Unitil Energy Systems

Report on
Least Cost Integrated Resource Planning
2020

Unitil
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1 EXECUTIVE SUMMARY

Unitil Energy Systems, Inc. ("UES") hereby submits its 2020 Least Cost Integrated Resource Plan ("LCIRP") pursuant to RSA 378:38.

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

The most recent five year capital budgets for UES-Seacoast and UES-Capital can be found in Appendix A – UES-Capital – 2020-2024 Capital Budget and Appendix B – UES-Seacoast – 2020-2024 Capital Budget, respectively.

UES serves two geographically separate regions in New Hampshire. UES-Seacoast serves the seacoast area of New Hampshire while UES-Capital serves the Concord, NH area and surrounding towns. The electric systems for both areas a not interconnected. Therefore, the planning for UES-Seacoast and UES-Capital is covered by separate planning studies.

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

Demand side planning is creating the need for change in the historical distribution and system planning processes. Customer acceptance of distributed generation technology coupled with expansion of existing energy efficiency and net metering initiatives is causing an increase in demand side resources. Unitil incorporates demand side resources in many ways and continues to evaluate how to better incorporate these resources into future planning efforts. The effect of these resources is generally included in the historical load data.

2 TERMINOLOGY

The following terms are used throughout this document.

System Supply – A collection of electrical facilities, including lines, transformers, and protection and control equipment that steps down electric power from the transmission system to the Subtransmission System. At this time UES owns two System Supplies (Kingston and Broken Ground substations). Four System Supplies serving UES are owned by Eversource (Timber Swamp, Great Bay, Garvins, and Oak Hill). UES connects to the Eversource System Supplies at 34.5kV. The System Supplies of UES connect to the transmission system at 115kV and 345kV.

Subtransmission System – A collection of 34.5kV lines, switching stations, and substations that serve distribution substations and 34.5 distribution circuit taps. The system is designed such that for the loss of a parallel or double-ended subtransmission line, switching can be performed to reconfigure the system to restore affected load. Unitil refers to Subtransmission System Planning as Electric System Planning.

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

Distribution Substation – A collection of equipment and transformers used to step the subtransmission voltage (34.5kV) down to a lower voltage (13.8kV or 4.16kV).

Subtransmission Tap – A collection of equipment used to tap the Subtransmission System to supply a 34.5kV Distribution Circuit.

Distribution Circuit – A radial feeder that serves customer load directly. A Distribution Circuit may originate from a Distribution Substation or a Subtransmission Tap. The primary voltages of UES distribution circuits are 4.16kV, 13.8kV, or 34.5kV. Some Distribution Circuits include stepdown transformers that convert the primary voltage from 34.5kV or 13.8kV to 13.8kV or 4.16kV. A Distribution Circuit may include a normally open switch that would allow a tie to another Distribution Circuit during planned or emergency system switching.

Distributed Energy Resources (DER) – Sources and groups of sources of electric power that are not directly connected to the bulk power system. DER includes both generators and energy storage technologies capable of exporting active power to the electric distribution system.

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

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

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

3 OVERVIEW OF LCIRP

UES, through Unitil, performs various and ongoing planning activities to assess the short-term and long-term requirements and capabilities of its electric distribution system. These activities include distribution system planning to evaluate primary distribution circuits and substations, electric system planning to evaluate UES subtransmission facilities and system supply points, joint system planning to evaluate the external delivery system which provides UES access to regional transmission and generation resources, and participation in statewide and regional transmission planning efforts. These planning efforts include the review of non-wires alternative (NWA) projects to alleviate system constraints. Additionally, Unitil's planning process along with its DG (Distributed Generation)/DER (Distributed Energy Resources) interconnection process review the impacts of existing and proposed DER on the system.

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

4 SYSTEM DESCRIPTION

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

UES does not own any generating facilities within either of its operating systems, nor does it own any transmission facilities. Therefore, UES is dependent on others to provide the physical access to the region's transmission and generation resources. UES receives Transmission Service from Eversource for connection to the region's transmission system. With the exception of two 115kV /34.5 V substations owned by UES, power is delivered to both the UES-Capital and the UES-Seacoast systems at the 34.5kV distribution level at multiple locations via a supplemental Distribution Service from Eversource.

4.1 UES–Capital System

The UES-Capital distribution system is comprised of forty-eight distribution circuits operating at primary voltages of 4.16kV, 13.8kV and 34.5kV. The majority of these circuits originate from sixteen distribution substations supplied off the UES-Capital 34.5kV subtransmission system. Three circuits and a few single customer taps are supplied directly off the 34.5kV subtransmission lines.

The UES-Capital Subtransmission System consists of ten 34.5kV subtransmission lines interconnecting the sixteen distribution substations. The subtransmission lines are generally constructed in off-road right-of-ways ("ROW"). The subtransmission system is a subset of the UES distribution system, and is classified as distribution facilities. However, UES uses the term "subtransmission" to distinguish these portions of the system for their particular function of transporting power from the various supply points to traditional distribution substations and circuits. The Eversource supply into the UES–Capital system is delivered at Eversource's Garvins substation, UES's Penacook substation (from Eversource's Oak Hill substation) and Eversource's Curtisville substation.

The Eversource Garvins substation, located in Bow, NH is served from three 115kV transmission lines. Two 115 - 34.5kV, 36/48/60 MVA transformers supply the Garvins 34.5kV bus which consists of six 34.5kV line breakers and a breaker interconnecting the adjacent Garvins Falls Hydro station. Three on the line breakers at Garvins directly supply UES-Capital subtransmission lines.

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

The Eversource Curstisville substation supplies the UES Broken Ground substation, located in Concord, NH, with two incoming 115kV transmission lines. Curtisville substation is supplied by an in-and-out loop of an Eversource 115kV line approximately mid-way between Garvins substation and Farmwood substation. Broken Ground substation consists of two 115 – 34.5kV, 60 MVA transformers supplying two 34.5kV buses. Three UES 34.5kV subtransmission lines originate at Broken Ground.

In addition to the interconnections with Eversource, four non-utility generating plants connect internally into the UES-Capital system. The largest, Wheelabrator Concord (SES-Concord), interconnects at 34.5kV 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 34.5kV in the vicinity of Penacook substation.

4.2 UES–Seacoast System

The UES-Seacoast distribution system is comprised of forty-seven distribution circuits operating at primary voltages of 4.16kV, 13.8kV and 34.5kV. The majority of these circuits originate from fifteen distribution substations supplied off the UES-Seacoast 34.5kV subtransmission system, while twelve circuits and a few single customer taps are supplied directly off 34.5kV subtransmission lines.

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

The Eversource Peaslee substation supplies UES's Kingston substation, located in Kingston, NH. Peaslee substation is a 5 terminal 115 kV switching station with two outgoing 115kV lines that supply the UES-Seacoast Kingston substation. Kingston substation consists of two 115 – 34.5kV, 60 MVA transformers and two 34.5kV buses. Four 34.5kV subtransmission lines and two 34.5kV distribution circuits emanate from Kingston substation.

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

Eversource's Timber Swamp substation is located in Hampton, NH, and consist of a 345kV high-side ring bus, two 345 – 34.5kV, 84/112/140 MVA transformers, and two 34.5kV low-side buses with a normally open bus tie breaker. Each transformer separately supplies one of the low-side buses in the normal configuration. UES's 3360 and 3371 subtransmission lines are supplied directly at the substation from two line breakers off one of the 34.5kV buses.

The UES-Seacoast system also has the ability to be served from alternate lines out of Timber Swamp substation.

5 SUBTRANSMISSION SYSTEM PLANNING

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

5.1 System Planning Objectives and Methodology

The main objective of Unitil's electric system planning process is to provide safe, economical, and reliable service of the subtransmission system. Planning for expansion of the electric system is performed by Unitil's Distribution Engineering Department. The electric system planning process evaluates the UES subtransmission systems and the System Supply points serving the UES system. A flow chart displaying the full process of planning system improvement through budgeting approval is included in Appendix C of this report.

The study process examines a ten year forecast of system conditions to identify when individual equipment loading and voltage performance concerns will occur, and propose specific system modification recommendations to meet Unitil's system planning guidelines (see Appendix D – Unitil Electric System Planning Guide).

