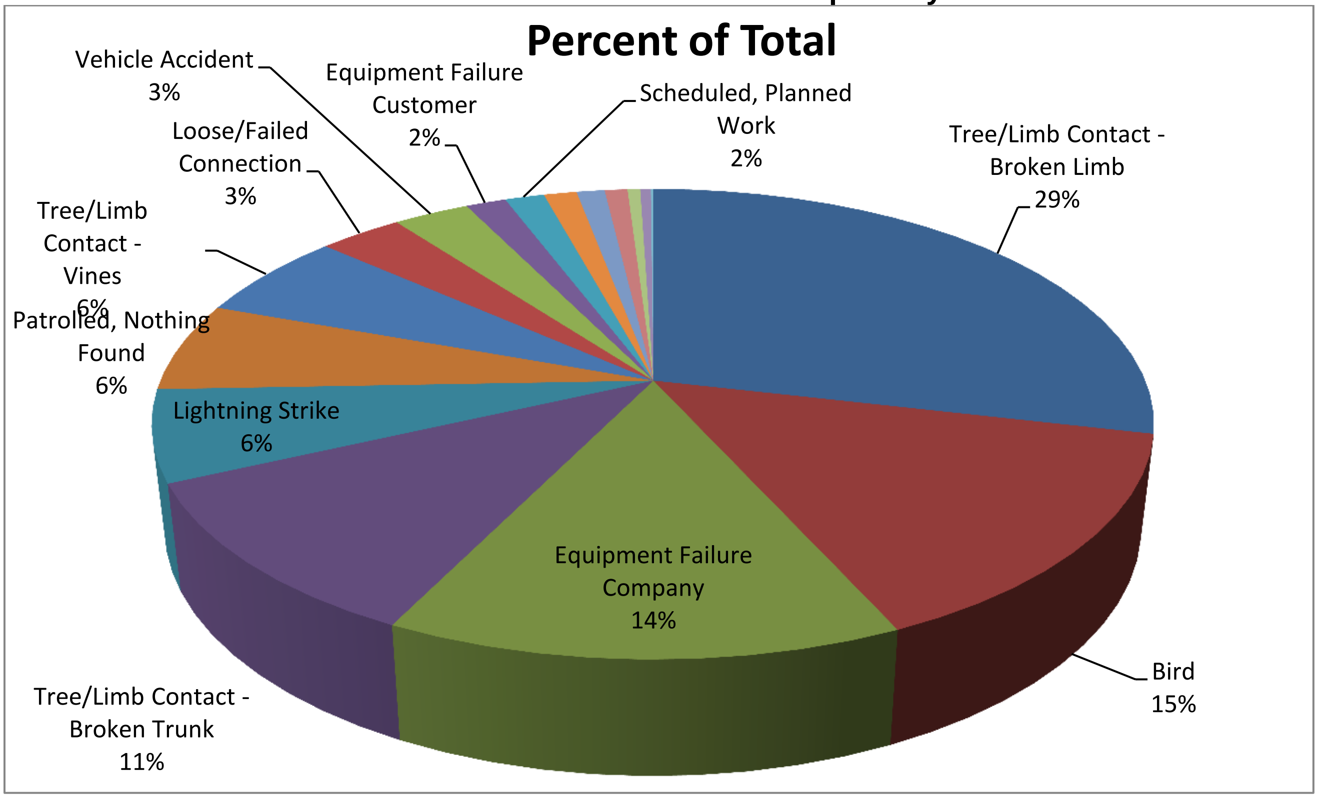


Chart 2
Percent of Customer-Minutes of Interruption by Cause



UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

4. 10 Worst Distribution Outages

The ten worst distribution outages ranked by customer-minutes of interruption during the time period from January 1, 2014 through December 31, 2014 are summarized in Table 1 below.

Table 1
Worst Ten Distribution Outages

Circuit	Date/Cause	Customer Interruptions	Cust-Min of Interruption	SAIDI	SAIFI
22W3	1/4/2014 Loose/Failed Connection	906	99,931	3.34	0.030
8X3	11/2/2014 Tree/Limb Contact - Broken Limb	443	96,101	3.22	0.015
15W2	4/23/2014 Vehicle Accident	350	95,425	3.19	0.012
8X5	12/9/2014 Equipment Failure Company	855	77,956	2.61	0.029
13W2	7/28/2014 Tree/Limb Contact - Broken Limb	972	70,324	2.35	0.033
13W1	2/12/2014 Loose/Failed Connection	483	70,035	2.34	0.016
13W3	5/7/2014 Vehicle Accident	204	51,772	1.73	0.007
15W1	7/15/2014 Tree/Limb Contact - Broken Limb	256	47,501	1.59	0.009
7W3	9/7/2014 Patrolled, Nothing Found	898	46,831	1.57	0.030
8X3	6/25/2014 Tree/Limb Contact - Broken Trunk	332	43,131	1.44	0.011

Note: This table does not include substation, sub-transmission or scheduled planned work outages.

5. Sub-transmission Line and Substation Outages

This section describes the contribution of sub-transmission line and substation outages on the UES-Capital system from January 1, 2014 through December 31, 2014.

All substation and sub-transmission outages ranked by customer-minutes of interruption during the time period from January 1, 2014 through December 31, 2014 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.

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Table 2
Sub-transmission and Substation Outages

Line/Substation	Date/Cause	Customer Interruptions	Cust-Min of Interruption	SAIDI	SAIFI
Line 396[1]	9/8/2014 Bird	11,910	1,003,440	33.58	0.399
Bow Junction Substation	4/19/2014 Equipment Failure Company - Transformer	5,129	480,605	16.08	0.172
Line 374[2]	9/13/2014 Tree/Limb Contact - Broken Trunk	5,909	446,659	14.95	0.198
Line 37	9/16/2014 Tree/Limb Contact - Vines	3,209	409,838	13.72	0.107
Line 35	7/16/2014 Lightning Strike	2,238	397,335	13.30	0.075
Line 33 (From Bow Junction)	7/2/2014 Tree/Limb Contact - Broken Limb	2,083	279,820	9.36	0.070
Line 374	2/13/2014 Equipment Failure Company - Insulator	3,056	189,460	6.34	0.102
Line 33 (From W. Concord)	7/5/2014 Patrolled, Nothing Found	1,197	143,524	4.80	0.040
Line 38[3]	1/10/2014 Equipment Failure Customer - Cable	873	100,056	3.35	0.029
Line 38	4/14/2014 Equipment Failure Company - Pole	1562	88,295	2.95	0.052
Line 38	9/3/2014 Operator Error/System Malfunction	689	42,316	1.42	0.023
Line 38[2]	1/10/2014 Equipment Failure Customer - Cable	687	7,534	0.25	0.023

[1] A fault on the 396 Line affected multiple sub transmission lines due to a protective device not operating. An investigation was completed and measures have been taken to prevent this situation from happing again.
[2] System was in an alternate configuration, thus the circuits affected had changed
[3] These outages are part of the same event, although the smaller of the two was about four hours after the first, which was required to reconnect the primary metered customer that caused the initial outage.

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Table 3
Contribution of Sub-transmission and Substation Outages

Circuit	Substation / Transmission Line Outage	Cust-Min of Interruption	% of Total Circuit CMI	Circuit SAIDI Contribution	Number of Events
C13W1	Line 37	61,789	31%	127.66	1
C13W2	Line 37	124,173	50%	168.71	1
C13W3	Line 37	201,488	44%	127.85	1
C13X4	Line 37	128	33%	127.93	1
C14H1	Line 374 Line 396*	25,261	100%	271.62	3
C14H2	Line 374 Line 396*	181,927	99%	269.52	3
C14X3	Line 374 Line 396*	1,094	62%	182.35	3
C15H3	Line 35 Line 396*	4,243	100%	249.60	2
C15W1	Line 35 Line 396*	243,452	50%	250.21	2
C15W2	Line 35 Line 396*	87,247	31%	245.76	2
C16H1	Line 396*	22,903	72%	76.86	1
C16H3	Line 396*	47,552	100%	76.33	1
C16X4	Line 396*	43,710	86%	76.68	1
C16X5	Line 396*	78	9%	3.38	1
C16X6	Line 396*	77	100%	77.03	1
C17X1	Line 374 Line 396*	215	96%	1.90	2
C18W2	Line 374 Line 396*	178,888	55%	160.73	2
C1H1	Line 396*	24,486	100%	77.24	1
C1H2	Line 396*	19,943	100%	77.30	1
C1H3	Line 396*	46,099	65%	76.20	1
C1H4	Line 396*	3,850	100%	77.00	1
C1H5	Line 396*	5,390	100%	77.00	1
C1H6	Line 396*	25,641	87%	77.00	1
C1X7A	Line 396*	77	100%	77.00	1
C1X7P	Line 396*	613	75%	76.58	1
C21W1A	Line 396*	21,560	26%	76.73	1
C21W1P	Line 396*	31,745	61%	77.24	1
C22W1	Bow Junction Substation Line 33 Line 374	104,396	39%	209.63	3
C22W2	Bow Junction Substation Line 33 Line 374	8,836	41%	210.38	3
C22W3	Bow Junction Substation Line 33	324,787	28%	205.30	3

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Circuit	Substation / Transmission Line Outage	Cust-Min of Interruption	% of Total Circuit CMI	Circuit SAIDI Contribution	Number of Events
	Line 374				
C24H1	Line 35 Line 38 Line 396*	171,333	95%	543.92	6
C24H2	Line 35 Line 38 Line 396*	203,884	100%	545.14	6
C2H1	Line 396*	34,632	100%	71.85	1
C2H2	Line 396*	76,248	92%	72.62	1
C2H4	Line 396*	6,768	100%	72.00	1
C33X2	Bow Junction Substation Line 33 Line 374	209	100%	209.18	2
C33X3	Bow Junction Substation Line 33 Line 396*	248	100%	247.50	3
C33X4	Bow Junction Substation Line 33 Line 396*	16,583	77%	247.50	3
C33X5	Bow Junction Substation Line 33 Line 396*	743	100%	247.50	3
C33X6	Bow Junction Substation Line 33 Line 396*	248	100%	247.50	3
C34X2	Line 396*	72	100%	72.00	1
C34X4	Line 396*	72	100%	72.00	1
C35X1	Line 35 Line 396*	2,505	31%	178.94	2
C35X2	Line 35 Line 396*	1,000	100%	249.88	2
C35X3	Line 35 Line 396*	250	100%	249.88	2
C35X4	Line 35 Line 396*	1,498	100%	249.73	2
C374X1	Line 374 Line 396*	3,002	100%	300.20	3
C375X1	Line 396*	466	100%	77.62	1
C37X1	Line 37	22,260	53%	127.20	1
C3H1	Line 374 Line 396*	169,056	94%	301.35	3
C3H2	Line 374 Line 396*	144,427	91%	282.64	3
C3H3	Line 374 Line 396*	32,469	99%	295.17	3
C6X3	Bow Junction Substation	266,697	76%	243.34	3

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Circuit	Substation / Transmission Line Outage	Cust-Min of Interruption	% of Total Circuit CMI	Circuit SAIDI Contribution	Number of Events
	Line 33 Line 396*				
C7W3	Bow Junction Substation Line 374	261,461	66%	291.48	2
C7W4	Bow Junction Substation Line 374	211,553	90%	248.59	2
C7X1	Bow Junction Substation Line 374	41,772	94%	262.72	2

* A fault on the 396 Line affected multiple sub transmission lines due to a protective device not operating. An investigation was completed and measures have been taken to prevent this situation from happening again.

6. Worst Performing Circuits

This section compares the reliability of the worst performing circuits using various performance measures. All circuit reliability data presented in this section includes subtransmission or substation supply outages unless noted otherwise.

6.1. Worst Performing Circuits in Past Year

A summary of the worst performing circuits during the year of 2014 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 affecting these circuits. Customer-minutes of interruption are given for the six most prevalent causes during 2014.

Circuits having one outage contributing to more than 75% of the Customer-Minutes of interruption of the circuit were excluded from this analysis.

Table 4
Worst Performing Circuits by Customer-Minutes

Circuit	No. of Customers Interruptions	Worst Event (% of CI)	Cust-Min of Interruption	Worst Event (% of CMI)	SAIDI	SAIFI	CAIDI
22W3	9,226	16.95%	1,154,184	40.33%	729.57	5.83	125.10
15W1	3,242	30.04%	486,372	35.66%	499.87	3.33	150.02
8X3	3,842	12.73%	470,761	20.41%	167.11	1.36	122.53
13W3	3,658	43.11%	455,916	44.19%	289.29	2.32	124.64
7W3	3,572	25.14%	398,770	42.55%	444.56	3.98	111.64
6X3	3,709	30.47%	349,127	38.66%	318.55	3.38	94.13
18W2	3,463	31.56%	324,955	37.67%	291.96	3.11	93.84
15W2	2,342	15.33%	282,163	33.82%	794.83	6.60	120.48
22W1	2,009	24.89%	266,112	56.60%	534.36	4.03	132.46
13W2	2,423	40.12%	247,111	50.25%	335.75	3.29	101.99

Note: all percentages and indices are calculated on a circuit basis

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Table 5
Circuit Interruption Analysis by Cause

	Customer – Minutes of Interruption / # of Outages					
Circuit	**Animal Combined**	**Tree/Limb Contact - Broken Limb**	**Equipment Failure - Company**	**Tree/Limb Contact - Vines**	**Tree/Limb Contact - Broken Trunk**	**Patrolled, Nothing Found**
22W3	2,022 / 2	793,760 / 17	75,075 / 2	0 / 0	149,962 / 7	19,198 / 9
15W1	75,399 / 3	186,016 / 9	0 / 0	0 / 0	15,358 / 3	3,438 / 5
8X3	6,510 / 9	312,788 / 40	10,395 / 7	0 / 0	67,727 / 12	69,545 / 19
13W3	20,804 / 10	110,611 / 14	359 / 2	201,488 / 1	30,720 / 10	5,439 / 11
7W3	2,584 / 3	26,871 / 6	177,269 / 2	0 / 0	93,494 / 2	49,157 / 2
6X3	79,203 / 1	35,679 / 3	57,964 / 3	0 / 0	5,982 / 1	169,044 / 4
18W2	133,679 / 9	57,986 / 10	75,728 / 2	2,117 / 1	0 / 0	25,206 / 6
15W2	26,537 / 2	25,502 / 3	43,916 / 4	0 / 0	0 / 0	5,617 / 3
22W1	130 / 1	217,346 / 2	34,920 / 2	0 / 0	13,662 / 1	0 / 0
13W2	0 / 0	99,069 / 4	382 / 3	129,537 / 3	0 / 0	9,611 / 1

6.2. Worst Performing Circuits of the Past Five Years (2010 – 2014)

The annual performance of the ten worst circuits in terms of SAIDI and SAIFI for the past five years is shown 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.

The data used in this analysis includes all system outages except those outages that occurred during the 2014 November 26 Cato Snowstorm, 2012 Hurricane Sandy, 2011 October Nor'easter, 2011 Hurricane Irene and 2010 Windstorm.

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Table 6
Circuit SAIDI

Circuit Ranking	2014		2013		2012		2011		2010	
	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI
1	15W2	794.83	16H1	1524.26	13W2	817.42	13W1	887.09	8X3	1,037.0
2	22W3	729.57	375X1[1]	1018.00	13W1	425.04	13W2	835.67	211A	650.29
3	35X1	573.63	37X1	861.07	211P	381.91	37X1	797.25	13W1	648.23
4	24H1[2]	570.48	13W2	744.95	211A	270.00	13W3	660.07	13W2	487.15
5	24H2[2]	545.14	13W1	739.74	8X3	244.17	18W2	593.77	13W3	417.67
6	22W1	534.36	16X5	720.50	18W2	223.12	22W3	421.91	2H4	414.01
7	22W2	512.65	8X3	708.72	7W3	193.84	17X1	388.00	2H2	353.25
8	15W1	499.87	13W3	609.67	34X2	165.00	13X4	369.00	37X1	304.57
9	7W3	444.56	24H1	524.03	15W1	152.67	21W1A	361.90	3H2	298.00
10	38W	441.97	18W2	521.30	15W2	135.36	38W	359.61	18W2	293.13

Table 7
Circuit SAIFI

Circuit Ranking	2014		2013		2012		2011		2010	
	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI
1	24H1[2]	7.143	13W2	7.068	13W2	9.520	13W3	10.379	13W1	5.956
2	24H2[2]	6.987	16X5	5.500	13W1	4.858	13W2	8.942	8X3	5.847
3	15W2	6.597	37X1	5.412	21W1P	3.037	37X1	7.660	13W3	5.561
4	22W3	5.832	13W1	5.405	7W3	2.458	13W1	7.500	13W2	4.638
5	3H1[3]	4.251	22W3	4.849	18W2	2.386	22W3	6.440	37X1	4.391
6	22W1	4.034	4W3	4.574	6X3	2.283	38W	5.428	211A	4.365
7	38W	4.022	13W3	4.547	8X3	2.250	13X4	5.000	1H5	4.235
8	22W2	4.000	7W3	4.547	15W1	2.053	22W2	4.881	1H3	4.135
9	7W3	3.982	18W2	4.337	22W1	2.000	3H1	3.245	1H4	4.127
10	14X3	3.500	16H1	4.120	13W3	1.834	4X1	3.100	3H2	4.000

6.3. Improvements to Worst Performing Circuit (2013-2015)

Projects completed from 2013 to 2015 that are expected to improve the reliability of the worst performing circuits are included in table 8 below.

[1] Only two outages, one of which happened during a major event accounted for 97% of the Circuit SAIDI minutes
[2] 90% or more of the circuit SAIDI minutes are due to sub transmission outages. Refer to Table 8 for improvements completed on the 35 Line
[3] 90% or more of the circuit SAIDI minutes are due to sub transmission outages.

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Table 8
Improvements to Worst Performing circuits

Circuits	Year of Completion	Project Description
37 Line[1]	2014	Cycle Pruning / New Construction on Failed Connection Pole / Replaced Insulators that are well known for Higher than normal failure rate
13W1	2013	Fuse Additions / Forestry Review / Mid Cycle Review / Storm Resiliency Pilot (SRP)
	2014	Cycle Pruning
	2015	Fuse Additions / Installed Animal Guards in problem areas
13W2	2013	Grey Spacer Cable Replacement
		Cycle Pruning
		Fuse Additions
	2015	Hazard Tree Mitigation
13W3	2013	Grey Spacer Cable Replacement
		Hazard Tree Mitigation
	2014	Hazard Tree Mitigation / Mid Cycle Review
13X4	2015	New Recloser Installation
15W1	2013	Fuse Addition
	2014	Forestry Review
	2015	Cycle Pruning / Hazard Tree Mitigation
15W2	2014	Fuse Additions
	2015	Cycle Pruning
18W2	2013	Hazard Tree Mitigation / SRP / Fuse Additions
	2014	Forestry Review / Installed Animal Guards in problem areas
	2015	Fuse Addition / Sectionalizer Installations / Forestry Review
33 Line[2]	2015	Install remote operation capability on switches and SCADA monitored Fault indicators
22W3	2013	Mid Cycle Review

[1] This work will improve reliability performance on circuits 13W1, 13W2 and 13W3.
[2] The 33 line project will improve reliability performance on circuits 22W1,22W2, 22W3 and 6X3

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Circuits	Year of Completion	Project Description
	2014	Forestry Review / Installed Animal Guards in problem area
	2015	Cycle Pruning / Hazard Tree Mitigation / Installed Animal Guards in problem areas / Fuse savings implemented in problem areas
3H1	2015	Cycle Pruning
4W3	2015	Storm Resiliency Pilot (SRP)
6X3	2014	Hazard Tree Mitigation
	2015	All Mainline One Bolt Connectors Replaced / Installed Animal Guards in problem areas / Fuse Additions
7W3	2013	Storm Resiliency Pilot (SRP)
	2015	Cycle Pruning / Hazard Tree Mitigation
8X3	2015	Hazard Tree Mitigation / SRP / Mainline One Bolt Connectors Replaced / Replaced Insulators that are well known for Higher than normal failure rate / Fuse Addition / Install Reclosing Devices
38W[1]	2013	Reconfigured 38W Source Recloser
	2014	Cycle Pruning / Hazard Tree Mitigation / Mainline One Bolt Connectors Replaced
396 Line[2]	2014	Installed Animal Guards on 396J2 switch
35 Line[3]	2015	Replaced Insulators that are well known for Higher than normal failure rate

7. Tree Related Outages in the Past Year (1/1/14-12/31/14)

This section summarizes the worst ten performing circuits by tree related outages during 2014.

Table 9 shows the ten worst circuits ranked by the total number of Customer-Minutes of interruption caused by tree related faults on the circuit. The number of customer-interruptions and number of outages are also listed in this table. Circuits having less than three outages were excluded from this table.

All streets on the Capital System with three or more tree related outages are shown in Table 10 below. The table is sorted by number of outages and customer-minutes of interruption and does not include major events.

[1] The 38W line work will improve reliability performance on circuits 24H1 and 24H2
[2] Many circuits affected by this line, please reference table 3 for this list
[3] The 35 line work will improve reliability performance on circuits 35X1, 15W1, 15W2, 15H3, 38W, 24H1 and 24H2

Table 9
Worst Performing Circuits – Tree Related Outages

Circuit	Cust-Min of Interruption	Customer Interruptions	No. of interruptions
8X3[1]	382,577	2,964	54
22W3[1]	229,024	1,667	25
15W1[1]	209,638	949	13
13W3[1]	164,043	1,474	27
13W2[1]	104,433	1,220	6
4W3[1]	62,414	630	6
18W2[1]	60,103	593	11
6X3[1]	42,916	195	5
7W3[1]	31,746	456	8
13W1[1]	31,702	303	19

Table 10
Multiple Tree Related Outages by Street

Circuit	Street	# of Outages	Customer Interruptions	Customer Min. of Interruptions
8X3[1]	Dover Rd, Chichester/Epsom	5	370	46,934
15W1[1]	Mountain Rd, Concord	4	515	179,776
22W3[1]	Page Rd, Bow	4	1,031	85,875
8X3[1]	Horse Corner Rd, Chichester	4	314	29,138
13W3[1]	Battle St, Webster	4	153	28,615
13W1[1]	Borough Rd, Canterbury	4	86	9,107
8X3[1]	Main St, Chichester	3	967	139,186
18W2[1]	Twist Hill Rd, Dunbarton	3	159	19,835
13W3[1]	High St, Boscawen	3	503	18,641
13W3[1]	Warner Rd, Salisbury	3	107	17,211
22W3[1]	White Rock Hill Rd, Bow	3	92	10,990
15W1[1]	Oak Hill Rd, Concord/Loudon	3	175	9,941
13W1[1]	Hackleboro Rd, Canterbury	3	19	5,030
8X3[1]	Sanborn Hill Rd North, Epsom	3	27	2,970
8X3[1]	Old Mountain Rd, Epsom	3	3	1,091

8. Failed Equipment in the Past Year

This section is intended to clearly show all equipment failures throughout the year of 2014. Chart 3 shows all equipment failures throughout the study period. Chart 4 shows each equipment failure as a percentage of the total failures within this same study period. Chart 5 shows the top four types of failed equipment within the study period with five years of historical data.

[1] Tree trimming efforts have been or will be completed, refer to table 8 for details

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Chart 3
Equipment Failure Analysis by Cause

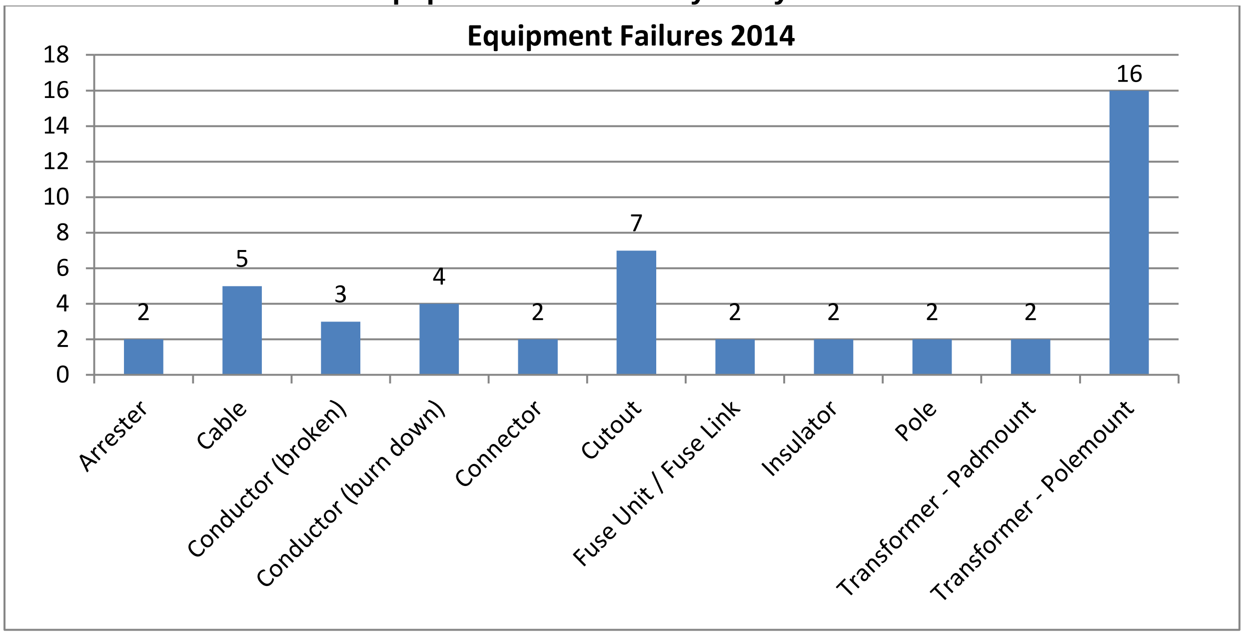
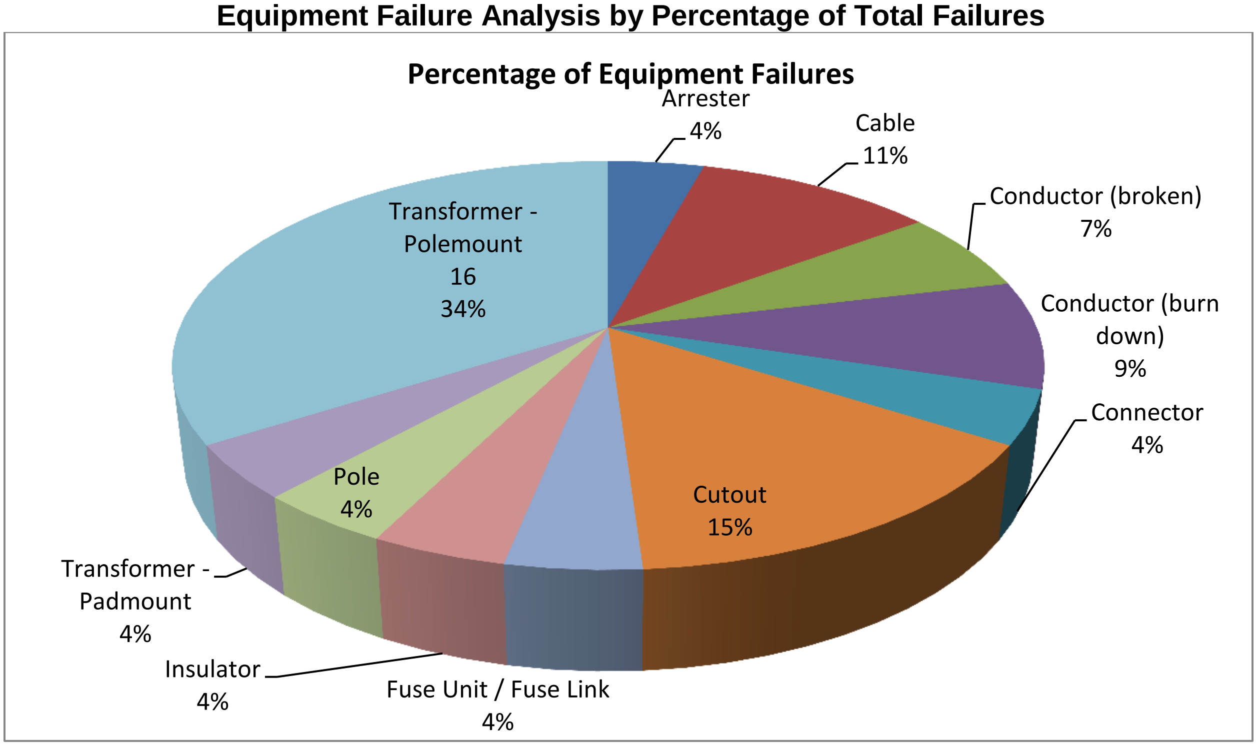


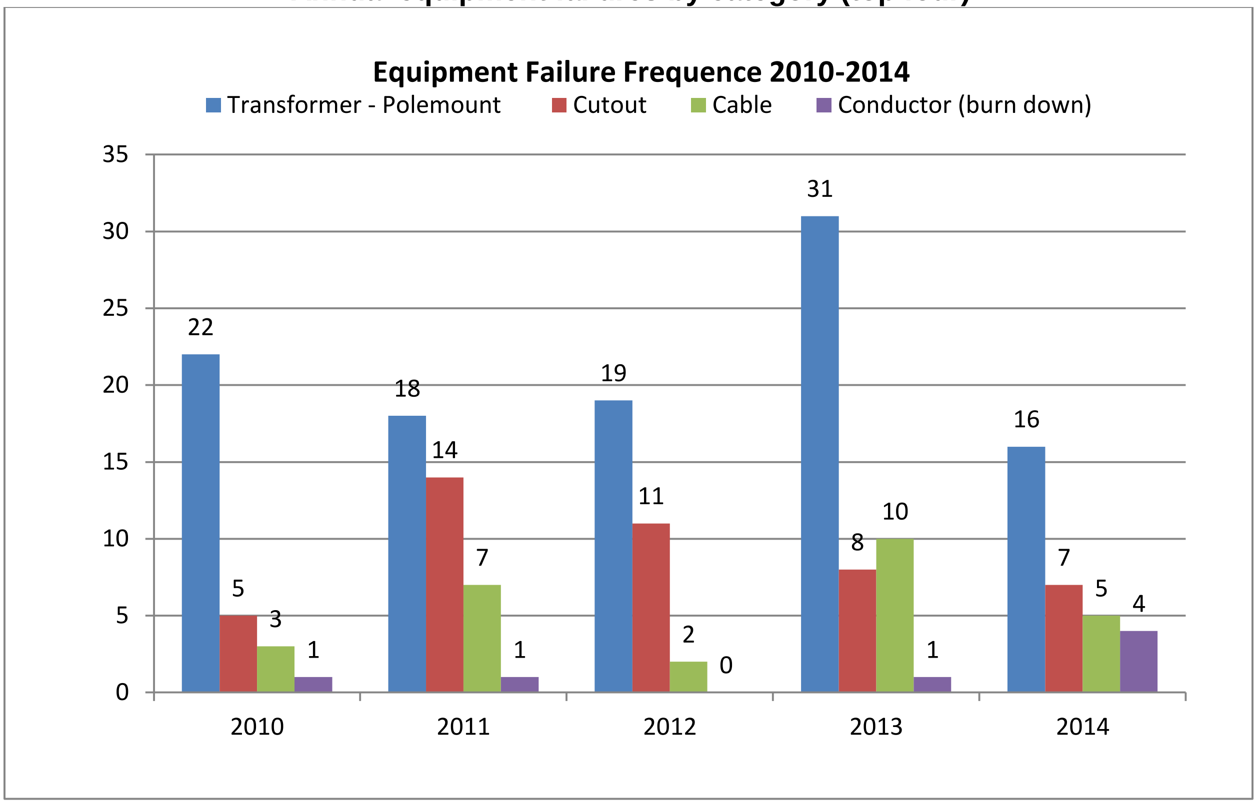
Chart 4
Equipment Failure Analysis by Percentage of Total Failures



UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

Chart 5
Annual equipment failures by category (top four)



UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

9. Multiple Device Operations in the Past Year (1/1/14-12/31/14)

Table 11 below is a summary of the devices that have operated three or more times in 2014. All exclusionary events are removed in this table.

Table 11
Multiple Device Operations

Circuit	Number of Operations	Device	Customer-Minutes	Customer-Interruptions
13W1[1,2]	6	Fuse, Pole 3, Hackleboro Rd, Canterbury	6,546.80	48
15W2[1]	5	Fuse, Pole 8, W. Portsmouth St, Concord	7,453.75	75
18W2[1,2]	5	Fuse, Pole 138-Z, Bow Bog Rd, Bow	7,384.65	105
22W3[1,2]	4	Fuse, Pole 1, Rocky Point Dr, Bow	102,111.70	385
4W4[1]	4	Recloser, Pole 1, Lake View Dr, Concord	24,565.31	147
15W1[1]	3	Fuse, Pole 5, Mountain Rd, Concord	183,646.07	582
18W2[1]	3	Fuse, Pole 211, Woodhill Rd, Bow	63,974.35	369
6X3[1]	3	Fuse, Pole 1, Currier Rd, Concord	53,780.17	210
8X3[1,2]	3	Fuse, Pole 26, New Orchard Rd, Epsom	40,718.13	201
8X3[1,2]	3	Fuse, Pole 54, Horse Corner Rd, Chichester	20,984.40	243
8X3[1]	3	Fuse, Pole 3, Canterbury Rd, Chichester	20,343.87	168
21W1P[2]	3	Fuse, Pole 12, Warren St, Concord	14,528.03	230
15W1[1]	3	Fuse, Pole 28, Oak Hill Rd, Concord	13,280.40	259
15W1[1]	3	Fuse, Pole 87, East Side Dr, Concord	13,107.90	181
18W2[1]	3	Fuse, Pole 34, Putney Rd, Bow	8,454.60	99
22W3[1]	3	Fuse, Pole 19, White Rock Hill Rd, Bow	8,215.00	144
13W1[1]	3	Fuse, Pole 50, Borough Rd, Canterbury	7,936.67	60
13W3[1]	3	Fuse, Pole 1, North Water St, Boscawen	5,582.70	84
8X3[1]	3	Fuse, Pole 1, Sanborn Hill Rd North, Epsom	2,969.55	27
8X3[1]	3	Fuse, Pole 2, Old Mountain Rd, Epsom	1,091.32	3

[1] Tree trimming efforts have been or will be completed by the end of 2015
[2] Reliability projects have been completed or will be completed by the end of 2015

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

10. Other Concerns

This section is intended to identify other reliability concerns that would not necessarily be identified from the analysis above.

10.1. Narrow subtransmission ROW expansion

The UES-Concord subtransmission system has some areas where the Right Of Way (ROW) is narrow, thus, even after pruning trees to the edge of the ROW we leave our system vulnerable to damage by falling trees. Historically, Unitil has experienced noticeably more outages, due to falling trees, on lines that are in narrow ROW in comparison to lines in larger ROW. Thus, Unitil has been working with land owners to allow tree removal outside of narrow ROW. If successful, this effort is expected to allow effective tree mitigation in the problem areas.

10.2. 13.8kV Underground Electric System Degradation

The 13.8kV underground electric system has been experiencing connector and conductor failures at an average rate of 0.8 per year for the last 5 years, but no failures in 2013 or 2014. This does not include scheduled replacement of hot terminations identified by inspection; hot terminations have been identified and replaced (without outage) in both 2013 and 2014. In 2015, a study on this system was completed. It identified age and use of 200A connectors may be a contributing factor to failures. Engineering and operations are evaluating underground design and material changes to address reliability concerns and future planning needs of this underground system.

10.3. Alternate Mainline for Large 34.5kV Circuits

Circuit 8X3 has the largest customer exposure on the capital system at 2,764 customers with an 11.5MVA peak, in 2014. This circuit has no alternate feeds to restore customers during mainline outages.

Building an alternate mainline to reduce customer exposure and allow an alternate feed during contingency scenarios is the ultimate goal for this area. Three alternatives where reviewed. One involved constructing a pole line outside of UES territory, one involved double circuiting, and the final involved rebuilding Horse Corner Rd. The Horse Corner Rd route is preferred because it will create an alternate pole line and does not involve joint construction with Eversource.

10.4. One Bolt Connector Replacement

One bolt connectors on primary conductor are required to be installed on stirrups, by existing construction standards. Surveys have found many one bolt connectors installed directly on primary conductor. It has been found that stranded conductor can become damaged by single bolt connectors directly connected, reducing the conductor’s thermal and mechanical strength. This damage has been found to be most drastic on 34.5kV energized conductor. Due to recent outages and noticeable damage found on 34.5kV circuits, it has become a priority to replace these connectors on 34.5kV energized mainline. Significant work was done in 2015 to mitigate this problem on circuits 6X3, 7X1, 8X5 and 8X3. Work is planned to continue on circuits 8X5 and 8X3 in 2016.

11. Recommended Reliability Improvement Projects

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

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 2016 capital budget. All project costs are shown without general construction overheads

11.1. Circuit 15W1: Install a Reclosing Device to Protect Shaker Road

11.1.1. Identified Concerns

Shaker Road, phase B, has experienced three outages and Snow Pond Road has experienced one outage, in 2014. This recloser will prevent temporary faults from causing permanent outages for Shaker Road and provide fuse savings for Snow Pond Road.

11.1.2. Recommendations

Install a V4L hydraulic recloser with a 70A trip coil in the vicinity of pole 89-S, on phase B.

Estimated Project Cost (without construction overheads): $ 9,000
Estimated Annual Savings – Customer Minutes: 6,600, Customer Interruptions: 69
Customer Exposure: 88

11.2. Circuit 13W1: Install Covered Wire

11.2.1. Identified Concern

This area experienced one outage, in 2014, which was due to a failed connection on a # 6 CU single phase run. This conductor is at the tail end of the mainline circuit, is surrounded by large trees and causes circuit outages when failed.

11.2.2. Recommendation

Replace #6 Cu open wire with 1/0 ACSR Covered Wire, single phase, between poles 73 and 83 on Kimball Pond Road (1400 feet)

Estimated Project Cost: $23,000
Estimated Annual Savings – Customer Minutes of Interruption: 3,300, Customer Interruptions: 34
Customer Exposure: 482

11.3. Circuit 4W4: Install Covered Wire

11.3.1. Identified Concern

This area experienced three broken conductor outages, in 2014, which could be partially due to the # 6 CU conductor in this area.

11.3.2. Recommendation

Replace #6 Cu open wire with 1/0 ACSR Covered Wire, single phase, between poles 1 and 57 on Lakeview Drive (7000 feet)

Estimated Project Cost: $99,000

Estimated Annual Savings – Customer Minutes of Interruption: 1,500, Customer Interruptions: 16
Customer Exposure: 37

11.4. Bow Junction Substation: Install an Auto Transfer Scheme

11.4.1. Identified Concern

This area experienced one outage, in 2014, which was due to failed insulator. This project would automatically transfer Bow Junction Substation load to the 374 Line from Bridge Street Substation.

11.4.2. Recommendation

Install automation that will automatically cause the 374J3 switch to open and the 374J4 switch to close during an up line 374 Line outage.

Estimated Project Cost: $100,000
Estimated Annual Savings – Customer Minutes of Interruption: *84,000, Customer Interruptions: 1,400
Customer Exposure: 4029

*To estimate the outage duration for the calculation of these minutes, engineering judgment determined 60 minutes was a good average for time required to transfer Bow Junction Substation to an alternative source.

11.5. 374 Line: Install an Autosectionalizing Scheme

11.5.1. Identified Concern

Every time the 374 line from Bridge Street Substation sees a fault, circuit 18W2 and circuit 17X1loses power, which happened once in 2014. This scheme would isolate these circuits from a fault on the 374 Line from Bridge Street.

11.5.2. Recommendation

Install an autosectionalizing scheme on either the 396J2 or 396J1 switch. This scheme will cause the switch to open during the 396/0374 breakers reclosing cycle.

Estimated Project Cost: $40,000
Estimated Annual Savings – Customer Minutes of Interruption: 31,000, Customer Interruptions: 514
Customer Exposure: 1100

*To estimate the outage duration for the calculation of these minutes, engineering judgment determined 60 minutes was a good average for time required to manually patrol and switch into this configuration.

11.6. Miscellaneous Circuit Improvements to Reduce Recurring Outages

11.6.1. Identified Concerns & Recommendations

UES - Capital Reliability Analysis and Recommendations 2015

Oct 1, 2015

The following concerns were identified based on a review of Tables 10 & 11 of this report; Multiple Tree Related Outages by Street and Multiple Device Operations respectively.

Mid-Cycle Forestry Reviews

The areas identified below experienced three or more tree related outages in 2014. It is recommended that a forestry review of these areas be performed in 2016 in order to identify and address any mid-cycle growth or hazard tree problems.

- 13W1, Hackleboro Road, Canterbury
- 13W3, Park Street Area, Boscawen
- 13W1, Borough Road (after Pole 50), Canterbury
- 4W4, Lakeview Road, Concord
- 15W1, East Side Drive (from pole 87 going towards pole 61), Concord

Animal Guard Installation Recommendations

The area identified below experienced three or more patrolled nothing found / animal outages in 2014. It is recommended that an animal protection review is performed in 2016 in order to identify locations in which animal protection can prevent outages due to animals.

- 21W1P, Warren St and Rumford St, Concord

Reclosing Device Installation Recommendations

The areas identified below a number of outages that may have been prevented with a reclosing device. The installation of reclosing devices at these locations is recommended to improve reliability performance in these areas.

- 8X3, New Orchard Road, Epsom
- 18W2, Bow Bog Road, Bow

12. Conclusion

During 2014, the Capital System has been greatly affected by interruptions on the sub transmission system. Although the most common cause among sub transmission outages is company equipment failure, there are no patterns to be recognized at this time and previous years do not present the same results. Tree related outages still present the largest problem, compared to other causes. Although compared to previous years, the worst performing circuits have seen a dramatic decrease in Customer Minutes of Interruption from tree related outages. Enhanced tree trimming efforts are still being implemented, which is expected to improve reliability for most of the worst performing circuits identified in this study.

Recommendations developed from this study are mainly focused on improving reliability of the sub transmission system because two thirds of the customer minutes in 2014 where due to sub transmission outages. At least one project is expected to be completed in 2015 that will improve the reliability of the sub transmission system. In addition, new ideas and solutions to reliability problems are always being explored in an attempt to provide the most reliable service possible.

Unitil Energy Systems – Seacoast

Reliability Study 2015

Prepared By:

Jake Dusling
Unitil Service Corp.
September 21, 2015

1 Executive Summary

The purpose of this document is to report on the overall reliability performance of the UES-Seacoast system from January 1, 2014 through December 31, 2014. The scope of this report will also evaluate individual circuit reliability performance over the same time period.

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 2016 budget development process.

Circuit / Line / Substation	Proposed Project	Cost ($)
47X1	Install Devices and Implement a "Pulsefinding" Scheme	$300,000
18X1	Install Recloser on Mary Batchelder Road	$55,000
13W2	Replace V4L Reclosers and Relocate Downline	$170,000
3347 Line Tap	Recloser Replacements	$125,000
22X1	Relocate Main Line to Route 111	$825,000
19X2/11X2	Distribution Automation Scheme with Portsmouth Ave	$175,000
3343/3354 and 3351/3362 Lines	Installation of Motor Operated Switches with SCADA Control	$190,000

Note: estimates do not include general construction overheads

2 Reliability Goals

The annual corporate system reliability goals and UES-Seacoast reliability goals have been at 191-156-121 SAIDI minutes and 208-165-123, respectively. 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

This section provides a breakdown of all outages by cause code experienced during 2014. Chart 1 lists the number of interruptions due to each cause. For clarity, only those causes occurring more than 10 times are labeled. Chart 2 details the percent of total customer-minutes of interruption due to each cause. Only those causes contributing greater than 2% of the total are labeled.

Chart 1
Number of Interruptions by Cause

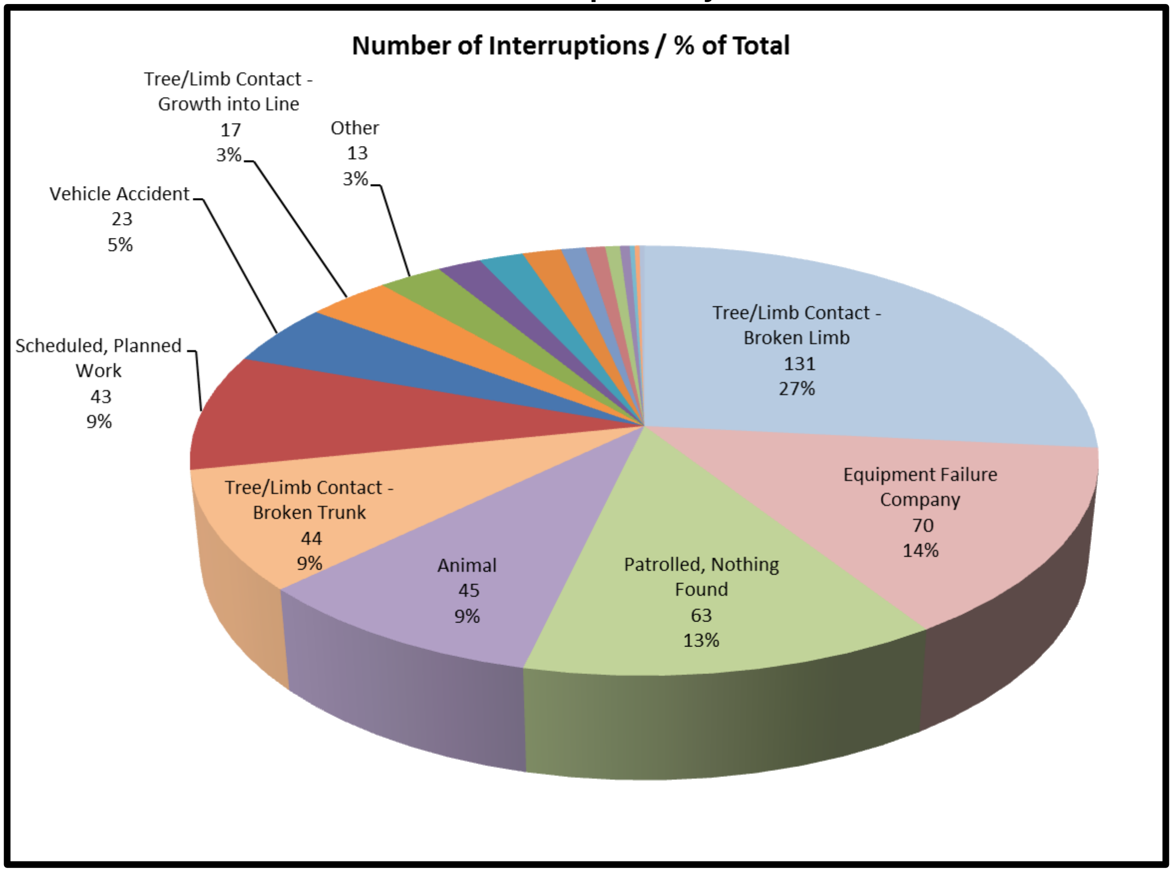
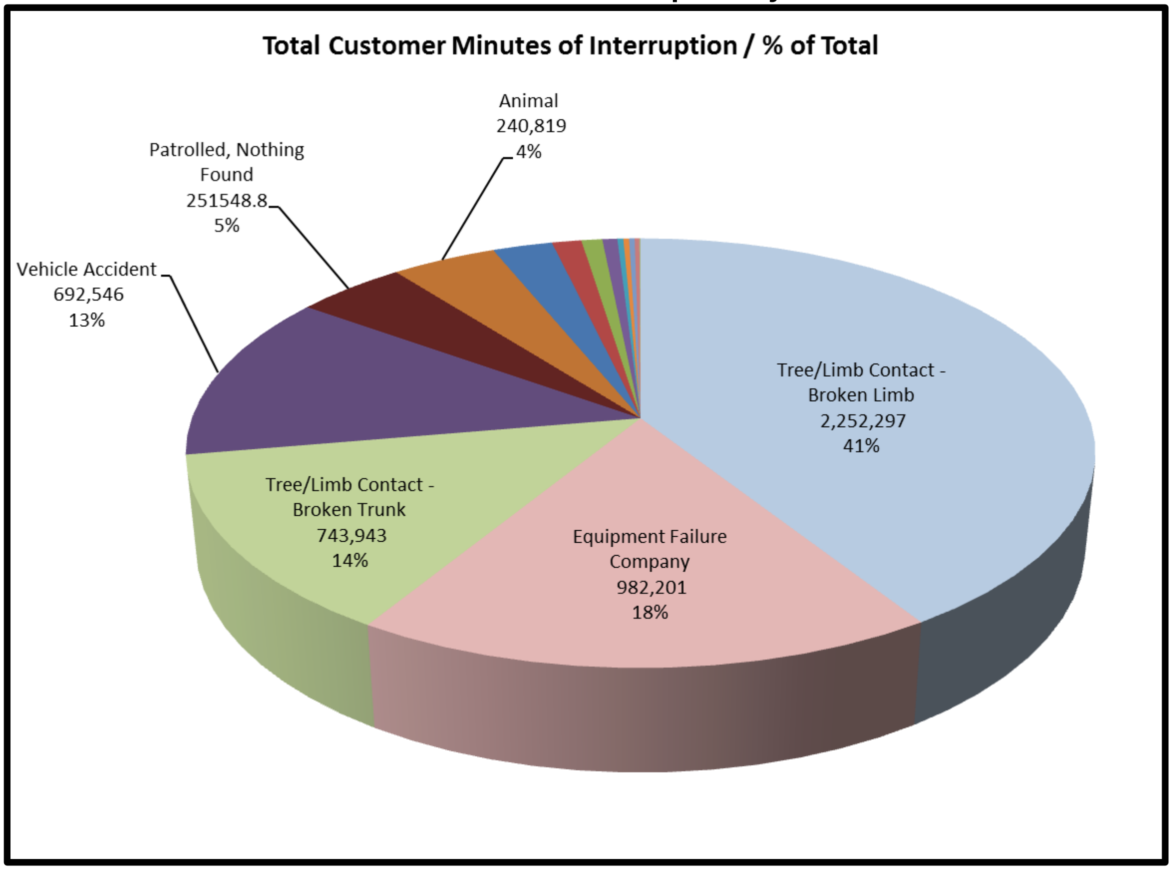


Chart 2
Customer-Minutes of Interruption by Cause



4 10 Worst Distribution Outages

The ten worst distribution outages ranked by customer-minutes of interruption during the time period from January 1, 2014 through December 31, 2014 are summarized in Table 1 below.

Table 1
Worst Ten Distribution Outages

Circuit	Description (Date/Cause)	No. of Customers Affected	No. of Customer Minutes	UES Seacoast SAIDI (min.)	UES Seacoast SAIFI
19X3	7/3/14 Tree/Limb Contact – Broken Limb	3,175	634,732	13.8	0.069
54X1	2/2/14 Vehicle Accident	1,442	381,510	8.29	0.031
43X1	8/1/14 Tree/Limb Contact – Broken Limb	1,861	231,167	5.03	0.040
18X1	10/22/14 Tree/Limb Contact – Broken Trunk	707	217,803	4.74	0.015
6W1	4/20/14 Tree/Limb Contact – Broken Limb	875	179,242	3.90	0.019
51X1	7/3/14 Tree/Limb Contact – Broken Limb	2,075	160,922	3.50	0.045
21W1	10/29/14 Vehicle Accident	1,365	159,599	3.47	0.030
7X2	10/22/14 Tree/Limb Contact – Broken Trunk	1,084	98,079	2.13	0.024
22X1	8/13/14 Tree/Limb Contact – Broken Trunk	2,068	93,060	2.02	0.045
15X1	2/19/14 Tree/Limb Contact – Broken Limb	664	68,447	1.49	0.014

Note: This table does not include outages that occurred at substations, on the sub-transmission system or during snowstorm CATO.

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, 2014 through December 31, 2014.

All substation and subtransmission outages ranked by customer-minutes of interruption during the time period from January 1, 2014 through December 31, 2014 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 19% of the total customer-minutes of interruption for UES-Seacoast.

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
Exeter Sw/S	3/30/14 Equipment Failure Company – Arrester	10,300	767,800	16.69	0.224
3343 Line	6/18/14 Operator Error / System Malfunction	3,284	130,833	2.84	0.071
Dow's Hill S/S	7/11/14 Squirrel	547	88,284	1.92	0.012
3351 Line	11/18/14 Tree/Limb Contact Broken Limb	2,311	79,685	1.73	0.051
3352 Line	11/26/14 Tree/Limb Contact – Broken Limb	4,677	196,961	4.28	0.102
3343 Line	11/26/14 Tree/Limb Contact – Broken Limb	3,088	447,763	9.74	0.067

Table 3
Contribution of Sub-transmission and Substation Outages

Number of events	Circuit	Trouble Location	Customer-Minutes of Interruption	% of Total Circuit Minutes	Circuit SAIDI Contribution
3	20H1	Dow's Hill S/S Exeter Sw/S 3351 Line	103,296	77.8%	233.31
2	1H3	Exeter Sw/S 3352 Line	106,450	49.4%	200.69
2	1H4	Exeter Sw/S 3352 Line	96,058	99.6%	199.15
2	19H1	Exeter Sw/S 3352 Line	29,640	79.1%	182.40
2	19X2	Exeter Sw/S 3352 Line	85,895	96.1%	159.88
2	19X3	Exeter Sw/S 3352 Line	563,093	30.5%	177.38
2	51X1	Exeter Sw/S 3351 Line	99,965	17.8%	52.91
2	27X1	3343 Line (2)	117,018	69.6%	155.47
2	27X2	3343 Line (2)	48,105	69.8%	115.25
2	28X1	3343 Line (2)	94,553	89.7%	189.39
2	43X1	3343 Line (2)	318,921	33.4%	171.59
1	11X2	Exeter Sw/S	15,226	10.2%	15.59
1	47X1	Exeter Sw/S	22,874	9.9%	15.46
1	11X1	Exeter Sw/S	10,235	8.5%	16.13

6 Worst Performing Circuits

This section compares the reliability of the worst performing circuits using various performance measures. All circuit reliability data presented in this section includes subtransmission or substation supply outages unless noted otherwise.

6.1 Worst Performing Circuits in Past Year (1/1/14 – 12/31/14)

A summary of the worst performing circuits during the time period between January 1, 2014 and December 31, 2014 is included in the tables below.

Table 4 shows the ten worst performing 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[1].

Circuits having one outage contributing more than 75% of the customer-minutes of interruptions were excluded from this analysis.

Table 4
Worst Performing Circuits Ranked by Customer-Minutes

Circuit	Customer Interruptions	Worst Event (% of CI)	Cust-Min of Interruption	Worst Event (% of CMI)	SAIDI	SAIFI	CAIDI
19X3	10,227	31.0%	1,844,551	34.4%	581.05	3.22	180.36
43X1	7,674	24.3%	953,763	46.4%	513.14	4.13	124.29
22X1	5,152	40.1%	712,991	33.4%	345.20	2.49	138.39
54X1	2,815	51.2%	693,162	55.0%	479.86	1.95	246.24
51X1	7,221	28.7%	561,412	38.4%	297.15	3.82	77.75
6W1	2,830	30.9%	481,745	37.2%	550.41	3.23	170.23
18X1	5,027	35.2%	464,682	46.9%	262.63	2.84	92.44
6W2	4,209	38.2%	301,017	35.4%	336.08	4.70	71.52
21W1	3,633	37.6%	246,118	64.8%	180.63	2.67	67.75
21W2	1,402	29.5%	235,674	38.1%	170.25	1.01	168.10

Note: all percentages and indices are calculated on a circuit basis

[1] Six most prevalent causes determined from UES-Seacoast system wide data, not individual circuit data.

Table 5
Circuit Interruption Analysis by Cause

Circuit	Customer – Minutes of Interruption / # of Outages					
	Tree/Limb Contact – Broken Limb	Equipment Failure Company	Tree/Limb Contact – Broken Trunk	Vehicle Accident	Patrolled, Nothing Found	Squirrel
19X3	1,346,588 / 18	460,268 / 9	2,086 / 1	24,490 / 1	910 / 1	110 / 1
43X1	843,913 / 15	240 / 1	5,043 / 3	350 / 1	24,531 / 3	99 / 1
22X1	522,311 / 30	11,530 / 6	144,725 / 6	0 / 0	2,448 / 5	0 / 0
54X1	280,171 / 14	4,874 / 3	1,446 / 1	381,510 / 1	2,959 / 5	0 / 0
51X1	470,658 / 14	28,523 / 2	18,960 / 1	12,581 / 2	4,672 / 1	19,941 / 7
6W1	272,858 / 11	23,050 / 2	137,401 / 7	19,862 / 1	13,207 / 5	4,756 / 1
18X1	96,400 / 5	24,760 / 4	250,088 / 3	25,279 / 2	42,048 / 1	17,809 / 2
6W2	242,635 / 20	13,218 / 1	30,092 / 1	0 / 0	12,964 / 1	1,212 / 1
21W1	50,140 / 6	706 / 1	6,981 / 2	159,599 / 1	2,059 / 2	17,249 / 3
21W2	196,748 / 8	3,774 / 4	203 / 1	0 / 0	0 / 0	2,587 / 1

6.2 Worst Performing Circuits of the Past Five Years (2010 – 2014)

The annual performance of the ten worst circuits in terms of SAIDI and SAIFI for each of the past five years is shown in the tables below. Table 6 lists the ten worst performing circuits ranked by SAIDI and Table 7 lists the ten worst performing circuits ranked by SAIFI.

The data used in this analysis includes all system outages except those outages that occurred during the 3342/3353 Line Outage in 2014, Hurricane Sandy in 2012, the 2011 October Nor'easter, Hurricane Irene in 2011 and the 2010 Wind Storm.

Table 6
Circuit SAIDI

Circuit Ranking (1 = worst)	2014		2013		2012		2011		2010	
	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI
1	19X3	581.05	6W1	384.28	56X2	590.69	13W2	698.61	51X1	582.06
2	6W1	550.41	27X1	300.82	13W2	556.17	54X1	557.90	3H2	575.51
3	43X1	513.14	47X1	275.19	13W1	383.59	17W2	429.40	22X1	518.07
4	54X1	479.86	18X1	255.15	2X2	376.99	22X1	407.92	59X1	509.53
5	1H3	406.51	21W1	242.80	58X1	339.87	17W1	381.20	15X1	387.88
6	22X1	345.20	13W2	212.92	7X2	317.63	46X1	372.37	23X1	378.56
7	6W2	336.08	59X1	197.65	47X1	297.13	13W1	275.45	17W2	361.53
8	20H1	299.78	22X1	136.57	43X1	296.43	21W2	239.71	58X1	308.72
9	51X1	297.15	15X1	128.33	23X1	292.58	11W1	226.92	46X1	306.30
10	18X1	262.63	43X1	122.34	15X1	263.38	7X2	213.44	21W1	291.33

Table 7
Circuit SAIFI

Circuit Ranking (1 = worst)	2013		2012		2011		2010		2009	
	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI
1	6W2	4.70	18X1	3.40	56X2	7.39	54X1	5.25	51X1	6.65
2	20H1	4.36	21W1	3.25	13W2	5.77	22X1	4.93	3H2	6.01
3	43X1	4.13	27X1	2.98	23X1	5.69	13W2	4.53	22X1	5.21
4	51X1	3.82	6W1	2.95	43X1	4.22	13W1	2.81	15X1	4.38
5	6W1	3.23	47X1	2.55	6W1	4.06	7X2	2.48	23X1	3.77
6	19X3	3.22	13W2	2.48	13W1	3.92	11W1	2.42	59X1	3.43
7	18X1	2.84	43X1	2.42	15X1	3.89	47X1	1.99	11W1	3.29
8	21W1	2.67	7X2	1.98	59X1	3.64	18X1	1.94	13W2	3.21
9	47X1	2.67	56X1	1.96	21W1	3.20	21W2	1.93	28X1	3.07
10	11X1	2.64	54X1	1.91	58X1	3.13	6W1	1.77	20H1	3.01

6.3 System Reliability Improvements (2013 and 2014)

Vegetation management projects completed in 2014 and 2015 that are expected to improve the reliability of the 2014 worst performing circuits are included in table 8 below. Table 9 below details electric system upgrades that are scheduled to be completed in 2015 or were completed in 2014 that were performed to improve system reliability.

Table 8
Vegetation Management Projects on Worst Performing Circuits

Circuit(s)	Year of Completion	Project Description
19X3	2014	Storm Resiliency pruning
		Planned Mid-Cycle pruning
43X1	2014	Storm Resiliency pruning
22X1	2015	Planned Cycle Pruning
		Hazard tree mitigation
	2014	Storm Resiliency pruning
54X1	2015	Planned Cycle Pruning
		Hazard tree mitigation
6W1	2015	Planned Cycle Pruning
		Hazard tree mitigation
	2014	Planned Mid-Cycle pruning
		Hazard tree mitigation
18X1	2014	Planned Cycle Pruning
6W2	2015	Planned Cycle Pruning
		Hazard tree mitigation
	2014	Planned Mid-Cycle pruning
		Hazard tree mitigation
21W1	2015	Planned Cycle pruning (Carryover from 2014)
		Hazard tree mitigation (Carryover from 2014)
	2014	Planned Cycle Pruning
		Hazard tree mitigation
21W2	2014	Planned Cycle Pruning

Circuit(s)	Year of Completion	Project Description
1H3	2015	Planned Cycle Pruning
20H1	2015	Planned Mid-Cycle pruning
47X1	2014	Planned Cycle Pruning
		Hazard tree mitigation
11X1	2015	Planned Mid-Cycle pruning

Table 9
Electric System Improvements Performed to Improve Reliability

Circuit(s)	Year of Completion	Project Description	Justification
54X1	2015	Recloser additions to split circuit 54X1 into two circuits, 54X1 and 54X1	2015 DRB Project
		Replace 54J54X1 and 43J54X1 switches with motor operated switches and connect to SCADA at New Boston Road Tap	2015 DRB Project
6W1, 6W2	2015	Replace J654 and J643 switches with motor operated switches and connect to SCADA at East Kingston substation	2015 DRB Project
13W1	2015	Install fuses – Upper Rd, Middle Rd, and Lower Rd	Multiple device operation pole 7 Danville Rd, Plaistow
13X3	2015	Upgraded fuse size, replaced insulators and upgraded overloaded transformer	Multiple device operation pole 19 Kingston Rd, Plaistow
7W1	2014	Install cone style animal guards and replace transformer wire taps with covered tap wire	Multiple device operation pole 1 Cross Beach Rd, Seabrook
		Install cone style animal guards and replace transformer wire taps with covered tap wire	Multiple device operation pole 20 Route 286, Seabrook

7 Tree Related Outages in Past Year (1/1/14 – 12/31/14)

This section summarizes the worst performing circuits by tree related outages during the time period between January 1, 2014 and December 31, 2014.

Table 10 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 three or more tree related outage are shown in table 11 below. The table is sorted by number of outages and customer-minutes of interruption.

Table 10
Worst Performing Circuits – Tree Related Outages

Circuit	Customer-Minutes of Interruption	Number of Customers Interrupted	No. of Interruptions
19X3[1]	751,819	6,614	21
22X1[1]	688,690	5,032	40
6W1[1]	420,710	2,474	19
51X1[2]	418,394	2,842	17
43X1[1]	412,556	4,005	22
18X1[1]	347,507	2,298	9
54X1[1,3]	288,788	765	16
6W2[1]	273,623	3,626	22
21W2[1]	225,174	1,312	11
13W2[2]	196,941	798	14

Table 11
Tree Related Outages by Street

Circuit	Street	# Outages	Customer-Minutes of Interruption	No. of Customer Interruptions
6W2[1]	South Rd, East Kingston / South Hampton	4	161,634	1,184
22X1[1]	Main St, Danville	4	128,683	1,437
6W2[1]	North Rd, Kingston	3	24,092	220
19X3[1]	Linden St, Exeter	3	45,247	122
58X1[2]	Sawyer Ave, Atkinson	3	29,323	57
19X3[1]	Brentwood Rd, Exeter	3	2,574	39
21W2[1]	Maple Ave, Atkinson	3	384	3
23X1[2]	Woodman Rd, South Hampton	3	290	5

[1] Pruning is planned or has been completed on this circuit (refer to table 8 for details)
[2] Refer to section 11 for recommendations in this area.
[3] Projects that are planned or have been completed on this circuit (refer to table 9 for details)

8 Failed Equipment

This section is intended to clearly show all equipment failures throughout the study period from January 1, 2014 through December 31, 2014. 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 four categories of failed equipment for the past five years are shown below in Chart 4.

Chart 2
Equipment Failure Analysis by Cause

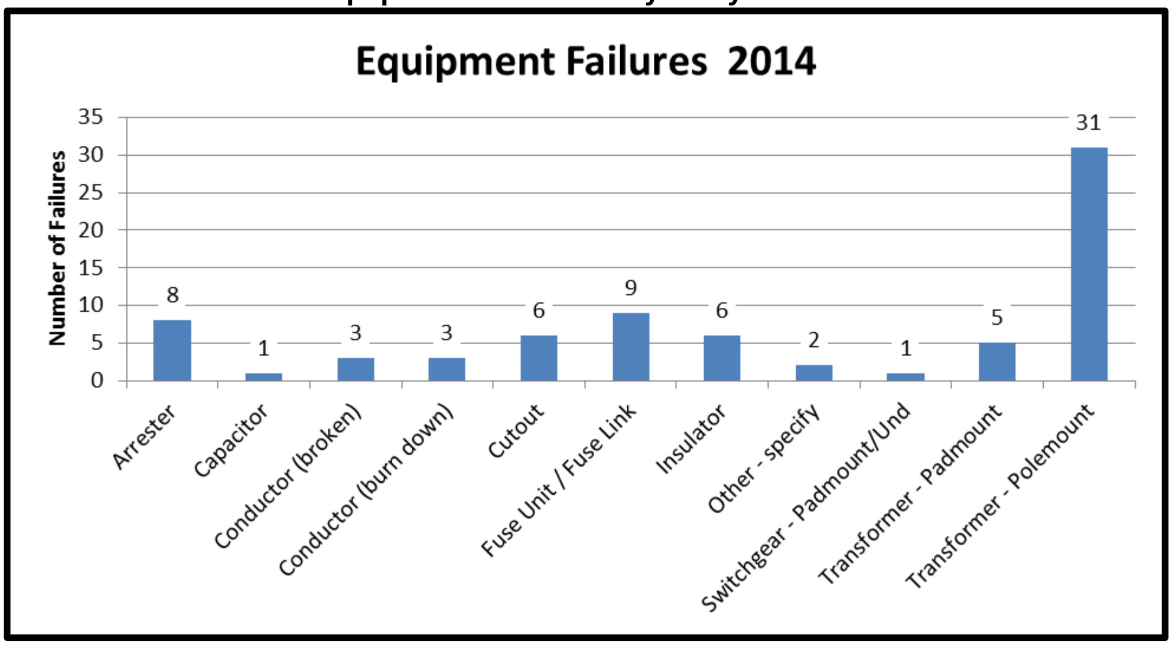


Chart 3
Equipment Failure Analysis by Percentage of Total Failures

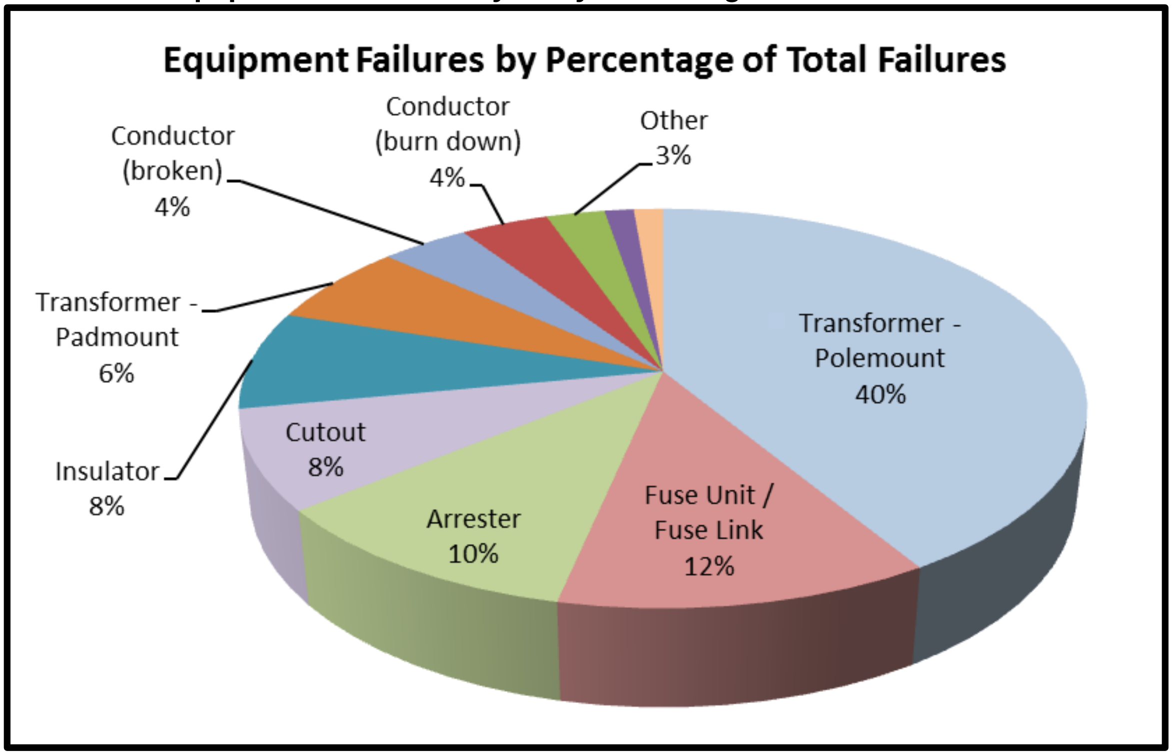
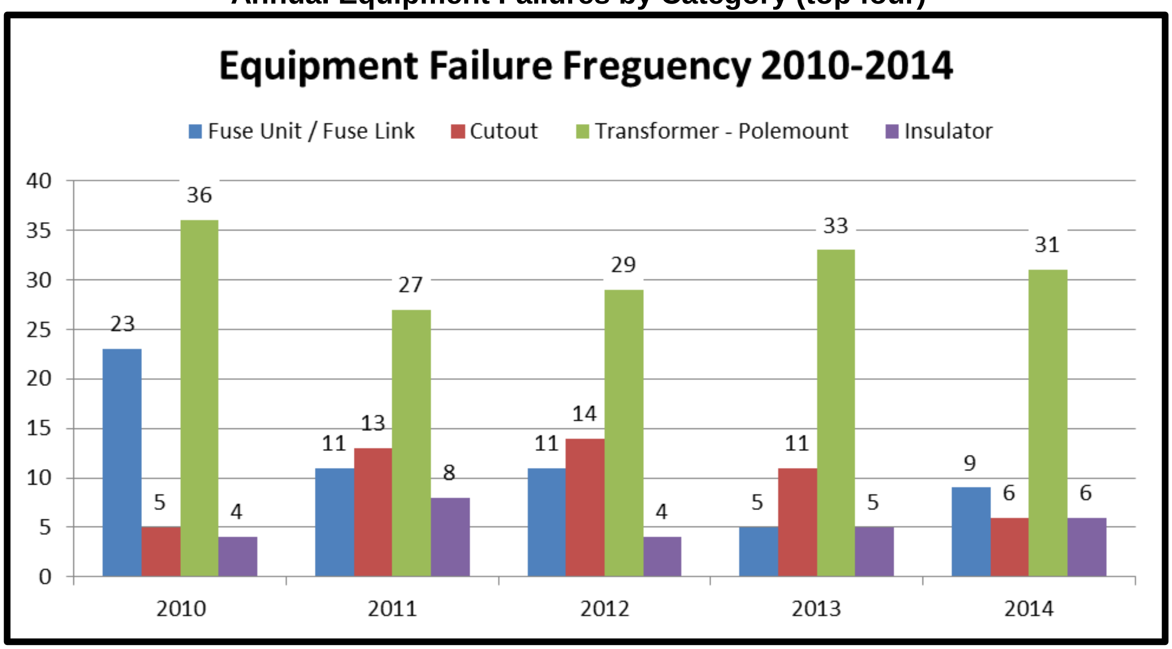


Chart 4
Annual Equipment Failures by Category (top four)



9 Multiple Device Operations in Past Year (1/1/14 – 12/31/14)

A summary of the devices that have operated three or more times from January 1, 2014 to December 31, 2014 are included in table 12 below.

Table 12
Multiple Device Operations

Circuit	Number of Operations	Device	Customer-Minutes	Customer-Interruptions
13X3[1,2]	6	Fuse – Pole 55/19 Kingston Rd, Plaistow	7,120	66
6W1[2]	4	Recloser – Pole 23/2 South Rd, East Kingston	150,639	1,024
7W1[1]	4	Fuse – Pole 128/1 Cross Beach Rd, Seabrook	17,855	100
18X1[2,3]	3	Fuse – Pole 172/1 Mary Batchelder Rd, Hampton	305,586	1,904
22X1[2]	3	Fuse – Pole 27/9 Kingston Rd, Danville	139,711	1,667
11X1[4]	3	Fuse – Pole 69/1 Patriots Rd, Stratham	33,594	375
58X1[3]	3	Fuse – Pole 76/1 Sawyer Ave, Atkinson	29,038	39
6W2[2]	3	Fuse – Pole 93/33 North Rd, Kingston	17,799	123
7W1[1]	3	Fuse – Pole 134/20 Route 286, Seabrook	12,666	150
13W1[1]	3	Fuse – Pole 25/7 Danville Rd, Plaistow	12,357	351

[1] Projects that are planned or have been completed on this circuit (refer to table 9 for details).
[2] Pruning is planned or has been completed on this circuit (refer to table 8 for details).
[3] Refer to section 11 for recommendations in the area.
[4] Operations performed a detailed review of the area and observed good tree clearance and animal guards installed on all transformers.

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

Power factor testing has identified that the solid dielectric material used for the poles on a specific type/vintage recloser degrades over time leading to premature failure. In follow up discussions with the manufacturer, they acknowledged that the solid dielectric material used for the recloser poles could prematurely degrade resulting in a dielectric failure.

Unitil has experienced two (UES-Seacoast and FG&E) failures of this type/vintage of recloser in 2011 and removed two others from service due to the appearance of tracking.

Based on this information, a multi-year replacement program began in 2013 to replace all reclosers of this vintage. There are currently four of these reclosers in service on the UES-Seacoast system two at Wolf Hill, which are scheduled to be replaced in 2015 and two at the 3347 Line tap.

It is recommended that this program continue in 2016.

10.2 Subtransmission Lines Across Salt Marsh

The 3348 line experienced one outage in 2012 caused by a failed insulator and has been damaged several times during major events in the past, causing outages to the customers on all the distribution circuits (2H1, 2X3, 3H1, 3H2, 3H3, 7W1 and 7X2) supplied by the 3348, 3350 and 3353 lines distribution . The 3348 line is constructed through salt marsh, making it very difficult to access and repair.

In 2012, during a wind and snow event, both the 3342 and 3353 lines were damaged resulting in an outage to the Hampton Beach area that lasted nearly thirteen hours. These lines being constructed through the salt march made them difficult to patrol and inaccessible to repair without a boat. There is a multi-stage project that began in 2014 to relocate these lines closer to the road.

The 3350 line is also constructed through salt marsh. This line has the same access concerns as the 3348, 3342 and 3353 lines in the past. The 3350 line is a radial line that supplies Seabrook substation, if damaged load may need to be left out of service until repairs are made.

Additionally the 3348/3350 tap structure was damaged during Hurricane Sandy in 2012, requiring the 3348 and 3350 lines to remain out of service for several weeks until repairs were made. During the time of year the damaged occurred the load normally supplied by the 3350 line was restored via distribution ties. During summer peak conditions the distribution circuits in the area do not have the capacity to restore all load for this type of event.

In 2014, Unitil began investigating the possibility of acquiring land rights that would accommodate relocating the 3348 and 3350 lines to the railroad right-of-way that runs from Hampton S/S to Route 286 in Seabrook in the future. This investigatory effort will continue in 2015.

Reclosers are scheduled to be placed in service at Hampton substation in 2015 to reduce the impact of 3348, 3350, 3342 and 3353 line faults.

10.3 3347 Line

The 3347 line has been damaged by trees during major events in the past, causing outages to customers served by Guinea Road tap, Portsmouth Ave substation and Osram/Sylvania until repairs are made.

The installation of reclosers at Portsmouth Ave Substation and the replacement of the 19X2 relay at Exeter Switching were completed in 2013. These upgrades allow all customers served from Portsmouth Ave substation to be restored via distribution ties for the loss of the 3347 Line. Guinea Road tap and Osram/Sylvania load will remain out of service until repairs are made.

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 2016 capital budget. All project costs are shown without general construction overheads.

11.1 Miscellaneous Circuit Improvements to Reduce Recurring Outages

11.1.1 Identified Concerns & Recommendations

The following concerns were identified based on a review of Tables 10 and 11 of this report; Multiple Tree Related Outages by Street and Multiple Device Operations respectively.

Mid-Cycle Forestry Review
The areas identified below experienced three or more tree related outages in 2014. It is recommended that a forestry review of these areas be performed in 2016 in order to identify and address any mid-cycle growth or hazard tree problems.

- 58X1, Sawyer Ave, Atkinson
- 23X1, Woodman Rd, South Hampton

11.2 Circuit 47X1 – Install Devices and Implement a “Pulsefinding” Scheme

11.2.1 Identified Concerns

Circuit 47X1 is routinely one of the worst performing circuits on the UES-Seacoast system. It has been on the worst performing SAIDI and SAIFI lists two of the past five years .

Additionally, 47X1 is served from the 3347 line which is a radial subtransmission line that typically is damaged during major events.

11.2.2 Recommendation

This project will consist of installing multiple S&C Intellirupters at strategic locations along circuit 47X1 and implementing a “pulsefinding” scheme.