The electric system planning process starts with the Distribution Engineering Department forecasting the system load demands for the each UES operating area. Three load levels (Average Peak Load, Peak Design Load and Extreme Peak Load) are calculated and projected for ten years in the future. In projecting future loads, it is important to use realistically conservative load projections. If the load projections are not conservative enough, the system could be undersized for the amount of load experienced and electric equipment could fail resulting in large customer outages. However, if the load projections are overly conservative, the cost to the ratepayers to design and build a system capable of serving the projected load could be unrealistically high. For that reason Unitil uses two load levels in its system planning process. The Peak Design Load is used when evaluating the system's ability during equipment contingencies. The Extreme Peak Load is the load level with a probability of being exceeded once every twenty-five years. This load level is used to evaluate the system's capability during normal system conditions with no equipment contingencies.

The load projections are then entered into a computer model of the lines and electric system equipment. The model contains impedance and thermal ratings of the electric equipment to calculate the expected voltages and power flows at each point on the subtransmission system. These calculated power flows are used to ensure the voltage is within specific ranges and the equipment is not overloaded.

5.2 System Load Projections

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

5.2.1 Projection Methodology

The historical basis for each system is a series of yearly regression models developed to correlate actual daily loads to a weighted temperature-humidity index (WTHI) derived from the average temperature and average dew point temperature of each day and the previous two days. Once a model is established, an estimated peak load can be derived for that season for any value of WTHI. There are two dimensions of variability introduced with this modeling. First is the highest WTHI 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 WTHI. 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 WTHI is assumed to follow the discrete distribution of past historical highest WTHI. The random possibilities of peak load outcomes for any specific WTHI are assumed to follow a standard probability distribution model with a mean centered on the point estimate of the peak load at that WTHI 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 WTHI and random peak load estimates at those WTHI 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 WTHI possibilities and variability in loads versus WTHI. 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.

DER that are operating during peak load conditions offset system tie point power flows consequently reducing historical system loads. Therefore, the power offset or produced from all known significant DER units must be accounted for in the load forecasts. Unitil adds the output from all known significant DER units to its historical systems tie point flows prior to calculating the load forecasts. These units are then modelled in different dispatch scenarios in the system modelling process.

The aggregate amount of small scale "behind the meter" DER, such as residential inverter based PV interconnections, has significantly increased over the last couple of years. The effect that these interconnections tend to lag the actual load reduction experienced since the load forecasting procedure is based on ten years of historical data. Prior to finalizing load projections, the impact of installed DER as well as the aggregate amount of applications being processed is considered. Engineering judgement is used to determine if load projections should be reduced due to DER on a case by case basis. It is not anticipated that this process will be required long term since the DER offset will become inherent in the forecasting process over time and once the amount of interconnection applications drops off.

Unitil's Electric System Load Forecasting Procedure can be found in Appendix E.

5.2.2 <u>Load Levels</u>

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

For the purpose of assessing the adequacy of system infrastructure, contingency studies for the loss of major system elements are evaluated against *Peak Design Load* levels to identify where and when system constraints do not meet planning guidelines. The attached *Peak Design Load* projections are set at the 90%

probability limit. This is intended to roughly equate to only a 1-in-10 year likelihood that the *Peak Design Load* level will be exceeded.

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

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

5.2.3 <u>System Historical and Projected Loads</u>
The most recent system load projections for UES and a summary of historical peak loads can be found in the 2020-2029 UES-Seacoast System Planning Study and 2020-2029 UES-Capital System Planning Study (Appendices F and G).

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

Unitil's Electrical Equipment Rating Procedures can be found in Appendix H.

5.4 <u>System Modeling and Analysis</u>
Traditional load flow analysis methods are used to evaluate the UES-Capital and UES-Seacoast systems for these studies. System modeling and power flow simulations are performed using Siemens PTI PSS/E power flow simulation software. Because summer hot weather conditions present the greatest thermal constraints on system

equipment, and both UES-Capital and UES-Seacoast are historically summer peaking systems, these studies examined summer peak load conditions only.

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

Basecase models for study of future years are developed from these historical peak models. System improvements and configuration changes that are anticipated to be completed during the year that the study is being performed are modeled, and known individual load adjustments are made. Then overall bus loads are scaled based on distribution load forecast and system load projections. Internal, non-utility generation is set to their output at the system peak hour with the exception of hydroelectric generators. In some cases the historical output of hydroelectric generators during the system summer peak has been zero; therefor the output of hydroelectric generators is set to zero in the basecase models.

These basecase models are used to analyze normal operating conditions, extreme peak conditions, and all major design contingencies for the ten years period under study. Unacceptable system conditions are identified as system deficiencies based on the Unitil Electric System Planning Guide (Appendix D). With assistance from the Energy Systems Engineering Department and the associated Electric Operations Department system improvement options are developed and evaluated per the Unitil Project Evaluation Process (Appendix I).

5.5 Recommendations

Recommendations resulting from the electric system planning process for the years of 2020 through 2029 are in included in Appendix F – UES-Capital 2020-2029 Electric System Planning Study, and Appendix G – UES-Seacoast 2020-2029 Electric System Planning Study.

6 DISTRIBUTION SYSTEM PLANNING

Distribution planning consists of radial circuit analysis planning on UES' 34.5kV, 13.8kV and 4.16kV distribution circuits. Distribution planning also includes circuit load forecasting and loading reviews of UES' distribution substation transformers and equipment. Distribution system planning is conducted annually and covers a five year timeframe. Since the UES system is comprised of two geographically separate and distinct systems (Capital and Seacoast) separate planning studies are completed for each system.

6.1 Distribution Planning Objectives

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

6.2 Distribution Planning Process

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

6.2.1 Circuit and Substation Load Projections

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

DER facilities that are operating during peak load conditions offset circuit and substation power flows consequently reducing historical loads. Therefore, Unitil adds the output from all known significant DER units to its historical substation and circuit loads prior to calculating the load forecasts. These units are then modelled in the circuit analysis process per Unitil planning guidelines.

As is the case with system load projections the effect of small scale "behind the meter" DER tends to lag the actual load reduction experienced since the forecasting procedure is based on five years of historical data. Engineering judgement is used to determine if load projections should be reduced due to DER on a case by case basis. It is not anticipated that this process will be required long term since the DER offset will become inherent in the forecasting process over time and once the amount of interconnection applications drops off.

Unitil's Distribution Projection Guideline can be found in Appendix K.

6.2.2 Substation Transformer and Circuit Position Loading

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

Summer and winter peak load projections for the five year study period are compared to these ratings. Individual assessments are made where projected loads reach 90% of the Normal ratings for any circuit position or transformer. These individual assessments determine whether the loading condition requires remediation or further monitoring. System enhancements and/or modifications are made prior to the load reaching 100% of the limiting element rating.

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

6.2.3 Distribution Stepdown Transformer Loading

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

Individual assessments are made where the existing or projected load on any unit reaches 90% of the transformer limit. The summer normal limit used for distribution stepdown transformers is 120% of the nameplate rating[1].

6.2.4 Distribution Circuit Modeling and Analysis

Circuit modelling is performed on every circuit on the UES system each year. Detailed analysis is performed on a three year rotating cycle for both UES-Capital and UES-Seacoast systems, where each circuit is analyzed at least once every three years and more often if required. All other circuits not scheduled for detailed analysis in a given year are reviewed to confirm previous

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

study results. WindMil® circuit analysis software by Milsoft Utility Solutions is used for circuit modeling to identify potential problem areas.

Detailed circuit analysis starts with each circuit being exported from Unitil's GIS. This ensures the engineers are starting with the most up to date model available. The circuits are then imported into Windmil and loads are applied across the circuit using historical customer billing data and the five year load projections discussed above. Current magnitudes are compared to the seasonal rating criteria for each conductor section or piece of equipment detailed in the model. If the projected loading appears to exceed 90% of the seasonal Normal rating for any portion of the circuit, or the projected operating voltage is expected to fall outside of an acceptable range (97.5% to 105% of nominal for primary voltages), an individual assessment is made to determine how likely this condition is and what follow-up actions are needed.