“Pulsefinding” is a technique that allows devices with the same overcurrent protection settings to be used in series without the installation of device-to-device communications. At this time S&C Intellirupters are the only device with this capability.

After the devices are installed and programmed the 47X1 recloser and all series Intellirupters will trip in response to a downstream fault. The 47X1 recloser will reclose and stay closed if the fault is no longer present. The first downstream Intellirupter, upon sensing the return of voltage, pulsecloses (pulsecloses are too short to initiate a time-overcurrent trip of the recloser) and the Intellirupter will close if the fault is no longer present. This continues with each Intellirupter until the fault is isolated or the circuit is fully restored.

Additionally, a new normally open Intellirupter will be installed at the 51X1/47X1 tie. Upon loss of voltage this Intellirupter will pulseclose and stay closed if now fault is detected. The pulse closing scheme would then continue to the new Intellirupter until the faulted section is left out of service or circuit 47X1 is restored in its entirety from circuit 51X1. This portion of the scheme needs to be reviewed in additional detail to determine its feasibility.

This project will act as a pilot installation for this technology and if successful there are several other large circuits in Unitil’s territory that could greatly benefit from pulseclosing.

- Estimated annual customer-minutes savings = 115,814
- Estimated annual customer-interruption savings = 1,206

Estimated Project Cost: $300,000 (4 Locations @ $75,000 per location)

11.3 Circuit 18X1 – Install Recloser on Mary Batchelder Road

11.3.1 Identified Concerns

Circuit 18X1 was one of the worst performing circuits in 2014 and has been on the worst performing SAIFI circuit list three of the last five years.

Additionally, the 175 QA at pole 1 Mary Batchelder Road operated three times in 2014.

11.3.2 Recommendation

This project will consist of replacing the 175 QA fuses at pole 1 Mary Batchelder Road with an electronically controlled recloser. The 175QA fuses will be relocated to the vicinity of pole 2 Towle Farm Road.

The new recloser will benefit approximately 700 customers and the new fuse location is expected save approximately 325 customer interruptions per year.

- Estimated annual customer-minutes savings = 30,994
- Estimated annual customer-interruption savings = 323

Estimated Project Cost: $55,000

11.4 Circuit 13W2 – Replace V4L Reclosers and Relocate Downline

11.4.1 Identified Concerns

Circuit 13W2 is typically one of the worst performing circuits on the UES-Seacoast system. It has been on the worst performing SAIFI four of the past five years and has been on the worst performing SAIDI list three of the last five years.

11.4.2 Recommendation

This project will consist of replacing the two existing sets of 140A V4L reclosers on circuit 13W2 with electronically controlled reclosers. This will allow the existing reclosers to be relocated to Peaslee Crossing Road and Thornell Road. Two additional sets of 100A V4L reclosers will be installed on Highland Street and Pond Street. The existing 13W2 recloser control at Timberlane substation will most likely need to be replaced to accommodate this project.

The new reclosers will benefit approximately 1,100 customers.

- Estimated annual customer-minutes savings = 34,200
- Estimated annual customer-interruption savings = 356

Estimated Project Cost: $150,000

11.5 Recloser Replacements

11.5.1 Identified Concerns

Unitil has experienced premature failures of a specific type/vintage of recloser due to insulation breakdown of the poles.

This will be the final year of a multi-year project to replace the reclosers of the identified type/vintage.

11.5.2 Recommendation

This project will consist of replacing the remaining two reclosers on the UES-Seacoast system.

- Two (2) at 3347 Line Tap

Below is a summary of the reliability benefit for this project:

Recloser	Customers of Exposure
3347A	5,350
3347B	7,900

- Estimated annual customer-minutes savings = 110,088
- Estimated annual customer-interruption savings = 1,147

Estimated Project Cost: $125,000

11.6 Circuit 22X1 – Relocate Main Line to Route 111

11.6.1 Identified Concerns

Circuit 22X1 was one of the worst performing circuits in 2014 and has been on the worst performing SAIDI circuit list four of the last five years.

Additionally, the existing main line along Kingston Road and Pleasant Street typically sustain significant damage during major storms, requiring lengthy repairs to energize the mainline of 22X1.

11.6.2 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 the Danville Tie. Route 111 is a major state road-way with very little tree exposure.

Once complete, the new main line of 22X1 will run along Route 111. 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 t. This will also reduce damage to the mainline of 22X1 during major events.

This project is being designed in 2015 and is currently budgeted for construction in 2016.

- Estimated annual customer-minutes savings = 287,266
- Estimated annual customer-interruption savings = 2,992

Estimated Project Cost: $825,000

11.7 Circuit 19X2 – Distribution Automation Scheme with Portsmouth Ave

11.7.1 Identified Concerns

On average one subtransmission outage per year causes an outage to Portsmouth Ave substation or Exeter Switching Station.

Additionally, Portsmouth Ave substation is supplied from the 3347 line, which is a radial line that typically experiences damage during major events.

11.7.2 Recommendation

This project will consist of replacing the 11X2J19X2 tie switch with a recloser and the installation communication infrastructure between the new recloser, the 19X2 recloser at Exeter Switching and Portsmouth Ave substation.

A distribution automation scheme will be implemented that will restore the 1,617 customers on circuits 11X1 and 11X2 via circuit 19X2 for the loss of the 3347 line. Additionally, for a fault on the 3352 or 3362 line the 538 customers supplied by circuit 19X2 will automatically be restored via circuit 11X2.

- Estimated annual customer-minutes savings = 71,149
- Estimated annual customer-interruption savings = 0

Estimated Project Cost: $175,000

11.8 Installation of Motor Operated Switches at Substations and Subtransmission Taps

11.8.1 Summary

Unitil acquired twenty-three motor operated switches and two additional motor operators in 2014. It was determined that some or all of these switches would be used to replace the existing manually operated switches that connect substations and distribution taps to the UES-Seacoast subtransmission system.

Reference the document titled Motor Operated Switch Installation – Project Justification, dated February 24th, 2015 for additional information.

11.8.2 Switches Proposed for Replacement – 2016

Based on the project justification document referenced above the following switches are proposed for replacement in 2016.

Location	Switches to be Replaced	Cost (w/o OH's)	Special Details
Willow Road Tap	54J43X1 43J43X1	$30,000	Pre-Existing SCADA Site
Shaw's Hill Tap	54J27 43J27	$30,000	Pre-Existing SCADA Site
Munt Hill Tap	54J28 43J28	$30,000	Pre-Existing SCADA Site
Winnicutt Road Tap	62J51X1 51J51X1	$50,000	SCADA Installation Required
Dow's Hill S/S	J2062 J2051	$50,000	SCADA Installation Required
Total	**10 Switches**	**$190,000**	

12 Conclusion

The UES-Seacoast system has been greatly affected by outages involving tree contact and equipment failures A more aggressive tree trimming program began in 2011 and has started to reduce the number and impact of tree related outages.

In 2012 three circuits on the UES-Seacoast benefited from a storm resiliency pruning pilot, which consisted of ground to sky trimming and hazard tree removal. Due to the success of this pilot, three additional UES-Seacoast circuits had storm resiliency pruning performed in 2014.

The recommendations in 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. This report is also intended to assist Unitil Forestry in identifying areas of the system that are being frequently affected by tree related outages to allow proactive measure to be taken.

Fitchburg Gas and Electric Light Company (d/b/a/Unitil) Grid Modernization Plan

Massachusetts Department of Public Utilities
Docket D.P.U. 12-76 and Docket D.P.U. 14-04

Contents

Table of Figures

Table of Tables

List of Acronyms Used in the Plan

Acronym	Term
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
AMF	Advanced Metering Functionality
AO	Application Owners
BCA	Benefit Cost Analysis
B/C	Benefit to Cost Ratio
BIA	Business Impact Analysis
CAIDI	Customer Average Interruption Duration Index
CIP	Critical Infrastructure Protection
CIS	Customer Information System
CISO	Chief Information Security Officer
CMI	Customer Minutes Interrupted
CPP	Critical Peak Pricing
CSR	Customer Service Representative
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DCF	Discounted Cash Flow
DER	Distributed Energy Resources
DERM	Distributed Energy Resource Management
DG	Distributed Generation
DOER	Department of Energy Resources
DPU	Department of Public Utilities
EE	Energy Efficiency
EM&C	Energy Measurement & Control
ES-C2M2	Electricity Subsector Cybersecurity Capability Maturity Model
ES-ISAC	Electricity Subsector Information Sharing and Analysis Center
ETR	Estimated Time to Restore
FAN	Field Area Network
FLISR	Fault Location, Isolation, and Service Restoration
FGE	Fitchburg Gas and Electric Light Company
FTE	Full Time Equivalent

GIS	Geographic Information System
GMP	Grid Modernization Plan
GSEAF	Gas System Enhancement Adjustment Factor
GSEP	Gas System Enhancement Plan
ICAP	Installed Capacity
ICS-CERT	Industrial Control Systems Cyber Emergency Response Team
IPS	Intruder Prevention System
ISO-NE	Independent System Operator- New England
IT	Information Technology
IVR	Interactive Voice Response
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkley National Lab
MDM	Meter Data Management
MVA	Mega Volt Amps
MW	Megawatts
NPV	Net Present Value
O&M	Operations and Maintenance
OMS	Outage Management System
ONG-C2M2	Oil and Natural Gas Subsector Cybersecurity Capability Maturity Model
OT	Operation Technology
PCI	Payment Card Industry
PLC	Power Line Carrier
PII	Personally Identifiable Information
PTR	Peak-Time Rebate
RD&D	Research, development & deployment
RFP	Request for Proposal
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SREC	Solar Renewable Energy Credits
SRP	Storm Resiliency Program
STIC	Short Term Investment Clause
STIAF	Short Term Investment Adjustment Factor

STIF	annual Short Term Investment Factors
STIP	Short Term Investment Plan
STIRF	Short-Term Investment Reconciliation Factor
T&D	Transmission & Distribution
TIRF	Targeted Infrastructure Recovery Factor
TOU	Time-of-Use
TSRG	Technical Standards Review Group
TVR	Time Varying Rates
VBA	Visual Basic for Applications
VVO	Volt/VAr Optimization
WACC	Weighted Average Cost of Capital
WISP	Written Information Security Plan

Executive Summary

This plan presents Fitchburg Gas and Electric Light Company's (FGE) d/b/a Unitil (Unitil or Company) ten-year Grid Modernization Plan (GMP) and includes a five-year Short-Term Investment Plan (STIP) in accordance with the requirements established by the Massachusetts Department of Public Utilities (Department or DPU). The GMP demonstrates Unitil will make "measurable progress" toward the Department's four grid modernization objectives:

(1) Reducing the effects of outages;
(2) Optimizing demand;
(3) Integrating distributed resources; and
(4) Improving workforce and asset management.

The Company anticipates the GMP will be an evolving process and that modifications to the GMP will be made from time to time, as a result of (a) changes in technology; (b) customer response to initial GMP deployments; and (c) experience gained in Massachusetts and other states. The STIP presents the costs of capital investments and expenses for GMP projects that will be initiated within the first five years. Since certain projects and investments will not be completed within the first five-year period, Unitil proposes to recover STIP investments and related expenses included in this initial plan through a STIP Cost Tracker that will extend beyond the initial five-year period until the STIP investments are in service and can be recovered through base rates.

The cornerstone of Unitil's approach is the nature of the Company's franchise area and the ability of its customers to afford the rate impact of the proposed GMP. As a result, Unitil's proposed GMP considers both the technical and financial aspects such as rate impacts and the ability of FGE customers to afford grid modernization. Unitil calls this approach "practical grid modernization" as it places a high value on enabling investments that provide net benefits for customers and have acceptable rate impacts. This approach is consistent with the feedback received from customers. Unitil's GMP reflects a balancing of five priorities:

(1) Meeting the DPU grid modernization objectives;
(2) Responding to customer interests including rate sensitivity;
(3) Supporting the role of third parties and market solutions available to customers;
(4) Continuing capital investment programs to replace aging infrastructure while pursuing grid modernization; and
(5) Anticipating the continued transformation of the electric delivery business model and related regulatory considerations.

The development of the GMP was guided by the executive management team and with active engagement of subject matter experts from many departments, with support from BRIDGE Energy Group. The BRIDGE team led the Company through a multi-step process to develop the projects that would make up the ten-year GMP. The process began with a visioning exercise through which major industry drivers, policy trends, and the future state of the electric distribution grid and its implications for Unitil were examined. The Company concluded that grid operations will become more complex and the Company's role with the customer will significantly change as a result of the increasing penetration of DER and as a more dynamic set of services proliferate in the marketplace. While grid operations will be more dynamic to manage diverse resources and two-way power flow, the Company envisions a shifting towards enabling many of these new and evolving services to customers rather than directly providing them.

The team identified gaps that need to be addressed in order to fulfill this vision. These gaps are described in the GMP and include systems, customer information and business process gaps. Much of the effort then focused on identifying fifty-two potential projects that address these gaps and subjecting them to rigorous Business Case Analysis (BCA). The projects were mapped to GMP objectives including policy and customer expectation goals and then organized into the following five "programs" for discussion and decision-making purposes. Ultimately, these fifty-two projects were reduced to sixteen capital investment projects, one non-capital project and a research, development and deployment plan:

(1) Distributed Energy Resources (DER) Enablement – four projects that encourage DER with a flexible grid along with DER pricing that reflects its value to both suppliers and customers;

(2) Grid Reliability – two projects that are designed to reduce the impacts of outages;

(3) Distribution Automation (DA) – six projects that are designed to automate grid operations;

(4) Customer Empowerment – three capital projects and one non-capital project that provide customers with information and tools for managing their energy choices; and

(5) Workforce and Asset Management – one project that can improve the efficiency and effectiveness of field crews and the management of assets**.**

Several capital investment projects incorporate enhancements to existing communications and network management systems that are necessary to accommodate the integration of large numbers of DERs and maintain the stability and reliability of the network. The Company proposes a conservation voltage reduction (CVR) program that will automate and optimize voltage and reactive power (VAr) equipment to lower energy bills for all customers. Since this is essentially a system-wide energy efficiency (EE) program, Unitil investigated funding approaches to pay for a portion of this program with energy efficiency funds, and thereby manage the potential bill impacts from other grid modernization investments. Although the final proposal does not reflect contributions from energy efficiency funds, utilizing efficiency funds would materially reduce the amount of new capital spending required to underwrite the GMP programs and thus the rate and bill impacts for customers. Unitil welcomes the opportunity to explore this concept further during the review of this Plan.

One of the Customer Empowerment projects is a Time Varying Rate (TVR) and Time-of-Use (TOU) pricing project, a potential service that has received considerable attention from the Department and stakeholders. Unitil was an early adopter of Advanced Metering Infrastructure (AMI) that provides some Advanced Metering Functionality (AMF) and has already achieved operational savings benefits that typically comprise the majority of economic benefits from advanced metering investments. Unitil has determined the most prudent approach is to offer AMF and TVR on an opt-in basis. This is the most practical way to meet the AMF requirement, based in part on experience with TVR during the Smart Grid Pilot. Unitil has familiarity with the technology and business requirements, costs of implementation and the level of interest that customers have shown. This proposal is consistent with a “practical” approach to grid modernization.

The Company took an overall portfolio approach to developing its GMP. Therefore all individual projects were evaluated together to assess the overall net benefit to the plan. As presented in this plan, several key projects have positive benefit-cost ratios. The Company found that the majority of the benefits accrue to customers, either through electricity cost savings (the value of reducing energy consumption in kilowatt hours (kWh) or the value of reducing outage minutes) rather than through operational efficiencies and cost reductions realized by Unitil. Several other projects recommended in the plan do not have a positive benefit-cost ratio when considered on their own but are needed strategically to achieve several of the company and DPU objectives.

Finally, Unitil also proposes a new tariff be established for distributed generation (DG). The Unitil vision and the GMP contemplates a future where distributed resources are increasingly prevalent as customers avail themselves of on-site supply through rooftop solar and other emerging technologies, or change their usage levels and patterns in response to home automation and demand response programs. These benefits are enabled by investments in the distribution system, information systems, and business processes that achieve multiple objectives, including empowering customers to make efficient decisions with respect to distributed generation and other DERs.

A consistent approach to pricing DERs that connect to the system is integral to the GMP and is required in order for GMP investments to be undertaken by Unitil on financial terms that will be affordable to customers. This linkage between investments in grid modernization and the ability through rate design to recover fixed costs of past and future grid investments on a timely basis is essential in order to align the interests of customers that take advantage of DERs, non-participating customers, and Unitil. DG customers require facilities that connect them to the electric distribution network to deliver surplus energy to the grid when DG production exceeds their demand as well as acquire unscheduled supply when the DG facility is either not producing at all or not producing sufficient energy to meet the demand at the customer site.

There are two fundamental problems with the current policy:

(1) the DG customer is providing a supply service yet being compensated at the full retail rate rather than the value of supply, and
(2) the DG customer does not pay the full cost of the facilities that they continue to depend on to receive and deliver power.

Unitil offers a Straw Proposal that is consistent with current metering capabilities and long-term vision for grid modernization and the role of the utility. In the proposed framework, the Company identifies ways in which the current compensation mechanisms under Net Energy Metering (NEM) can be transitioned to a more sustainable methodology that balances the need to recover the fixed costs of operating the grid with the value that is provided by DER. As part of the framework, Unitil suggests that customers who flow electricity into the utility grid: 1) are compensated for the electricity they generate, at the Fitchburg Independent Systems Operator - New England (ISO-NE) pricing point; 2) pay for distribution, supply, and other services provided by the electric utility at fees and rates that reflect the fixed and variable costs incurred to serve them. Unitil is offering this conceptual framework recognizing that the Department will likely want to address this issue on a generic basis.

The success of Unitil's GMP requires engagement of customers. Unitil's Customer Education and Outreach Plan will educate and engage customers in grid modernization opportunities. Specifically, it will inform and engage customers in (1) their options for managing their energy consumption; (2) the tools and technologies that will assist them in managing that consumption; and (3) the benefits associated with reductions in consumption and/or shifting consumption away from high-cost times of day. The plan will utilize existing and new technologies and channels of communication to both educate and engage customers.

In total, the Company's proposed short-term investment plan is estimated at $11.9 million and the total ten-year GMP at $23.9 million, yielding $25.2 million in estimated benefits. The plan is designed to respond to the grid modernization objectives, and over time transition Unitil to be a dynamic enabling platform that supports resource diversity and increases customer choice. The Company is confident it has developed a plan that can advance these objectives while generating net benefit for its customers with a relatively modest impact on revenue requirements, and thus on energy bills. The Company looks forward to engaging with the Department and interested parties regarding the plan.

1 Introduction

1.1 PURPOSE OF THE FILING

This plan presents Fitchburg Gas and Electric Light Company's d/b/a Unitil (Unitil or Company) ten-year Grid Modernization Plan and includes a five-year Short-Term Investment Plan in accordance with the requirements established by the Massachusetts Department of Public Utilities (Department or DPU) in Docket D.P.U. 12-76 and Docket D.P.U. 14-04.[1]

1.2 REGULATORY REQUIREMENTS

The Department requirements for the GMP are addressed in orders issued in June and November 2014. The June 12, 2014 order in Docket D.P.U. 12-76 (GMP Order) defined the requirements of the GMP and STIP. The Department simultaneously issued an order in Docket 14-04 addressing time-varying rates (TVR Order). On November 5, 2014, the Department issued orders in D.P.U. 12-76 addressing the Business Case Analysis (BCA Order) and the modeling of TVRs as part of the BCA. Collectively, these orders comprise the policy mandate for jurisdictional utilities to file comprehensive grid modernization to advance policy objectives with responsive programs and investments.

1.2.1 GMP AND STIP REQUIREMENTS

The GMP is a ten-year plan that demonstrates how each electric distribution utility will make "measurable progress" toward four grid modernization objectives:

(1) Reducing the effects of outages – by using technologies to reduce outages or accelerate restoration efforts, especially after major weather events;
(2) Optimizing demand, which includes reducing system and customer costs – by reducing the need for peaking resources in part by empowering customers through time-varying price signals and technology-based means to shift demand from peak to off-peak hours;
(3) Integrating distributed resources such as intermittent renewable generation, electric vehicles, micro grids and energy storage – to advance fuel diversity, clean energy, and resiliency; and
(4) Improving workforce and asset management – to improve operational efficiency.[2]

---

[1] More specifically, the June 12, 2014 Order in D.P.U. 12-76-B setting out the basic framework for the GMP, the November 5, 2014 Order in DPU-76-C establishing the benefit cost framework, and orders in D.P.U. 14-04 regarding Time Varying Rates that were issued on June 12, 2014 and November 5, 2014.

[2] June 12, 2014 Order in D.P.U. 12-76-B, page 2, and as further expanded upon on pages 10-13.

"Measurable progress" is to be gauged by a set of common utility and company-specific metrics that track progress toward (a) implementation of grid modernization technologies, and (b) achievement of GMP objectives.

The GMP Order established three additional requirements for the content of the GMP and required that stakeholder input be considered in developing the plan. The GMP must include:

(1) Timing and priorities for grid modernization planning and investment over the ten-year period;
(2) A marketing, education and outreach plan; and
(3) A research, development and deployment (RD&D) plan.

The GMP must also address how cybersecurity will be preserved by preventing unauthorized access to control systems, operations, and data "in accordance with existing and emerging best practices, national standards, and state and federal laws."[3]

The STIP presents the capital investments that will be initiated within the first five years. Each investment must be supported by a "comprehensive" BCA. The BCA evaluates whether the benefits (quantifiable and non-quantifiable) justify the proposed STIP investments. The Department concluded that "advanced metering functionality" is a basic technology platform for grid modernization, although it declined to specify a particular technology or suite of technologies to achieve the desired functionality. This is consistent with the November 5, 2014 Order in D.P.U. 14-04 in which the Department declared a policy preference that default basic service be a time-of-use rate, with a critical peak pricing (CPP) component. The STIP must include an approach to achieve AMF within five years of receiving Department approval for the GMP, unless the BCA indicates that a longer timeframe is required to justify the enabling investments, in which case an alternative BCA may be submitted.[4] Consistent with this guidance regarding AMF, Unitil examined the benefit and cost of a five-year deployment of AMF and found that it was not cost effective. However, the Company presents a more cost effective alternative in the plan that deploys AMF capability and installs interval metering only where customers opt-in to a time varying rate service. At the latter stages of the GMP the existing AMI system will be reaching its end of life; therefore Unitil will be able to assess opportunities to commence a broader upgrade to AMF when it is expedient to do so.

The Department recognized that customer engagement is a key success factor to deliver the desired benefits from investment in grid modernization. This requires that customers be informed of new

---

[3] GMP Order, p. 35.
[4] TVR Order, p. 4, footnote 5.

energy management options and the enabling technologies, as well as the savings that can be realized by changing their energy consumption behaviors. Thus, the Department indicated that each GMP must include a "marketing, education, and outreach plan."[5]

The Department directed the Massachusetts electric utilities to propose RD&D plans that advance its grid modernization objectives by testing new and emerging technologies, along with proposed funding mechanisms.[6]

Finally, the GMP Order addressed the method by which Unitil and the other Massachusetts electric utilities would recover the costs attributable to its GMP. STIP investments are eligible for "pre-authorization" to the extent supported by the BCA and may be recovered through a GMP capital expenditure tracker (herein referred to as a STIP Capital Tracker) to the extent that they are "incremental" and reflect investments that represent new technologies or investment levels that exceed normal business investment levels. Unitil's cost recovery proposal is presented in Section 3.2.

1.2.2 THE BUSINESS CASE ANALYSIS

The GMP Order specified that the BCA focus on investments to be included in the STIP and should include:

(1) A detailed description of the proposed investments, including scope and schedule;
(2) The rationale and business drivers for the proposed investments;
(3) Identification and quantification of all quantifiable benefits and costs associated with the STIP; and
(4) Identification of all difficult to quantify or unquantifiable benefits and costs."[7]

The Department expanded on the detailed requirements of the BCA in the BCA Order, after seeking stakeholder input through working group meetings and written comments. The BCA Order specifies filing requirements, and includes a template with a set of instructions for the submittal of the BCA. The BCA Order also resolved several implementation issues related to the development of the BCA. For example, while the template provides information necessary to evaluate each STIP investment, the BCA Order resolved that companies need only provide a single BCA that would cover the collection of STIP investments, rather than separate BCAs for each STIP investment.

[5] GMP Order, p. 26.
[6] GMP Order, p. 28-29.
[7] GMP Order, p. 17.

The Department directed the electric utilities to quantify costs and benefits to the extent possible, and further, to apply a common set of assumptions when performing quantitative analysis, including assumptions relating to energy and capacity prices and customer responsiveness to time-varying rates. The Department ordered the electric utilities to apply a common discount rate (the weighted average cost of capital or WACC) and a 15-year planning horizon when evaluating STIP investments. The Department's BCA Order clarified that the BCA should reflect the policy preference for time-of-use rates with CPP, and directed the companies to report their service area-specific assumptions regarding the responsiveness of customer peak loads to the CPP signal, using a common Massachusetts forecast for energy and capacity prices. Several other assumptions are required to model the impact of TVRs for purposes of performing the BCA. Unitil's BCA assumptions, including those related to TVRs, are presented in the discussion of AMF and TVR in Section 2.4 of this plan.

The BCA Order also directed the electric utilities to include a bill impact analysis in the GMP that assesses the potential impact of the STIP on customer bills as part of the overall assessment of the STIP.

1.3 UNITIL'S COMPLIANCE WITH THE GMP FILING REQUIREMENTS

The GMP is a representation of the Company's recommendation of projects and investments that will advance the grid modernization goals. These projects are informed by the Company's knowledge of its customers and stakeholders' interests and concerns.

The Company's GMP is structured to be responsive to the Department's regulatory guidance. This document includes the following required elements of the GMP:

- STIP, with supporting BCA
- Marketing Education & Outreach Plan
- Research, Development, and Deployment (RD&D) Plan
- Performance Metrics
- Report on Stakeholder Engagement
- Approach to Cybersecurity

Unitil proposes to recover its STIP investments through a cost recovery tracker as described in Section 3.2. Unitil recognizes that AMF is expected to be part of a GMP/STIP and be deployed within five years to be eligible for recovery through a dedicated recovery tracker.[8] Unitil has determined that the most prudent approach is to install systems with base AMF functionality and offer AMF metering and TVR on an opt-in basis as the most practical way to meet the AMF requirement.[9] This is addressed in the detailed STIP and BCA sections of the plan, but the analysis reveals that AMF investments have very poor net benefits if deployed for the total system, especially if municipal aggregation continues to proliferate and large groups of customers are not eligible or opt-out of TVR. By offering AMF metering and TVR as an opt-in program, the Company is able to minimize the ratepayer exposure to an investment that is not currently cost effective. This approach sets Unitil on the path to full AMF capability and offers TVR as an economic, practical and prudent approach to achieve the Department's policy objectives.

Further, Unitil proposes a cost recovery tracker remain in place to recover the costs associated with all approved STIP investments, even if certain investments continue to be implemented beyond the initial five-year STIP timeframe. Grid modernization investments are complex and take multiple years to source, design and implement. It is impractical and counterproductive to restrict the recovery of STIP investments within such a short window. To minimize risk and maximize ratepayer benefit it is imperative that these projects be thoroughly planned, staged, implemented and tested. There are numerous interdependencies among STIP investments where a particular technology or system is reliant upon another. The GMP reflects these interdependencies and incorporates a rational sequencing to deployment that extends the time to deploy the entire portfolio beyond the initial five-year period. Cost recovery is discussed in full in Section 3, "Rates and Regulatory".

1.4 UNITIL'S CURRENT SITUATION

1.4.1 SERVICE TERRITORY, DISTRIBUTION SYSTEM AND CUSTOMER BASE

Unitil's Massachusetts service territory lags behind the rest of the state from an economic perspective and has higher than average percentage of customers that qualify for low-income rate discounts. Not surprisingly, residential and business customers are sensitive to the cost of energy. Further, there is an interdependency whereby residential customers who struggle to pay their bills rely on the viability of

[8] The DPU guidance regarding the capital tracker emphasized deployment of AMF during the STIP, or first five years of the GMP, but allowed for the consideration of a longer implementation if it was shown to be cost effective.

[9] The Department set forth its definition of AMF for purposes of this requirement on page 3 of the GMP Order (footnote 1): "(1) the collection of customers' interval usage data, in near real time, usable for settlement in the ISO-NE energy and ancillary services markets; (2) automated outage and restoration notification; (3) two-way communication between customers and the electric distribution company; and (4) with a customer's permission, communication with and control of appliances."

the commercial and industrial sector to provide employment. Several economic data points demonstrate this concern:[10]

- An unemployment rate of 7.9% while the statewide rate is 4.9%;
- A 13% poverty rate vs. 10% statewide rate;
- A median income that is below statewide median for all household sizes except households with seven or more members; and
- A lower representation of households with earned income and higher representation of state assistance.

Unitil is acutely aware of the energy cost sensitivity of its residential and business customers, who often must remain globally competitive to maintain employment levels.

In addition, the Unitil FGE service area is a small distribution system, consisting of 10 substations and 44 distribution circuits serving 28,600 customers, with almost 90 percent being residential customers. For day-to-day field operations, such as responding to routine power outages, Unitil is able to meet the needs with a field force of five two-man utility crews. In terms of acceptable levels of capital expenditures, there is a need to find a balance between continuing demands to replace and upgrade existing grid infrastructure as it nears the end of its useful life versus incremental investment in grid modernization. There are practical limits of allocating available capital among infrastructure replacement, new technologies, and other capital needs. In short, given the rate impact concerns, the capital demands of maintaining current systems will compete with the financial demands of grid modernization.

Unitil has adopted an overarching theme of “practical grid modernization” to inform the reach and scale of an appropriate grid modernization effort. This means that Unitil’s proposed GMP considers both technical and financial considerations such as rate impacts and the ability of its customers to afford grid modernization.

Unitil believes it is prudent from a societal perspective to temper the identification of long-term grid capability needs by the financial stresses of customers. As a result, practical grid modernization places a high value on finding the enabling investments that provide net benefits for customers and have acceptable rate impacts. A great majority of the benefits derived from Unitil’s GMP projects accrue to customers in the form of efficiency savings and improved reliability as well as hard to quantify benefits stemming from the enablement of DER.

[10] “Customer and Housing Unit Characteristics in the Fitchburg Gas & Electric Service Territory”, prepared for Unitil Corporation d/b/a Fitchburg Gas Electric, Fisher, Sheehan & Colton, Newton MA April 2012.

One important consideration of this GMP is the fact that Unitil was an early adopter of AMI that provides most of the specified AMF and has already achieved operational savings benefits that typically comprise the majority of economic benefits from advanced metering system investments. In addition, Unitil gained experience with TVR during the Smart Grid Pilot. As a result, the Company has familiarity with the technology and business requirements, costs of implementation and the level of customer interest with TVR.

1.4.2 SYSTEM LOAD AND RELIABILITY CHARACTERISTICS

Unitil's FGE service area has seen a persistent decline in peak power demand over the past ten years as illustrated in Figure 1 below. This decline has been attributed to a very limited recovery from the economic downturn of several years ago, the exponential growth of rooftop solar as a result of net metering policies and the success of the energy efficiency programs being promoted by Massachusetts and Unitil. As a result, there is essentially no distribution system benefit (e.g., deferred or avoided investments in the capacity of the distribution system) gained from reducing peak demand. The preponderance of the benefits from load response and optimization of demand will be experienced directly by participating customers or by all customers through reductions in the market price of energy.

In addition, Unitil is seeing increasing interest by communities in its territory to move towards municipal aggregation. Under municipal aggregation, participating towns can vote to purchase electricity from a third-party supplier as a collection of individual customers. When aggregation is set in motion, the distribution utility loses the energy supply obligation for this large number of retail customers. If this trend continues, Unitil will increasingly shift to a delivery only or "pure network" company. This shift will also prevent these customers from participating in a company sponsored TVR program.

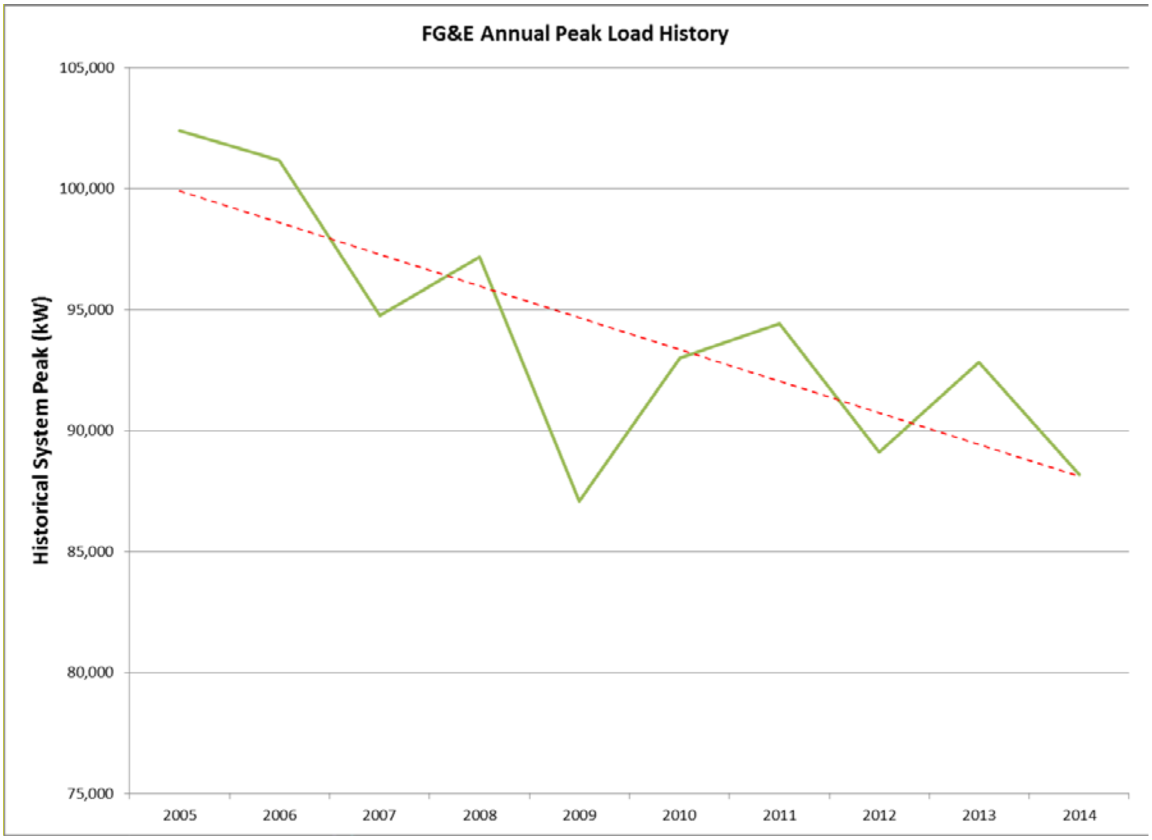


Figure 1: FGE Annual Peak Load History

From a reliability standpoint, Unitil has been making improvements over the past several years, both on an exclusionary (outages due to extreme weather are excluded from the service quality metrics) and non-exclusionary basis (including outages due to extreme weather) as shown in Figure 2 below. Both views of reliability are relevant for purposes of achieving the objectives expressed in the GMP Order which includes a concern for the potential impacts from extreme weather events. Distribution automation, increased vegetation clearance and other outage reducing techniques have been strategically applied in an effort to optimize capital and operations and maintenance (O&M) expenditures in addressing specific reliability issues on the grid. As the SAIFI (System Average Interruption Frequency Index) and SAIDI (System Average Interruption Duration Index) charts below clearly illustrate, the average frequency and duration of power outages have been declining as a result of these efforts.[11] With respect to the GMP, this indicates that incremental investment to enhance

[11] The reliability charts were prepared with data in accordance with the D.T.E. 04-116 final order assumptions for calculating electric reliability measures. No exclusions were taken for Non-Primary/Secondary events.

reliability must be carefully evaluated since the benchmarks for system reliability are already being exceeded and existing approaches are proving to be very effective.

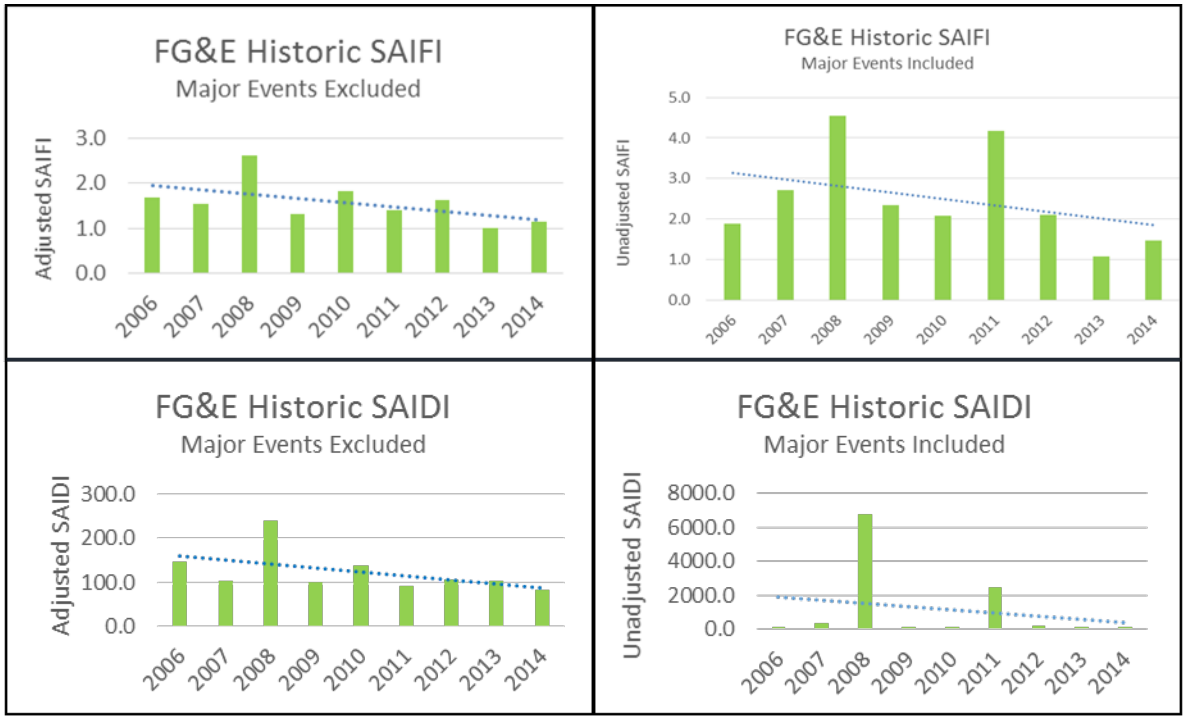


Figure 2: FGE Historic SAIFI and SAIDI Results

The increasing penetration of distributed generation, primarily rooftop solar, in the service area has also contributed to the decrease in peak demand in Unitil's service area. As illustrated in Figure 3 below, the amount of interconnected DG capacity has increased exponentially over the last five years and is expected to continue into the immediate future. In addition, this exponential growth is causing voltage fluctuations on particular circuits and reverse power flows, which will need to be addressed in the near term by system investments. Over the longer term, Unitil envisions enhanced visibility and control at the operator level as a critical part of integrating and optimizing distributed resources that may limit system upgrades.