A circuit review starts with a previous year's circuit model and has updated load projections. The circuit is reviewed for voltage and loading constraints to confirm previous results. Any discrepancies between results are reviewed in more detail.

Where a concern in considered likely to exist, improvement options are developed and evaluated in accordance with the Unitil Project Evaluation Process (Appendix F). In some cases, the condition may need field measurements or future monitoring to verify whether or not a present or future concern truly exists. In other cases, a concern is considered likely based on the confidence in the data and knowledge of the situation.

6.2.5 Distribution Study Results

Recommendations resulting from the distribution system planning process for the 2020 through 2024 planning period are in included in Appendix L – UES-Capital Distribution System Planning Study – 2020-2024, and Appendix M – UES-Seacoast Distribution Planning Study – 2020-2024.

7 JOINT SYSTEM PLANNING

Unitil participates in an annual joint system planning process with Eversource to establish an integrated, least cost plan of wholesale delivery facilities that affect both companies' systems.

7.1 Joint Planning Objectives

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

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

7.2 Guidelines and Design Criteria

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

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

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

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

7.3 Joint Recommendations

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

Recommendations resulting from the joint planning process for the years of 2020 through 2029 are in included in Appendix N – 2019 Joint Planning Report.

8 TRANSMISSION PLANNING

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

8.1 Eversource Transmission Planning and NH Network Operating Committee

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

8.2 ISO-NE System Planning

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

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

9 PROJECT EVALUATION

All loading and/or voltage based projects are reviewed and evaluated per Unitil's Project Evaluation Process (Appendix I). This process establishes a workflow for project evaluation, thresholds for alternative requirements, such as non-wires alternatives and a detailed cost/benefit analysis template.

9.1 Project Evaluation Workflow

Whenever a loading and/or voltage driven constraint is identified that will require upgrades to the distribution system, subtransmission system and/or within a substation the Project Evaluation Workflow Diagram defined in the Project Evaluation Process shall be followed to determine the need for alternatives and the necessary detail of project evaluation that will be required.

9.2 Detailed Cost/Benefit Analysis Template

The detailed cost benefit analysis template establishes a weighted scoring methodology that is used to calculate an overall ranking of alternatives. Alternatives are reviewed based on functionality, environmental impacts, reliability, feasibility, cost and value added benefits of DER.

9.3 UES-Capital 37 Line Loading Constraint

Unitil's 2019 planning process identified one proposed traditional project that triggered the review of non-wires alternative projects. In early 2019 as part of the UES-Capital system planning process Unitil identified the need to reconductor the 37 Line from Penacook to the MacCoy Street Tap in 2020. The estimated cost to reconductor the 37 line is $750,000 without construction overheads. This is the most costly project identified as part of the 2019 planning process

This project was evaluated per the Project Evaluation Procedure described in this section. Per the procedure non-wires alternatives (NWA) were not required to be evaluated, because the implementation date of the proposed traditional option is less than three years in the future. However, it was determined that Unitil would accept minimal risk and defer the reconductoring of the line to provide sufficient time to obtain information regarding NWA options.

Unitil issued a request for information for non-wires alternatives to nineteen vendors with four vendors submitting responses. A cost benefit analysis was performed and it was determined that Unitil would move forward with the traditional option.

Additional information regarding the project evaluation can be found in Appendix O – 37 Line / 4X1 Non-Wires Alternatives for Load Relief – Request for Information Evaluation.

9.4 Iron Works Transformer High-Side Fuse Loading Constraint

Unitil's 2019 planning process identified a loading constraint of the Iron Works substation transformer high-side protection in 2022. The proposed traditional alternative to address this constraint is to replace the existing fuses with a breaker or recloser and an associated relay. This is second most costly project identified as part of the Company's 2019 planning process.

This project was evaluated per the Company's Project Evaluation Process and did not require the review of NWA because the estimated cost of the project was less than $250,000 without construction overheads.

9.5 Dow's Hill Transformer Loading Constraint

Unitil's 2019 planning process identified a loading constraint of the Dow's Hill substation transformer in 2022. The proposed traditional alternative to address this constraint is to convert a portion of circuit 20H1 to 34.5kV operation and transfer the load to circuit 28X1. This is third most costly project identified as part of the 2019 planning process.

This project was evaluated per the Company's Project Evaluation Process and did not require the review of NWA because the estimated cost of the project was less than $250,000 without construction overheads.

9.6 Concord Downtown Conversion

In 2019 Unitil began construction on the conversion of portions of the Concord downtown area from 4.16kV to 13.8kV operation. The distribution upgrades and associated substation and subtransmission upgrades are expected to cost approximately $3,000,000. The construction to accommodate the conversion is expected to be completed by June of 2020.

These upgrades were required to accommodate unforeseen customer load additions in the downtown area. This project was evaluated per the Company's Project Evaluation Process and did not require the review of NWA because the required construction start date was one year in the future.

9.7 Other projects in 5 year budget

There are other projects in the Company's five year capital budget that are expected to cost more than $250,000 without construction overheads. However, these projects are not load and/or voltage driven and thus did not require NWA to be reviewed.

10 DISTRIBUTED ENERGY RESOURCES

UES does not own or operate any DER facilities and has no plans to install any at this time. Unitil does have two ongoing DER projects in its Fitchburg Gas and Electric Light Company (FG&E) subsidiary in Massachusetts. The first project is a 1.3MW Photovoltaic (PV) facility that was placed in service in 2017. This project was implemented in conjunction with the MA DPU and MA DOER to further the renewable energy goals of the Commonwealth of Massachusetts. The MA DPU granted Unitil accelerated rate recovery as well as recovery of O&M expenses associated with the project. In addition, this project is installed on a brownfield site of an old coal gasification plant allowing the company to make use of location that is not suitable for most uses. Since the project was installed and as of the end of 2019 the system has generated approximately 2,900MWh which has offset electricity that would have otherwise been purchased through the ISO-NE market.

The second project is a 2MW/4MWh energy storage facility that is scheduled to be placed in service in 2020. Unitil submitted and was awarded a grant covering one-half of the project cost by the MA Clean Energy Council. The energy storage facility is being installed to defer the need to upgrade substation transformer capacity. The addition of the grant allowed this project to be a good non-wires alternative to the traditional substation upgrade project. Both the PV facility and energy storage facility will allow Unitil to study the capabilities of these technologies as well as their invertors to better understand how they can benefit the electric distribution system. If these installations prove viable as non-wires alternatives, Unitil will look for opportunities to implement these solutions in New Hampshire.

The interconnection of DER onto the UES electric system is administered by the Distribution Engineering Department using a detailed process which is consistent with other utilities in the states of New Hampshire and Massachusetts. Over the past ten years (2010 through 2019) Unitil has had approximately 2700 DG facilities interconnect to the system for a total 42.5MW of generation capacity over that same timeframe.

Unitil is currently in the process of developing a hosting capacity map as well as heat maps that show electric load and the most constrained areas on the distribution system. These maps can then be used by DER vendors to determine what areas of the system to target for potential installations. If these efforts prove successful, Unitil plans to create these maps for UES.

Customer owned DER consists of facilities producing power for the purpose of selling to the wholesale market or directly to Unitil, as well as generating units installed to assist with customer thermal loads or load reduction units. The number of small (less than 250 kVA) Net Metering units have increased noticeably over the past couple years. For planning purposes, these units become part of the historic load and are accounted for in load regression models.

Generators larger than 500 kVA are evaluated in the System Planning process. 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. For basecase modeling of the system, any one generating plant and the largest distributed generation facility, as well as any one additional distributed generation facility shall be modelled out of service. For contingency modeling of the system all distributed generation facilities are modeled at their historical output during the season of study with the largest facility modelled off-line. All generation that is expected to trip offline during the fault under study is considered to remain offline following restoration switching. In addition, the largest single generator interconnected to the source/line used for restoration of load is modelled offline prior to the fault occurring and following restoration switching.

Generators 500 kVA or larger are also evaluated in the distribution planning process. Due to the uncertainty of the availability of a single DG facility, when performing peak load analysis on any circuit with only one 500 kVA or larger facility interconnected the facility is modelled offline. When performing analysis on circuits with more than one 500 kVA or larger generator interconnected the circuit shall be analyzed under various generation dispatch scenarios.

10.1 DER Projections

Unitil produces five year projections of the installed capacity of DER. The process for developing the DER capacity projections requires the projection of small DER facilities based on five years of historical data. These projections are then added to the capacity of all DER facilities to create an overall DER capacity projection for each distribution circuit, distribution substation transformer and the overall system. Overall system DER capacity projections also include the projected penetration of medium and large DER facilities.

Due to the limited number of medium and large facilities and the uncertainty of where these facilities may be located it was determined that these would not be included in the circuit and substation transformer DER projections. Similarly, circuit, substation transformer and system projections will not include the forecasting of utility scale facilities. Instead Unitil has elected to treat these facilities in similar fashion to large customer load additions and add them to the DER projections as step-adders per the customer schedule and engineering judgement.

The DER capacity projection are developed as a tool to assist in determining when large scale system improvements are required due to DER penetration and are not intended to forecast peak load reductions due to DER.

Unitil's DER Load Projection Guideline can be found in Appendix Q. The UES-Capital and UES-Seacoast DER Projections can found in Appendix R and Appendix S, respectively.

The Company is also engaged in the Locational Value of DG study that has been initiated by the Commission and is being conducted by Navigant Consulting a Guidehouse Company. The company supports this effort and has been working closely with Navigant to provide information on our system, load forecasting, system planning, and engineering guidelines. The company is interested in the outcome of this study and how it can be used to better guide the locational benefit of DG on the distribution system.

11 RELIABILITY PLANNING

Unitil believes that reliability planning is just as important as traditional load flow or circuit analysis planning. Reliability planning is conducted by Operations and Engineering staff on an ongoing basis. Unitil implements projects and programs that 1) eliminate the outage from occurring or 2) minimize the impact of an outage by reducing the number of customers affected and/or the duration of time they are affected for. The various types of reliability planning are identified below.

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

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

Monthly – On a monthly basis, Unitil summarizes the significant outages – outages that account for 75,000 customer-minutes of interruption or more, that occurred in each of the operating companies over the past month. Unitil also reports on devices that have experienced multiple outages over a specific period of time and also reports on outages caused by failures of company equipment. The goal of this reporting is to identify trends and potential causes for the trends and initiate system improvements to address those trends.

System Event Report (SER) – At the discretion of Unitil's executive team any outage can have an SER report completed. An SER is a root cause analysis conducted by Operations and Engineering. The goal is to identify ways that the outage could either be avoided or the response shortened in the future. Typically an SER recommends action items that are assigned and completed.

Annual – Unitil conducts reliability analysis on an annual basis that is focused upon the overall reliability performance of the UES systems for a 12 month period. The reports evaluate individual circuit reliability performance over the same time period. These reports are developed per Unitil's Reliability Analysis Guideline (Appendix P) and include:

- Analysis of the ten worst outages that occurred over the timeframe along with their associated impact to SAIDI and SAIFI
- Analysis of the effect of sub-transmission and substation outages on circuit performance.
- Analysis of the worst performing distribution circuits over the reporting period
- Analysis of the major causes of sustained interruptions.
- Analysis of performance issues on specific circuits as well as recommendations for improvement
- Analysis of equipment failures to identify trends and provide recommendations when necessary.
- Analysis of areas with multiple tree related outages for consideration for additional tree trimming.
- Analysis of devices that have operated on more than three occasions over the timeframe.

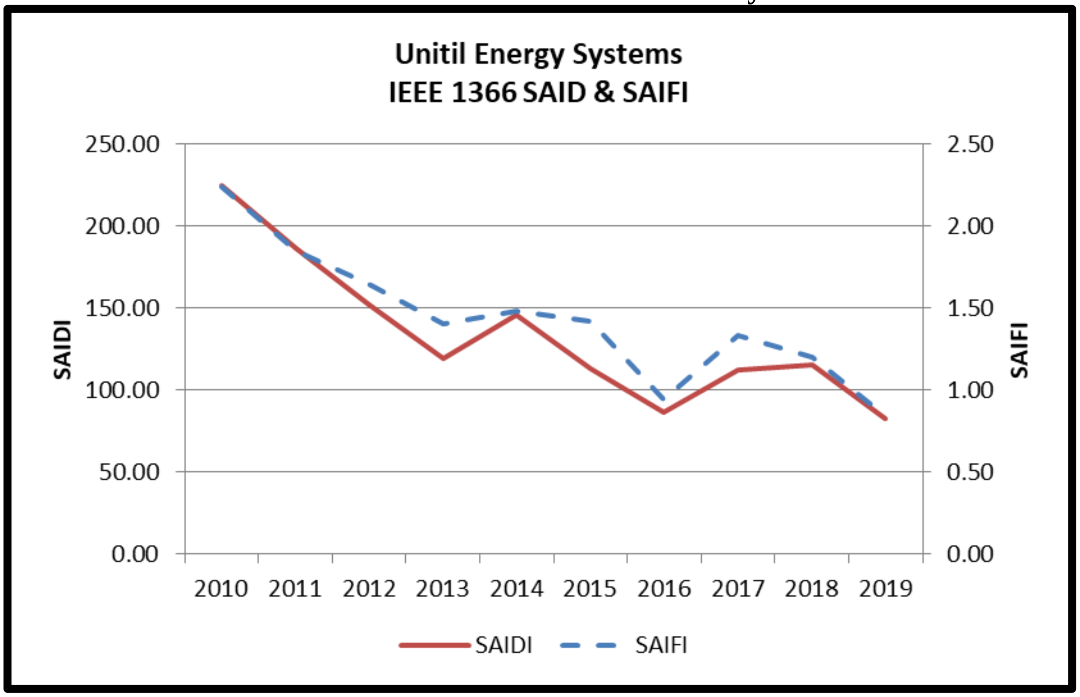
Reliability improvement projects are designed and estimated. Each of the projects is compared based upon a cost per saved customer-minute and saved customer-interruption basis. These projects are submitted for capital budget consideration.

Reference Appendix T – UES-Capital Reliability Study 2019 and Appendix U – UES-Seacoast Reliability Study 2019 for the most recent annual reliability reports.

The reliability planning process that Unitil uses has proven very successful. The historical reliability performance for the UES system for the time period from 2010-2019 is outlined below. Chart 1, below, displays annual SAIDI and SAIFI for the combined UES systems. The reported reliability performance of the UES systems in 2019 (based on IEEE-1366) was the best performance in the last ten years in terms of SAIDI, SAIFI and the number of interruption events experienced. The combined UES system SAIDI of 82.53 minutes is roughly 38% lower than the 10 year average of 133.88 minutes and approximately 19% lower than the 5 year average of 102.11 minutes. The UES combined system SAIFI for 2019 was 0.845 interruptions which was the best performance in the last ten years. The system SAIFI was approximately 41% lower than the 10 year average of 1.437 and roughly 26% lower than the 5 year average of 1.148.

UES' vegetation management program (including its cycle pruning and Storm Resiliency Program) has a large impact on the reliability performance of the company. UES is experiencing better performance during both blue sky as well as major outage situations. The vegetation management program is resulting in less damage during storms allowing UES to consistently complete restoration ahead of neighboring utilities and send line resources to assist others with restoration. The company continues to evaluate the program for improvements where practical.

Chart 1: UES Annual Reliability



12 <u>SMART GRID</u>

In addition to Unitil's detailed approach to reliability planning, Unitil has been implementing Smart Grid (or Grid Modernization) technologies for many years. Each of these smart grid technologies are tools the Company uses to improve reliability.

12.1 <u>Advancing the Grid Vision Team</u>

The Company has recently updated its mission and vision as part of its strategic plan. This process identified several vision teams to develop the long term strategic direction for the company on various emerging topics. One of the emerging topics is the future of the electric system.

The Advancing the Grid vision team consists of managers and senior level executives and reports directly to the CEO of the company. The goal of the team is to determine what the future grid looks like and how the company can make progress towards the future grid. The Advancing the Grid team meets regularly while it is developing a roadmap towards the future grid.