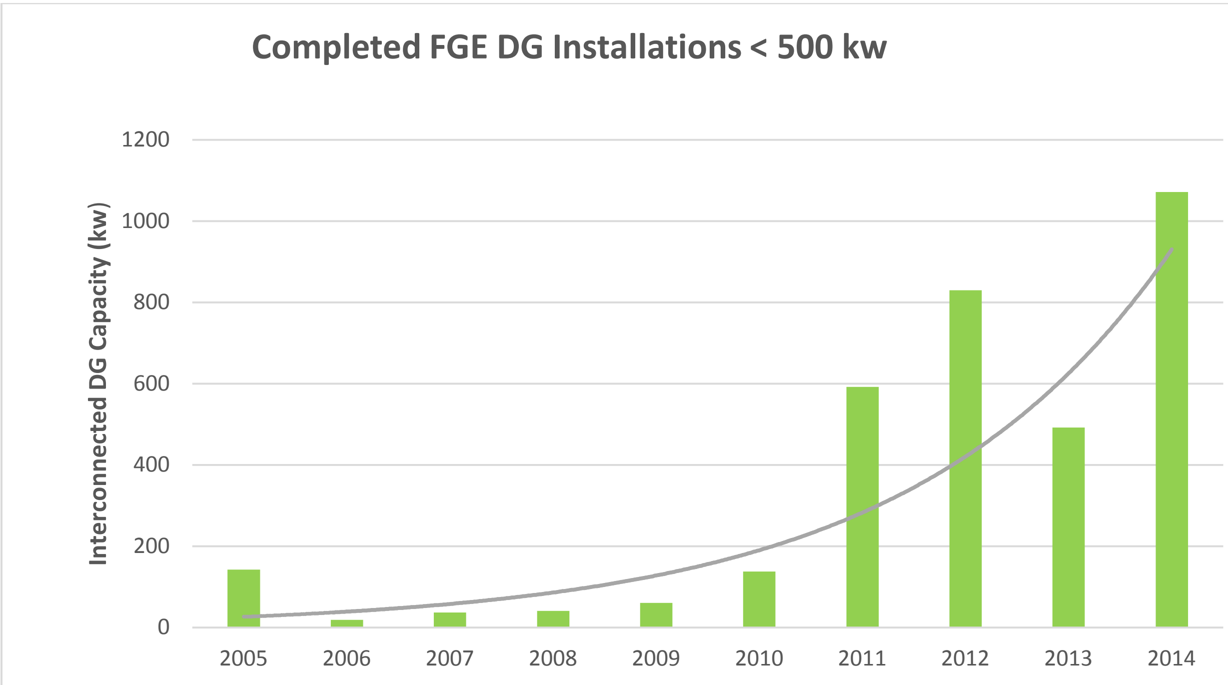


Figure 3: Completed FGE DG Installations < 500 kW

All of the Unitil-specific factors presented in this section were taken into account in developing Unitil's GMP, along with the Department's grid modernization objectives. These include the state of the economy, customer rate impacts, existing AMF capabilities, and capital requirements. As described in the next section, they are layered on top of Unitil's objective to provide a platform for new customer services, while continuing to provide reliable and cost effective service for its customers.

2 Grid Modernization Plan

2.1 APPROACH

2.1.1 BALANCING MULTIPLE PRIORITIES

Unitil views the development of a GMP requires a balancing of multiple interests:

- Meeting the DPU grid modernization objectives;
- Responding to customer interests including rate sensitivity;
- Supporting the role of third parties and market solutions available to customers;
- The need to continue capital investment programs to replace aging infrastructure while pursuing grid modernization; and
- Anticipating the continued transformation of the electric delivery business model and related regulatory considerations.

2.1.2 FROM VISION TO PLAN

The GMP was guided by the executive management team and was supported by an internal team of subject matter experts from many departments:

- Metering
- Engineering
- Finance
- External Communications
- Customer Service
- Energy Efficiency
- Business Continuity
- Vegetation Management
- Regulatory
- Information Technology (IT)
- Electric Operations
- Dispatch
- Substations
- Customer Energy Solutions
- Legal

The subject matter experts were led through a multi-step process to ultimately develop the projects that would make up the ten-year GMP. The term "initiatives" was initially used to capture conceptual programs and offerings to customers and investments in technology that would best advance grid modernization objectives while considering the system and customer base within the FGE territory. Identifying important initiatives allowed the Company to think openly and broadly about ways to achieve objectives and chart a path towards its long-term vision of utility service. Thinking about initiatives led to specific projects that were subjected to detailed scoping that included estimated cost[12], benefits, and timing for deployment.

Projects, once fully scoped, were iteratively evaluated and refined to arrive at the final list of investments proposed, while other projects were deferred for future consideration as conditions warrant. The Company found that the projects had a natural grouping in terms of the objectives they advanced and the technologies or capabilities they contained that led to the identification of core programs.

The key stages of the process were as follows:

(1) Current State Assessment
(2) Future State Visioning
(3) Project Definition
(4) Project Analysis & Vetting

Current State Assessment

Figure 4: Four-Stage GMP Process

The Company undertook a thorough examination of its current capabilities, focusing on utility operations, customer services and the supporting infrastructure (grid components, supporting systems and information technology). Unitil reflected on the needs of customers, and confirmed these

12 Although many of the estimates involved past project spending experience or vendor estimates, it is expected that Unitil will revisit these estimates after acceptance of the Plan and before seeking internal approvals. Many of the larger projects will be revisited through a full request for proposal process with vendors.

perspectives through outreach to customers and stakeholders. This profile provided a baseline view of the current level of capability to meet grid modernization policy objectives.

The subject matter experts were engaged to address a broad range of GMP topics:

- Reducing the Effects of Outages
- Optimizing Demand & Integrating DER
- Improving Workforce & Asset Management
- Advanced Metering Functionality
- Marketing, Education and Outreach
- Research Development & Deployment
- Cybersecurity
- IT Architecture
- Stakeholder Process
- Metrics
- Rates and Regulation

Future State Visioning

Unitil performed a visioning exercise to examine the future state of the electric distribution grid and its implications for Unitil as an investor-owned utility. Unitil developed an operational and capabilities profile consistent with that future state over the span of the GMP. As a part of this exercise, the following were considered:

- Industry Drivers: advancing technology, customer experience;
- Policy objectives: grid modernization objectives and other Massachusetts energy and environmental policy objectives;
- Evolving Utility Business Model: potential paths that the utility business model might take in response to industry drivers and policy objectives; and
- Required Capabilities: the critical capabilities a distribution utility must have to operate in the industry future state.

The Company concluded that as DER and a more dynamic set of offerings from the marketplace for consumers proliferate, grid operations will become more complex and the Company's role with customers will need to evolve. As grid operations will be more dynamic to manage diverse resources and two-way power flow, the Company envisions shifting its focus towards enabling new and evolving services to customers rather than directly providing them. The outline of Unitil's vision of an enabling platform environment is more fully described in Section 2.2.1.

Project Definition

This effort allowed the Company to identify the gaps between current capabilities and its goals for infrastructure and services at the conclusion of the ten-year planning horizon, considering grid modernization objectives and increasing customer expectations. Workshops were conducted across the organization to identify projects to bridge these gaps in ways that were responsive to identified objectives and achieve the future state vision.

The initiatives below served to close the gaps and guided the development of the GMP:

(1) A more robust field communications network is needed to support many of the grid modernization technologies such as voltage optimization and AMF;
(2) Greater visibility into the grid in near real-time is essential to managing and controlling the impacts of DG/DER;
(3) Enhance existing system functionality through further integration between operating systems to improve operations and restoration efforts;
(4) Automating existing manual operations to improve operational efficiency and effectiveness; and
(5) Enhancing customer information and education in order to empower customers to manage their electrical usage and make more informed decisions.

As specific projects were identified, they were purposefully mapped to the objectives they would impact in a direct and material way. The STIP details how the Company's proposed projects impact or advance identified objectives. The following table illustrates the cross-section of objectives that were considered to capture these objectives from each of three perspectives: the state, customer and Unitil.

Objective Areas	Objectives
State Policy Goals	Reduce the Effects of Outages Optimize Demand Integrate DER Improve Workforce and Asset Management
Customer Experience	Minimize Rate Impacts Improve Reliability Integrate Solar and Other Renewables Initiate New Service Options, More Granular Data
Unitil Strategic Objectives	"Enabling Platform" (see Section 2.2.1) Practical Grid Modernization Actively Manage DER Provide Safe & Reliable Service

Table 1: Grid Modernization Plan Objectives

The projects were mapped to GMP objectives including policy and customer expectation goals and then organized into the following five “programs” for discussion and decision-making purposes. The five programs are:

1. **DER Enablement** – collection of potential projects encourage DER with a flexible grid along with DER pricing that reflects its value to both suppliers and customers;
2. **Grid Reliability** – collection of proposed projects that are designed to reduce the impacts of outages;
3. **Distribution Automation** – a collection of proposed projects that are designed to automate grid operations;
4. **Customer Empowerment** – a collection of proposed projects that provides customers with information and tools for managing their energy choices; and
5. **Workforce and Asset Management** – a collection of proposed projects that can improve the efficiency and effectiveness of field crews and the management of assets.

Project Analysis & Vetting

In this phase, a “Project Input Form” (PIF) was utilized to capture all aspects of a proposed project consistent with DPU guidance. The PIFs enabled each potential project to be specified, quantified and analyzed consistent with the filing guidelines in Grid Modernization Business Case Filing Requirements (D.P.U. 12-76-C). This examination allowed Unitil to convert a roster of projects into a set of proposed investments in the GMP.

The cost and benefit data from the PIFs were the source inputs to the BCA to assess net benefit by project and program. The BCA allowed Unitil to iteratively look at projects in differing combinations and timeframe and to examine how the nature of the underlying benefit can impact the overall cost effectiveness of the investment.

Some select projects that do not generate a net benefit have been advanced because of their close alignment to DPU, Massachusetts energy policy, and Unitil objectives.

Consistent with Unitil’s emphasis on practical grid modernization evaluation, the Company also considered the relative size of each investment, time to implement, perceived level of risk, and rate impact. Projects were repeatedly discussed; costs and benefits reexamined, and were considered in the context of their alignment to identified objectives. The BCA was a valued tool that expressed the proposed initiatives in quantitative terms that allowed a more concrete assessment of net benefit to the operation of the distribution system and to customers.

The outcome of the review and prioritization process is a set of specific investments for which Unitil seeks DPU pre-approval. Refer to Appendix A for a complete list of projects that were considered and vetted with this process.

2.2 OVERVIEW OF THE PLAN

2.2.1 THE VISION - A PLATFORM FOR THE 21ST CENTURY

Unitil identified a set of prevailing business and operating conditions that will develop over the next ten years that will dictate the technical capabilities that will be needed in Unitil's FGE service territory. Unitil's grid modernization and executive management teams developed a profile of the modern electric system in Massachusetts to serve as an ambition for the GMP development effort. It is clear that the environment of the distribution business is shifting. The Company's long-term view is to transition the distribution operations to serve as a platform for Distributed Energy Resources, increasing stakeholder requirements, and enhanced customer experience (the "Enabling Platform").

Figure 5 depicts the utility as an Enabling Platform that will serve the needs of customers and third-party providers while integrating with the bulk electric system and complying with regulatory requirements. DER is a term that incorporates end-use energy efficiency, demand response, distributed generation such as rooftop solar, energy storage, and micro grids. The prevailing policy framework in Massachusetts places a particular emphasis on energy efficiency, renewable energy sources, and increasing the role of DER. The modern electric distribution business, especially in restructured markets where generation and transmission are owned and operated separately, will be less focused on delivering electricity to consumers and increasingly focused on integrating resources that depend on the grid. The distribution grid will be reconfigured as necessary to integrate DERs and optimize customer demands.

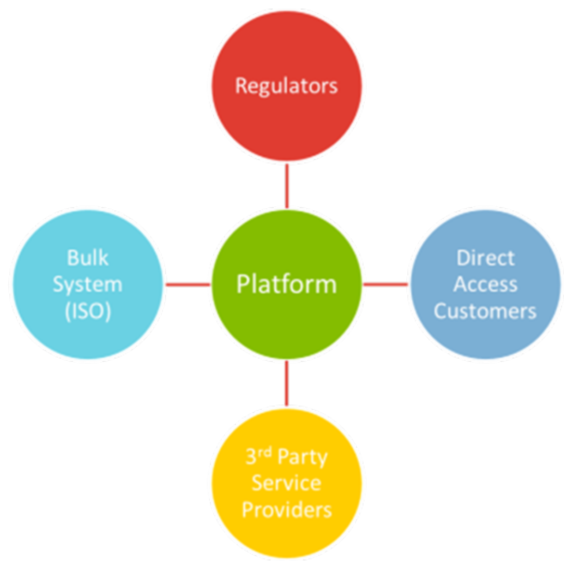


Figure 5: Enabling Platform Model

Unitil will continue its traditional role of maintaining a safe and reliable distribution grid and operating it efficiently as a core responsibility within the platform. However, there are ranges of activities and services that will take place on the grid and behind the customer meter that will be provided by the marketplace. Unitil's role as the Enabling Platform will be to create the physical operating environment and the enabling functionality that supports these diverse actions by third-party providers and customers.

The Company embraces the role of the Enabling Platform as it is closely aligned with its experience and knowledge of operating a distribution network that is safe and reliable and serves as a critical foundation for commerce and society. The Company envisions a critical role for the Enabling Platform to integrate DER, reduce the effects of outages and advance workforce and asset management, consistent with the Department's four grid modernization objectives. Moreover, the Company also envisions the optimization of demand as an objective that is ultimately achieved by the marketplace and made possible by the enabling technology on the distribution grid.

The operating nature of the Enabling Platform as an integrator and enabler of diverse customer services was a major driver in Unitil's effort to identify grid modernization investments.

2.3 STAKEHOLDER ENGAGEMENT

The GMP Order directed Unitil and the other Massachusetts electric distribution utilities to solicit stakeholder input into the development of the GMP and to include a summary of the solicitation process, input received, and integration of input into the development of the GMP.[13] The Company has shared its approach and efforts to develop a practical grid modernization plan with its stakeholders including customers (residential, commercial & industrial), local government, civic organizations and others. The intent was to get their perspective as to whether this approach made sense and to make sure the Company was incorporating their interests and concerns into the analysis of grid modernization projects.

Unitil organized its stakeholder input process to obtain input from:

- Interveners in Unitil and Department proceedings, including participants in the Department's grid modernization "Working Group" discussions that preceded the formal opening of the grid modernization proceeding,
- Local government and municipal leaders, and
- Customers.

The outreach was designed to leverage outreach protocols that were most comfortable for each group.

---

[13] GMP Order, page 51.

Unitil met with the intervener group in Boston on May 8, 2015. The meeting consisted of a presentation by Unitil with facilitation and meeting notes by BRIDGE.[14] The presentation described the results of Unitil's GMP efforts and included a summary of the Company's vision with respect to the GMP, the four GMP objectives identified in Section 1, and a list of specific programs to accomplish each of the objectives that Unitil intended to evaluate using the BCA methodology. The stakeholders expressed support for Unitil's vision to be an Enabling Platform that would integrate DER. They were most interested in TVR options and Unitil's approach to TVR. The stakeholders expressed interest in energy storage as a DER. A few participants expressed interest in how the programs Unitil shared could advance grid modernization while managing costs to customers. Stakeholders were also interested in how Unitil would identify investments as "grid modernization" related.

These stakeholder discussions took place at a point in time as GMP programs were beginning to take shape. The stakeholder session provided a timely opportunity to share the Company's thinking with respect to programs and potential initiatives and gauge the priorities of these parties. The stakeholders responded favorably to the approach to developing the plan and the vision of an Enabling Platform environment. The Company was able to share how preliminary analyses indicated that a service area-wide deployment of AMF and TVR on an opt-out basis would not be cost-effective and that the Company had begun to consider approaches that would offer TVR programs and AMF on an opt-in basis. Certain stakeholders shared a perspective that the energy savings and benefit derived would be sufficient to justify the overall investment even if the number of participating customers was a small percentage of the total customer base.

The outreach to government and municipal leaders was designed to leverage the existing consultative process, by which designated Unitil representatives meet regularly with these constituencies on a one-on-one basis or in small groups to discuss matters that are likely to be of interest to them. By relying on existing relationships, Unitil fostered an environment that would be conducive to obtaining constructive feedback. The Unitil representatives were briefed on the GMP proceeding, Department objectives, and the effort to develop a GMP for the FGE service territory. Unitil customer representatives and government relations staff have shared the information regarding the grid modernization directives and Unitil's approach to developing a GMP during ongoing interactions so that the Company could ensure there was an awareness of the direction. The Company did not receive any significant concerns about the general approach.

---

[14] Participants included representatives from the Department's Electric Division, MA Department of Energy Resources, Office of the Attorney General, New England Clean Energy Council, Acadia Center, Utilidata, and EnerNOC, and Energizing Company

Finally, in an effort to obtain input from customers, Unitil prepared a survey that was distributed to approximately 7,400 customers via email (primarily small customers). The survey format is provided in Appendix C. The survey sought customer feedback with respect to their electricity bills and other energy priorities, familiarity with "grid modernization", solar and renewable energy as a resource, and specific programs that Unitil was considering. Unitil received completed responses from 324 customers concentrated in the residential customer class (322), a relatively high response rate for a survey of this type.

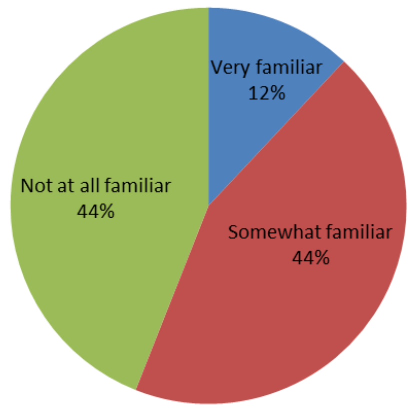
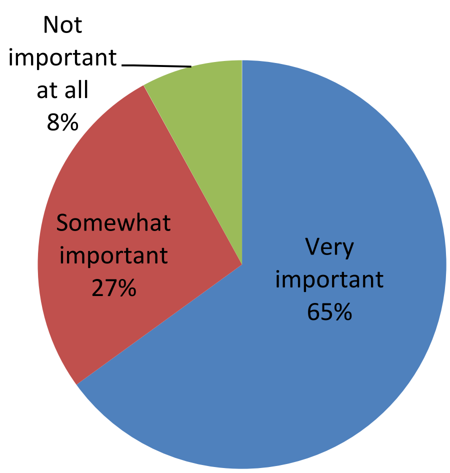


Figure 6: Unitil Customer's Familiarity with Grid Modernization

There was considerable awareness of "grid modernization" as a concept with 56% of respondents indicating that they were either "very familiar" or "somewhat familiar" with the term, as shown in Figure 6.

When customers were asked about their energy use and the notion of a modernized grid, their primary interest was what that would mean in terms of electric rates, followed closely by how reliability can be maintained or improved. When asked in more detail about reliability, customers rated overall improvement in reliability highest, followed by shortening the duration of outages and lastly, being provided additional outage information.



Power Technology

Customers expressed considerable interest in solar with 91.6% of customers indicating that Unitil's investment in technologies to support solar power was important or very important, as seen in Figure 7. As shown in Table 2 below, Customers cited lower energy costs as well as an appreciation for the environmental value of clean renewable energy as important concerns. These two preferences can be reconciled for customers that are interested in solar energy as a way to save on their electricity bills.

Topic	Score	Overall Rank
Rates	1,581	1
Reliability	1,460	2
A Clean Environment	1,133	3
Ability to Manage My Energy Usage	1,044	4
Ability to Generate My Energy	970	5
Encouraging Technology and Innovation for the Electric Industry	684	6

Table 2: Sampling of Customer Survey Responses

The stakeholder input validated Unitil's "practical" approach to the GMP. Stakeholders expressed a primary interest in controlling their electricity costs. At the same time, customers and stakeholders expressed an interest in the potential contribution of grid modernization to improved reliability, the integration of distributed resources, and the ability to leverage information to be more efficient. This engagement and feedback is reflected in the GMP. As described below, the GMP presents a combination of programs and specific investments that advance grid modernization consistent with Unitil's strategic objectives, and provides a positive net benefit at a scale of investment that result in a modest increase in retail rates over the duration of the plan.

2.4 SHORT-TERM INVESTMENT PLAN (STIP)

2.4.1 KEY FACTORS FOR STIP PROJECTS

The specific STIP projects were selected because they will help Unitil develop capabilities necessary for the Enabling Platform during the initial five-year STIP period. They are designed to help empower customers, enable DER, and create a more flexible and robust distribution system. Part of the challenge in designing this portfolio was creating foundational capability while avoiding unacceptable rate impacts. Like most utility customers, people served by Unitil want to avoid higher energy bills. Unitil's stakeholders want a pragmatic, measured approach to grid modernization that delivers real, measurable benefits for customers.

Strategic objectives and drivers of the STIP:
As Unitil considered the competing interests that influence the selection of STIP projects, it became obvious there were some high level areas of capability and enabling technology that warranted thorough analysis. The provisioning of AMF and TVR, DER integration and leveraging voltage optimization technologies were all priorities of the DPU, while expanding field communications is a foundational capability of a modernized grid. These became critical capability quadrants of Unitil's GMP and STIP.

- **AMF and TVR**
  The order requires that utilities provide advanced metering functionality, and offer customers TVR on an opt-out basis following the deployment of advanced metering functionality (see D.P.U 14-04-C). In order to offer AMF and TVR to all of the customers on an opt-out basis, Unitil investigated upgrading all of its smart meters. This replacement proved to be an expensive endeavor and would cost about $12.0 million and deliver benefits of only approximately $3.3 million. This high cost is further exacerbated by the fact that the existing smart meters have not reached the end of their useful life, and there is an increasing interest in municipal aggregation, which would greatly reduce the number of customers likely to participate in a TVR program. Therefore, Unitil proposes a transitional approach that uses the existing smart meters and a new communications network to enable AMF. This approach will allow Unitil to offer customers TVR on an opt-in basis, and provide those customers who choose to participate a new smart meter that meets the full AMF/TVR criteria.

- **Field Area Network (FAN) Communications System**
  The communications network is foundational. A modern grid is full of sensors that measure and capture information, and computers that make use of the data. Additionally, active control of the grid requires the capacity to remotely control field devices in real time. The communications network makes it all work, and many of the other STIP projects will leverage its capability (including AMF and TVR).

- **DER Enablement**
  Unitil's vision is to be an Enabling Platform for electricity consumers and producers, and recognizes the need to provide service to DER. The DER enablement projects included in the STIP are fundamental to achieving this vision. The technologies identified, together with a sustainable pricing framework, will allow DER to grow in the Company's service territory.

- **Voltage and VAr Optimization (VVO)**
  VVO is a proven way for utilities to save energy for customers, ensure reliable service, and help integrate DER. The VVO projects will deliver significant and measurable benefits for Unitil and its customers, while creating platform capability to be leveraged in the future. VVO also provides active voltage control, further enabling DER.

2.4.2 STIP ASSUMPTIONS

The STIP is a five-year implementation plan for grid modernization technology and infrastructure. The Company assumes that the STIP will begin in 2017 (Year 1) and end in 2021 (Year 5). Most projects will begin in 2017 and be completed over the course of the ten-year GMP with approximately one-half of the spending occurring in the first five years. All projects in the STIP will be recovered via a dedicated cost recovery tracker.

Unitil's STIP supports five grid modernization programs:

(1) DER Enablement – encourage DER with a flexible grid and DER pricing that recognizes its value for producers and consumers;
(2) Grid Reliability – ensure that power outages and their impacts are minimized
(3) Distribution Automation – make the grid more flexible and efficient
(4) Customer Empowerment –provide customers information and tools for managing energy choices; and
(5) Workforce and Asset Management – improve performance of operations and infrastructure.

The recommended projects for each of these areas are listed in Figure 8 below and are discussed in detail in the following sections. In the presentation of the individual STIP projects, all cost and benefit information is presented on a nominal dollar basis. The BCA analysis, however, uses a Net Present Value (NPV) approach to calculate the benefit/cost (B/C) ratios to illustrate the cost effectiveness of each proposed projects.

DER Enablement	Reliability	Distribution Automation	Customer Empowerment	Workforce & Asset Management
• Circuit capacity study • DER analytics and visualization platform • 3V0 protection at substations • Substation	• Integrate Enterprise mobile damage assessment tool • Integrate AMS with OMS	• Auto cap banks for VVO • Auto voltage for VVO • Auto LTCs for VVO • SCADA comms to FGE substations	• Energy information web portal • Gamification pilot • TVR AMS	• Mobility platform for field work

Figure 8: Recommended Programs and Projects in Unitil's STIP

2.4.3 STIP Project Portfolio

DER Enablement

Grid Modernization Objective

- Ensure that the distribution system can physically accommodate high penetration of DER, and create a pricing approach that can recognize the value of DER without cross subsidies between customers with DER and those without.

DER Enablement Projects

- Circuit Capacity Study for DER
- DER Analytics and Visualization Platform
- 3V0 Relay Protection and Voltage Regulation Controls

1. Annual Circuit Capacity Study for DER

Circuit Capacity Study for DER Overview	
Description	Evaluate the existing capacity of each substation and mainline circuit to determine how much DG could be added without the need for distribution system upgrades. The results of the study will help Unitil encourage the development of DG on feeders where it can be readily accommodated. The study will also identify substations that require upgrades to accommodate more DG. The general results of the study will be posted on the Unitil website along with other interconnection requirements for DG developers and customers to reference when siting future DG. This study will be reviewed annually to keep the information up-to-date.
Benefits	The circuit capacity study will help Unitil and DG developers to better plan for DG growth. It will also help speed the process for DG applications and system upgrades. The benefits of DER Enablement ultimately depend on how much DER is installed in the FGE service territory. Large DG developers will no longer end up submitting multiple applications in order to identify suitable locations where DG can readily interconnect with the grid. Of the 12 applications for DG 250 kilowatt (kW) or larger, one was cancelled after impact study ($35,000) and two were cancelled after impact study agreement ($10,000) was sent. Potential total cost wasted would amount to $50,000 over 12 applicants in five years. These benefits are savings to the applicant rather than Unitil.

Implementation Timeline & Cost	Annual study in 2017 through 2026 for a total cost of $180,000 over ten years

Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs (000s)	$30	$30	$15	$15	$15	$15	$15	$15	$15	$15
Benefits (000s)	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10

Under the present tariff model, those wishing to interconnect onto electric distribution system submit an application with all of the applicable information along with the location of the interconnection. The utility then evaluates each application to determine if any system improvements are required. This process works well, but without knowledge of the general capacity and limitations of specific areas, some applications are likely to be determined to be economically impractical. If these developers or DER owners had a greater visibility into the ability for the grid to accept DER, this should reduce some of the iterative analysis by the utility and developer trying to identify a good location. The overall goal is to improve the quality and practicality of the applications submitted for review.

Circuit capacity, sometimes referred to as “integrated capacity” or “DER hosting capacity,” is challenging to define, because each circuit has its own characteristics and these characteristics change over time. The “hosting capacity” of a feeder is the amount of DER a feeder can support under its existing topology, configuration, and physical response characteristics without affecting power quality or reliability. Many considerations need to be evaluated depending on where the DER is located. The utility needs not only to look at the grid in the area of the interconnection (i.e. transformer and wire capacity, voltage control, etc.) but they also need to determine if this installation will have any effect on the overall loading on the circuit, substation or even back flow of power onto the subtransmission or transmission systems. This is a highly variable calculation depending on the situation on each individual circuit. There are many additional concerns that require analysis on a case-by-case basis for specific applications, but general loading information can be supplied at a substation or circuit level prior to receiving specific applications.

The utilities in Massachusetts through joint collaboration with the Technical Standards Review Group (TSRG) have begun analyzing the ability and process of developing a DER Hosting Capacity for each circuit or substation. The analysis will quantify the capability of the system to integrate DER with the existing thermal ratings, protection and control system limits, and safety standards of the existing equipment.

Unitil will continue its involvement in the TSRG to develop an approach to evaluate the hosting capacity of each substation and circuit to determine how much DG could be added without the need for distribution system upgrades. Unitil is still working on the best way to present this data in a usable manner to those who are interested in the information. The results of the study will help Unitil encourage the development of DG on feeders where it can be readily accommodated. The study will also identify substations that require upgrades to accommodate more DG.

Developing the benefits for integrating DERs into the grid is a more complicated calculation than identifying the circuit capacity. The benefits include but might not be limited to the generation energy, generation capacity (distribution and transmission level capacity), reduction in losses, environmental, and other benefits. The circuit capacity study will help Unitil and DG developers to better plan for DG growth. The benefits of DER Enablement ultimately depend on how much DER is installed in the FGE service territory. No monetized benefits are assigned to DER Enablement as part of the STIP.

2. DER Analytics and Visualization Platform

DER Analytics and Visualization Platform Overview	
Description	Develop a Distributed Energy Resource Management System (DERMS) to monitor and manage/control DER across its service territory. This technology could be implemented as a module to work with a Distribution Management System (DMS), or as a stand-alone system. The technology will improve situational awareness and operational intelligence for this increasingly important resource. DERMS will be used by grid operators and engineers for efficient grid operations and planning.
Benefits	Benefits are qualitative rather than quantitative, addressing the integration and management of DER installations throughout the Unitil system. This will further the Unitil objective of being an Enabling Platform for DER, with the ability to manage high penetration of DER and support innovative energy business models for Massachusetts.
Implementation Timeline & Cost	One-time implementation in 2021 for a total cost of $650,000 with $100,000 per year for on-going licensing fees.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$0	$0	$0	$0	$650	$100	$100	$100	$100	$100
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

As the penetration density of DER continues to increase on the grid, the utility as the grid operator has less insight into the real time conditions of the system. A DERMS is a software-based solution that allows the distribution operator real-time visibility into the DERs interconnected to the grid. The most important function of a DERM is to manage a large quantity of distributed resources through a process, which is enabled by the bidirectional flow of information.

The DERMS system will provide the operator with the information and control necessary to effectively manage the technical challenges posed by a more complex grid. A DERMS can be particularly effective in areas where there is a great deal of intermittent renewable resources such as wind and solar. The DERMS system provides the utility the ability manage the impact of DER and operate the system more efficiently.

This project consists of developing a DERMS to monitor and manage DER across its service territory. This technology could be implemented as a module to work with a DMS, or as a stand-alone system. The technology will improve situational awareness and operational intelligence for this increasingly important resource. Currently, Unitil does not know when individual DERs are operating since many of these installations are net metered rather than having generation metered separately. This makes engineering analysis and planning more difficult to develop models, which accurately depict the actual conditions. DERMS will be used by grid operators and engineers for efficient grid operations and planning.

The overall benefits of a DERMS are difficult to quantify because the benefits are more qualitative rather than quantitative. A DERMS provides the tools necessary to improve Unitil's ability to deal with integrating and managing DER installations within the Unitil system. This will further Unitil's objective of being an Enabling Platform for DER, with the ability to manage high penetration of DER and support innovative energy business models for Massachusetts.

3. 3V0 Overvoltage Relays and Voltage Regulation Controls

3V0 Relays and Voltage Regulation Controls Overview	
Description	Install zero sequence voltage (3V0) relaying and voltage regulator controls at substations to alleviate voltage control and equipment damage concerns caused by reverse power flow from DER on feeders. The protection system will allow output from DER such as solar PV to flow upstream from the distribution system to the subtransmission system, without jeopardizing the reliability or health of substation equipment. The installation of this protection system will enable the

	installation of larger amounts of DG on the distribution system.
Benefits	Benefits are qualitative rather than quantitative, addressing the integration and management of DER installations throughout the Unitil system. 3V0 protection will allow reverse power flow that may result from high penetrations of PV on distribution feeders. This will prepare the Unitil distribution system for operating in a high penetration environment, reducing the need to closely study each new installation of PV, and making it possible for more PV to come onto the system more quickly and easily.
Implementation Timeline & Cost	3V0 and Voltage regulator controls will be implemented in Year 1 through Year 10 for a total combined cost of $2,520,000

Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs (000s)	$252	$252	$252	$252	$252	$252	$252	$252	$252	$252
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

As described earlier in this plan, Unitil has experienced an exponential increase in DG applications and interconnections to the system. DG penetration has grown so quickly in the past three years that portions of the Unitil system have begun to reach capacity limits.

The technical concern is one that all utilities will face at some point in time unless protection modifications are made. Since the conception of the electric transmission and distribution (T&D) grid, in the late 1800s, the electric system was designed and operated for power flow in one direction: from the transmission system, through substations, to the distribution system to supply the customers. The electric system was originally designed to accommodate one-way power flow.

Installations of generators on the distribution system must be studied to determine the impact that DG will have on the electric system. Analysis performed includes system capacity, fault current and protection analysis, as well as power flow study. High penetration of DG on distribution circuits will result in two-way power flow within the distribution network and can result in reverse power flow during times of light load. This reverse power will adversely affect the voltage control and system protection schemes at the substation. Therefore, substation control and protection systems will need to be replaced or enhanced to accommodate increased penetration of distributed generation and associated reverse power-flow.

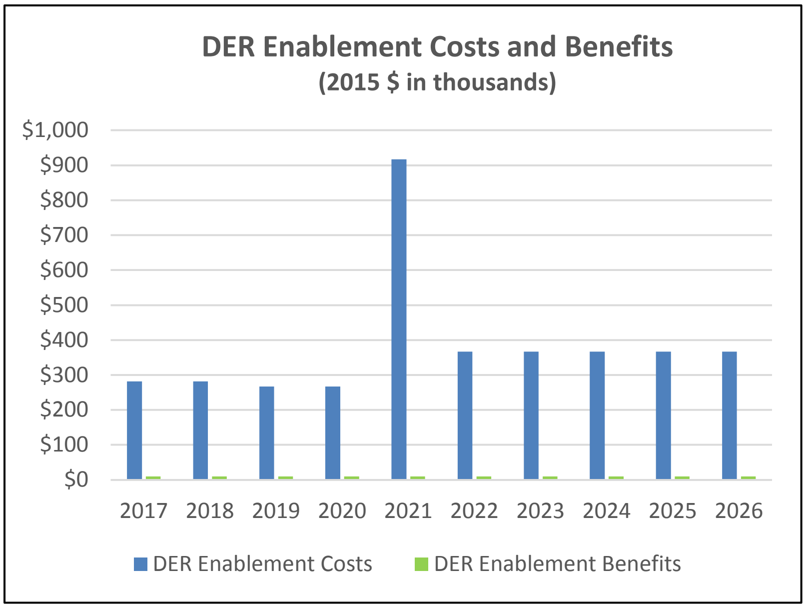
The predominance of DG installed on the Unitil system in the past three years had been solar developments and roof top systems without any type of energy storage systems (i.e. batteries, thermal or otherwise). These types of systems tend to exacerbate the backflow situation. Consider that the sun provides the most energy in the daytime hours when individuals are generally at work and their load is the lowest. In the evening hours, the sun does not provide as much power but the customer load is generally the greatest. Hence, these systems are producing power at times when load is at a low level so the output is flowing back onto the distribution system.

Currently, one of Unitil's ten substations (two circuits) has reached the point where reverse power flow at the substation is causing backflow through the substation transformer and onto the subtransmission system under light load and high generation conditions. Two other substations are quickly approaching the point where backflow is likely to occur.

This project consists of installing zero sequence voltage (3V0) relaying and protection at substations to manage reverse power flow from DER on feeders. The protection system will allow output from DER such as solar PV to flow upstream from the distribution system to the transmission system, without jeopardizing the reliability or integrity of substation equipment. The installation of this protection system will enable the installation of larger amounts of DG on the distribution system.

The benefit of this project is qualitative rather than quantitative, dealing with integrating and managing DER installations within the Unitil system. 3V0 protection will allow reverse power flow that may result from high penetration of PV on distribution feeders. This will enable the Unitil distribution system to accommodate much higher levels of PV penetration while reducing the need to closely study every new installation of PV, and making it possible for more PV to come onto the system quickly and easily.

DER Enablement Program Cost and Benefit Summary

Cost and Benefit Profile	Remarks
	• Almost $4M over ten years with a DERMS investment in Year 2021 • Early work to upgrade substation protection, develop a tariff for customer-owned DG, and to conduct a capacity study to identify the best locations for DG • Will produce the qualitative benefits of enabling high penetration of DER • This is a strategic investment that will help Unitil make the transition to becoming an Enabling Platform

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$282	$282	$267	$267	$917	$367	$367	$367	$367	$367
Benefits (000s)	$10	$10	$10	$10	$10	$10	$10	$10	$10	$10

Grid Reliability

Grid Modernization Objective

- Ensure operational efficiency and maintain strong restoration performance

Grid Reliability Projects

- Integrate Enterprise Mobile Damage Assessment Tool
- Integrate AMI with OMS

1. Integrate Enterprise Mobile Damage Assessment Tool

Integrate Enterprise Mobile Damage Assessment Tool Overview	
Description	Use mobility technology for storm damage assessment following major outage events such as ice storms, hurricanes and lightning storms. Integrate damage assessment information with the outage management system (OMS) and work order management system to improve the situational awareness and speed the restoration process.
Benefits	Unitil can make quicker, better-informed decisions regarding the extent of the damages, the level of effort needed for restoration and estimated time to restore (ETR) power to its customers. It will also help Unitil secure sufficient resources for restoration, and allow earlier release of foreign crews with more confidence to 'cut the tail off' of the restoration effort and save money. The overall effect is to reduce customer outage minutes following storms. Quantified benefits are a function of reduced outage minutes applied to the ICE Model developed by the Lawrence Berkeley National Laboratory. The ICE Model is the result of extensive study that has estimated the avoided economic losses caused by power interruption across all customer classes.
Implementation Timeline & Cost	This project will be implemented in 2017 and 2018 for a total cost of $300,000

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$150	$150	$0	$0	$0	$0	$0	$0	$0	$0
Benefits (000s)	$0	$0	$702	$702	$702	$702	$702	$702	$702	$702

2. Mobile Damage Assessment Tool

Unitil is currently developing and testing a mobile damage assessment application or "app" operated on a tablet or smartphone and used by damage assessors in the field to capture detailed distribution system damage information following a major storm event. The app will contain distribution asset information from the geographic information system (GIS) to allow specific asset attributes, such as pole size, to be gathered at each damage location. This damage information will then feed a backend system where it will be used to generate work orders for the restoration crews and a global estimated time of restoration. When each work order, is closed, manual processes are required to synchronize with the outage management system to close the appropriate outage event. Manual processes are also required to update the accounting plant records with new asset information.

This project will integrate the mobile damage assessment application with the outage management and accounting plant records systems. Each outage event number along with its predicted distribution-clearing device (e.g. line fuse, transformer, etc.) will be available to the mobile application. The damage assessor in the field will be able to verify the predicted device and make updates if necessary. This corrected information will reconcile back to the outage management system and validate the event as a confirmed outage or re-predict to the corrected clearing device, thereby improving the accuracy of the customer count and outage event details, leading to greater situational awareness and better decision making throughout the restoration process. As damage information is gathered, it will be associated with a specific outage event in the OMS, thereby providing additional information to customers and Unitil management involved in the restoration process. As work orders are created to manage the restoration work, each outage event will be associated with a specific work order. Upon completion of repair work, the work order will be closed, automatically closing the outage event in the OMS and eliminating the need for manual updates. The work order closeout will also provide all required asset information to the accounting plant records systems.

3. Further Integrate Existing AMI with OMS

Integrate AMI with OMS Overview	
Description	Improve the integration of outage information from meters into the OMS outage prediction engine, thereby improving the outage prediction process, reducing false positives and improving the ability to identify the location of nested outages.[15]
Benefits	Customers will experience shorter outages as Unitil will be able to locate outages more quickly, and improve detection of nested outages before crews leave the area. The utility benefits by reducing the time required to locate and restore outages, and reduce the number of return trips to repair nested outages. Quantified benefits are a function of reduced outage minutes applied to the ICE

[15] Often during storm events smaller outages can be "nested" inside a larger outage area – for example, a downed tree cuts service to several houses within an area affected by a feeder outage. Since most customers do not call to report power restoration, utilities have no way to verify whether service has been restored to all customers. Absent the data from a fully integrated OMS, the crew assigned to fix the large outage often leaves the area before any nested outages are detected.

	Model developed by the Lawrence Berkeley National Laboratory. The ICE Model is the result of extensive study that has estimated the avoided economic losses caused by power interruption across all customer classes.
Implementation Timeline & Cost	The integration of the AMI to OMS will cost $59,000 over the ten-year GMP, comprised of an implementation cost of $50,000 in 2017 and a recurring $1,000 per year in support fees to the vendor.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$50	$1	$1	$1	$1	$1	$1	$1	$1	$1
Benefits (000s)	$0	$117	$117	$117	$117	$117	$117	$117	$117	$117

Unitil's OMS system relies on customer outage calls processed by the IVR system, web outage form entries, and manual entries of customer and municipal calls to determine the location and extent of outages. Most outages are reported by only a small percentage of customers contributing to the outage information (typically, only 1-2% of the customers notify Unitil when they are out of power). This small percentage of customer notifications may lead to an erroneous outage location and extent, or delay the field trouble shooting process.

Unitil's AMI system is currently integrated with OMS as a "view only" overlay. The AMI system communicates with all meters through a parallel channel power line carrier (PLC) system. Essentially, the system continuously communicates with all the meters on the system while data collectors in the substations transmit meter status to the head end software system called the Command Center. Changes in meter status are shared through live integration with the OMS where they can be represented visually. Because communication with meters could be lost for reasons other than an outage (e.g., noise on power line, loss of AMI network communications), Unitil does not use this information in the algorithm for modeling outages in OMS. Instead, the visual AMI information is presented in OMS to help determine the extent of the outage (i.e. all outage meters go "lost" or red when they lose power) and the extent of restoration (i.e. all restored meters restored become "found" or green).

The Figure 9 below shows a partial restoration of an outage. The red icons indicate customers still out, the green are customers that have been restored.

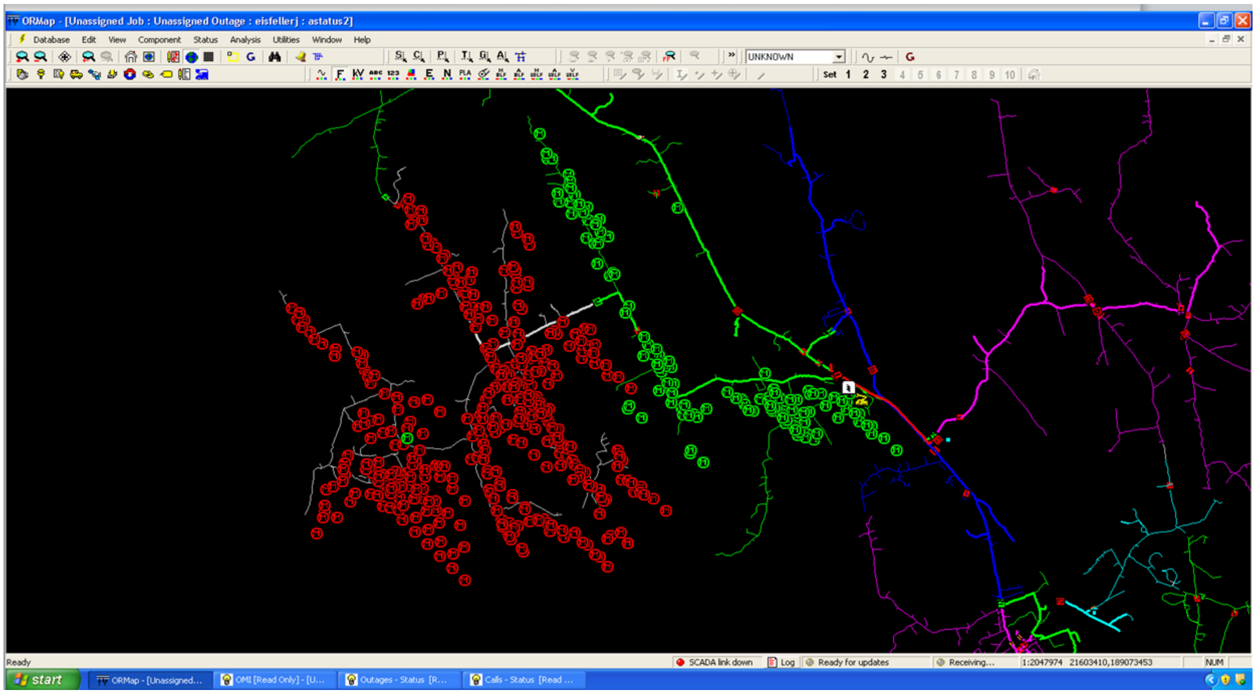
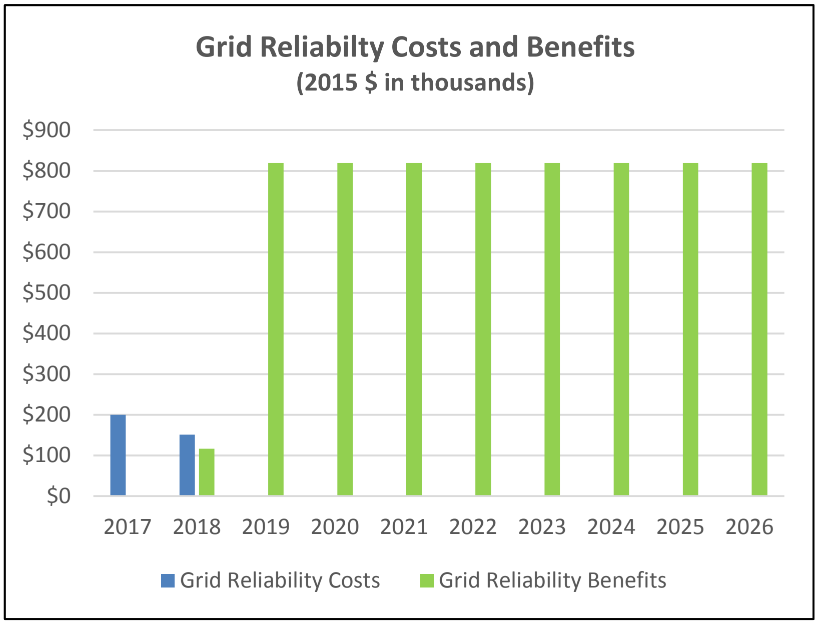


Figure 9: Unitil's AMI

This project will combine AMI status information, modem status information, and current outage input data (IVR, Web, and manual entries), and process this information through a series of software filters and logic to allow AMI information to be used in the outage algorithm. The goal will be to develop this filter to the point at which there is high confidence in the result (i.e., the AMI status change is a result of an actual outage). If a high confidence is achieved, the AMI data will allow Unitil to determine the probable location and extent of an outage in a shorter timeframe, resulting in improvements in outage response time estimates and related customer communications.

The new AMI system will be integrated to the Command Center and OMS, and can utilize this software filter if the outage notifications require filtering for accuracy. As a result, either AMI (old or new) could be "fine-tuned" to ensure a high degree of confidence in the outage prediction.

Grid Reliability Program Cost and Benefit Summary

Cost and Benefit Profile	Remarks
	• About $7M in benefits over 10 years • Integrating AMI and OMS for faster outage detection and restoration • Incorporating damage assessment information from the field into the OMS • Work Order (WO) system enable quicker, well-informed decisions regarding extent of damages & the level of effort needed for restoration • More accurate Estimated Time to Restore

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$200	$151	$1	$1	$1	$1	$1	$1	$1	$1
Benefits (000s)	$0	$117	$819	$819	$819	$819	$819	$819	$819	$819

Distribution Automation

Grid Modernization Objective

- Create the communication layer of the Enabling Platform to support advanced metering functionality and distribution automation applications. The communications network will be a multi-layer system consisting of wireless mesh and fiber optic infrastructure.
- Automate and optimize voltage and reactive power equipment to implement CVR and respond to changes in DER output.

Distribution Automation Projects

- Field Area Network (FAN)

- Substation SCADA (Supervisory Control and Data Acquisition)
- Automated Distribution Devices for VVO
    - Automated Capacitor Banks
    - Automated Voltage Regulators
    - Automated Transformer Load Tap Changers
- Advanced Distribution Management System (ADMS)

1. Field Area Network

Field Area Network Overview	
Description	Install a FAN including wireless mesh communications between collectors and endpoint devices (meters and distribution devices), and fiber backhaul communications to collectors at each substation. In the context of the modern grid, communications is the glue that makes it possible for all parties to interact and share information. The FAN will handle data traffic between distribution and grid edge devices and centralized information and operational systems. The FAN will be used by most of the modern grid systems that Unitil implements. These will include advanced metering and TVR, distribution automation and DER management.
Benefits	Communications is a foundational investment on which other investments rely to deliver benefits. No monetized benefits are assigned to communications.
Implementation Timeline & Cost	Implementation will begin in 2017 and continue each year for a cost of $280,000 per year, totaling $2.8M over the ten-year GMP.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$280	$280	$280	$280	$280	$280	$280	$280	$280	$280
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

FANs have gained a considerable amount of interest from utilities and regulators who are interested in modernizing their electric systems. A FAN is the communications network between the field end devices such as meters, reclosers, regulators, fault sensors, and any other intelligent end devices capable of gathering and recording information. The FAN takes that information and transmits the data back to the head end system such as and ADMS, OMS, Meter Data Management (MDM) or other database.

There are many different technology options for a FAN such as wireless mesh, point-to-point fiber, point-to-point POTS line, radio, and microwave, just to name a few. Unitil met with many different engineering firms and vendors to discuss and evaluate the benefits of the different communication networks. For reasons more fully explained below, Unitil has determined that a wireless mesh network offers a compelling solution for AMF as well as distribution automation (DA) and other communication needs.

In a wireless mesh network, nodes act as routers to transmit data from nearby nodes to a third node that might be too far away to reach in one hop. If one node drops out of the network due to hardware failure, the nearby nodes can be used to efficiently find another route back to the head end system. This results in a network that can span larger distances with greater redundancy and reliability. Wireless mesh networks, if designed well, provide a cost effective and flexible communications system capable of transferring the amount of data for all of the programs that Unitil is considering in its grid modernization plan such as AMF, expanded SCADA, VVO, and the communications needed to operate an ADMS.

With the implementation of the GMP, Unitil is considering a replacement of its AMI system with a system that can provide added AMF functionality, primarily interval metering. Any change-out of existing meters presents an opportunity to implement a FAN using each meter as a node in the mesh.

Wireless mesh networks will allow Unitil to deploy a communications network at the pace consistent with both the deployment of DA and AMF. Unlike other types of communications networks, mesh networks can be expanded across the system in a systematic fashion as more and more end devices are deployed. The implementation of the communications network can be accomplished over time, which aligns well with Unitil's approach to grid modernization.

This project will consist of deploying a FAN including wireless mesh communications between collectors and endpoint devices (meters and distribution devices), and fiber backhaul communications to collectors at each substation. Unitil worked with engineering consultants and communications vendors to review technical alternatives and develop an estimate for the Massachusetts service territory and came up with an estimate between $1.5 million and $2.4 million. This estimate assumes fiber connection to the substation (or collector) points, and a radio frequency (RF) network out to the field devices and meters. An additional 15% would be required for engineering, design and project management. Annual O&M costs are estimated at 3-5% for annual maintenance and 2.5% for a technology refresh.

The implementation of a FAN is an enabling technology that would provide the Company with the communications backbone to install many of the grid modernization initiatives being considered. The installation of a FAN without any of the other programs does not result in any monetizable benefits.

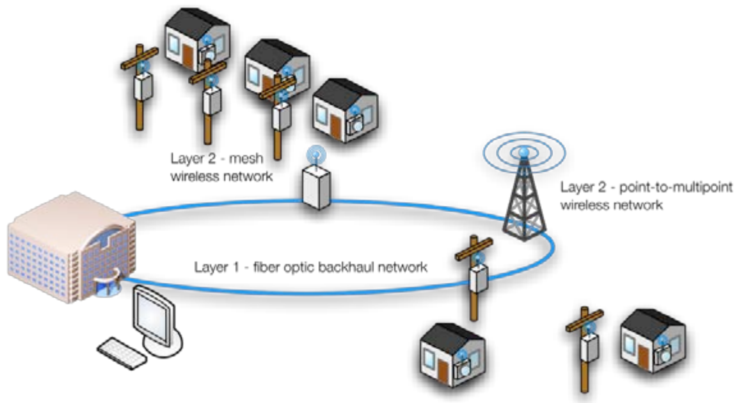


Figure 10: Multi-Layer Communication Networks

2. Substation SCADA

Substation SCADA Overview	
Description	Install SCADA communications to all substations, including communications between substations remote terminal units (RTUs) and the master system, as well as communications within the substation between the station RTU and equipment. SCADA allows grid operators to monitor and control substation equipment from a remote control center. This capability will manage the reliability and operational efficiency of an increasingly distributed grid.
Benefits	Communications is a foundational investment on which other investments rely to deliver benefits. No monetized benefits are assigned to communications.
Implementation Cost & Timeline	Implementation will begin in 2017 and continue each year for a cost of $100,000 per year, totaling $1M over the GMP.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$100	$100	$100	$100	$100	$100	$100	$100	$100	$100
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

SCADA allows grid operators to monitor and control substation equipment from a remote control center. This capability will manage the reliability and operational efficiency of an increasingly distributed grid. Historically, utilities installed very sophisticated SCADA systems to control their transmission systems and were primarily fed from transmission substations. Installing SCADA in distribution substations was considered secondary and not as important as having control of the transmission system. Grid modernization will require as much control and information on the distribution system as possible.

Unitil has one transmission substation, which has SCADA installed, while the remaining substations are distribution substations. Unitil presently has SCADA at three of its distribution substations and does not have SCADA communications to the remaining eight substations.

This project consists of installing SCADA at all of the remaining distribution substations, including communications between substations RTUs and the master system, as well as communications within the substation between the station RTU and equipment. The estimates for this project were developed from past SCADA projects completed by the company.

SCADA control of distribution substations is foundational to improving outage response, adding switching schemes, implementing DA, and achieving other important functionalities. It is assumed that SCADA can reduce the length of an outage by 10 minutes (5 minutes at the front end and 5 minutes at the end of the outage) resulting in savings of 20,000 customer-minutes of interruption per circuit level outage or 15,000 customer-minutes of interruption per month or 180,000 customer-minutes of interruption time per year.

3. Automated Distribution Devices for VVO

Automated Distribution Devices for VVO Overview	
Description	Install automated controls on voltage and reactive power equipment including capacitor banks, voltage regulators and transformer load tap changers (LTCs). The operation of these control devices can be coordinated and optimized by a central ADMS described later.
Benefits	Automated equipment will allow Unitil to more precisely control voltage on the distribution system, and do so more quickly and efficiently. The benefits from this equipment are enabled by the Communications projects described above, and the ADMS project described below.
Implementation Cost & Timeline	Implementation will begin in 2017 for the voltage regulators, load tap changers, and continue throughout the ten-year GMP. Capacitor controls will begin in 2022 and continue for the remaining five years in the GMP. Total cost in the GMP will be $9,080,000.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$ 739	$ 739	$ 739	$ 739	$ 739	$ 1,077	$ 1,077	$ 1,077	$ 1,077	$ 1,077
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Traditionally, utilities including Unitil have used local control to operate their voltage regulators, LTCs, and distribution capacitor banks. These devices incorporate inputs from locally available measurements such as voltage or current and are set to accommodate a wide range of operating conditions from peak load conditions to light load conditions. These devices act independently of other devices on a given circuit or feeder, which may result in suboptimal affects across the circuit.

The technology has improved to the point where implementing Volt/Volt-Ampere Reactive Optimization equipment and software can reduce line losses by optimizing the distribution system. Circuit optimization is affected by many different factors across the circuit such as substation bus voltage, end of line voltage, types and sizes of loads, length of feeder and type of conductors, as well as the size, quantity and type of DER located on the circuit. The ever-changing load and DER conditions make optimizing a circuit very challenging.

VVO utilizes dynamic operating model of the system in conjunction with real time information from the field and runs this information through a complex optimization algorithm to optimize the performance of the distribution system. The system model and algorithm combined with remote field measurements and control enable the circuit to be optimized based upon minimizing power loss or demand while maintaining acceptable voltage profiles on each distribution circuit. VVO operates by trying to optimize voltage regulation (voltage regulators, LTCs and reactive compensation (switched capacitor banks). Effective VVO programs have been proven to typically reduce demand by 2-4%.

There are three primary aspects to implementing a VVO program: communications, software intelligence and field equipment. A robust communications network is the foundation for a successful VVO program. The communications network described earlier in this report will be designed to support the VVO program. The software intelligence will be discussed as part of the ADMS.

Voltage regulation refers to the management of circuit level voltage in response to the varying load conditions. There are two primary devices required to control the voltage on a distribution circuit: transformer LTCs and voltage regulators. The distribution management system uses input from voltage sensors across the system to adjust the voltage regulators and LTCs up and down to provide power within an appropriate voltage limit. Capacitors are used for VAr regulation.

This project consists of enabling voltage regulating devices (regulators and LTCs) and switched capacitor banks with new controls and communications. The estimates for this project are based on an overall assumption of one LTC, three sets of voltage regulators, and three capacitor banks per circuit. The estimate assumes that the major equipment will not be replaced, only the controls. Equipment and labor estimates are estimated based upon past projects. Each of these locations will need to have the existing control changed to a control that is capable of providing some status and measurement capabilities and the ability to communicate. This project will also need to be integrated with the ADMS projects in order for a VVO program to be implemented and the benefits to be experienced. Benefits have not been directly attributed to this project.

4. Advanced Distribution Management System

Advanced Distribution Management System Overview	
Description	Implement an ADMS and integrate the system with Unitil's existing GIS, OMS, SCADA and CIS. The ADMS will support VVO; CVR; 3 phase unbalanced power flow analysis; and distribution system operations. The ADMS will also be capable of automated distribution switching and fault location, isolation, and service restoration (FLISR).
Benefits	The ADMS will enable effective CVR, reducing customer energy consumption by 2-3% or more and commensurate peak demand reductions. The benefits will accrue directly to consumers as reductions in electricity bills, and through utilities as reductions in demand charges. The ADMS will also enable better voltage control for integration of DER, and improved reliability through FLISR. The DMS will serve as a platform for more advanced modules such as a DERMS.
Implementation Cost & Timeline	Implementation will begin in 2019 and run for 3 years. Additional cost will be incurred starting post-implementation in 2022 for on-going license fees and additional Full Time Equivalent (FTE). Total cost in the GMP is $2.9M.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$0	$0	$700	$700	$700	$160	$160	$160	$160	$160
Benefits (000s)	$0	$0	$0	$548	$907	$1,339	$1,806	$2,064	$2,067	$2,069

An ADMS is the next step in the evolution of distribution management systems. An ADMS integrates a comprehensive set of monitoring, analysis, control, planning, and informational tools that work together with one common network model. An ADMS merges existing OMS, ADMS, circuit analysis, load flow, and SCADA systems together to provide all of the information to one location. An ADMS allows its users, operators, and dispatchers a real-time view of the distribution system. In order for the ADMS to provide benefits, it must be integrated with the Field Area Network, Substation SCADA and Automated Field Device projects.

An ADMS system can provide many different functions such as (but not limited to) self-healing automation, control for distributed energy resources, additional SCADA functions across the distribution system, real-time load flow and circuit analysis, demand response, outage restoration, direct load control, network configuration, and integration of outside data sources such as real-time weather and VVO. This portion of the report will only focus on the VVO functionality of an ADMS.

Unitil hosted meetings with many different vendors to review their ADMS system. The Company initially focused on the vendors that provide existing in-house systems such as OMS and SCADA, but also met with vendors that do not presently have software systems integrated at Unitil. These meetings allowed vendors to demonstrate the functionality of their systems while also obtaining information about Unitil's distribution system and the software systems already in use.

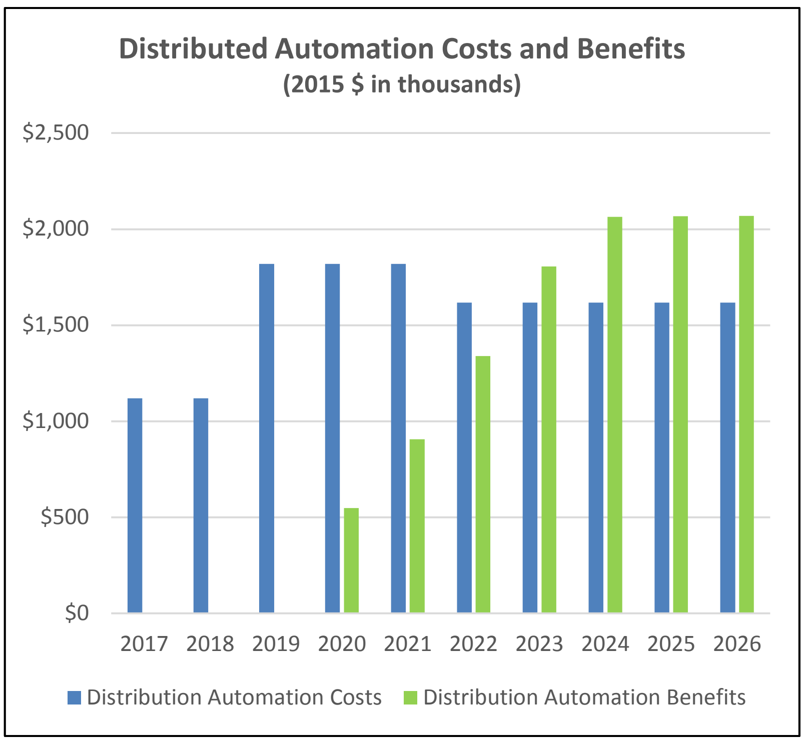
The following functionalities are considered as part of this ADMS integration:

- GIS editor to transfer the network model from the GIS system to the ADMS system on a routine basis as changes to the network topology are made in GIS
- Verification of network connectivity
- Integration with existing OMS and SCADA systems
- Switching manager and simulation module
- Volt/VAr Optimization
- Crew assignments
- Engineering based load flow and circuit analysis tools
- Hardware, software, and training

Each of the vendors was asked to provide a budgetary estimate for implementing an ADMS for Unitil. In addition to the costs assumed for the software purchase, an additional amount was added for internal integration with other systems and an additional staff member who would focus on operating the ADMS.

The benefits for implementing a VVO are a direct result of reducing demand and losses. As described earlier in the document, the Unitil system has been experiencing demand reduction over the past 10 years, so the benefits associated with implementing a VVO are primarily estimated to be energy savings to the customer and capacity savings to the transmission system. As described above, VVO programs generally result in 2-4% in demand reduction. Based upon the Company's circuits, Unitil estimates that the program will result in a 2% reduction in demand, which is estimated to reduce energy consumption by 2%. These benefits are assumed to be linear with the implementation of the program. For instance, this current plan is for a 10-year VVO implementation. Therefore, the benefits in year one are assumed to be 1/10 of the expected savings, year 2 would experience 2/10 of the expected savings and so on until year 10 when 100% of the savings will be experienced each year.

Distribution Automation Program Cost and Benefit Summary

Cost and Benefit Summary	Remarks
	• Almost $16M costs in ten years with the significant investment in first five years • Voltage and VAr optimization capability to implement CVR for energy efficiency and manage high penetration of DER on feeders • Produces dramatic benefits (almost $11M) from lowering customer energy consumption with CVR, and could also reduce system capacity requirements • Includes a foundational investment in communications • Includes the hire of two new technical resources

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$1,119	$1,119	$1,819	$1,819	$1,819	$1,617	$1,617	$1,617	$1,617	$1,617

Benefits (000s)	$0	$0	$0	$548	$907	$1,339	$1,806	$2,064	$2,067	$2,069

Customer Empowerment

Grid Modernization Objective

- Put information and tools in the hands of customers to help them make good energy choices.

Customer Empowerment Projects

- Energy Information Web Portal
- Gamification Pilot
- TVR Program

1. Energy Information Web Portal

Energy Information Web Portal Overview	
Description	Provide customers a web portal and mobile application for access to key energy and account management information and tools.
Benefits	Offering expanded customer self-service tools will allow Unitil to better manage a growing customer base. Expanded communication options, energy management tools, and account management tools will improve the customer experience and overall customer satisfaction. Highly satisfied customers place fewer calls to their utility than dissatisfied customers, and tend to manage their accounts and statements on a current basis. More satisfied customers are also more receptive to educational and engagement campaigns, making it more likely that future energy programs will achieve their intended results. Quantified benefits are based on projected savings from reduced call volume and average duration of calls.
Implementation Timeline & Cost	This project will cost $440,000 over ten years, with the initial software implementation in 2019 through 2021 for $250,000 and then annual recurring software maintenance fees of $38,000 totaling $190,000 from 2022 to 2026.

Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs (000s)	$0	$0	$100	$100	$50	$38	$38	$38	$38	$38

Benefits (000s)	$0	$0	$0	$0	$20	$20	$21	$21	$22	$22

This project will build on the existing Customer Information System (CIS) to include a web portal for customers to access their electric usage information to make better decisions about their energy consumption. Customers will need to register for this service in order for them to access their energy usage information and other services. This includes daily energy usage and comparison information, analytical tools, bill payment options, and outage information. The system will provide information to encourage saving energy, shifting demand, and reducing electricity bills. Future web portal application releases may introduce additional features and functionality over time.

The mobile application aspect of this project will enable customers to utilize their smartphones to access billing information, pay bills, and report power outages. An app will be developed and made available for download.

2. Gamification

Gamification Pilot Overview										
Description	Gamification is the use of game thinking in non-game contexts to engage users in solving problems and increase users' contributions. In the context of Grid Modernization, a gamification pilot will engage customers in a new, novel way to interact with their utility; help customers realize energy and bill savings; improve customer satisfaction; learn and better understand the efficacy of gamification as a new channel for customer engagement; and learn more about what channels customers prefer.									
Benefits	The gamification pilot will encourage changes in customer behavior (shifting or curbing energy usage), increasing the effect of energy programs such as TVR. Based on industry reports for customers participating in this type of program, customers participating in the gamification pilot have reduced energy consumption by up to 5%.									
Implementation Timeline & Cost	This project will be implemented beginning in 2020 of the GMP for a total cost of $350,000, with $250,000 for the initial implementation in 2020 through 2022, and then $25,000 annual software maintenance fees from 2023 through 2026.									
Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Costs (000s)	$0	$0	$0	$50	$100	$100	$25	$25	$25	$25

Benefits (000s)	$0	$0	$0	$0	$0	$0	$81	$81	$81	$81

Unitil's intent with gamification is to make a game of cutting usage by encouraging customers to participate in energy-saving challenges and generate a friendly sense of competition. Working with a vendor (yet to be determined) Unitil will use customer data and analytics to create things like home energy reports that show how much energy customers use, compare their usage with that of neighbors, and offer tips for reducing consumption and costs. It has not been determined yet if Unitil will offer any other tangible rewards for customer participation or "winning the game". The primary purpose is to improve user engagement, validate the quality and flow of customer data, timeliness of information being provided, the perceived entertainment value, measurement of any behavioral changes in energy usage, and to improve the perceived ease of use of information systems.

3. **TVR and AMF Program**

TVR and AMF Program	
Description	The TVR initiative involves an optional TOU service with a CPP rate. The optional TOU service will include on peak, off-peak and critical peak components calculated from wholesale energy and demand costs. Delivery rate components will not change. This service requires advanced metering capability. Using ISO New England SMD hourly data for 2012 to 2014, critical peak, peak and off peak periods were defined, and rates were calculated that reflect (a) average hourly cost per kWh, by period, and (b) ICAP costs allocated to costing periods according to Unitil-specific load shapes. The calculated On-Peak to Off-Peak ratio

is 3.28 and the Critical Peak to Off Peak ratio is 7.67[16]. These rates are designed to be revenue neutral, on average, for Small Basic Service and Medium Basic Service customers, assuming no more than 12 Critical Peak Day events annually. Notifications for peak reductions will be via automated phone messaging, email, text/SMS messaging, and/or other social media programs on a day ahead basis. Customers will have access to current day and historical usage through the customer portal to monitor usage.

This project will require an upgrade to the existing AMI system in order to perform the CPP metering. Meter installations will only be necessary for customers that opt-in to the TVR program, though. Customers opting into the optional TVR service will pay for the meter upgrade upon enrolling in program. The extent of integration of the new AMI with the Meter Data Management System and Customer Information System will vary depending on the AMF vendor and system selected. Rollout of the program (primarily meter installations) will begin in Year 4 and finish in Year 8 to follow the communications installation associated with the VVO and DA efforts. Base AMF capabilities will be available by Year 4 to precede the meter deployments.

The rates will vary with market prices but the pricing ratios are expected to remain constant. Ultimately, a statewide TVR program can be expected to reduce market capacity and energy prices over time and have a corresponding reduction in emissions. Residential customers that participate in the optional TVR program can shift loads in response to the TVR price signals by changes to equipment or lifestyle. For example, residential customers could install programmable thermostats that reduce critical peak and peak period electric usage from air conditioning and electric heating. In addition, these customers can shift load by washing and drying clothes and washing dishes during off peak periods. Commercial customers that participate in the optional TVR program could, for example install energy storage technologies such as ice storage or batteries to shift load to off peak periods. Commercial customers can also install

[16] The calculated rates are:

	$ / kWh
Off Peak	$0.05554
On Peak	$0.18231
Critical Peak	$0.42639

	programmable thermostats and energy management systems to reduce electric usage from air conditioning and electric heating. Lastly, these customers can also participate in the energy efficiency programs to reduce load around the clock with technologies such as LEDs and lighting controls.
Benefits	Benefits to participating customers include lower energy bills. Benefits to society include lower peak and critical peak energy usage - forestalling the construction of more fossil fuel or nuclear power plants. Over time, the impact is expected to reduce overall market rates for all customers. Unitil may also realize a lower peak and critical peak capacity level, which could push out investments in equipment. With FGE's reducing load, this is not expected to happen in the near future. Installation of AMF enables improvements in outage monitoring and circuit monitoring. To achieve savings resulting from this improved capability, other systems upgrades or additions may be necessary (such as ADMS or OMS integration). These additional savings are included elsewhere.
Implementation Cost & Timeline	Implementation of the TVR will begin in 2020 and continue each year through the ten-year GMP for a total cost of $2,135,000.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$0	$0	$0	$767	$317	$317	$317	$317	$50	$50
Benefits (000s)	$0	$0	$0	$0	$44	$93	$147	$202	$250	$258

TVR Model

The Department required each company to include in their business case analyses the implementation of the time varying rates framework established in D.P.U. 14-04-C. At a minimum, such analyses must include an estimate of the benefits and costs associated with customer peak load response to time varying rates. As discussed previously and further below, Unitil must upgrade its AMI to provide TVR functionality. Due to the investment cost associated with this required upgrade, Unitil considered opt-in to be the more practical, cost effective approach.

The DPU also recommended the utilities collaborate on their approach to TVR. In order to develop a common basis for the TVR analysis the distribution companies commissioned two studies: An energy and capacity study and a time varying rate study:

Tabors Caramanis Rudkevich (TCR) was hired to provide forecasts of wholesale electric energy and capacity market prices, renewable portfolio standard ("RPS") compliance costs and demand reduction induced price effects ("DRIPE") for capacity and energy. The objective of this report was to project electric market prices through the timeline of the BCA. TCR developed these forecasts using the same methodologies it used to prepare the 2015 Avoided-Energy-Supply-Component Study ("AESC 2015"). TCR's report is provided as Appendix F.

Concentric Energy Advisors ("Concentric") was retained to conduct primary research on the load impacts, customer participation rates and a variety of program design parameters for selected TVR programs offered throughout the United States in recent years. The distribution companies selected seventeen TVR programs for Concentric to research, and collect program data that could be used in the development of a TVR program. The variety of TVR alternatives and conditions observed in the selected programs provided a range of results and were used to inform the Grid Modernization Business Case. Concentric's report, "Time-Varying Rates: Industry Experience" is attached as Appendix G.

Concentric was retained separately by Bridge Energy Group to offer advice to Unitil on the development of a TVR program and to perform the analysis for the TVR model development and benefit analysis.

The timing of the TVR program follows the availability of AMF and upgrades to systems needing enhancements to offer TVR (specifically the CIS), testing of new meters in the field and data flows from our metering systems through the MDM and CIS. Unitil modeled three separate TVR programs: a mandatory TOU rate with CPP; an Opt-out rate with Peak-Time Rebate (PTR); and an Opt-in TOU rate with CPP. All programs were designed to be revenue neutral, encourage customer response, and provide customer and system benefits through demand reduction. For declaration of peak days, Unitil proposes to follow a process similar to that used in the **Smart Grid Pilot Program, "Energy Savings Management Pilot"**[17] and use day-ahead weather forecasting to announce a critical peak event.

TOU Pricing

TOU Pricing ratios are based on first selecting the hours of peak demand, then determining peak to off peak price ratios based on this division of hours, and finally using these ratios in conjunction with FGE Basic Service rates to determine price structures for each program.

[17] Report filed in January 2012 under Docket DPU 09-31.

In order to select the hours of peak demand, Unitil selected the top five ISO-NE peak days per year over a three-year period (2012-2014) and developed an average load profile for these five days for each year. As presented in the following table, this load profile was inspected for peak hours exceeding 90%, 95%, and 97% of peak to determine the number of hours above these load levels.

Year	% Load	Peak Period Hours ending	Total Peak Hours in Peak Period
2012	90%	11-20	10
2012	95%	12-18	7
2012	97%	13-17	5
2013	90%	11-21	11
2013	95%	12-20	9
2013	97%	13-18	6
2014	90%	12-20	9
2014	95%	13-18	6
2014	97%	14-18	5

Table 3: Load Profiles

Based on this analysis, Unitil selected a 10 hour TOU period for on-peak consideration (hours 11-20) based on a 90% threshold for the peak period and a 6 hour CPP period (hours 13-18) based on a 97% threshold for the peak period. The table 4 with corresponding graph below further illustrate the critical peak load periods relative to the average load profile for 2013. This same analysis was done for all three years for the peak and critical peak periods and produced similar results.

The next consideration was to determine a load level that resulted in a reasonable number of critical peak days that encompassed these peak periods where costs were highest. The Concentric TVR Study was relied upon to determine a reasonable quantity of events. It was determined that it would be reasonable to set the threshold load / temperature for a critical peak event so that on average, a critical event day would occur 12 or fewer times per year. These load levels along with the hours for each period were combined with Unitil Small and Medium Basic Service load data to determine the price ratios for the off peak, on-peak and critical peak periods.

2013 Average Load Profile		
Hour	Load	% Load
1	17,000	65.0%
2	16,027	61.3%
3	15,395	58.8%
4	15,046	57.5%
5	15,095	57.7%
6	15,659	59.9%
7	17,238	65.9%
8	19,364	74.0%
9	21,119	80.7%
10	22,604	86.4%
11	23,951	91.5%
12	24,906	95.2%
13	25,500	97.5%
14	25,949	99.2%
15	26,098	99.8%
16	26,163	100.0%
17	26,162	100.0%
18	25,934	99.1%
19	25,310	96.7%
20	24,529	93.8%
21	24,141	92.3%
22	23,236	88.8%
23	21,222	81.1%
24	19,162	73.2%

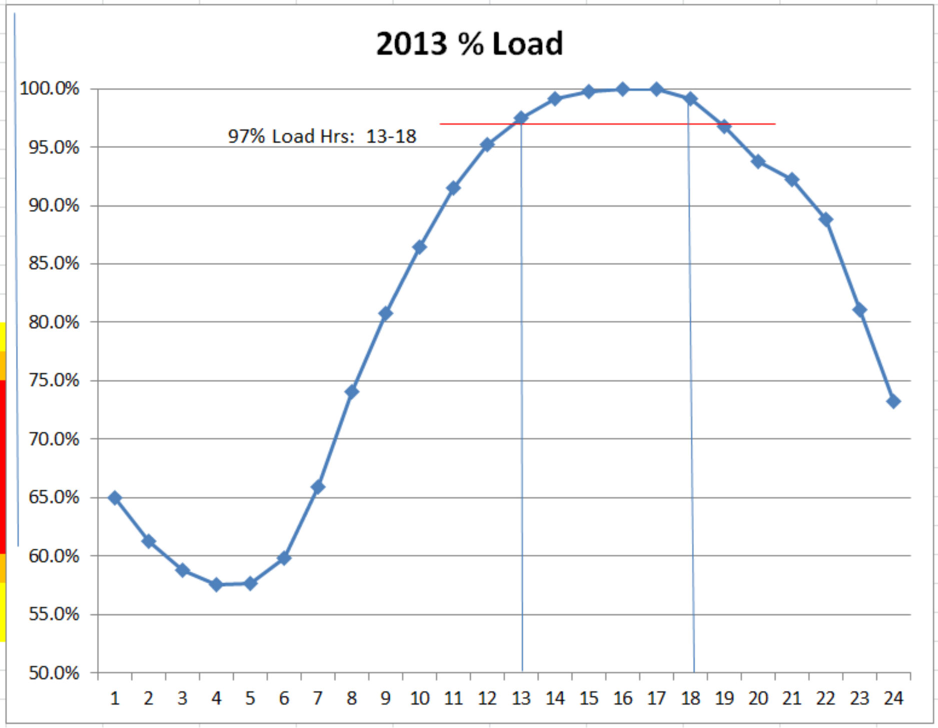


Table 4: Average Load Profiles

Model Parameters

The TVR savings model calculated savings attributable to capacity only. DRIPE-related savings were not included in the analysis, as project benefits were not expected prior to 2018, the time period when DRIPE impacts were more consequential. Capacity costs were based on values provided in the TCR study for the WCMA zone for "new" capacity. An adjustment factor was applied to convert the values to nominal dollars and adjust the FCA clearing price (the price generation is paid) to the price that load will pay. This adjusted price of capacity was used to determine savings based on customer response to prices and annual reduction in demand as a result. Customer growth was projected based on recent corporate forecasts (0.27% for Small BS and 0% for Medium BS). Capacity forecasts used the TCR study values as basis with adjustments described above.