The Advancing the Grid team has determined that the DOE vision of grid modernization remains the focus of the company. The company has followed and generally adopted the DOE vision of grid modernization since it first emerged in 2007. Over time, this framework has guided the Company's efforts in such areas as integration of DER, implementation of Advanced Metering Infrastructure (AMI), implementation of Outage Management Systems (OMS), and integration of various other information technologies including Supervisory Control and Data Acquisition (SCADA), Geographic Information Systems (GIS), fleet telematics, together with AMI and OMS. While the DOE framework does an excellent job defining the characteristics and value areas of the modern grid and provides a general road map to achieve the required functionality, it does not identify the specific technologies needed, nor does it define "who" is best positioned to implement specific technical capabilities and services. Instead, it is assumed that new markets and new technologies will emerge in response to changing policies and clean energy objectives, and in response to the changing preferences and needs of customers.

Unitil believes that the primary role of the electric distribution companies, first and foremost, is to provide safe and reliable service while implementing technologies, investments and programs aimed at making the grid more efficient, economic and secure. This encompasses several of the value areas and characteristics of the DOE smart grid framework. Beyond these traditional obligations, the Company sees itself as responsible for implementing enabling technologies supporting both traditional electric company operations and new smart grid capabilities. Unitil's vision of the modern grid is that it will be defined by the functionality that it delivers as opposed to the specific technologies deployed, many of which are only now emerging or have yet to be developed. The Company sees its business model changing in order to become an "enabling platform" supporting diverse activities by third parties and electricity customers. This is consistent with the Energy Vision described in the NH Energy Strategy.

Under the Company's vision, the utility electric grid and associated Operations Technology (O.T.) and Information Technology (I.T.) systems will function as an open, flexible platform integrating customers, competitive markets and service providers in a way that delivers the functionality of the DOE's smart grid vision. Under this vision the modern grid is not simply a newer, upgraded version of the legacy electric system, nor is it a specific technology or suite of technologies layered onto the existing utility systems. The modern grid is instead the foundation of a larger ecosystem of customers, competitive markets and service providers who are interacting with the utility electric grid and the utility's information systems. Utility investments should be focused on those areas that support or enable the development of this new operating environment, including the necessary information systems. State strategy should be aimed at putting in place the essential policies necessary for this ecosystem to develop, grow and flourish.

The Advancing the Grid team is currently developing the roadmap to achieve the functionality needed for the company and its customers. The roadmap will be accompanied with a business plan which will detail the project costs as well as the benefits to customers

12.2 <u>Smart Transportation & Heating Solutions Vision Team</u>

Another vision focus team created by the company is the Smart Transportation and Heating Solutions team. Unitil is committed to a sustainable, low-carbon and affordable energy future for our customers, our people and the communities we serve.

The Smart Transportation & Heating Solutions Vision Team was established to explore, evaluate, recommend, and facilitate the implementation of mid to long-term strategies and initiatives focused on the transformation of the transportation and thermal sectors to low-carbon alternatives. Our focus is a transition to electrification and other low-carbon fuels for the transportation sector and helping our customers' transition to next-generation electric and/or gas systems within the heating sector.

12.3 Existing & Planned Technology

Unitil's Advanced Metering Infrastructure (AMI) system is capable of 2-way communication between the Command Center and the meter. UES is currently in the process of upgrading its AMI system. Endpoints that have been upgraded will be capable of providing interval metering information. Additionally, as part of Unitil's Grid Modernization Plan in Massachusetts a project is underway to improve the integration of outage information from AMI into the OMS prediction engine, thereby improving the outage prediction process, reducing outage durations and improving the ability to identify and locate nested outages. It is Unitil's intention to implement the improvement to this AMI/OMS integration in both its FG&E and UES subsidiaries.

Unitil's Geospatial Information System (GIS) allows spatial data management with analysis capabilities. GIS supports numerous corporate business applications at Unitil including: 1) outage management; 2) design management used in preparing construction work sketches; 3) network and asset management for the management and configuration of all Unitil electric circuits; 4) distribution mapping, querying, and reporting; 5) system integration with external databases (CIS and AMI, CMS, and OMS) for visualization and analysis; 6) exporting technical information and connectivity data for the purposes of distribution circuit analysis.

Unitil has implemented an integrated voice recognition system which provides outage information automatically into the OMS system. The IVR system also serves as the means that the OMS system uses to provide outbound calls to customers and provide them with updates about their outage.

In July of 2017 Unitil completed an upgrade of its Customer Information System. This upgrade allowed the Company to improve its ability to communicate outage information with customers and provided additional methods to report power outages, receive outage statuses and confirm outage restoration based on pre-selected communication preferences. Additionally, this upgrade has allowed Unitil to plan for future customer-facing outage communication enhancements as system integrations and digital platforms are developed.

Unitil's Outage Management System (OMS) provides a single automated and authoritative status of customer electrical outages across all Unitil electric operating companies. Outage reports are sent internally to Central Electric Dispatch (CED), communications, customer service, emergency operations centers, operations, engineering, and senior management. External reports are sent to regulators, media (via communications team), municipal and elected officials, and customers. There are four principal software applications in Unitil's OMS: 1) ABB Network Manager DMS which includes the outage reporting map, providing a visual display of power distribution systems, and operations management interface, which allows operators to view data and update data in various ways. 2) SienaTech Suite of Reporting and Management Tools providing trouble call entry, reporting calls, outage dashboard, and Siena Support in a web presentation format. 3) SienaTech Custom Unitil Reports offering Unitil-specific, read-only reports for daily reporting and regulatory requirements. 4) SienaTech Hosted Outage Web Map providing a hosted web page presenting public-facing near real-time outage information.

As part of Unitil's Grid Modernization Plan in Massachusetts Unitil's existing OMS will be upgraded to an ADMS that will support Volt-VAR Optimization (VVO)[1], Conservation Voltage Reduction (CVR)[2], power flow analysis and short circuit analysis. Additionally, ADMS will include a switch order module that will improve distribution system operating efficiencies. Unitil plans to utilize the switch order module in both FG&E and UES and where the necessary SCADA information is available Unitil also plans to utilize the powerflow and short circuit analysis functionality of ADMS in the UES territory. In the future the AMDS will be capable of supporting VVO deployment, distribution system automation, including automated distribution switching and fault location, isolation and service restoration (FLISR), and Distribution Energy Resource Management System (DERMS) in the UES territories. ADMS Implementation is expected to be a multi-year project starting in 2020.

Unitil implemented supervisory control and data acquisition (SCADA) at most of its distribution substations as well as some recloser and switch locations out on its subtransmission and distribution systems. In addition, field RTUs and similar RTU-like devices are deployed at locations where distribution circuits originate directly off the subtransmission lines.

Unitil has begun implementing distribution automation which consists of five separate locations that perform their own independent decision-making for automatic sectionalizing and restoration. Four of these locations involve interconnection between two adjacent intelligent devices with communications between them utilizing various communications methods. Additionally, Unitil has implemented one logic-based (without communications) automatic restoration scheme between two circuits in the UES-Seacoast territory. This scheme involves three normally closed reclosing devices and a normally open circuit tie. UES has two similar schemes planned with one scheduled to be placed in service in 2020 and the other in 2021.

Unitil has a project underway as part of its Grid Modernization Plan in Massachusetts to implement a Mobile Damage Assessment Tool. The tool will be deployed in both Unitil's FG&E and UES service territories. This tool will be utilized by damage

[1] VVO - optimally manages system-wide voltage levels and reactive power flow to achieve efficient distribution grid operation. VVO assists distribution operators reduce system losses, peak demand or energy consumption using Conservation Voltage Reduction (CVR) techniques.

[2] CVR - is a proven technology that has been used by utilities on a limited scale for the past two decades. By better managing distribution system voltages, utilities can improve efficiencies, realize significant energy savings, and reduce demand.

assessors during major storm events to provide damage information to regional operations centers. It will also provide analytics to the regional and system operations centers to allow Unitil to make quicker and better-informed decisions regarding the extent of damage, level of effort needed for restoration and estimated time of restoration.