The rates were analyzed for two separate deployment scenarios: one option where Unitil offers the Mandatory TOU/CPP rate offered to all customers and the Opt-out PTR rate for those who opt-out of the mandatory rate; and a second option where Unitil offers standard rates (existing) and offer customers an opt-in TOU/CPP rate. The models included Small and Medium Basic Service customers only.

Therefore, Large Basic Service customers and customers currently taking third party supply were not modeled as participants. Customers choosing to opt-out of the Mandatory Program were modeled taking service under the PTR option. Customers' peak loads were based on the average maximum hourly demand for both customer classes. Customers in the Opt-In Program were assumed to have a higher peak load than the average. A 50% load adder was applied to the opt-in analysis to reflect the expectation that larger customers are more likely to be opt-in candidates due to their higher potential for savings. This assumption was supported by data gathered in Unitil's Smart Grid Pilot Program, which indicated average loads of opt-in participants far exceeding the average customer loads.

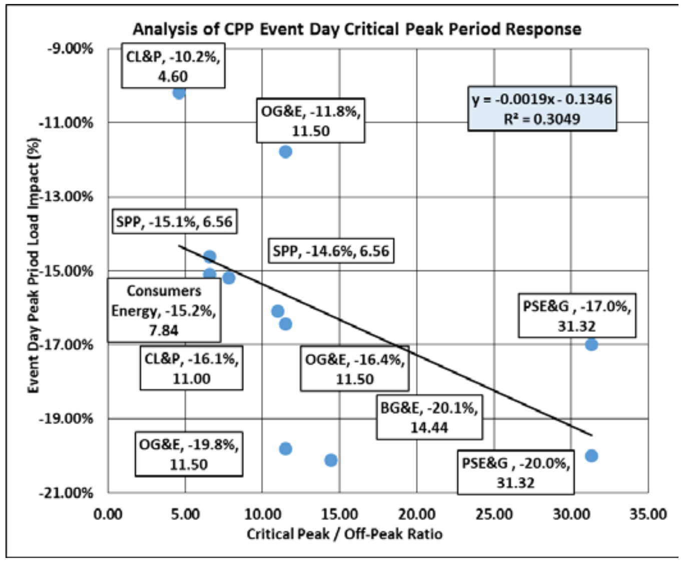


Figure 12 : Opt-in Response Curve

Analysis of CPP Event Day Critical Peak Period Response		
Regression Equation		
Constant		-0.1346
Critical Peak/Off-Peak Ratio Coefficient		-0.0019
Calculated Event Day Peak Hour Load Impacts		
Critical Peak/Off-Peak Ratio		**Event Day Peak Hours Load Impact (%)**
CPP Event Day Critical Peak / Off-Peak Price Ratios	5.00	-14.41%
	10.00	-15.37%
	15.00	-16.32%
	20.00	-17.28%
	25.00	-18.24%
	30.00	-19.19%
	35.00	-20.15%
Average Sample Critical Peak / Off-Peak Price Ratio (11 observations)	**13.47**	**-16.03%**
Critical Peak/Off-Peak Ratio	7.68	-14.92%

Figure 11: Response to CPP Pricing

Customer response to pricing was modeled specifically for the two programs and two customer classes using data from the Concentric TVR study and follow on analysis that provided price response curves that were developed from regression analysis of appropriate TVR pilot program data. The residential opt-in response curves were used to determine Unitil Small and Medium Basic Service customer response. Since there was insufficient TVR pilot program data customers, the residential opt-in response curve, with a 50% reduction, was used to model their response[18]. The opt-in response curve is shown in Figure 11 and the

[18] The pilot program data suggests that commercial customers are less responsive to TVR price signals than Residential customers.

regression equation is shown in Figure 12 above indicate the relationship between response to CPP pricing and the price ratios.

Other model parameters such as customer persistence, opt-out due to AMF technology are shown below in table 5 along with a summary of other information requested in the Orders.

Results of TVR Modeling

Both TVR options investigated by Unitil resulted in B/C ratios less than one (see BCA section below for details on long term benefits and several additional TVR modeling scenarios). Unitil's analysis reveals that AMF investments have very poor net benefits if deployed for all customers. Unitil has already captured most of the traditional benefits of an AMI system with the deployment of the AMI system in 2008. As a practical means to offer TVR pricing to customers, the company is proposing a project within the STIP that will provide TVR and in tandem AMF capability to customers on an opt-in basis.

The Department required each company to include in their business case analyses the implementation of the time varying rates framework established in D.P.U. 14-04-C. At a minimum, such analyses must include an estimate of the benefits and costs associated with customer peak load response to time varying rates. A number of key variables will affect the impact and, therefore, the benefits of the time varying rate framework. The variables analyzed and the resulting impacts of time varying rates are further summarized in Table 5 below.

Mandated Variable Analysis	Analysis Approach	Impact
Customer peak load reduction in response to time varying rates	Unitil modeled two options: a mandatory TOU rate with CPP; an Opt-out rate with PTR and an Opt-In TOU rate with CPP. All rates were specifically for Small and Medium Basic Service customers.	Option 1 Gross Benefit: $3,311,000 over ten-year GMP period with investment of $11,732,000. Option 2 Gross Benefit: $993,000 over ten-year GMP period with investment of $2,135,000.
Percentage of customers that opt-out of advanced metering functionality technology (e.g., advanced meters)	Unitil assumed a 0% Opt-out rate. Studies indicate Opt-out AMF rates are in the range of 0-1%. Unitil is proposing an Opt-in TOU that will require AMF technology.	Not applicable. Opt-in to TVR rate understanding that AMF is requirement.

Mandated Variable Analysis	Analysis Approach	Impact
Percentage of customers that opt-out of the default basic service rate offering and receive service under a flat rate with a PTR component	Leveraged Concentric TVR study, which indicates, opt-out rates ranged from 10-25%.	Assumed a 20% Opt-out rate.
Persistence over time of the level of customer response	Leveraged Concentric TVR study, which indicates TOU/CPP programs see, impacts ranging from +3% to -42%.	Study results are inconclusive. Assume no change in customer response.
Percentage of customers served by competitive suppliers who opt to receive flat rate service	These customers were assumed to stay on competitive supply.	Used current basic service customers for analysis.
Low end of customer response rate	Leverage Concentric TVR study. Used average customer response	Option 1 Gross Benefit: $2,510,000 over ten-year GMP period with investment of $11,732,000. Option 2 Gross Benefit: $753,000 over ten-year GMP period with investment of $2,135,000.
High end of customer response	Leverage Concentric TVR study. Used average customer response	Option 1 Gross Benefit: $4,111,000 over ten-year GMP period with investment of $11,732,000. Option 2 Gross Benefit: $1,233,000 over ten-year GMP period with investment of $2,135,000.
All distribution customers are subject to a time of use rate with a critical peak pricing component	Modeled mandatory TOU with CPP and Opt-in TOU with CPP rates.	Recommend Opt-in TOU with CPP rate.

Table 5: TVR Impacts

Advanced Metering System (AMF Functionality and Enablement of TVR)
In order to provide hourly interval data, Unitil must upgrade its existing AMI to full AMF. This data is also used to determine the CPP or PTR usage because of a triggered critical peak event. The AMI upgrade costs for an opt-In TVR program are included in the TVR project BCA.

Existing Capabilities and Limitations
Unitil currently obtains customer energy usage data through deployment of a PLC based AMI. FGE's system consists of dual endpoints, which provide the ability to read meters daily for both the electric meter and up to two coupled gas meters. This system facilitates a flow of data between the Command Center application server and the TS2 endpoints transceivers installed in electric meters. Each endpoint has its own unique frequency allowing every endpoint to transmit or receive continuously. Data received are posted and stored in an open architecture environment and can be easily integrated and analyzed permitting data to be distributed throughout the organization.

The Command Center provides data necessary for billing and is also the user interface for managing the AMI system. The Command Center Dashboard is a configurable web interface to assist in daily administration of the system. Although there is capability for load control and disconnection, Unitil has not utilized these functions.

The AMI system is integrated with a variety of other operational systems:

- OMS, allowing a near-time push of endpoint outage detection status;
- CIS, daily push of meter changes, customer data, and location;
- GIS, daily push of electrical distribution network topology providing real time view of AMI status changes; and
- MV90/MVRS.

The system utilizes a combination of wired and wireless communication to transmit data to and from Command Center and field equipment, including collectors and transmitters. Network security has been enhanced to move the wireless routers to a Verizon Wireless private network infrastructure. The Verizon environment provides a secure and encrypted communications path from the substation to the Hampton facility. AMI substation communication is segmented from the corporate network via firewall interface. An Intruder Prevention System (IPS) feature on the firewall monitors each interface.

AMF Considerations

The Grid Modernization Order defines advanced metering functionality as:

(1) The collection of customers' interval usage data, in near real time, usable for settlement in the ISO-NE energy and ancillary services markets;

(2) Automated outage and restoration notification;
(3) Two-way communication between customers and the electric distribution company; and
(4) With customer's permission, communication with and control of appliances.

Unitil's existing AMI system is capable of items 2 through 4 and additional capabilities such as remote disconnect power quality monitoring, outage history, and voltage data. In locations where Unitil has advanced interval metering, the AMI endpoint can bring back single-phase voltage and current, as well as harmonics data. With upgrades to the collectors, the system can provide the first AMF functional requirement (interval data on an hourly basis), but would be limited to providing this data to only a few thousand endpoints per collector. This inexpensive upgrade to full AMF capability is unable to provide full AMF functionality to every meter, and so was not considered a viable option.

Unitil evaluated a number of other AMF options to achieve the full functionality requested in the Grid Modernization Order including other power line carrier communication options; several mesh radio frequency options and a cellular option.

All of the options considered would require replacement of the existing meter infrastructure (communications hardware, meter and endpoint). One vendor option would leverage the existing head end system, which would substantially reduce integration, and incremental software costs. The table below highlights the functional differences among these systems.

	AMF Options				
Function	**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
Communication	2-way	2-way	2-way	2-way	2-way
Utility-owned communication network	YES	YES	YES	YES	NO
Operational lease costs	NONE	NONE	NONE	NONE	Data Services, monthly
Network availability	Always on	Always on	Always on	Always on	Always on
Near real-time view to available power	YES	YES	YES	YES	YES
Data traffic	Load control messages have higher priority	Load control messages have higher priority	Load control messages have higher priority	Load control messages have higher priority	Data traffic always lower priority

Function	Option 1	Option 2	Option 3	Option 4	Option 5
Bandwidth	20 Baud, multi-channel (44,000 channels)	20+ Baud, multi-channel (100,000+ channels)	Max 300 kb/s (900 MHz)	Max 300 kb/s (900 MHz)	>1Mb/s (4G-LTE)
Typical command travel time	5-25 seconds	5-25 seconds	1-5 seconds	1-5 seconds	Depends on network (2G/3G/4G typically 5-20 seconds)
Data security/privacy	YES, end-to-end	YES, end-to-end	YES, end-to-end	YES, end-to-end	YES, cellular data is encrypted
Message broadcast	YES	YES	YES	YES	NO
Message prioritization for load mgt	YES	YES	YES	YES	NO
Limits on deployment	4,400 endpoints with interval data	NONE	NONE	NONE	NONE
Interval capability	60 min, streaming	15 minute, with storage	5 or 15 minute, with storage	5 or 15 minute, with storage	15/30/60 minute with storage
Gas meter read upgrade needed	NO	YES	YES	YES	YES
ZigBee capabilities	YES	NO	YES	YES	YES
Voltage data	YES, meter dependent	YES	YES	YES	YES

Table 6: AMF Options

As shown in Table 6, the various technologies offer similar capabilities. Option 1 is an upgrade of the existing system to the collectors, is capable of AMF, but can only offer that capability on a limited deployment basis. Option 2 is a power line carrier option, capable of providing interval and other operational data in near real, but is still awaiting ZigBee in-home wireless functionality. It should be noted this PLC system is also backwards compatible with existing endpoint technology, which would provide a seamless transitional option.

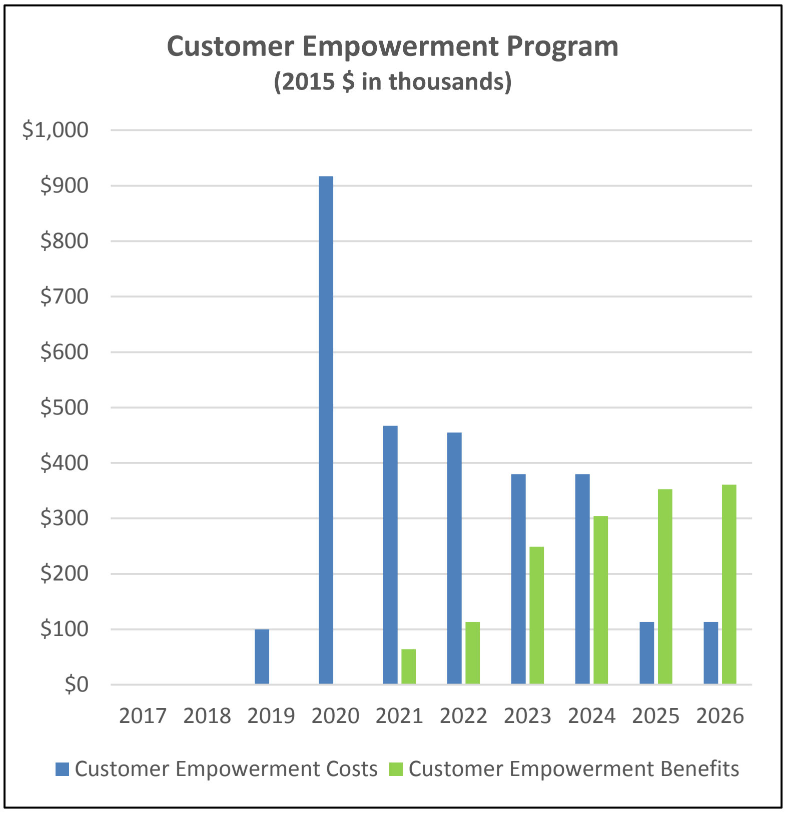
Pricing and interoperability were explored further for the four primary options that offered full functionality. The radio frequency (RF) solutions offered additional interval metering capability, namely five-minute interval data, but this difference was not valued as the ISO-NE requirements for interval data are hourly. Since all four of these options were incapable of reading the Company's existing gas meters without replacement, the cost of a mobile reading solution for gas meters that would allow a drive by read for billing purposes was included in all options. Additional integration costs were added to systems that did not utilize the Command Center as a gateway to other systems. Estimates for these systems ranged from $1.5M to $3.0M for a deployment on an opt-in TVR, assuming replacement of 10% of the meters. The Mesh RF options offered the lowest price options, ranging from $1.5M to $2.0M.

These estimates do not include the annual fees associated with additional software licensing or support. These ongoing costs further increase the cost differential of the new systems, which cannot use the Command Center software, which is already being utilized for meter reading in Unitil's other operating centers and is fully integrated with the Company's OMS, CIS and mobile data systems.

The RF system has the lowest installed cost and complements the ADMS and VVO projects since it utilizes and augments the FAN communications system. If the deployment of the AMI upgrade is coordinated with these other projects, it also lowers the cost of the communication infrastructure deployed for AMI because of the shared functionality. A sequenced mesh FAN deployment indicated a reduction of $170,000, making it an even more attractive option.

Customer Empowerment Program Cost and Benefit Summary

Cost and Benefit Summary	Remarks



- Almost $3M in costs over ten years with the significant investment starting in 2020
- The large costs of opt-in TVR metering starting n 2020 are borne by the opt-in customers– they will not be added to rate base
- Energy information and education for customers through the Customer Education and Outreach effort will help customers manage usage and bills
- Opt-in AMI program starting in 2020 will allow incremental spending on smart meter replacements
- Drives monetizeable customer benefits in the form of reduced costs

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$0	$0	$100	$917	$467	$455	$380	$380	$113	$113
Benefits (000s)	$0	$0	$0	$0	$64	$113	$249	$304	$353	$361

Workforce and Asset Management

Grid Modernization Objective

- Ensure operational efficiency and maintain strong restoration performance.

Workforce and Asset Management Projects

- Mobility Platform for Restoration Workforce

Mobility Platform for Restoration Workforce Overview	
Description	Expand Unitil's existing workforce mobility tool to FGE restoration field crews. This will enable faster and more efficient assignment of electronic trouble tickets. Electronic data capture and reporting by field crews will increase data accuracy and reduce the time required to communicate information from the field to restoration managers. The ability of the crews to provide or update estimated restoration times will give Unitil and its customer's information faster and more accurately, thereby enabling better decision-making around the restoration effort.
Benefits	Benefits of the improved dispatch and field reporting capabilities are estimated to improve crew productivity on restoration by 15-minutes, saving $42,485 per year. Customers will also see benefits in terms of improved information flows and reduced outage times, estimated at $644,000 per year (savings based upon ICE Model). Total benefits estimated to be $686,000 per year.
Implementation Timeline & Cost	This will be implemented in Year 1 at a cost of $217,000.

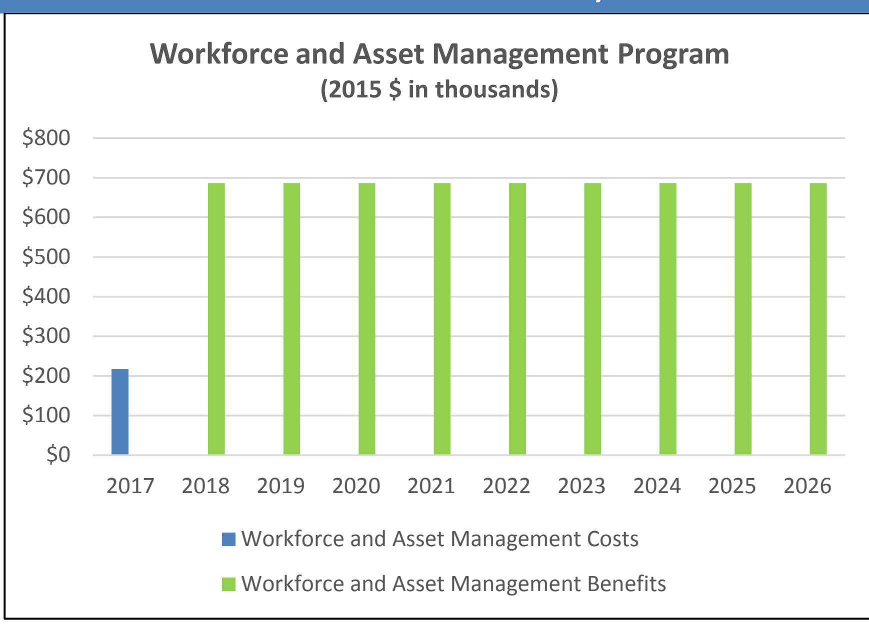
Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$217									
Benefits (000s)		$686	$686	$686	$686	$686	$686	$686	$686	$686

Mobility Platform for Restoration Workforce

Unitil currently utilizes mobility across the gas operations but uses radio or cell phone communications to manage work with the electric field crews and record critical outage event information. This project entails expanding the use of "computers in the truck" to the workforce normally involved with power restoration to improve communication and efficiency between the grid operator and the restoration crews. The functional requirements for this mobility platform include but are not limited to:

- Electronically receiving work orders in the field from the OMS;
- Presenting all fields in OMS outage event on the mobile screen, e.g. predicted device out, location of device, name of device, feeder number, number of customers, event start time, etc.;
- Reporting crew status, e.g. Enroute, On Site & Complete, back to OMS;
- Updating the ETR;
- Reporting time of completion of work order;
- Capturing data required by OMS to close event and transmit to OMS;
- Referring (return) work order back to dispatch for re-dispatch or follow up work to be performed;
- Accepting electronic timesheets to capture labor and equipment charges, and auto-route for approval and input to other enterprise systems for processing;
- Sorting orders, rearranging column headers, hiding columns, etc.;
- Automatically reestablish communication connection and transmit any pending information;
- Logging crew and equipment IDs to events; and
- Capturing and retaining field crew comments with completed or referred work orders.

Workforce and Asset Management Program Cost and Benefit Summary

<table>
<tr><th>Cost and Benefit Summary</th><th>Remarks</th></tr>
<tr><td>
</td><td>Extension of the existing field workforce mobility to restoration field crews
Improved dispatch capabilities to more efficiently dispatch restoration orders to field crews electronically
Improvements in data capture and reporting
Ability for crews to provide updated restoration times for more accurate ETR’s</td></tr>
</table>

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$217	$0	$0	$0	$0	$0	$0	$0	$0	$0
Benefits (000s)	$0	$686	$686	$686	$686	$686	$686	$686	$686	$686

2.4.4 IMPLEMENTATION ROADMAP

Unitil's project implementation is designed to follow a logical sequence based on implementing foundational projects first along with other projects that achieve results and benefits quickly. The Grid Reliability and Mobile Platform projects were selected for early implementation because they are relatively low cost and produce the highest benefit/cost ratio of all the programs. Likewise, the Circuit Capacity Study project is an annual study that can be completed with existing staff and provides information that customers and DG vendors can access quickly on the Unitil website. Foundational projects such as the FAN or field automation also start early.

Figure 13 below shows the start year and duration for each of the STIP projects discussed above in section 2.4.3, with the addition of the Customer Education and Outreach program. It should be noted that the timelines shown are only for the implementation of the core product, software or technology, and do not show all the expenditures that may follow the initial implementation of each STIP project. For example, in the Gamification project the core implementation will occur from 2020 to 2022. This is shown on the implementation schedule below. However, the cost for Gamification extends beyond 2022 to cover on-going software licensing cost. This is not reflected in the implementation schedule. Similarly, the ADMS project is a 3-year implementation from 2019 to 2021, which is shown in the implementation schedule, but the cost continue beyond 2021 as well for annual software licensing and additional FTE resources to support the system. A summary of the annual costs for the projects is presented at the bottom of the Roadmap. This cost stream includes the cost of the core implementation plus any additional on-going costs post-implementation.

The 3V0 protection and voltage regulation control projects are annual projects to enable DER and need to be done at the same time. These projects will begin in Year 1 and will be prioritized by substation starting with the highest DG penetration to provide immediate protection to the Unitil assets from any adverse reverse power flow situations. Installations will continue across the system annually until all substations have this protection installed.

Installations of the required field area network, SCADA and necessary field devices to provide volt-VAr control will also begin in Year 1 and continue each year until the installations are complete. These installations will start several years before the implementation of the ADMS actually begins in 2019 in order to have an adequate population of devices to use when the ADMS project starts for testing. Automation of the capacitor banks will start after the ADMS is operational. The decision to schedule the capacitor bank installations in this way is because the Unitil power factor already meets the stringent ISO-NE criteria on a high penetration of capacitors with local controls. Automation of the capacitor banks and integration with the ADMS will provide additional data points to fine tune the VVO functionality and provide additional optimization of the voltage profiles.

Starting dates for the Customer Portal and Gamification were based the starting date of the TVR and AMF projects. Some functionality of the web portal will be available to customers early in the project, such as bill pay. Other functionality, such as interval data, will be dependent on the TVR and AMF projects, which includes the installation of new metering system to provide interval data. In addition, the starting date of the TVR and AMF projects is dependent on the deployment of the FAN and consideration to minimizing stranded metering investments.

The Analytics & Visualization System Platform was slotted to sequence towards the end of the ADMS implementation to avoid too much overlap of major system implementations and to allow time to gain understanding of how the ADMS operates. Research, Development & Deployment is scheduled to start a couple of years into the plan for capital spending purposes and to allow resources to be focused on getting some of the more critical GMP projects started. Of course, Customer Outreach & Education will begin on “Day One” and run the entire length of the GMP, refocusing the messaging as projects are launched.

FG&E, d/b/a Unitil
August 19, 2015
DPU 15-121
Grid Modernization Plan

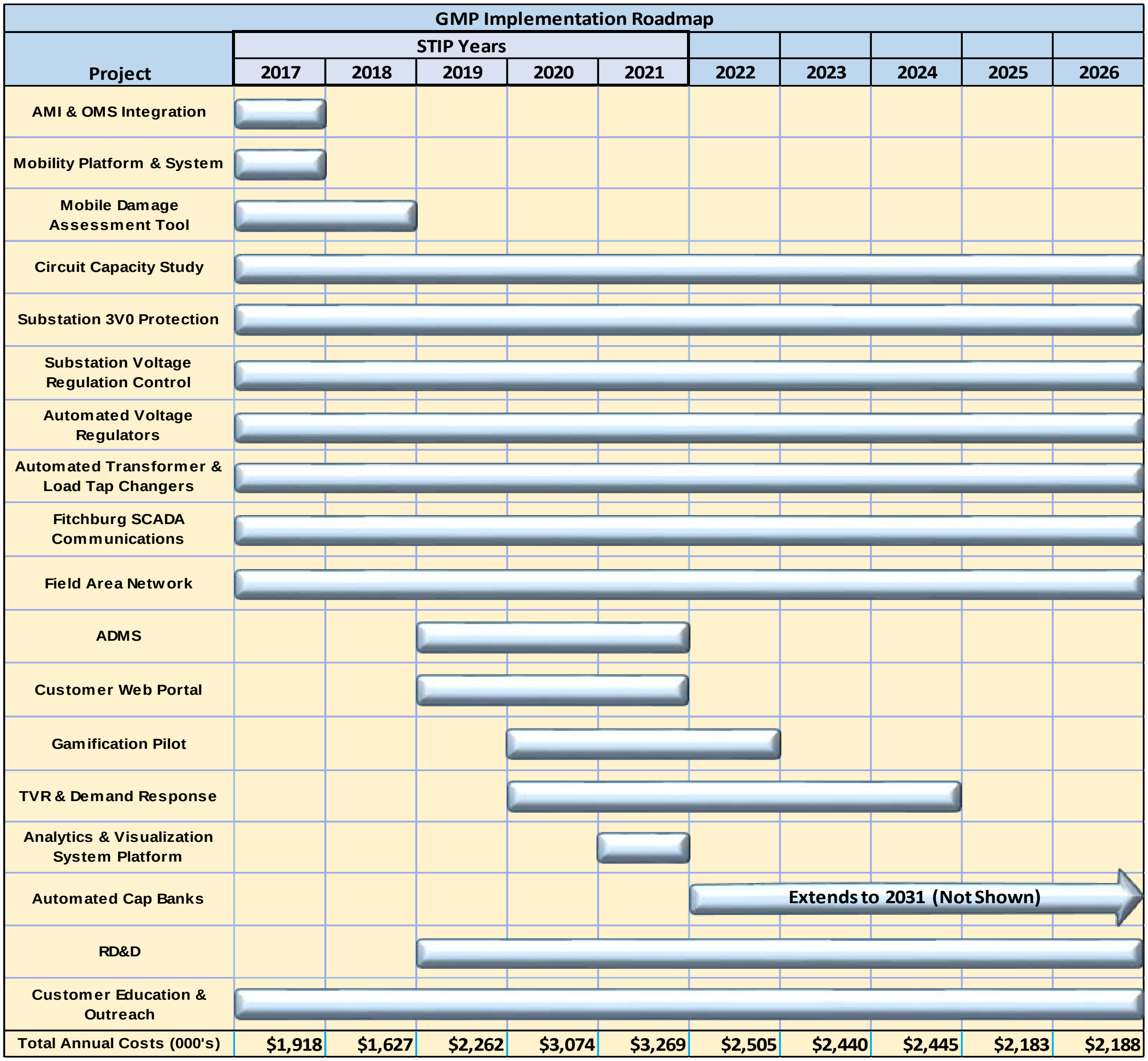


Figure 13: GMP Implementation Schedule

2.4.5 Benefit Cost Analysis

Each Program area of the STIP builds capabilities for helping Unitil achieve that goal. Table 7 summarizes the strategic importance of each area.

Programs	Strategic Importance
Distribution Automation	Enables energy efficiency and the dynamic flexibility to utilize variable distributed energy
Customer Empowerment	Provides technology and programs for customers that help them make informed decisions about their energy usage, and save money
DER Enablement	Helps lower existing barriers to solar PV by upgrading the distribution system and providing tools to manage distributed energy
Grid Reliability	Provides Unitil's field workforce with better and more timely information for restoring power
Workforce and Asset Management	Improved efficiency and information gathering for field workforce

Table 7: Strategic Importance of STIP Areas

Estimating Benefits

Unitil examined the benefits that each project could provide. Some projects were relatively easy to estimate, including those that yield operational cost savings. Other project benefits, like those that might improve the satisfaction of customers, were harder to quantify. Benefits that improve the operation of the grid and reduce costs overall are designated as “grid” benefits while those that lower the costs for customers on their bill (reduced energy consumption or capacity), or reduce the effects of outages are designated as customer benefits. Table 8 shows examples of benefits that are more or less difficult to quantify and monetize. Table 9 shows how the total benefits (in nominal dollars) over the ten-year GMP are distributed between Unitil and the customers for each of the program areas and demonstrates that the majority of benefits accrue to the customer. Table 10 presents the benefits that were estimated and monetized in each STIP program area.

Easier to quantify and monetize	Harder to quantify and monetize
Operational cost savings	Value of customer satisfaction
Cost of electricity	Value of distributed generation
Value of saving energy	Value of reducing carbon emissions
Value of reducing outages	Value of reducing blackouts

Table 8: Examples of Benefits That Are Easier/Harder to Quantify

Program	Grid Benefits	Customer Benefits	Total Benefits
DER Enablement	$0	$100	$100
Grid Reliability	$556	$6,115	$6,671
Distribution Automation	$0	$10,800	$10,800
Customer Empowerment	$126	$1,318	$1,444
Workforce and Asset Management	$378	$5,796	$6,174
Total	**$1,060**	**$24,129**	**$25,189**

Table 9: Grid vs. Customer Benefits (000s)

Program	Reduce T&D Ops Cost	Reduce Customer Ops Cost	Reduce Capacity Cost	Reduce Outage Minutes	Reduce Electricity Cost
DER Enablement					
Grid Reliability	◆			◆	
Distribution Automation			◆	◆	◆
Customer Empowerment		◆			◆
Work and Asset Management	◆			◆	

Table 10: Grid vs. Customer Benefits by Program Area

Comparison of STIP Benefits and Costs

Unitil has designed a STIP that supports the transition to an Enabling Platform, while delivering benefits that exceed the costs. The benefits and costs for the projects in the STIP summarized in Figure 14 and Table 11 below as net present values calculated over a 15-year analysis period.

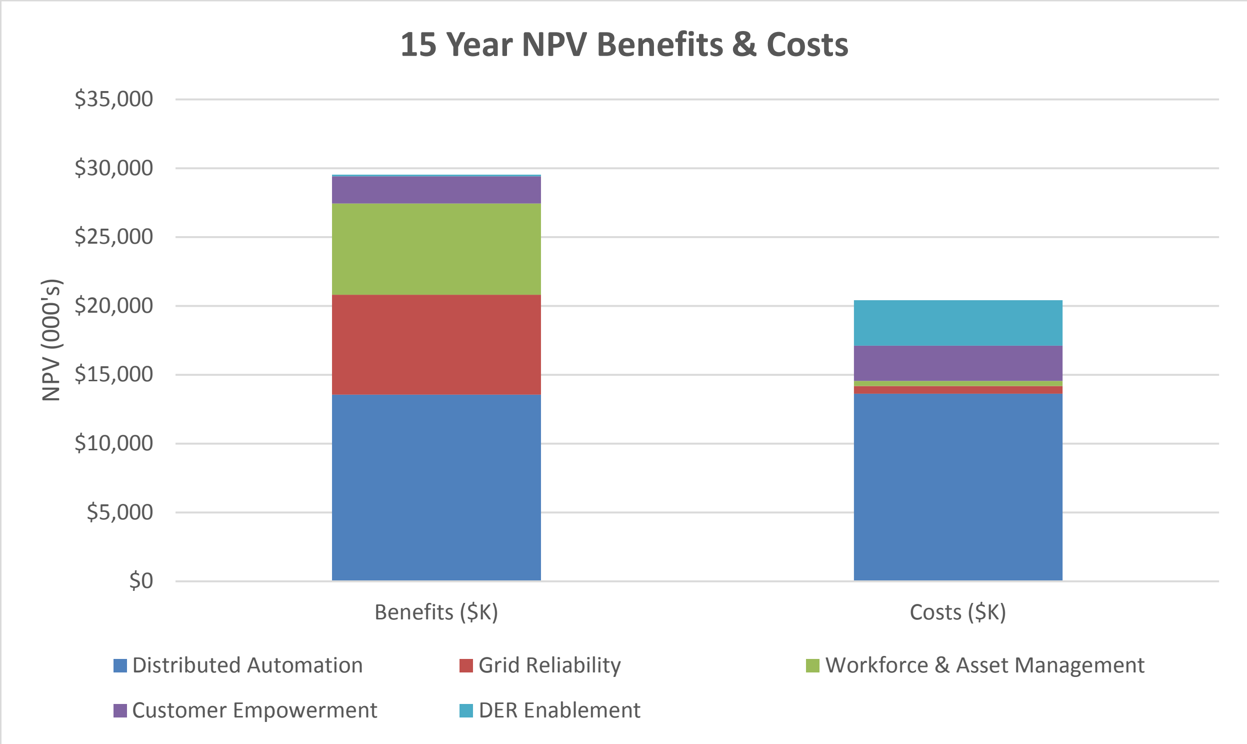


Figure 14: STIP Benefits Exceed Costs Over 15 Years

Program	Benefits ($K)	Costs ($K)	B/C Ratio
Distribution Automation	$13,551	$13,632	0.99
Grid Reliability	$7,265	$559	13.00
Workforce & Asset Management	$6,625	$365	18.15
Customer Empowerment	$1,987	$2,566	0.77
DER Enablement	$106	$3,304	0.03
Overall	**$29,533**	**$20,426**	**1.5**

Table 11: Benefit Cost Analysis by Program Area (15 Year Timeframe in Net Present Value)

Key Observations for Benefits and Costs

- The investments in the STIP will not "pay for themselves" through operational efficiency and cost reductions
- The benefits primarily accrue to customers, either through electricity cost savings (the value of a kWh) or the value of reducing outage minutes (Lawrence Berkley National Lab's (LBNL) ICE calculator)

- The cost savings for customers created by VVO will create downward pressure on electricity bills, even though the grid modernization investments in the STIP increase the revenue requirement – investments cost money, but customers save energy which holds the line on bills

Sensitivities for Benefit Cost Analysis

After identifying the recommended projects for inclusion in the STIP, a simplified, single variant sensitivity analysis was performed to evaluate the impact on the total B/C ratio of the STIP. A base case was designated and sensitivity cases were run by changing one variable at a time in the BCA model for comparison to the base case. Below is a summary description of each sensitivity case with the analysis results summarized in Table 12.

Sensitivity Case Descriptions

- **Base Case:** This includes all the STIP projects with the costs and benefits occurring at the full estimated values. For purposes of the sensitivity analysis, a 15-year time horizon and an after-tax weighted average cost of capital of 6.85% was used for the base case. The base case is identified as "STIP – Opt-in" for the recommended STIP projects and reflects the costs and benefits of the opt-in strategy being recommended for TVR.
- **Case #1:** This analysis examines at a 20-year time horizon rather than a 15-year horizon.
- **Case #2:** This case evaluates the B/C impact of a 50% increase in costs for all the projects in the STIP, as indicated by a cost multiplier of 1.5 being applied in the BCA model. This multiplier was applied across the board to all cost components rather than to any single component, such as Unitil labor or vendor software estimates, that made up the cost estimate
- **Case #3:** This case evaluates the B/C impact of the realizing only 50% of the estimated benefits for all benefits in the STIP, as indicated by a benefit multiplier of 0.5 being applied in the BCA model. As with the cost multiplier, the benefit multiplier was applied to all benefit components such as benefits from reduced outage frequency or duration estimates, capacity saving estimates, internal labor or customer impact savings.
- **Case #4:** The 20-yr T-Bill rate of 2.69% as of 6/25/15 is used as the discount rate.
- **Case #5:** The final case evaluates the B/C if the mandatory TVR approach is taken with an opt-out feature and the peak time rate.

As can be seen in the table, the results of the sensitivity analysis show the collection of STIP projects still produce B/C ratios greater than one, with the exception of Case #3, a 50% realization of benefits. The result of reducing the estimated benefits by 50% had the biggest impact to the B/C ratio compared to the base case, reducing it by half. Changing the time horizon from 15 to 20 years at 50% of the benefits still results in a B/C ratio of 0.90. Further sensitivity analysis, however, shows that if 70% of the benefits are realized for Case #3, a B/C ratio of 1.0 is obtained (not shown in table). Given the conservative nature in which estimated benefits were made for improvements in reliability, Unitil concludes that the results of the sensitivity analysis did not change the list of recommended projects in the STIP.

Sensitivity Case	Sensitivity Variables					Total B/C Ratio
	Description	Cost Multiplier	Benefit Multiplier	Time Horizon	Discount Rate	
BASE CASE	*STIP & Opt-in*	*1.0*	*1.0*	*15*	*WACC (6.85%)*	*1.5*
Case # 1	STIP & Opt-in	1.0	1.0	20	WACC (6.85%)	1.8
Case # 2	STIP & Opt-in	1.5	1.0	15	WACC (6.85%)	1.0
Case # 3	STIP & Opt-in	1.0	0.5	15	WACC (6.85%)	0.7
Case # 4	STIP & Opt-in	1.0	1.0	15	20 Yr T-Bill (2.69%)	1.6
Case # 5	STIP & Opt-out	1.0	1.0	15	WACC (6.85%)	1.2

Indicates Sensitivity Variable Changes

Table 12: Sensitivity Analysis Results

2.5 ADDITIONAL PLAN COMPONENTS

2.5.1 MARKETING, EDUCATION AND OUTREACH FOR CUSTOMERS

Unitil's Customer Education and Outreach Plan is designed to educate and engage customers relating to grid modernization opportunities. Specifically, it will inform and engage customers in:

(1) Their options for managing their energy consumption;
(2) The tools and technologies that will assist them in managing that consumption; and
(3) The benefits associated with reductions in consumption and/or shifting consumption away from high-cost times. The plan will utilize existing and new technologies and channels of communication to both educate and engage customers.

Unitil is proposing a multi-phased Customer Education and Outreach strategy, designed to engage customers early and often. This strategy leverages existing communication channels and aligns with existing programs that are already in place. The following depicts a high-level approach to communicating and reaching customers:

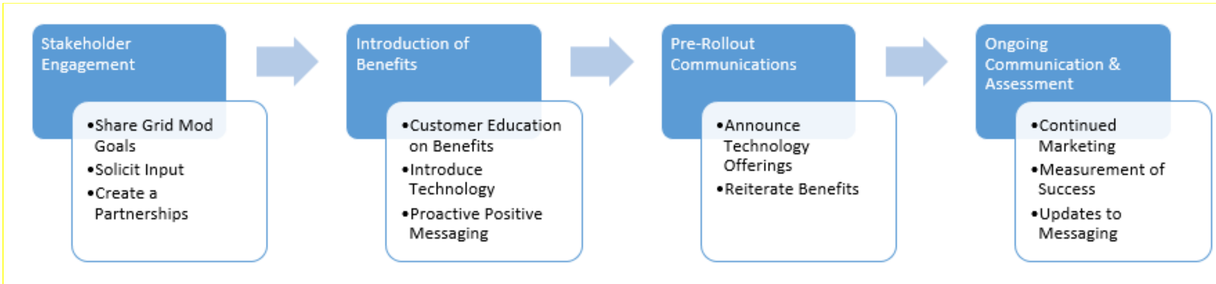


Figure 15: Multi-Phased Customer Education and Outreach Strategy

The Customer Education and Outreach Plan begins with early identification and engagement of key stakeholders. This process has already begun through the Stakeholder Engagement process. Key stakeholders including regulatory interveners, elected and municipal officials and customers were engaged through group and one-on-one meetings, as well as a customer survey to solicit input and feedback on the Grid Modernization plan. This early engagement establishes a partnership with the impacted parties and allows them to guide and influence the outcome and decisions. Early engagement of stakeholders has proven to be successful in generating excitement and timely buy-in.

Once the plan is submitted and a final order from the DPU is received, the Customer Education and Outreach Plan will enter its next phase with the introduction of benefits. This phase focuses on educating customers about the overall GMP and customer benefits and will educate customers about specific initiatives and programs that will be offered, sharing the benefits of the programs and providing guidance as to how customers will engage and participate to realize the benefits. Unitil will leverage traditional communication channels such as IVR/on hold messages, customer service representative training, customer newsletters, bill inserts, bill messages, social media and proactive public relations. New CIS-enabled technology including email and texting will also be utilized where appropriate. Education and outreach plans will be tailored for each program/initiative/project and will be aligned with customer communication preferences when possible.

The goal of this second phase will be to increase customer awareness including a better understanding of grid modernization in general and then specifically how they will benefit from participating, resulting in changed customer behavior regarding energy awareness and consumption.

As programs and technology are rolled out to customers, there will be a need for pre-rollout communications as well as launch announcements. The pre-rollout communications will be critically important, particularly for programs that require customer preparation. An example of this would be TVR. Customers will need to enroll in the TVR and be aware of the impacts and benefits from these types of rate structures.

Key success metrics will be defined for each initiative and the metrics will be monitored and measured on an ongoing basis. To ensure engagement is ongoing and benefits are persistent, Unitil will continue to market the programs, aligning with other initiatives where appropriate, and tailor the messaging to maximize the benefits. This initiative will be a joint effort among Communications, Customer Service, Energy Measurement and & Control (EM&C), Electric Operations and Information Technology (IT).

As outlined above, the Customer Education and Outreach has already begun through the stakeholder engagement process. In Year 1 there will be a strong push to educate customers around grid modernization as a whole, and in all successive years there will be education and outreach around specific programs and projects that require customer engagement and participation. In order for Grid Modernization to be a success, it requires engagement and participation from customers. Without a robust education and outreach, plan customers will fail to realize the benefits and cost savings available through grid modernization initiatives.

Unitil has met with the other Massachusetts electric utilities to discuss the utilities' plans to market and educate their customers about grid modernization. The marketing approach being taken by Unitil is tailored to the unique characteristics of its service territory, aligning with the other utilities where possible. It will be a high touch, multi-channel strategy including social media, the web, bill messages, and other traditional communication methods. An example of an exception to the utility alignment is the media buy, especially with TV, due to the location and demographics of Unitil's service area. While the messaging around grid modernization in general will be similar between all the utilities, there will be some differences due to the specific grid modernization projects being implemented across the different service areas. The exact messaging will be developed to coordinate with the type and implementation timeline of each GMP project. Unitil will continue to meet with the other Massachusetts electric utilities on an on-going basis as the GMP moves forward, to work collaboratively and look for areas of commonality that can be leveraged.

The cost for the Customer Outreach & Education plan is summarized in the table below.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$100	$75	$50	$40	$25	$15	$15	$10	$10	$10

2.5.2 RESEARCH DEVELOPMENT &DEPLOYMENT (RD&D)

The Unitil GMP proposes to implement commercially available technology with proven performance and tested value propositions. However, several areas of the modern grid are still emerging, and will continue to evolve to meet the specific needs of utilities and their customers across Massachusetts.

Thus, Unitil will support the RD&D of new and emerging technologies and is expecting to contribute $430,000 over the course of the GMP to a collaborative RD&D effort.

Historically, Unitil's RD&D efforts have been largely based upon project need (i.e. a need that cannot be solved with the technology presently being used). Unitil would consider specific business needs and use a pilot based approach to implement new technology that would allow an opportunity to gain needed experience and project knowledge. Unitil does not currently have a specific RD&D budget due to the relative size of the Company. In fact, Unitil may never have a large RD&D budget, so Unitil will be looking to identify partnerships with the other utilities and as well as collaborative partners (including universities) which might be able to use the unique characteristics of the Unitil system or Unitil's existing technology to deploy RD&D projects. Unitil is interested in obtaining input from the stakeholder group, vendors and customers on ideas for increasing innovation and partnering initiatives that may be available and how different funding alternatives may be used to facilitate these initiatives.

The three investor-owned electric utilities ("The Utilities") propose to collaborate and share their RD&D findings, both privately with each other and with external stakeholders. Collaboration amongst the three electric distribution utilities will help maximize the benefits from RD&D investments. As part of the broader collaboration effort, the Joint Utilities collaborated with the New England Clean Energy Council (NECEC) to conduct an "Innovation Forum". The utilities shared their research and development plans with NECEC staff and their members. The themes of the workshop focused around utilities bringing innovation opportunities to the innovation community earlier and different ways of funding the innovation research as opposed to looking for customer dollars to fund RD&D. The participants have committed to establish an ongoing discussion that will explore how the private marketplace can be part of providing new technologies and solutions that dovetail with the utility grid modernization programs. The group will consider opportunities for joint research projects that can test new technologies and products where the cost and risk can be shared between utilities and the vendor community. This approach is consistent with Unitil's Enabling Platform vision to enable and foster third party solutions that can enhance service to customers and optimize the grid over time. The report from the NECEC on this Forum has been included in Appendix E.

To facilitate ongoing collaboration between the electric distribution utilities, periodic confidential meetings will be held to enable the free flow of information that may be sensitive in nature or may discuss specific products, technologies or funding sources. It is anticipated that each utility will provide a brief overview of each RD&D project in their portfolio, including lessons learned and best practices. Discussion will also encompass identifying new technologies and funding opportunities for RD&D and how the utilities can collaborate on additional research that benefits all Massachusetts customers. These opportunities may include responding to opportunities from Federal or Commonwealth programs or could arise from public/private partnerships. Collaboration will also permit sharing of knowledge of specific utility initiatives such as energy efficiency and electric vehicle programs.

To ensure the collection of the broadest possible stakeholder engagement, the utilities will conduct an annual forum where a selected stakeholder group will be invited to inform The Utilities on the challenges they foresee and discuss the innovation and partnership models necessary to potentially meet the challenges. Stakeholders can also bring ideas to the utility group at any time and the utilities will use the periodic meetings to discuss the ideas. Particular stakeholders or technology vendors may also be invited to any meeting to get more information or collaboration with a particular technology or funding opportunity.

At this time, projects under consideration for inclusion in the RD&D Plan include:

- **Distributed Generation Pilot Program:** This pilot will collaborate with new or existing DG installations in order to gain performance and operating experience.
- **Breakaway Service Connector Pilot Program:** This program will evaluate new hardware technology to reduce outage duration by minimizing the damage caused by trees falling into service drops to houses.
- **Energy Storage Pilot Program:** This pilot would partner with energy storage (i.e. battery, thermal, etc.) vendors to investigate the opportunities that energy storage might have on a residential, commercial or utility application and how these devices might be used to increase DER hosting capacity and reduce the impact of distribution system interruptions.
- **Automated Fault Locating and Restoration:** This pilot would work on integrating existing and new protection schemes with an ADMS system to initiate automated sectionalizing and restoration.
- **Electric Vehicle Charging**: This pilot would work on integrating electric vehicle charging into the electric distribution system.
- **RF Survey Pilot**: This pilot will attempt to use both fixed and mobile radio frequency technology to identify equipment-demonstrating signs of eminent failure in advance of the outage. The goal would be to replace the equipment prior to the failure causing an outage.

The cost for the RD&D project is summarized in the table below.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Costs (000s)	$0	$0	$25	$30	$40	$50	$60	$70	$75	$80

2.5.3 Cybersecurity, Privacy and Data Access

The Company views this planning process and the implementation of the GMP as an opportunity to enhance its cybersecurity program to meet its evolving security and compliance needs over the next ten years.

The following paragraphs describe the cybersecurity processes and procedures that Unitil has adopted to prevent unauthorized access to control systems, operations, and data in accordance with existing and emerging best practices, national standards, and state and federal laws. These processes will be incorporated into future program capabilities as a framework for the further enhancement of the program.

Cybersecurity Governance

Executive Oversight & Reporting

The Vice President of Information Technology and Chief Information Security Officer (CISO) who reports to the Executive leadership and has overall responsibility for cyber security at Unitil oversees the current cyber security program. The CISO reports quarterly to the Executive leadership on the status of cybersecurity as well as other matters of significance in this area. The CISO has responsibility of proper reporting both internally and externally of cybersecurity events when they occur.

Stakeholder Engagement

As per Unitil's Written Information Security Plan (WISP) and current policies, system Application Owners (AOs) are responsible for working with the IT Department on any issues and technical problems including identified security issues or concerns. Unitil periodically participates in Business Impact Analysis (BIA) where business units conduct tabletop exercises of various scenarios including cyber security events to determine overall risks to the organization as well as practical measures to mitigate risks of high impact and/or probability. Unitil also participates in NERC's GridEx North America grid security exercise, where remediation exercises are vetted and potential gaps are identified.

Operating Model

The Information Technology Department has overall responsibility for cybersecurity at Unitil. For new projects, IT is involved in the beginning of the process and is engaged to determine the best practices for implementation from a cybersecurity perspective. Cybersecurity will be a critical component of all GMP projects.

Risk Management

Unitil participates in annual Risk Management Exercises with senior managers and Executive staff where risks to company operations are identified. Their potential impact and likelihood are assessed. Appropriate mitigation measures are determined and implemented as appropriate in applicable areas of the organization. The IT department closely monitors resources such as ES-ISAC, and Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) for current cybersecurity risk identification.

Policy Development & Deployment

Policies and other procedural controls are implemented as the result of industry best practice, past experience, information garnered from internet sources, and research through professional organizations.

Standards Development & Sustainment

Standards at Unitil are largely derived from published standards adapted to meet Unitil's specific circumstances. Experiential knowledge, joint exercises with other entities, outside consultants, and independent research with on-line resources are the basis for most of the standards in place.

Cybersecurity Asset Management & Protection

Cyber Control Framework

Unitil maintains the WISP and related policies for the maintenance and protection of cyber assets. The WISP and related policies detail processes and procedures for the management of assets, security of systems, and maintenance of Personally Identifiable Information (PII) privacy.

Cybersecurity IT & OT Technical Controls

Standards & Control Implementation

The Unitil WISP details controls and standards for the securing of systems and handling of PII. Details such as password requirements, access control for PII, and protection controls for data are enumerated in the document. The WISP is supported by other polices such as Asset Management, Backup and Recovery, Change Management, and Security Administration to define the cyber security posture for Unitil.

Security Planning & Architecture

The overall security environment is designed around the corporate network perimeter "shielding" the more sensitive SCADA and control environments. Operational control networks, such as SCADA are isolated.

Intrusion & Threat Detection

Unitil employs Intrusion Detection and other threat detection tools within its network environments. Systems and networks are monitored for anomalous events with automatic notifications to appropriate personnel.

Incident & Event Management

The WISP details the response plan for the investigation and subsequent reporting in the event of a suspected security breach

Vulnerability Assessment

Unitil actively assesses cybersecurity vulnerabilities with internal and external expertise. Assessment methods include external penetration tests, compliance review against standards, industry collaboration, and monitoring of online resources. Unitil evaluates vulnerabilities for their potential impact to Unitil and prioritizes for remediation through additional technical, operational, or physical controls.

Readiness Verification

Program Capability Assessment

Unitil reviews its cyber security program against published industry standards to assess maturity level and to identify gaps.

Compliance Assessment

The Company underwent NERC Critical Infrastructure Protection (CIP) audits for its FGE and UES divisions in 2014, which resulted in no violations, no potential violations, and no recommendations. The Company will assess NERC CIP compliance against all GMP activities. The Company engages an outside entity for Payment Card Industry (PCI) compliance and testing activities.

Incident / Event Investigations

Investigation & Reporting

The Manager of Data Security and Compliance is responsible for conducting the investigation of suspected breaches at the Company.

Risk and Threat Management and Reporting

Assessment & Ranking of Threats & Risks

Threat information from outside sources and log activity is evaluated for its potential impact to Unitil. Threats are prioritized for remediation through additional technical, operational, or physical controls.

Compliance Reporting

Unitil has established processes for the reporting of incidents related to NERC CIP and/or PCI compliance.

Report Compilation

Report compilation for the data security and privacy events is the responsibility of the Manager of Data Security. The Manager of Data Security acts as custodian of compliance reports according to Unitil's data retention policy.

Customer Access to Consumption Data

Unitil embraces the opportunity to enhance customer access to consumption data. Unitil intends to deploy a Green Button compliant customer web portal, providing secured access to consumption and other related meter data. The Unitil web portal will have charts and graphs in an easy to read, graphical format to aid users. Complying with the standard will enable customers to leverage the multitude of available Green Button compliant applications and to download data in a standard format for delivery to third parties. A list of applications supporting Green Button can be viewed at http://en.openei.org/apps.
Granularity of the data will be determined by the capability of the meter deployed at the customer's premise. Customers will manage the privacy of their data, providing data to applications and third parties of their choosing.

> "Green Button is the common-sense idea that electricity customers should be able to download their own detailed household or building electricity usage information from their utility website, in a common consumer- and computer-friendly format.
>
> With the Green Button initiative, energy providers are giving customers easy and secure online access to their personal energy use data. The program is the response from participating utilities to a challenge issued by the White House in 2011. The Green Button appears on the websites of participating utilities. Utility customers who log in and click the button are able to retrieve and download their personal energy use information.
>
> The program also offers opportunity for developers and third parties to design Green Button Applications that can use the energy use data from customers, should they decide to upload and/or share it"

Source: http://en.openei.org/wiki/Green_Button

Aggregate Usage Data

Unitil will have the capability to make anonymous aggregate usage data available to third parties with the implementation of a planned Meter Data Management System. The most straightforward method to ensure meter readings cannot be linked to any individual customer is to strip meter IDs from the data. Unitil anticipates data aggregation will follow a standard to ensure uniformity across all data sources. Metering systems approved within the GMP and agreed upon data standards will drive the ultimate design of the process.

2.5.4 PERFORMANCE METRICS

Grid modernization is a journey that will happen over many years. The changes that utilities make to their infrastructure, customer programs and business model will be incremental. Measuring the progress toward a modern grid is important for ensuring outcomes remain consistent with the vision held today.

Types of Metrics

In its Guidebook for ARRA Smart Grid Program Metrics and Benefits, the US Department of Energy presented the idea of using two types of metrics with which to measure program progress: build metrics and impact metrics. Build metrics refer to the electricity infrastructure assets, devices, technologies and programs related to the build-out of a smart or modern grid. Impact metrics refer to capabilities enabled by grid modernization projects and the measurable effects of the projects that deliver value to stakeholders.

Metric Type	Examples
Build metrics	• The number of distribution automation devices or automated feeders that can be used to perform automated functions such as switching or voltage control • The number of customers participating in a TVR program
Impact metrics	• Reliability indices (e.g., customer-minutes interrupted) for modernized infrastructure • Peak demand of residential customers in TVR programs

Table 13: Types of Metrics

Proposed State Wide Performance & Infrastructure Metrics

The Massachusetts utilities developed common metrics for use on a statewide basis. Statewide metrics are always met with some challenges because not every system is the same. Each of the utility systems in Massachusetts differ based upon geography, size, number of customers, amount and type of load, age and functionality of existing equipment, existing integration of technology and rate structures. The company does not believe a direct comparison of these metrics between the utilities will provide "apples-to-apples" comparisons due to the differences in each system described above. The metrics are designed to be used as a relative measure over time to determine trends for a given utility.

The statewide metrics use the following common definitions:

Grid Modernization Device - Any device that meets the requirements of either a fully automated or a partially automated device

Fully Automated Device - Meets all of the following requirements:

- Reacts to system conditions to isolate or restore portions of the electric system
- Communicates system quantities (e.g., voltage, trip counts) to a central location, such as SCADA
- The state of the device can be remotely controlled by dispatch

Partially Automated Device – Meets at least one of following requirements:

- Reacts to system conditions to isolate or restore portions of the electric system

- Communicates system quantities (e.g., voltage, trip counts) to a central location, such as SCADA
- The state of the device can be remotely controlled by dispatch

AND capable of upgrade to a fully automated device without full replacement

Sensor – Equipment that sends or records information of the electric system that can be used to improve the efficiency or effectiveness of workforce or asset management (e.g. Fault locators that would help pinpoint a problem for more efficient crew deployment)

The company plans to use the following statewide metrics to quantify the company's progress towards modernizing the grid. Further analysis will be required to refine the metrics and determine how those metrics are ultimately used. The company reserves the right to add, delete or modify any of its metrics in an attempt to provide the most use set of information to measure this performance.

Program Area	Program Metrics
DER Enablement	1. Total number of grid-connected distributed generation facilities, nameplate capacity and estimated output of each unit, and type of customer-owned or operated units
Grid Reliability (Reduce the Impact of Outages)	1. # Customers Impacted by GMP investments • Tally of customers served that can benefit from investments installed via the GMP that either proactively (i.e. sense & prevent) or reactively (i.e. wait & react as needed) prevent or minimize an outage situation. o Customers that can benefit from multiple devices are counted as 1. o Not limited to the primary/back-bone infrastructure o Includes no-load circuits and DSS lines

Grid Reliability (Reduce the Impact of Outages)	2. System Automation Saturation • Illustrates the scope of automation on the electric system measured as Customers / # Fully or Partially Automated Devices Installed • The baseline saturation rate will be calculated as what exists on the system as of the date GMPs are approved. Ideally, over time, this metric would decrease based specifically on GMP-installed devices only $$\frac{\text{Customers Served}}{\text{Fully Automated Device} + 0.5*(\text{Partially Automated Device})}$$
Distribution Automation (optimize demand - including reduced system and customer costs)	1. Load Reduction during declared event (TVR rate customers) • Measures the difference between the expected load and the actual load for TVR rate customers during a critical peak pricing event (CPP) o Methodology to determine the 'expected load' to be determined, potentially based on ISO NE formula 2. Total number & percent of customers on TVR
Workforce and Asset Management	1. Number and percent of sensor installed vs. GMP plan • Refer to common definition of 'sensor' for these 3 metrics 2. % Circuits with installed sensors

Table 14: Proposed Statewide Metrics

DER Enablement

Name	DER customers
Description	The total number and type of grid connected generation facilities
Type	Build
Program Area	DER Enablement
Input Data	The total number by type of DER units connected to the grid

Period	Annual
Calculation	Sum total
Units	Number of DER units
Rationale	Unitil will be modernizing its grid to enable simpler interconnection of DER and ensuring that DER hosting capacity is sufficient to meet the demand from customers. Tracking the number of customers taking service under the DER tariff will help Unitil determine the growth of DER in its service territory and plan for future grid enhancements.

Name	DER capacity
Description	The total capacity of grid connected generation facilities
Type	Build
Program Area	DER Enablement
Input Data	The total capacity of DER units connected to the grid
Period	Annual
Calculation	Sum total
Units	Capacity, kilowatts(kW), megawatts (MW)
Rationale	Unitil will be modernizing its grid to enable simpler interconnection of DER and ensuring that DER hosting capacity is sufficient to meet the demand from customers. Tracking the capacity of DER connected to the grid will help Unitil determine the growth of DER in its service territory and plan for future grid enhancements.

Grid Reliability

Name	Customers Impacted by GMP investment
Description	Measures the total number of customers benefitting from GMP investments.
Type	Build
Program Area	Grid Reliability
Input Data	Number of customers that benefit from investments installed via the GMP
Period	Annual
Calculation	Sum total • Customers that can benefit from multiple devices are counted as 1. • Not limited to the primary/back-bone infrastructure • Includes no-load circuits and DSS lines

Units	Number of customers
Rationale	Unitil will be modernizing its grid in an effort to make further improvements in reliability for its customers. Understanding the number of customers benefitting from grid modernization investments is important to determine the scale of grid modernization across the system.

Name	System Automation Saturation
Description	Measure of the scope of automation throughout the system
Type	Build
Program Area	Grid Reliability
Input Data	Number of customers served compared to the number of automated devices
Period	Annual
Calculation	$\dfrac{\text{Customers Served}}{\text{Fully Automated Device} + 0.5*(\text{Partially Automated Device})}$
Units	Customer/device
Rationale	Unitil will be modernizing its grid in an effort to make further improvements in reliability for its customers. Understanding the number of customers per automated device is important to determine the scale of grid modernization across the system.

Distribution Automation

Name	Load Reduction per event
Description	Measures the amount of load reduction during CPP events
Type	Build
Program Area	Distribution Automation
Input Data	Difference between the expected load and actual load during CPP events
Period	Per event
Calculation	Methodology to determine the “expected load” based upon ISO-NE formula
Units	kW or MW
Rationale	Unitil will be modernizing its grid in an effort to provide better ways to manage peak load. Understanding the expected load savings during CPP

	events is important to determine the impact of load reduction capability of the system and how that can be used to maximize the system capacity.

Name	Customers on TVR
Description	Total number & percent of customers on TVR
Type	Build
Program Area	Distribution Automation
Input Data	Number of customers on TVR
Period	Annual
Calculation	Total number of customers on TVR as a percentage of total customers served
Units	Customer and percent
Rationale	Unitil will be modernizing its grid in an effort to provide better ways to manage peak load. Understanding the scale of the TVR program is important to understanding the penetration of the TVR program and the customer's acceptance of the program.

Workforce and Asset Management

Name	Sensors installed versus GMP Plan
Description	Measures the number of sensors installed as compared to the GMP plan
Type	Build
Program Area	Workforce and Asset Management
Input Data	Comparison of number of sensors versus the GMP plan
Period	Annual
Calculation	Total number of sensors installed divided by the number of sensors in the GMP plan
Units	Quantity and percent
Rationale	Unitil will be modernizing its grid in an effort to provide better ways to make is workforce more efficient. Understanding the progress of installed sensors versus the plan is one way to measure progress of the plan.

Name	Circuits with installed sensors
Description	Measures the percent of circuits that have sensors installed

Type	Build
Program Area	Workforce and Asset Management
Input Data	Number of circuits with installed sensors and the total number of circuits
Period	Annual
Calculation	Number of circuits with installed sensors divided by the total number of circuits
Units	Percent
Rationale	Unitil will be modernizing its grid in an effort to provide better ways to make is workforce more efficient. Understanding the progress of installed sensors versus the plan is one way to measure progress of the plan.

Additional Proposed Metrics

Unitil proposes to use additional Build and Impact metrics tailored for its Grid Modernization Program. These metrics have been proposed to measure the impacts and benefits of STIP projects, and other GMP programs.

Program Area	Program Metrics
DER Enablement	• Number of DG customers (by circuit, substation) • Interconnected DG capacity (by circuit, substation)
Grid Reliability	• No additional metrics proposed. Extensive metrics already exist to measure reliability performance.
Distribution Automation	• Conservation Voltage Reduction Factor • Number of customers on CVR feeders
Customer Empowerment	• Number of customers using self-service through web portal and mobile app • Average cost per customer contact • Number of customers participating in TVR program
Workforce and Asset Management	• Traditional reliability metrics

Table 15: Additional Proposed Metrics

DER Enablement

Name	DG customers (by circuit, substation)
Description	The number of customers (by circuit, substation) taking service under Unitil's DG tariff

Type	Build
Program Area	DER Enablement
Input Data	The total number of customers (by circuit, substation) subscribed for service under the DG tariff
Period	Annual
Calculation	Sum total
Units	Customers
Rationale	Unitil will be modernizing its grid to enable simpler interconnection of DG and ensuring that DG hosting capacity is sufficient to meet the demand from customers. Tracking the number of customers taking service under the DG tariff and their location on the circuits will help Unitil determine the growth of DER in its service territory and plan for future grid enhancements.

Name	DG capacity (by circuit, substation)
Description	The total installed capacity (ICAP) (by circuit, substation) of DG by type and location (could be by feeder, substation or some other factor)
Type	Build
Program Area	DER Enablement
Input Data	The total installed capacity of DG at different places in the distribution system (by circuit, substation). Technology type, customer class, feeder, substation or other factors could collect this data.
Period	Annual
Calculation	Sum total
Units	Capacity, kilowatts(kW), megawatts (MW)
Rationale	Unitil will be modernizing its grid to enable simpler interconnection of DG and ensuring that DG hosting capacity is sufficient to meet the demand from customers. Tracking the installed capacity of DG and their location on the circuits will help Unitil determine the growth of DG in its service territory and plan for future grid enhancements.

Distribution Automation

Name	CVR Factor
Description	The reduction of energy and demand that can be achieved for a given reduction in voltage (i.e. change in energy/demand per change in voltage)
Type	Impact

FG&E, d/b/a Unitil
August 19, 2015
DPU 15-121
Grid Modernization Plan

Program Area	Distribution Automation
Input Data	Energy and/or demand at the feeder level Feeder voltage Input data to be collected periodically, or as part of a test
Period	Calculated periodically or as part of a test
Calculation	Divide the change in energy and/or demand with and without CVR, by the change in voltage with and without CVR
Units	kW per volt, kVA per volt
Rationale	Unitil will be implementing CVR on its distribution system to reduce energy consumption and peak demand by lowering the voltage, within service standards. Measuring the CVR factor will show the amount of energy and/or capacity savings that can be achieved by reducing the distribution voltage incrementally. This will allow Unitil to develop forecasting techniques for CVR performance.

Name	CVR Customers
Description	The number of customers served by distribution feeders employing CVR
Type	Build
Program Area	Distribution Automation
Input Data	The number of customers that are served by distribution feeders employing DER.
Period	Monthly
Calculation	Total number of customers by feeder
Units	Customers
Rationale	Unitil will be implementing CVR on its distribution system to reduce energy consumption and peak demand by lowering the voltage, within service standards. Measuring the number of customers on distribution feeders with CVR will help estimate the demand and energy savings that should be expected from CVR, and allow Unitil to develop forecasting techniques for CVR performance.

Customer Empowerment

Name	Self-service customers
Description	The number of customers using self-service through the web portal and mobile app

Type	Build
Program Area	Customer Empowerment
Input Data	The number of active self-service accounts. Active status will be determined by meeting a threshold of the number of times in a certain period that the customer used the systems. This could be measured by system interactions or notifications sent to customers that subscribe.
Period	Monthly
Calculation	Total number of active accounts
Units	Accounts
Rationale	Unitil will be implementing self-service capability with a web portal and mobile app, both of which will provide access to customers for information energy usage, billing and other information related to their accounts. Self-service options will make it more convenient for customers to get the information they want, improving their experience and satisfaction. It will also reduce the amount of time Unitil Customer Service Representatives (CSR) spend providing this information to customers over the phone.

Name	Cost per customer contact
Description	The average cost of interacting with a customer to provide information or manage an account
Type	Impact
Program Area	Customer Empowerment
Input Data	- The number of customer contacts handled by Customer Service Representative - the number of Self-Service transactions recorded by the CIS through the web portal and mobile app.
Period	Monthly
Calculation	Divide the total loaded cost of handling customer transactions (CSR plus Self-Service) by the number of transactions
Units	Dollars per transaction
Rationale	Unitil will be implementing self-service capability with a web portal and mobile app, both of which will provide access to customers for information energy usage, billing and other information related to their accounts. Self-service options will make it more convenient for customers to get the information they want, improving their experience and satisfaction. It will also reduce the amount of time Unitil Customer Service Representatives spend providing this information to customers over the phone.

Name	TVR customers
Description	The number of customers with TVR service
Type	Build
Program Area	Customer Empowerment
Input Data	The number of active TVR accounts
Period	Monthly
Calculation	Total number of active accounts
Units	Accounts
Rationale	TVR will encourage customers to manage their electricity usage and use less during peak times. Peak demand reduction will help Unitil reduce capacity cost.

Name	Peak demand per customer
Description	The average demand per customer measured at the system peak
Type	Impact
Program Area	Customer Empowerment
Input Data	- Number of customers taking service - System demand in MW measured at the Unitil peak hour
Period	Monthly
Calculation	Divide the system peak demand by the number of customers
Units	kW per customer
Rationale	TVR will encourage customers to manage their electricity usage and use less during peak times. Peak demand reduction will help Unitil reduce capacity cost.

Workforce and Asset Management

The benefits identified from this program, primarily reliability improvement, are already tracked by existing metrics, i.e. SAIDI and Customer Average Interruption Duration Index (CAIDI). As part of Unitil's ongoing examination of metrics, Unitil will be looking at the relationship between its workforce and asset management projects and these existing outcome metrics.

Baselines

The purpose of these metrics is to determine how performance can be changed because of grid modernization activities. Weather, customer behavior and economic conditions and other factors have a significant influence on the parameters that measured. At first, the changes resulting from grid modernization may be subtle and difficult to detect. As part of developing its performance metrics, Unitil will establish baselines against which to measure ongoing performance. This will help develop an understanding of how efforts are “moving the needle” with grid modernization.

2.6 FINANCIAL SUMMARY

Table 16 below provides a summary of the overall cost of the STIP and GMP program for which Unitil will be seeking recovery. The costs are in the form of capital from the STIP projects and the RD&D program. The remaining project, Customer Outreach & Education, in the GMP will be recovered as O&M costs. The costs portrayed here are in nominal dollars.

Costs & Benefits Summary Nominal Dollars	Project Costs		Project Benefits	
Program	5-Yr STIP	10-Yr GMP	5-Yr	10-Yr
DER Enablement	$2,015	$3,850	$50	$100
Grid Reliability	$354	$359	$2,575	$6,671
Distribution Automation	$7,695	$15,780	$1,455	$10,800
Customer Empowerment	$1,484	$2,925	$64	$1,444
Workforce and Asset Management	$217	$217	$2,744	$6,174
RD&D	$95	$430	$0	$0
Total	**$11,860**	**$23,561**	**$6,888**	**$25,189**

Table 16: Total Proposed GMP Spending ($000)

The Company estimates that $11,860,000 of the total of $23,561,000 of GMP capital costs will be incurred during the initial five-year STIP period. An additional O&M amount of $290k for Customer Education & Outreach will be incurred in the first 5-Yr STIP window and included for cost recovery as discussed in section 3.2 Cost Recovery, bringing the 5-Yr total to $12,150M. Similarly, an additional O&M amount for Customer Education & Outreach will be incurred over the entire 10 year GMP ($290k in Years 1 - 5, and an additional $60k in Years 6 – 10) to be included for cost recovery as discussed in section 3.2 Cost Recovery, bringing the 10-year total to $23,911M. Unitil may pursue funding for a portion of the costs of the VVO program using Energy Efficiency (EE) program funds. Conservation voltage reduction (a form of VVO) is a means to achieve energy efficiency through a lowering of the voltage level across the distribution system which can result in considerable energy savings for customers. Using existing EE program funds could dramatically reduce the rate impact of the overall GMP cost to customers. Unitil estimates that almost $14,000,000 of the total GMP cost could be considered for EE recovery.

3 Rates and Regulatory

3.1 REGULATORY/RATEMAKING FRAMEWORK

The Unitil vision and the GMP contemplates a future where distributed resources are increasingly prevalent as customers avail themselves of on-site supply through rooftop solar or other emerging technologies and/or change their usage levels and patterns in response to home automation and automated demand response programs. These benefits are enabled by investments in the distribution system, information systems, and business processes that achieve multiple objectives including empowering customers to make efficient decisions with respect to distributed generation and other DERs. Unitil is prepared to transition to an Enabling Platform model through which it enables and supports increasing reliance on DERs as a means to achieve Massachusetts' energy policy objectives. The proposed GMP will meet these objectives while continuing to ensure safe and reliable service to customers, even as the network becomes increasingly complex to manage.

A consistent approach to pricing DERs that connect to the system is integral to the GMP and is required in order for the GMP investments to be undertaken by Unitil on financial terms that will be affordable to customers. Thus, the physical investments and rate design/pricing proposals in this GMP are inextricably linked. Achievement of this vision will require changes to existing rate design policies and principles that were developed decades ago based on a more traditional concept of the role of the electric utility. This linkage between investments in grid modernization and the ability through rate design to recover fixed costs of past and future grid investments on a timely basis is essential in order to align the interests of customers that take advantage of DERs, non-participating customers, and Unitil.

Two critical ratemaking issues need to be addressed to make the transition to the modern distribution utility characterized by a proliferation of DERs and enabling grid modernization investments. The first ratemaking issue is the current reliance on volumetric, per-kWh charges to recover a disproportionate percentage of the fixed costs attributable to the capital-intensive distribution network. As customers generate their own electricity, they reduce their kWh usage and shift the burden of fixed cost recovery to other customers. Thus, DG customers no longer pay their fair share of the fixed costs associated with facilities necessary to connect them to the grid and to provide distribution service that they continue to rely on either to buy electricity when their generation is not sufficient to cover their load and or export electricity when their generation exceeds their load. The continued recovery of fixed costs through per-kWh charges is inconsistent with a policy framework and GMP investment plan that is explicitly designed to encourage all DERS, including DG, energy efficiency, demand response, and emerging electricity storage technologies. As long as fixed costs are recovered through volumetric charges, utilities will not recover the costs of a more complex distribution grid that is necessary to support DERs.

The second issue relates to the policy of compensating customers for generation that is surplus at various hours during the year to their requirements (i.e., the net metering policy). This exacerbates the under-recovery of fixed costs associated with self-generation that reduces utility net revenues (and associated fixed cost recovery) because the surplus generation for the majority of customers is compensated at close to the full retail rate. These two issues compound each other to challenge the ability of electric distribution utilities to recover the fixed costs of the distribution network and will result in a shift of the cost burden to customers that have not, or cannot, take advantage of emerging DER options. These two interrelated issues are being discussed throughout the country, especially in states like Massachusetts that are leading the effort to transform the role of the electric utility. They must be addressed in order to:

(1) Maintain the financial sustainability of electric utilities that are being asked to invest in grid modernization,
(2) Provide efficient price signals to customers that are considering investing in DERs, and
(3) Ensure fairness and the public acceptance of the new utility business and regulatory model.

3.1.1 Recovery of Fixed Costs Through per kWh Charges

Unitil's rate design and allocated cost study witness in the Company's 2013 rate case, D.P.U. 13-90, determined that almost 100% of FGE's distribution costs are fixed. A substantial portion of Unitil's fixed costs (approximately 70%) is currently recovered through per-kWh charges rather than through either the monthly customer charge (paid by all customers) or demand charges (paid by the larger C&I customers).[19] The current cost recovery model is a "closed" financial construct with the potential for under-recovery of fixed costs from energy efficiency and net metering policies being addressed through decoupling policies that result in cost shifting and subsidies.

However, recovering most of a distribution company's fixed costs through a kWh energy charge it is no longer financially viable if Massachusetts implements policies that "open" the system and more aggressively promote all forms of DERs. Non-participants will bear an increasing, discriminatory, and unfair proportion of fixed costs unless the pricing model is fixed before DERs proliferate. A financially viable and more efficient long-term pricing approach requires efficient pricing of distribution services and shifting the recovery of fixed costs from volumetric charges to customer and demand charges.

[19] Estimate is based on information provided in Unitil's 2015 rate filing, D.P.U. 15-80.

The transition to customer and demand charges that reflect cost causation factors will encourage more efficient utilization of the distribution system, enhance the ability of utilities to finance investments in the distribution grid, and provide better and more efficient price signals to customers that are evaluating DERs. For example, customers that are considering electricity storage technologies will only make properly informed economic decisions if they are faced with a demand charge that reflects the cost of using the network. It is essential for a policy that promotes DERs to be accompanied by a rate design that sends accurate price signals.

3.1.2 DER PRICING

The Unitil vision and the GMP contemplates a future where distributed resources are increasingly prevalent as customers avail themselves of on-site supply through rooftop solar and other emerging technologies and/or change their usage levels and patterns in response to home automation and automated demand response programs.

DG customers require facilities that connect them to the electric distribution network to deliver surplus energy to the grid when DG production exceeds their demand as well as acquire unscheduled supply when the DG facility is either not producing at all or not producing sufficient energy to meet the demand at the customer site. There are two fundamental problems with the current policy:

(1) the majority of DG customers are providing a supply service yet being compensated at close to near full retail rates rather than the market value of supply; and
(2) the DG customer does not pay the full cost of the facilities that they continue to depend on to receive and deliver power.

The current policies were intended to stimulate investment in the solar industry and have been successful. The range of options available to customers has expanded dramatically over the past decade and the cost of solar systems has declined. However, rather than spreading the burden across all citizens that benefit from clean energy, the costs have been assigned to the subset of customers which do not or cannot afford to install solar (or other DG) generation. This rate impact was initially small, but the development of the solar industry and overall rate impacts have reached a point where the policy should be updated to focus primarily on economic efficiency and other valid rate design and pricing objectives. This will contribute to a more sustainable solar industry and efficient customer energy decisions. The subsidy is an obvious issue but there are other issues as well. The utility is placed in the position of denying new applications to connect solar installations when the cap is reached, exacerbating the fairness problem. There are also localized distribution system integrity issues that may be caused by a concentration of solar and other DG applications in parts of the distribution network.

As Massachusetts Net Metering and Solar Task Force recognized prior to the beginning of this proceeding, it is time to reassess its approach to solar energy, including the net metering policy.[20] The elements of a solution to the net metering tariff design are a return to longstanding ratemaking principles, modified as necessary to accommodate the new utility business model. These principles call for customers to pay rates that reflect the costs of providing them with service.

A Pricing Framework

There are certainly alternative approaches that can address these issues. The concepts include compensation for the supply that is provided to the grid, with the price based on the market value of supply at the time that it is provided. The approach may also include a greater reliance on demand charges for certain customers, including some residential customers.[21] Unitil recognizes that the Department may want to address DER pricing on a generic basis.

Unitil offers the following as a Straw Proposal that is consistent with current metering capabilities and the long-term vision for grid modernization and the role of the utility. Unitil considered a set of four guiding principles for a new approach to rate design:

(1) Customers are able to generate power "behind the meter" to serve their own load; customers are also entitled to take other actions that change their demand for utility-provided electricity, including conserving electricity, use electricity more efficiently or install customer-sited electric battery storage devices. Customers who generate power must notify the utility and meet other requirements if they would like to be compensated for electricity that flows into the utility grid.
(2) Customers that flow electricity into the utility grid will be compensated for the electricity at the Fitchburg ISO-NE pricing point.
(3) Customers should pay for distribution, supply, and other services provided by the electric utility at rates that reflect the fixed and variable costs incurred to serve them.
(4) Utilities will facilitate the connection of customer-sited distributed resources to their grid.