12.4 Unitil's Vision of Grid Modernization

Unitil began a process in 2014 to develop a Grid Modernization Plan (GMP) for its Massachusetts subsidiary FG&E in response to the Massachusetts Department of Public Utilities docket 12-76.[1] The GMP was developed specifically for FG&E but throughout the process, Unitil was focused on identifying projects and programs which could readily be applied in New Hampshire due to the similarities of the distribution systems and common software platforms used across the company.

As part of the MA Grid Modernization Plan, the company is implementing the following projects and technologies:

Field Area Network (FAN) – This project consists of installing a FAN, including communications between collectors and endpoint devices (meters and distribution devices), and backhaul communications from collectors at each substation to the central office. 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 the Company implements. These will include advanced metering and TVR, distribution automation and DER management.

ADMS – This project consists of upgrading the Company's current OMS to an ADMS that will support VVO, CVR and power flow analysis. In the future the AMDS will also support distribution system automation, including automated distribution switching and fault location, isolation and service restoration (FLISR). The ADMS will serve as a platform for more advanced modules in the future such as a Distribution Energy Resource Management System (DERMS). The existing system integrations with GIS, CIS, OMS, IVR, Web Map Reporting and SCADA will be enhanced to provide the necessary technical information for ADMS to perform the functions described above.

DERMS - This project is to implement DERMS functionality to monitor and manage/control DERs across the service territory. This technology will be implemented as a module to work with the ADMS the company is in the process of implementing. 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.

[1] The proposed Grid Modernization plan for Fitchburg Gas and Electric Light Company was filed on August 19, 2015 pursuant to the MA DPU Orders in Modernization of the Electric Grid, DPU 12-76-B (2014) and 12-76-C (2014) and has docketed DPU 15-121.

VVO – Is a proven means for utilities to save energy for customers and reduce system demand all while ensuring reliable service. It also can help integrate DERs, by controlling the voltage variations caused by DERs. The VVO project will deliver significant and measurable benefits for the Company and its customers, while creating platform capability to be leveraged in the future.

SCADA – The objective of this project is to implement key SCADA functionality at all of the Company's substations where existing SCADA functionality may be lacking. SCADA provides for the remote monitoring of conditions on the electric system and the remote control of equipment and functions by operating personnel or automation systems. The substation SCADA project is an enabling technology for other projects in the GMP including VVO and ADMS. In conjunction with other components of the Plan, it will support the objectives of reducing the effects of outages and optimizing demand.

AMI to OMS Integration – The Company's AMI system provides information on outages for every meter on the system. This project is designed to 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.

Mobile Damage Assessment – This project is to implement a Mobile Platform Damage Assessment Tool to make quicker, better-informed decisions to ensure operational efficiency and maintain strong restoration performance by significantly reducing the amount of time for field information to be relayed. This would allow for a greater situational awareness.

13 DEMAND SIDE ENERGY MANAGEMENT PROGRAMS

Unitil manages both Energy Efficiency (EE) and Active Demand Management Programs aiming to reduce energy consumption and demand.

13.1 Energy Efficiency

The energy efficiency ("EE") programs UES offers to its customers are developed as part of a comprehensive, statewide approach to optimizing energy use by electricity and natural gas customers. These efforts aim to transform the marketplace for energy-using services and equipment in the built environment by working with distributors and retailers, building and installation contractors, and end use customers in the commercial, industrial, and residential sectors.

In 2016, New Hampshire entered a new phase in energy management strategy. The New Hampshire Public Utilities Commission established an Energy Efficiency Resource Standard ("EERS")[1] that defines energy savings targets for the state's utilities and established a framework to achieve those goals. The established EERS framework ensures Commission oversight of the EERS programs, establishes three-year planning

[1] New Hampshire Public Utilities Commission (2016, August 8), Order No. 25,932, "Energy Efficiency Resource Standard – Order Approving Settlement Agreement". Retrieved from http://www.puc.state.nh.us/Regulatory/Orders/2016orders/25932e.pdf

periods and savings goals as well as a long-term goal of achieving all cost-effective EE. UES actively participates in the statewide coordinated and integrated planning process established by the EERS framework to design EE programs and establish savings targets. This process results in the development of the New Hampshire Statewide Three-Year Energy Efficiency Plan that is submitted to the Commission for approval and once approved, is implemented by the state's utilities.

Since the adoption of the EERS by the Commission, the Company has pursued cost effective EE in pursuit of annual energy saving goals established through a robust stakeholder process. The Commission approved a settlement agreement allowing for the implementation of the New Hampshire electric and natural gas utilities' first three-year EE plan on January 2, 2018.[1] The Commission subsequently approved Plan Updates for 2019 and 2020 that continues previously approved EE program elements while adding new initiatives such as active demand response.[2]

UES's EE programs are informed by nearly two decades of experience working with stakeholders, consultants, our colleagues at the other gas and electric utilities, as well as our customers. Our internal EE staff of more than a dozen planners, implementers and administrators work across jurisdictions (i.e., in Massachusetts as well as New Hampshire) and is supported by a broad complement of vendors, contractors, builders and evaluation firms, all with in depth knowledge of demand side efficiency and conservation. UES's investment in EE has grown from approximately $3.4 million in 2017 to an approved budget of $7.7 million in 2020, a 126 percent increase over the past three years.

The Company's existing portfolio of electric efficiency programs focuses on customers in three categories: non-low income residential customers, low income residential customers, and commercial and industrial ("C&I") customers. The primary electricity-saving residential offering is the Energy Star® Products program, which provides discounted retail pricing to residential customers who purchase high efficiency lighting and electric appliances. Along with the other electric utilities in the state, we collaborate with retailers and distributors to ensure that high efficiency products are marketed to customers, and that point-of-sale discounts are provided to customers on high-efficiency promoted products.

By moving consumers and contractors away from less efficient products and appliances, our incentives continue to transform the market for lighting and equipment and train customers to consider not just up-front cost but lifecycle costs. For more substantial and expensive projects completed under the Home Performance with Energy Star program involving heat pumps or whole-home weatherization, the Company offers on-bill and third party financing options that allow customers to spread their share of the investment over a longer period of time and experience cash-flow positive savings. For income eligible customers participating in the Home Energy Assistance program to weatherize their homes, the Company pays 100% of the cost of

[1] DE 17-136, 2018-2020 New Hampshire Statewide Energy Efficiency Plan, Order No. 26,095 (Jan. 2, 2018)
[2] DE 17-136, 2018-2020 New Hampshire Statewide Energy Efficiency Plan, Order No. 26,207 (Dec. 31, 2018)

energy improvements, eliminating one of the major barriers to participation for these customers.

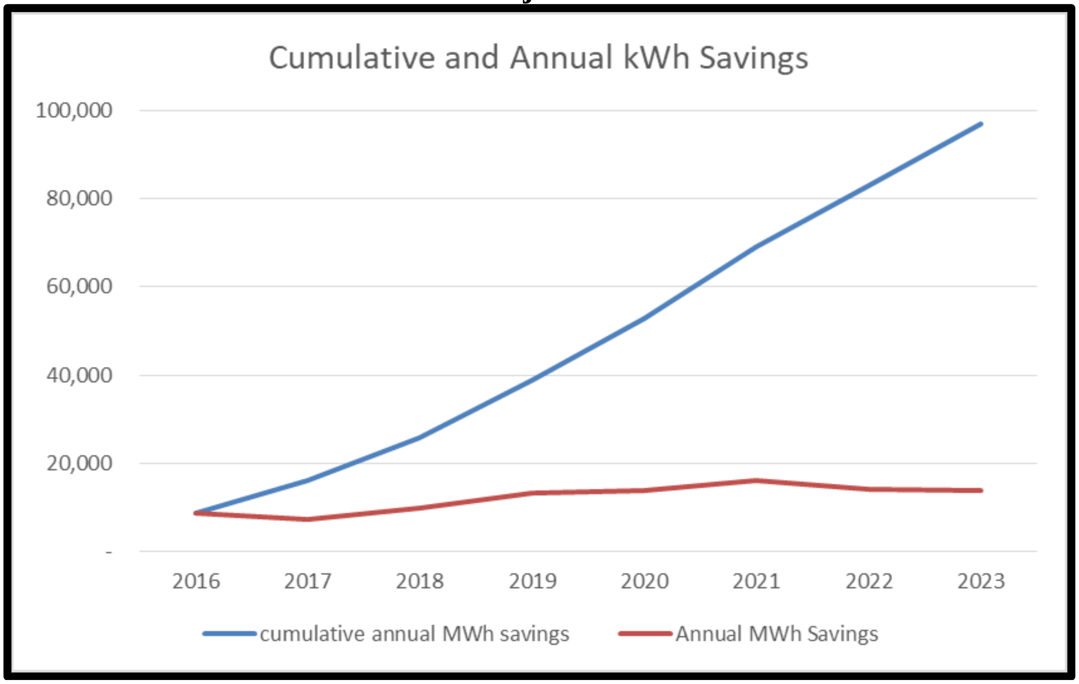
In the C&I sector, the Company also works closely with retailers and distributors to ensure that high efficiency lighting, motors and drives, HVAC, controls and other equipment are an accessible and attractive choice for contractors, builders and end use customers. By providing both technical assistance and cash incentives, our efficiency programs reduce the barrier that a higher up front cost presents to C&I customers, including municipalities and nonprofit organizations. As in the residential sector, on-bill financing programs allow qualifying C&I customers to offset some or all of the up-front cost of new or retrofitted equipment that is not covered by the program's cash incentive.