These principles become the basis to propose a specific rate design proposal that reflects existing (and new) metering capability that can accommodate demand charges:

(1) DG customers must have a meter capable of measuring maximum demand and net kWh that is either delivered to or received from the customer.

---

20 Massachusetts Net Metering and Solar Task Force Final Report to the Legislature, April 30, 2015

21 There is considerable work that would need to be done to accommodate demand billing to large numbers of customers (e.g., calculating rates, supporting load research, changes to billing systems, etc.)

(2) DG customers will pay customer and demand charges that recover all of the fixed costs necessary to serve them.
(3) DG customer charges will be charged a one-time "connect" charge that recovers the incremental costs associated with purchase, installation and maintenance of a new meter, if one is required to serve the customer.
(4) DG customers will pay demand charges for power received each month that is calculated as the product of their maximum-metered demand for power either received or delivered in the month times a demand rate that is based on the demand-related fixed costs incurred by Unitil to serve customers within their rate class. They will not pay a volumetric distribution charge for distribution service although they may continue to pay a volumetric supply charge.[22]
(5) DG customers will be compensated for power provided to the grid that is in excess of their needs and pay for net supply service received at the applicable hourly ISO-NE energy charge for all generation in excess of their needs.

3.2 COST RECOVERY

3.2.1 UNITIL'S PROPOSED STIP COST RECOVERY FRAMEWORK

The Company proposes to recover STIP-related investment and expense through a Short Term Investment Clause[23]", or "STIC." Unitil's proposed STIC will recover (a) the costs of the Company's pre-authorized STIP investments that are made in each STIP Investment Year, and (b) the associated STIP expenses. As explained in this GMP, Section 2, some of the Company's STIP projects that will be initiated within the first five years of the GMP will not be completed until GMP Year 10. Corresponding to this ten-year period of STIP investment, the proposed STIC would remain in effect for at least ten years, until the Company's Year 10 STIP investments and expenses are included in base rates.

Key details of the Company's proposed STIC[24], are provided in Appendix D, and summarized below:
(1) Unitil proposes to make annual STIC filings October 1 of each year, for Short Term Investment Factor ("STIF") rates that will become effective the January 1 following the filing, based on planned Eligible STIC investment and expenses made during that upcoming GMP Cost Year that starts the January 1 following the filing.

[22] Under current Department policies, certain non-by-passable charges are recovered through volumetric distribution charges. It may be necessary under this proposal to recover these costs through the customer or demand charge.
[23] The Company will file a draft Short Term Investment Tariff when appropriate.
[24] The Company's proposed STIC is generally consistent with the approaches taken by the other Massachusetts EDCs while also reflecting the specifics of Unitil's GMP and Unitil's business conditions.

(2) Unitil will calculate STIP Revenue Requirements that reflect (a) the Company's pre-tax rate of return applied to average rate base plus depreciation expense and property taxes, and (b) STIP-related expenses, which includes direct project expenses, Customer outreach costs and the costs of the Company's RD&D program.
(3) In the annual STIC filings, separate STIF rates will be determined for each of the Company's rate class groupings by applying distribution revenue allocators to the total annual STIP Revenue Requirement. STIF rates for Unitil's rate classes that do not employ a distribution demand rate will be calculated by dividing (a) the allocated shares of STIP Revenue Requirements by (b) annual forecast kWh billing determinants. STIF rates to be charged to rate classes that employ a distribution demand rate will be calculated by dividing (a) the allocated shares of STIP Revenue Requirements by (b) annual forecast kW or kVA billing determinants.
(4) Unitil's proposed STIC will also include a Short-Term Investment Reconciliation Factor ("STIRF") to reconcile the difference between actual cumulative STIP Revenue Requirements for a GMP Cost Year and the billed revenue from the STIF associated with that GMP Cost Year.

3.2.2 Summary of STIP Cost Recovery and Rate Impact Analysis

As shown in the table below and more fully explained in Appendix D and supported in Attachments 1, 2, 3, and 4 of Appendix D, the Company's STIP is projected to produce an average incremental (i.e., year-to-year) STIP Revenue Requirement of $315,000, which would result in a rate increase of 0.4% per year, averaged over all customers.

	STIP Year 1	STIP Year 2	STIP Year 3	STIP Year 4	STIP Year 5	STIP Year 6	STIP Year 7	STIP Year 8	STIP Year 9	STIP Year 10	10-Year Average
STIP Revenue Requirement Analysis ($000)											
Capital	$170	$476	$805	$ 1,198	$ 1,675	$ 2,025	$ 2,163	$ 2,275	$ 2,354	$ 2,364	$ 1,550
Expense	$100	$ 76	$ 86	$ 81	$ 76	$364	$399	$404	$459	$464	$251
Total	$270	$552	$891	$1,279	$1,751	$2,389	$2,562	$2,679	$2,813	$2,828	$1,801
Incremental	$270	$282	$339	$472	$638	$174	$116	$134	$15	$283	$472
STIP Rate Impact Summary[25]											
Incremental	0.3%	0.3%	0.4%	0.4%	0.5%	0.7%	0.2%	0.1%	0.2%	0.0%	0.3%
Cumulative	0.3%	0.6%	1.0%	1.5%	2.0%	2.7%	2.9%	3.1%	3.2%	3.2%	2.1%
Note: For planning purposes, the Company assumes that STIP Year 1 will be the calendar year 2017.											

Table 17: STIP Cost Recovery and Rate Impact Summary

[25] Rate Impact calculations are based on $87,398,000 total company distribution revenues, default service revenues, and imputed default service revenues to customers of competitive suppliers.

Appendix A. The Projects that were Considered

The table below shows the progression of projects that were considered for the GMP from the initial project list to the final STIP recommendation. As the project evaluation and selection process moved from left to right (Version 1.0 to Version 4.0), projects were dropped for various reasons or combined with other projects. The gray boxes indicate a project has stopped progressing or did not make the STIP.

The four progressive "versions" of project lists are:

- **Version 1.0:** Initial list of projects from "brainstorming" workshops to identify projects that address gaps between Unitil's current state and Unitil's desired future state and ability to meet the GMP objectives.
- **Version 2.0:** Projects in the Version 1.0 list were then scored on various criteria such as cost, time to implement, risk, level of effort and ability to meet the GMP and Unitil objectives.
- **Version 3.0:** Additional cross-functional workshops were held to further classify the list of projects as low or high priority based on their ability to meet the GMP and Unitil's objectives. Only the high priority projects moved on for detailed cost and benefit development for evaluation in the BCA model.
- **Version 4.0:** After completion of the BCA, projects were evaluated and selected based on STIP criteria, the BCA results and Unitil's vision of becoming a distribution platform.

GMP Project List Progression to Final Recommended STIP

Project Being Considered **Project Dropped from Consideration**

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Adopt Class B distribution construction standards for better resiliency	Adopt Class B distribution construction standards for better resiliency	Deemed Low Priority. More of a long-term business practice vs a grid mod project.	
Reduce Storm Resiliency Program (SRP) form current 10-yr to 5-yr cycle	Reduce SRP form current 10-yr to 5-yr cycle	Reduce SRP form current 10-yr to 5-yr cycle	Dropped from STIP because project is purely O&M

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Enhance Hazard Tree program	Enhance Hazard Tree program	Enhance Hazard Tree program	Dropped from STIP because project is purely O&M
Perform pole-loading calculations when doing work on poles.	Perform pole-loading calculations when doing work on poles.	Deemed Low Priority. More of a long-term business practice vs a grid	
Proactive pole inspections and replacements (Investigate adding fumigation to the pole inspection routine and using c-trusses vs. pole replacement.)	Proactive pole inspections and replacements (Investigate adding fumigation to the pole inspection routine and using c-trusses vs. pole replacement.)	Deemed Low Priority. More of a long-term business practice vs a grid mod project.	
Upgrade #6 copper to jacketed ACSR for additional strength and resistance to tree contact.	Upgrade #6 copper to jacketed ACSR for additional strength and resistance to tree contact.	Upgrade #6 copper to jacketed ACSR for additional strength and resistance to tree contact.	Low NPV
Replace bare conductor with jacketed wire or spacer cable where incidental tree contact is an issue.	Replace bare conductor with jacketed wire or spacer cable where incidental tree contact is an issue.	Replace bare conductor with jacketed wire or spacer cable where incidental tree contact is an issue.	Low NPV
Develop analytics and visualization platform for DG & DER across service territory	Renamed: DER Analytics and Visualization Platform	DER Analytics and Visualization Platform	DER Analytics and Visualization Platform
Proactively replace underground cable (unjacketed direct bury and PILC)	Proactively replace underground cable (unjacketed direct bury and PILC)	Deemed Low Priority. Currently have a PILC replacement program and URD cable failure is not a significant contributor to outages.	

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Investigate Break-Away service connections	Investigate Break-Away service connections	Moved to possible RD&D project	
Implement an integrated Business Intelligence dashboard for outage monitoring and asset management	Implement an integrated Business Intelligence dashboard for outage monitoring and asset management	Dropped from consideration. New software update includes dashboard views that achieve most of this functionality.	
Improve ETR calculation and restoration status communication process for both blue sky and storm days.	Rolled ETR improvements into the Mobility project		
Integrate Mobile Damage Assessment tool into enterprise systems	Integrate Mobile Damage Assessment tool into enterprise systems	Integrate Mobile Damage Assessment tool into enterprise systems	Integrate Mobile Damage Assessment tool into enterprise systems
Increase visibility of real-time asset performance and status information, e.g. dissolved gas monitors on substation transformers	Increase visibility of real-time asset performance and status information, e.g. dissolved gas monitors on substation transformers	Rolled into Condition Based Maintenance project	
Investigate options for emergency communications out of cell/radio range	Dropped from consideration. Satellite phones are available for emergency communications.		
Expand AVL capability for viewing foreign crew locations on internal Unitil OMS map	Expand AVL capability for viewing foreign crew locations on internal Unitil OMS map	Dropped from consideration. Cost and effort not practical for the frequency of foreign crew assistance during	

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Implement OMS and IVR hot-standby technology	Implement OMS and IVR hot-standby technology	Implement OMS and IVR hot-standby technology	Low NPV
Conduct a DG monitoring pilot to learn about performance and management of distributed generation.	Conduct a DG monitoring pilot to learn about performance and management of distributed generation.	Conduct a DG monitoring pilot to learn about performance and management of distributed generation.	Moved to possible RD&D project
Implement VVO to manage the impact of DG on distribution feeders. (Split into more specific VVO components)	Automate Capacitor Banks for VVO	Automate Capacitor Banks for VVO	Automate Capacitor Banks for VVO
	Automate Voltage Regulators for VVO	Automate Voltage Regulators for VVO	Automate Voltage Regulators for VVO
	Automate Transformer Load Tap Changers for VVO	Automate Transformer Load Tap Changers for VVO	Automate Transformer Load Tap Changers for VVO
	Extend SCADA Communication to all FGE Substations	Extend SCADA Communication to all FGE Substations	Extend SCADA Communication to all FGE Substations
Implement an automated crew callout system	Implement an automated crew callout system	Deemed Low Priority. Costly, high level of effort to maintain and little savings due to small	
Implement Mobility platform for electric distribution crews for improved dispatching and status updates	Implement Mobility platform for electric distribution crews for improved dispatching and status updates	Implement Mobility platform for electric distribution crews for improved dispatching and status updates	Implement Mobility platform for electric distribution crews for improved dispatching and status updates
Install remote SCADA-enabled faulted circuit indicators in URD and strategically on overhead feeders.	Install remote SCADA-enabled faulted circuit indicators in URD and strategically on overhead feeders.	Deemed Low Priority. Faulted circuit indicators already strategically installed. Due to small service area, moving to SCADA-enabled provided	

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Implement Local Control option for automated feeder ties	Implement Local control option for automated feeder ties	Renamed: Auto-sectionalizing and Restoration	Low NPV
Install automatic Throwover in 69-kv substations for loss of source	Install automatic Throwover in 69-kv substations for loss of source	Install automatic Throwover in 69-kv substations for loss of source	Low NPV
Underground critical sections of the overhead distribution system	Underground critical sections of the overhead distribution system	Deemed Low Priority. High cost item relative to other options that impact outage frequency and	
Implement a Distribution Automation strategy. Install SCADA enabled reclosers, faulted circuit indicators and feeder ties strategically and tie	Renamed: Automated reclosers for FLISR	Deemed Low Priority. Given the high reliability and small number of circuits in FGE, the incremental benefits vs level of effort to implement is not practical.	
FLISR module for ADMS	FLISR module for ADMS	Deemed Low Priority. Given the high reliability and small number of circuits in FGE, the incremental benefits vs level of effort to	
Integrate AMI with OMS	Integrate AMI with OMS	Integrate AMI with OMS	Integrate AMI with OMS
Use Unmanned Aerial Vehicles (UAV, a.k.a drones) to patrol lines for vegetation management and restoration field assessment.	Moved to possible RD&D project		

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Implement a robust field communications architecture to support DA/ADMS/AMI/Radio	Renamed: Field Area Network for Distribution Automation	Field Area Network for Distribution Automation	Field Area Network for Distribution Automation
Develop microgrid strategy	Rolled into DG Pilot project		
Build a battery "farm" for DG energy storage	Build a battery "farm" for DG energy storage	Deemed Low Priority. High cost option. Preferred approach to DG through an appropriate tariff strategy that is fair	
Develop a probabilistic outage prediction tool to predict storm impact	Develop a probabilistic outage prediction tool to predict storm impact	Deemed Low Priority. Seen as a long-term business process strategy vs a grid mod project	
Develop an EV charging tariff	Dropped from consideration. Given the low penetration of electric vehicles in FGE and customer demographics, this did		
Develop business and technical architecture requirements for ADMS	Renamed: Implement ADMS	Implement ADMS	Implement ADMS
Utilize energy efficiency tariff for VVO	Utilize energy efficiency tariff for VVO	Utilize energy efficiency tariff for VVO	Utilize energy efficiency tariff for VVO
Improve internal planned outage communication process to minimize customer impacts.	Improve internal planned outage communication process to minimize customer impacts.	Deemed Low Priority. More of a long-term business practice vs a grid mod project.	

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Improve work management process automation & integration.	Improve work management process automation & integration.	Dropped. Project already in-progress	
Install EV charging stations	Dropped from consideration. Given the low penetration of electric vehicles in FGE and customer demographics, this did		
Move from time based maintenance in substations to condition based, e.g. dissolved gas monitors on substation transformers.	Move from time based maintenance in substations to condition based, e.g. dissolved gas monitors on substation transformers.	Move from time based maintenance in substations to condition based, e.g. dissolved gas monitors on substation transformers.	Low NPV
Propose a Tariff framework for customer owned DG	Propose a Tariff framework for customer owned DG	Propose a Tariff framework for customer owned DG	Propose a Tariff framework for customer owned DG
Evaluate residential level ice storage for demand reduction	Dropped from consideration. Prefer to be an 'enabler' and customer side solutions be provided by third parties rather than		
Proactively study circuits for future DG and construct system improvements to allow DG connection.	Proactively study circuits for future DG and construct system improvements to allow DG connection.	Proactively study circuits for future DG and construct system improvements to allow DG connection.	Proactively study circuits for future DG and construct system improvements to allow DG connection.

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Install territorial weather stations to enhance the accuracy of predicting the impact of weather events on the gird.	Dropped from consideration. Limited ability to impact grid mod objectives and evaluating weather data is not a core competency.		
Implement third party interest/partnerships to enable customer to make decisions about and control their energy usage.	Implement third party interest/partnerships to enable customer to make decisions about and control their energy usage.	Rolled into web portal	
Create a customer web portal for customers to access 15-minute interval data on their account information and usage on-line.	Create a customer web portal for customers to access 15-minute interval data on their account information and usage on-line.	Create a customer web portal for customers to access 15-minute interval data on their account information and usage on-line.	Create a customer web portal for customers to access 15-minute interval data on their account information and usage on-line.
Implement an integrated mobile app (e.g. iFactor, Exceleron) for customers to report and monitor power outage, manage and pay their bills, etc.	Rolled into customer portal initiative		
Implement customer prepay option	Implement customer prepay option	Dropped from consideration. Current consumer protection rules seen to be an obstruction to implementation when other solutions may achieve the same goals	

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Implement forward looking bills	Determined to be low priority		
Issue usage alerts and new rates	Determined to be low priority		
Control of appliance	Control of appliance	Dropped from consideration. Prefer to be an 'enabler' and customer side solutions be provided by third parties rather than specify a solution.	
Educate the customer by providing more clarification of the source of the various cost components of their total electric cost.	Redefined: GMP Customer Education Program	GMP Customer Education Program	GMP Customer Education Program
Develop customer focused process for DG interconnection	Develop customer focused process for DG interconnection	Rolled into DG Capacity Study project	
Offer TVR and Demand Response rates.	Redefined: TVR and AMF	Renamed: TVR and AMI	TVR and AMI
Gamification of energy efficiency and demand reduction.	Gamification of energy efficiency and demand reduction.	Gamification of energy efficiency and demand reduction.	Gamification of energy efficiency and demand reduction.
Upgrade the metering system to allow for the collection of customers' interval usage data in near real-time.	Rolled into TVR and AMF project		

Version 1.0 Initial GMP Project List	Version 2.0 Refined GMP Project List	Version 3.0 High Priority GMP Project List	Version 4.0 Recommended STIP Project List
Install 3VO relay protection in substations	Install 3VO relay protection in substations	Install 3VO relay protection in substations	Install 3VO relay protection in substations
Upgrade voltage regulation controls in substations for two-way power flow	Upgrade voltage regulation controls in substations for two-way power flow	Upgrade voltage regulation controls in substations for two-way power flow	Upgrade voltage regulation controls in substations for two-way power flow

Appendix B. Benefit/Cost Analysis (BCA) Model

Model Satisfaction to the BCA Order

The BCA model was designed with respect to the five-year cost (STIP) and fifteen-year benefit (GMP) horizons elaborated by DPU Order 12-76-C. The model, optionally, can also calculate costs out to a twenty-year horizon. Additionally, Unitil relied on the DPU Business Case Template Excel document as a starting point in the structuring of data fields and category relationships in the model. The model, therefore, closely resembles the DPU template in many organizational and hierarchical aspects. It also includes several spreadsheets enabling the end-user to transfer benefit and cost results to the DPU Template. Enclosed with the filing is an electronic copy of the BCA model spreadsheet and sensitivity analysis results.

The model consists of sheets grouped into five color-coded, logical sections:

(1) Introduction,
(2) Results & Summaries,
(3) Parameters & Inputs,
(4) Terms & Definitions, and
(5) Miscellaneous.

The final benefit and cost results appear in the second section. They are triggered and calculated by the current STIP Option selected in the model. The parameters and STIP data are in the third section. The fourth and fifth sections contain tables, calculations, and validation lists needed for the second and third sections.
The Unitil internal project team also developed a supplemental PIF in Excel and distributed the file to Unitil staff for data collection purposes. The PIF is the standardized data entry tool for the various programs, initiatives, and projects described in the GMP and required by the model. The model enables the end-user to quickly import the data from the PIF by an automated Visual Basic for Applications (VBA) routine.

Quantifiable and Non-quantifiable benefits and costs

DPU Order 12-76-B directs utilities to calculate the quantifiable benefits and costs resulting from capital investments made in the STIP. Consequently, these investments form the basis of the business case analysis. Utilities may also deem changes in projected O&M expenses resulting from the STIP as benefits, if there is a decrease, or as costs, if there is an increase.

The BCA Model summarizes benefits by the various program, initiative, and project categories outlined in the GMP, as well as the customer and utility categories specified in the DPU Business Case Template. Likewise, the costs are tracked by the GMP categories, and the "Type" classification identified in the Template. Several figures in the model also show additional groupings of benefits and costs.

Model assumptions and Global Parameters

Sensitivity Analysis

The GMP BCA Model enables a sensitivity component of the comprehensive business case analysis. For this purpose, the model provides two primary methods of comparing variable STIPs and the accompanying differences in benefits and costs. The first method is a STIP-to-STIP comparison, in which the resulting changes between two plans containing different sets of project line items and/or project data inputs are compared. The second method is a parameter comparison, where STIPs are compared under different global assumptions (set in the Parameters worksheet).

By default, the model contains a side-by-side comparison view, which allows the end-user to load both a primary case (e.g. "base") and a secondary case (e.g. "alternate").[26] The tool is limited to two cases only for the sake of preserving system resources and aiding computation speeds. A two-case sensitivity comparison could involve two different STIPs, the same STIP with different parameters, or some combination of the two approaches.

From the process of developing the high priority project list, more detailed cost information was gathered from vendor quotes and internal Unitil estimates. Any unquantifiable costs were also captured. Both quantifiable and unquantifiable benefits were estimated for both the utility and the Unitil customers. The quantifiable costs and benefits were inputs into the BCA model for analysis.

The reliability customer benefits were quantified using a modified approach to the Lawrence Berkeley National Labs ICE (Interruption Cost Estimate) calculator that estimates the cost of power interruptions to customers. For projects that resulted in customer benefits due to few or shorter duration outages, a dollar figure was calculated. The BCA was run with and without the inclusion of these benefits as a sensitivity analysis in order to gauge the impact of customer benefits on the feasibility of the project.

[26] However, through copying, saving, and opening multiple instances of the model Excel file, one could conceivably expand such a comparison to three, four, or more cases.

Sensitivity analyses were performed on projects through the BCA and the results were evaluated for inclusion in the STIP. Other factors such as rate impact to the Unitil customers and Unitil's ability to manage and implement multiple projects were also a part of the decision making process to determine which projects were to be included in the STIP.

Appendix C. Unitil Grid Modernization Customer Survey Report

Unitil Grid Modernization Customer Survey Report
6/3/2015

Background
From May 27-June 2, 2015, Unitil issued an email survey to 7368 of its gas and electric customers to gather input for Unitil's Grid Modernization Plan, as well as educate customers on grid modernization.

The survey sought customers' thoughts on Unitil's approach to the Grid Modernization plan, their reaction to the list of initiatives and whether the plan reflects their priorities and concerns. Additionally, the survey gauged familiarity with grid modernization, the importance of Unitil investing in solar power, service and rate satisfaction and demographic information.
457 customers participated in the survey, netting 324 completed surveys (6 were disqualified with a quality control question) and 127 partial surveys. This report analyzes the completed survey responses only.

Demographic Information
Most of the survey responses were residential customers, with only two small C&I customers responses. 76% own their primary residence, and number per household was:

- 1: 20.4%
- 2 : 37.2%
- 3-4: 32.8%
- 5-6: 8.7%
- 7 or over: 0.9%

Income breakouts were: less than \$35,000 - 19.2%; \$35,000-\$65,000 - 26%; \$65,000-\$95,000 - 24% and over \$95,000 - 30.8%.

The percent respondents in each age range were:

- 18-25: 3.1%
- 26-35: 22%
- 36-45: 22.3%
- 46-55: 18.3%
- 56-65: 20.7%
- 66-75: 10.2%
- 76 or older: 3.4%

51.9% of the responses were from desktop computers, and 47.2% were from mobile devices.
Survey Results

Unitil customers' overwhelming concern was high rates, ranking it as the top priority for grid modernization. (While 77.3% were very satisfied or somewhat satisfied with Unitil service, 82.6% were dissatisfied or very dissatisfied with Unitil rates.) Some expressed disinterest in grid modernization if it did not lower rates.

The second grid modernization priority was reliability. The bottom priority of six grid modernization choices was "encouraging technology and innovation for the electric industry."

Customer familiarization with grid modernization (very familiar and somewhat familiar) was 55.8%, suggesting awareness of "grid modernization." Unitil also believes focused outreach and education explaining Unitil's grid modernization program is critical.

There is significant interest in solar – 91.6% indicated that Unitil's investment in solar power was very important or important. Chief reasons cited were lower energy costs and the environmental value of clean renewable energy.

Continuing the thread of high rates, customers ranked the most important the grid modernization program under consideration was "New tools and information to enable you to use less electricity when prices spike". The second most important program was "Utility scaled energy management systems to support more residential solar, wind and other local and renewable sources of power." Their least important program of the seven choices was "A mobile app to manage your account, monitor your energy use and report power outages."

71.4% of the respondents believed the list of initiatives reflected their priorities and concerns. 28.6% did not believe their priorities or concerns were not included and they listed:

Priority/Concern	***Count***
High cost	54
Solar and green energy	7
Reliability	3
Choice of other distribution companies	2
Burying lines underground	2
Unitil operating more efficiently	2
Dislike of Unitil	1
Energy efficiency	1
Going off the grid	1
More energy usage information	1
Synchronizing meter info with bill, improved vegetation management and lower generation costs	1
Other	1

Customers were also asked if they had additional comments, and below are the categories of responses:

Comment	***Count***
High cost	51
Solar/generating own power/renewables	11
Dislike of Unitil	5
More energy efficiency incentives	3
Improved reliability/maintenance	3
Bury lines underground	2
Improved vegetation management	2
Choice of other distribution companies	2
Grid security	1
Unitil offering same service and price as munis	1
More details on rates	1
Grid vulnerability to natural disasters and terrorism	1
Sustainability	1
Vendor offering Smart grid sensors	1
Concern with RF pollution	1
Gas leak issue	1
Mobile app and web upgrade	1
Don't do TVR	1
Provide tools to manage energy usage	1

Survey Content

Email

Subject: Survey Request – Influence Unitil's Plans to Modernize Its Electric Grid

Email Text:
Unitil, part of a Massachusetts –wide electric grid modernization initiative, seeks your input in the following online survey (hyperlink to survey) and introduce you to the concept of grid modernization.

Unitil, along with all of Massachusetts' electric utilities, is developing plans to modernize its electric grid and the ways in which we serve customers. The electric industry is in the midst of a transformation where digital technologies that have reshaped so many industries are now available to improve operations of the electric system and service to electric customers.

The Massachusetts Department of Public Utilities has directed the utilities to examine investments that can leverage new technology to:

- Help customers better manage and reduce electricity costs
- Enhance the reliability and resiliency of electric service during extreme weather events
- Support innovation and investment in new technology and infrastructure designed to strengthen the state's competitive electricity market
- Meet clean energy requirements by integrating renewable power, demand response, energy storage, microgrids and electric grids, and increased energy efficiency.

We are excited about the opportunity to enhance the electric system and offer new tools to our customers, but we are sensitive to the costs and what they mean for rates paid by our customers. Your confidential feedback in the form of this brief 5-minute survey (hypertext link) will help us develop our plan. Please complete this as soon as possible, but no later than June 3.

Thank you. We value your insights.

Unitil's Grid Modernization Team

Here is a link with more information on this concept of "Grid Modernization:" http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/grid-mod/grid-modernization.html

Survey

Introduction

Our Commonwealth's vision of the electric system of the future is for a cleaner, more efficient, more reliable and able to empower customers to manage and reduce their energy costs. The modern electric system will build on the Commonwealth's progress towards clean energy goals by maximizing the integration of solar, wind and other local and renewable sources of power. It would aim to minimize outages by automatically re-routing power when lines go down, and alert the utility when customers have lost power. As part of this vision, customers will have new tools and information available to enable them to use less electricity when prices spike. As a result, the Commonwealth hopes the electric system may be appropriately sized and less expensive.

Your confidential answers to the following questions will help guide us as we develop our 10-year plan to modernize is electric system. We appreciate your thoughts.

What type of customer are you?

- Residential
- Commercial or Industrial

FOR RESIDENTIAL CUSTOMERS:

Your primary residence is

- Rental
- Owned
- Other

Number of people in your household

- 1
- 2
- 3-4
- 5-6
- 7 or over

What is the total annual income of all members in your household?

- Less than $35,000
- $35,000 to less than $65,000
- $65,000 to less than $95,000
- $95,000 or more

Which of the following best describes your age?

- 18-25
- 26-35
- 36-45
- 46-55
- 56-65
- 66-75
- 76 or older

FOR COMMERCIAL AND INDUSTRIAL CUSTOMERS:

How many of your company employees work in Massachusetts?

- 0-10
- 11-50
- 51-100
- 101-500
- Over 500

What is your approximate total annual revenue?

- $0-50,000
- $50,001-$100,000
- $100,001- $500,000
- $500,000-1,000,000
- Over $1,000,000

ALL CUSTOMERS

Overall, how satisfied are you with Unitil's service?

- Very satisfied
- Satisfied
- Dissatisfied
- Very dissatisfied

Overall, how satisfied are you with Unitil's rates?

- Very satisfied
- Satisfied
- Dissatisfied
- Very dissatisfied

As you think about your energy use and the notion of a modernized grid please prioritize the following (1=highest priority and 6=lowest priority)

- Reliability
- A clean environment
- Ability to manage my energy usage
- Ability to generate my energy
- Rates

- Encouraging technology and innovation for the electric industry

How familiar are you with the term "grid modernization?"

- Very familiar
- Somewhat familiar
- Not at all familiar

For quality control, please select the answer twenty-five for this question

- 5
- 15
- 25
- 50

About how many power outages have you experienced in the last 6 months. (Please count sustained outages lasting more than 5 minutes.)

- 0
- 1-2
- 3 or more

Please rank from most important = 1 to least important = 3 the following items that answer this question: If we could improve overall reliability, provide additional outage information and shorten the duration of outages, how valuable would that be to you?

- Improve overall reliability
- Provide additional outage information
- Shorten the duration of outages

If Unitil made the investment to enable more solar power in its service territory, how important would it be to you?

- Very important
- Somewhat important
- Not important at all

Below is a partial list of programs we are considering. Please rank them with 1=most important and 7=least important. (Please note, we will be evaluating these programs on customer benefit, cost effectiveness and practicality, so some may not be pursued.)

- Enhanced hazard tree trimming programs to minimize electric outages

- Improved Outage Estimated Time of Restoration information
- Web site to provide customers the ability to manage their account and energy use
- A mobile app to manage your account, monitor your energy use and report power outages
- Utility-owned energy management systems to support more residential solar, wind and other local and renewable sources of power
- New tools and information to enable you to use less electricity when prices spike
- Digital automation technologies to manage the grid, reduce outages

Does the above list of initiatives reflect your priorities and/or concerns?

- Yes
- No. My priorities and/or concerns are ______________________________________

Additional Comments____

Appendix D. STIP Revenue Requirement and Bill Impact

A. Introduction

The following summary of the Company's proposal to recover STIP related investment and expenses includes: (a) an overview of the framework of Unitil's proposed STIP cost recovery clause ("Short Term Investment Clause", or "STIC"), which the Company will file at the appropriate time, (b) an analysis of the annual STIP Revenue Requirements and rate impacts that are associated with the Company's STIP, (c) an explanation of the methodology that was used to calculate the annual Short Term Investment Factors ("STIF"), based on the calculated STIP Revenue Requirements, and (d) the bill impacts associated with the calculated STIFs. The Company's calculations and supporting data for the STIP Revenue Requirements and adjustment factors are provided in Appendices D, Attachments 1 through 5.

B. Recovery of STIP-related Costs

1. Overview

Some of the Company's STIP projects that will be initiated within the first five years of the GMP will not be completed until GMP Year 10. As a result, the Company's proposed STIC will recover the revenue requirements associated with the Company's STIP-related plant and expenses over GMP Years 1 to 10, which are assumed to be the calendar years 2017 through 2026. The STIP-related plant and expenses are explained and supported in detail in this GMP Report, Section 2. The calculation of the STIP Revenue Requirements is explained in Appendix D and the supporting data and calculations are provided in Appendix D, Attachments 1, 2 and 3.

2. Details of the Company's STIC Approach

<u>STIC Schedule</u>: Unitil proposes the following schedule:

- Annual STIC filings will be made October 1 of each year, for STIF rates that are to be effective the January 1 following the filing, based on planned Eligible STIC investment and expenses made during that upcoming GMP Cost Year that starts the January 1 following the filing.
- The Short Term Reconciliation Factor filing will be made March 1 following each GMP Cost Year, to be effective June 1.

STIP Revenue Requirement: The annual GMP Revenue Requirement will include (a) return on rate base[27] plus associated taxes calculated by applying Company's pre-tax rate of return to average rate base; property taxes, (c) depreciation expense and (d) GMP-related expenses.

STIF Rate Design: The Company proposes to use a distribution revenue allocator as determined in the Company's most recent base rate case filing to allocate the total STIP Revenue Requirement to each rate class grouping, The STIF for each rate group will be determined by dividing the rate group's share of the STIP Revenue Requirement by forecasted kWh for each Rate Class that does not employ a distribution demand rate and by kW or kVA for each Rate Class that employs a distribution demand rate

Short-Term Investment Reconciliation Factor: The Company will include a Short-Term Investment Reconciliation Factor ("STIRF") to reconcile the difference between actual cumulative STIP Revenue Requirements for a GMP Cost Year and the billed revenue from the STIF associated with that GMP Cost Year.[28]

C. STIP Revenue Requirement Details

Appendix D, Attachment 1 provides a summary of the STIP revenue requirements for the 2017 through 2026 GMP Cost Years, and Appendix D, Attachment 2 provides the detailed Revenue Requirement and Deferred Tax calculations for the 2017 GMP Cost Year. Appendix D, Attachment 3 provides detailed STIP costs by FERC account for the 10-year period 2017 to 2026.

1. Rate Base

Detailed calculations for 2017 GMP Cost Year Rate Base are provided in Appendix D, Attachment 2, lines 70 - 74. Line 70 shows Total Capital Expenditures, which is the sum of net plant additions (line 7) and cost of removal (line 19). For preliminary purposes, the Company has applied a 5% cost of removal factor to the forecast STIP plant additions in Account 362, 364, 365, and 370 (lines 2 – 5).[29]
Year-End Rate Base (line 74) is the sum of total capital expenditures (line 70); Accumulated Depreciation (line 71); and deferred taxes (line 37). Return and Taxes (line 78) is calculated by multiplying (a) the

[27] Because the Company will charge Customers opting into the optional TVR service the costs of the meter upgrade as part of the rate, the meter upgrade costs would not be recovered through the STIF. Accordingly, STIP meter upgrade costs are not included in the STIC revenue requirement calculations and STIF bill impact analyses provided in Appendix D, Attachments 1 – 5.

[28] The Company would include interest on any GMP Reconciliation balance, accrued at the prime rate as reported by the *Wall Street Journal*.

[29] The Company will use the actual cost of removal rate in the Company's annual GMPAF reconciliation filings.

Company's pre-tax rate of return, approved in the Company's most recent rate case[30] (D.P.U. 13-90) times (b) the average of current year and prior year-end rate base.

2. Deferred Income Taxes

Detailed calculations of deferred taxes is shown in Appendix D, Attachment 2, page 3. The calculation of capital repairs deductions is shown on lines 3-5 (Federal) and lines 29 – 31 (State). These calculations are based on a forecasted repairs deduction rate of 39% of utility plant. [31]
The Company is not assuming a Bonus Depreciation tax deduction.

3. Additional Revenue Requirement Details

- The book depreciation rates (Appendix D, Attachment 2, Page 1, lines 33 – 38) are based on those established in the Company's most recent rate case, D.P.U. 13-90.
- The calculated book depreciation expense (Appendix D, Attachment 2, Page 2, line 53) is the net of book depreciation associated with plant additions (Appendix D Attachment 2, Page 2, lines 40 – 45) minus book depreciation associated with retirements (Appendix D, Attachment 2, Page 2, lines 47 – 52). For these calculations, a forecast 5% retirement rate was used.[32]
- The calculated property tax expense (Appendix D, Attachment 2, Page 2, line 80) is based on the Company's 2014 property tax rate, which is calculated using plant and depreciation balances as reported in the Company's 2014 FERC Form 1 (page 200) and per books Property Tax Expense.[33]

[30] Details of the Company's pre-tax rate of return, approved in D.P.U. 13-90:

		Cost of Capital		Pre-Tax Cost of Capital	
Item	Percent Total	Rate	Weighted Cost	Tax Factor	Weighted Cost
Debt	52.22%	6.99%	3.65%		3.65%
Equity	47.78%	9.70%	4.63%	1.6469	7.63%
Total	100.00%		8.28%		11.28%

[31] The Company will use the actual repairs deduction rate in the Company's annual STIRF filings.
[32] The Company will use the actual retirement rate in the Company's annual STIRF filings.
[33] The Company will use actual FERC Form 1 and per books data to calculate the property tax rate in the Company's annual STIRF filings.

4. Overhead Tests

To ensure that the Company does not double recover overhead costs, the Company will apply a two-step process[34] in the annual STIRF filings that (a) compares actual labor overheads and clearing account burdens charged to O&M expense in the applicable year, to the base-line amounts embedded in base rates as established in the Company's most recent base rate case proceeding; and (b) evenly allocates capitalized labor overheads and clearing account burdens across all capital projects.

5. STIP Expenses

As explained in Section 2 the estimated STIP costs include STIP-related expenses that are provided in Appendix D, Attachment 1, line 19; the STIP-related expenses consist of (a) expenses that are directly related to the GMP project investments, (b) Customer education and outreach expenses, and (c) the Company's research, development, and deployment plan costs.

D. STIP Revenue Requirement Summary

The Company's forecast STIP Revenue Requirements to be recovered by the proposed STIF are provided in Appendix D, Attachment 1, line 15 (cumulative revenue requirements) and line 16 (incremental revenue requirements. Appendix D, Attachment 1, line 18 indicates that the incremental rate impact of the Company's STIP, averaged over all customers, is never greater that 0.7% of total revenues (2022); the ten year[35] incremental rate impact averages 0.3%. Appendix D, Attachment 1, line 19 indicates that the cumulative rate impact of the Company's STIP, averaged over all customers, is 3.2% in Year 9 and Year 10.

E. STIF Rate Design

Appendix D, Attachment 4 provides the supporting detail for the calculation of the class-specific STIFs. The GMP Cost Year Revenue Requirements (line 3) are allocated to rate groups based on distribution revenues by rate group (lines 4 – 8, 10 – 14 and 15 – 19) as approved in the Company's most recent rate case, D.P.U. 13-90. The STIF rates to be charged to rate classes that do not employ a distribution demand rate (RD-1, RD-2, GD-1, GD-5 and the outdoor lighting classes) are calculated by dividing (a) the allocated shares of the STIP Revenue Requirements (lines 15 – 20) by (b) annual forecast kWh billing determinants (lines 22 – 27). The STIF rates to be charged to rate classes that do employ a distribution demand rate (GD-2, GD-3, and GD-4) are calculated by dividing (a) the allocated shares of the STIP

[34] This process is not reflected in the forecasted STIP investments that are provided in Appendix D, Attachment 2, page 1, lines 1 - 6. Rather, the Company will apply this two-step process in the Company's annual STIRF filings.

[35] Assumed to be 2017 – 2026.

Revenue Requirements (lines 15 – 20) by (b) annual forecast kW or kVA billing determinants (lines 22 – 27). The resulting STIF rates are shown on lines 33 – 39.

F. STIF Bill Impacts

Appendix D, Attachment 5 provides a condensed Bill Impact Analysis for each of the Company's rate classes, for appropriate ranges of monthly usage.

Appendix E. NECEC Report

Appendix F. TCR Report

Appendix G. Concentric Report on TVR