For both residential and C&I customers, the Company provides technical assistance, training and cash incentives to ensure that new buildings are built and equipped to high EE standards. This assistance is facilitated not only by Unitil's key account managers, but supplemented by engineering and design-build firms that are familiar with both good building design and with our incentive programs.

Over the 2018-2020 Energy Efficiency Resource Standard term, Unitil received approval to invest a total of $15.8 million in program costs, to be supplemented by $8.2 million in participant contributions, to achieve more than 32,000 MWh of electric savings in the first year of installation, and an estimated 366,000 MWh in electric savings over the life of all the EE measures installed in the term. In the residential programs, a fuel-blind approach to energy use results in significant heating fuel savings in programs focused on new construction and weatherization of existing homes. Just under half of the resulting energy savings comes from a reduction in electricity use from high efficiency HVAC, appliances and lighting.

For the commercial and industrial sector, which comprises approximately 65 percent of total portfolio savings, the majority of savings come from custom projects among manufacturers, retail establishments, municipalities, and schools. While high efficiency lighting and controls continue to be the most important single contributor to overall EE savings, the Company is dedicated to reducing both energy use and demand by incenting high efficiency HVAC measures, motors and drives, appliances, plug loads, and process equipment. Technical assistance, professional referrals and financial assistance help customers to overcome non-cost barriers to the adoption of energy efficient equipment and operations.

Chart 2 Cumulative Energy Efficiency Savings 2016-2019 Actual and 2020-2023 Projected



13.2 <u>Active Demand Management</u>

Over the past several years, Unitil, along with the other electric utilities in New Hampshire, have been monitoring demand management demonstrations and programs taking place in other states to advance tailored methodologies for adoption in New Hampshire. The goals of active demand offerings are to flatten peak loads, improve system load factors, and reduce costs for all customers. The 2019 and 2020 Updates to the 2018-2020 Statewide Energy Efficiency Plan included proposals for pilots to pursue active demand reductions. The approved pilot targeted C&I customers in the summer of 2019 and was expanded to residential customers with wireless thermostats interested in participating in the offering during the summer of 2020.

In 2019 Unitil and Eversource implemented an active demand reduction ("DR") offering, based on evaluated Commercial and Industrial ("C&I") active demand reduction efforts from across Massachusetts, Connecticut, and Rhode Island. Based on the success of these regional demonstration efforts, the New Hampshire offering was designed to provide incentives to encourage customers to reduce demand at peak times. By reducing load during the ISO summer peak, the Company can reduce New Hampshire's share of the installed capacity cost allocation, thereby reducing costs for both customers and the Company.

The C&I load curtailment pilot was launched in April 2019. Utilizing both Unitil's existing EE program staff along with support from a third party Curtailment Service Provider ("CSP"), Unitil assessed curtailment opportunities at customers' facilities and ultimately enrolled seven customer accounts by summer. The CSP worked with Unitil to identify curtailable load, enroll customers, manage curtailment events and calculate performance and payments. The targeted dispatch load curtailment is operated on a technology agnostic pay-for-performance model in which participating customers are notified the day before the demand response event by 1:00 PM, giving them a chance to prepare to curtail operations.

One important objective of the initiative is to time curtailment events during the ISO-NE ICAP (“ICAP”) hour. Because customers’ kW usage on the ICAP hour determines the customers’ capacity charges for the following year, aligning the event timing with the ICAP hour results in the greatest impact both to the customer and the electric grid. In order to increase the likelihood of achieving this alignment, several events are typically called over the course of the summer, but not so many that customers’ are unnecessarily impacted. In 2019, Unitil called one event on July 30th from 3:00 PM to 6:00 PM coinciding with the ICAP day and hour, which was 5:00 to 6:00 pm that day.

A multi-state draft evaluation of the summer 2019 load curtailment efforts examined performance of utilities engaged in active demand management strategies with C&I customers. The evaluation, which is nearing completion, developed three different baselines against which to measure performance: a) Settlement Performed, b) Evaluated Asymmetric Adjustment, and c) Evaluated Symmetric Adjustment. Unitil calculates and pays customer incentives based on average actual load reduction during all curtailment events compared to the Settlement Performed Baseline. Table 1 shows the draft results of the evaluation against these various baselines.

Table 1 – Interruptible Load Offering

		Summer 2019	**Summer 2020**
PLANNED	Reduction target	1,800 MW (C&I only)	3,100 MW (C&I and residential)
ENROLLED	An ex ante estimate based on customer recruitments ahead of summer activity, multiplied by an estimate of expected response based on experience. Also referred to as Nominated Capacity.	1,300	N/A
REPORTED ASYMMETRIC ADJUSTMENT	An ex post gross average DR calculation reported by vendors using all customer data, used for customer settlement. The baseline used for settlement is a 10-of-10 baseline with an asymmetric (positive only) day-of adjustment.	1,299	N/A
EVALUATED ASYMMETRIC ADJUSTMENT	An ex post gross average DR calculation performed by the independent evaluator—based on validated data only—using a 10-of-10 baseline with an asymmetric (positive only) day of adjustment.	1,363	N/A

		Summer 2019	Summer 2020
EVALUATED SYMMETRIC ADJUSTMENT	An ex post gross average DR calculation performed by the independent evaluator—based on validated data only—using a 10-of-10 baseline with a symmetric (positive & negative), day-of adjustment. This calculation is the most neutral and is used for reporting and benefit calculation, as recommended by the independent evaluator.	1,185	N/A

13.3 Planned Load Curtailment in 2020 and Beyond

The 2020 C&I load curtailment pilot will build upon the 2019 experience, increasing the goal from 1,800 kW to 3,000 kW. As in 2019, customers have flexibility to use whatever technology or strategy to reduce load, but may only use properly permitted natural gas or wood fired generators, since they have the lowest carbon emissions per Btu. Unitil will also add a pay-for-performance battery storage pathway ("C&I batteries") totaling 100 kW

A residential program based on one developed in Massachusetts' will be launched in New Hampshire in the summer of 2020. Customers must already have a Wi-Fi thermostat controlling central air condition in order to participate. Through its vendor's Demand Response Management System, Unitil will send an event notice to the Wi-Fi thermostat manufacturer, which will then send a signal to each enrolled Wi-Fi thermostat to temporarily raise the thermostat by up to 40 F, resulting in load reductions. Unitil's target is to enroll 500 thermostats prior to the summer season, each reducing load by an average of 0.4 kW. Unitil expects to call up to 15 events lasting two or three hours each. Customers will be incented to enroll, and then provided additional rebates for participating.

Unitil will also pilot a residential battery storage offering in the summer of 2020. Batteries will be dispatched from 40 to 60 days during the summer via the same path as Wi-Fi thermostats. Incentives will be paid based on the customer's annual average kW discharged over all events called. A battery generally discharges 5 kW over the event hours, with two or three participating per event. With a target of 10 battery storage systems enrolled, Unitil anticipates providing incentives for an estimated 50 kW of residential peak reduction this summer. For both residential offerings, customers retain the right to opt out of any event at any time.

For the 2021-2023 Term, Unitil will continue to coordinate with our colleagues at Eversource to develop a full-fledged load curtailment program. We will be filing a comprehensive draft EERS plan with the Commission and interested stakeholders on April 1, 2020 with a final draft to follow on July 1, 2020. Details regarding future load curtailment efforts will be included in those plans and are subject to Commission approval.

13.4 Baseline and Energy Efficiency Potential Study

The 2020 C&I load curtailment pilot will build upon the 2019 experience, increasing the goal from 1,800 kW to 3,000 kW. As in 2019, customers have flexibility to use whatever technology or strategy to reduce load, but may only use properly permitted natural gas or wood fired generators, since they have the lowest carbon emissions per Btu. Unitil will also add a pay-for-performance battery storage pathway (“C&I batteries”) totaling 100 kW

Along with the other New Hampshire gas and electric utilities, Unitil is in the process of undertaking a statewide baseline and EE potential study to inform the development of the second Three-Year Plan under the EERS, which will start in January 2021 and end in December of 2023. Together with Staff from the Commission, along with their evaluation consultants, and the Office of Consumer Advocate, the utilities are working with Dunsky Corporation, which along with subcontracting firms Itron and ERS to develop a detailed analysis of the penetration and saturation of high efficiency electric equipment in both the residential and C&I sectors. This information will be used to develop a model of the remaining EE potential. Also estimated and modeled will be the rate of natural adoption of high efficiency equipment in order to arrive at an estimate of potential that EE programs can capture using a combination of incentives, loans, technical assistance and other interventions to overcome customer barriers to adoption.

In the fall of 2019, a new facilitated process to plan for the 2021-2023 EERS Three Year Plan began. Commission Staff issued a request for proposals and selected a facilitator, Vermont Energy Investment Corporation, to help guide stakeholders through a process expected to be similar to the one undertaken in the development of the first Three Year plan under the EERS. The utilities are scheduled to provide a draft plan in April of 2020, which will be followed by facilitated discussions with the parties. A final plan is to be submitted in September of 2020 and vetted in a formal proceeding before the Commission similar to the process used to establish the prior plan.

Because many of the strategies aimed at reducing electric consumption during peak periods include an increase in the use of electricity for heat and other end uses, and because the generation of electricity in our region is also dependent on the supply of natural gas, it is critical that utilities and regulators take a holistic approach to fuel use reduction. This approach, which takes all fuels into consideration, is often referred to as ‘energy optimization’. Because reducing electric consumption by end users is not in and of itself a complete solution to the problem of limited capacity and high peak prices, the Company’s gas and electric EE programs are integrated into a coherent whole.

Several studies in New Hampshire are investigating many of these inter-related opportunities, including one on fuel switching and energy optimization and is focused primarily on electric heat pump technologies; another focuses on the method by which EE programs’ cost effectiveness is measured (namely with or without customer impacts included), and finally, the baseline / potential study described above. Together, these studies will help the utilities to develop a coherent suite of programs aimed at optimizing energy use for our customers, and capturing the opportunity to reduce both electricity and natural gas use while promoting economic development among our customers and within our communities over the next Three Year EERS period.

Shown below in Table 2 is a modified version of the "Program Cost-Effectiveness - 2020 PLAN" table from the Company's EERS 2020 Plan Update. In this version of the table, the average cost per MWh has been included in the far-right column, showing the pro-rated cost per lifetime kWh. Because three of our residential EE programs are focused primarily on saving heating fuels (e.g., heating oil, propane, kerosene, etc.) we have used the kWh savings as a percent of all energy savings and applied it to the total company investment to arrive at a $/lifetime kWh achieved. Not accounting for participating customer contributions to the total cost of measures, the company invests an average of $51.90 per lifetime MWh for residential customers and $27.16 per lifetime MWh for C&I customers. Again, this calculation makes no adjustments for time value of money and assumes 100 percent persistence of savings over the life of the measures to be installed.

Table 2 – modified version of the "Program Cost-Effectiveness - 2020 PLAN"

	Utility Costs ($000)	Customer Costs ($000)	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	Number of Customers Served	% kwh savings	Prorated Cost/Lifetime MWh
Residential Programs									
Home Energy Assistance	$ 1,353.131	$ -	78	1,148	10.2	12.3	122	6%	$ 73.27
Energy Star Homes	$ 446.821	$ 91.740	98	2,033	10.1	23.7	66	13%	$ 29.35
HPwES	$ 801.804	$ 408.512	93	1,666	11.3	19.0	109	8%	$ 38.98
Energy Star Products	$ 1,044.547	$ 317.160	2,270	16,835	570.2	306.1	35,887	84%	$ 52.28
Home Energy Reports	$ 153.784	$ -	675	1,851	34.1	11.4	22,700	100%	$ 83.08
FCM Expense	$ 26.500	$ -	-	-	-	-			
Res Active Demand	$ 122.100	$ -	-	-	-	-	510		
Sub-Total Residential	**$ 3,948.687**	**$ 817.412**	**3,214**	**23,533**	**635.9**	**372.5**	**59,394**	31%	$ 51.90
C&I & Municipal									
Large Bus Energy Solutions	$ 1,632.099	$ 1,605.916	6,051	77,989	886.3	725.5	248	100%	$ 20.93
Small Bus Energy Solutions	$ 1,570.430	$ 1,049.158	4,224	54,646	277.2	356.8	259	100%	$ 28.74
Municipal Energy Solutions	$ 265.230	$ 74.000	459	6,813	17.1	19.0	27	96%	$ 37.33
Education and ISO expense	$ 99.785	$ -	-	-	-	-			
C&I Active Demand	$ 227.343	$ -	-	-	-	-	9		
Sub-Total C&I	**$ 3,794.887**	**$ 2,729.073**	**10,735**	**139,448**	**1,180.5**	**1,101.3**	**542**	100%	$ 27.16
Total	**$ 7,743.573**	**$ 3,546.485**	**13,949**	**162,981**	**1,816.4**	**1,473.9**	**59,936**	76%	$ 35.88

In terms of Fuel Security and Price Stability, EE is a favorable investment. So long as the measures installed remain in place and the buildings remain occupied, efficiency savings are expected to persist over the lifetimes of the measures installed.

EE provides meaningful local economic development and job opportunities. New Hampshire plans for 11,733 jobs supported by EE investments in 2019, an increase of 3.5% from 2018 to 2019. The largest number of these EE employees work in high efficiency HVAC and renewable heating and cooling firms, followed by ENERGY

STAR and efficient lighting, and EE employment is primarily found in the construction industry.[1]

Lastly, in terms of Health and Safety, there could be limited health risks associated with the work required to install insulation and various efficiency measures. On the positive side, a significant body of research has shown non-energy related benefits associates with energy efficiency improvements worth in some cases more than the value of the avoided energy itself.[2]

Particularly for households which are low income, the building shell improvements and appliance upgrades resulting from energy efficiency interventions can result in improved health outcomes, fewer missed workdays, increased comfort and a greater sense of well-being. While it is inherently difficult to put a dollar value on these benefits, many studies have endeavored to do so using various methodologies. Beyond low income homes, improvements in HVAC systems, lighting, and new construction building design that save energy generally lead to improved occupant health, whether those occupants are workers, residents, students, patients or customers.

14 CONCLUSION

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

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

[1] Energy Employment by State — 2019, A Joint Project of NASEO & EFI, U.S. Energy and Employment Report 2019, New Hampshire section, page 1-4 of 7.

[2] Non-energy Impacts Approaches and Values: an Examination of the Northeast, Mid-Atlantic and Beyond – 2017

APPENDICES

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O. 37 Line / 4X1 Non-Wires Alternatives for Load Relief – Request for Information Evaluation

P. Unitil Reliability Analysis Guideline

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R. UES-Capital 2020-2024 DER Projections

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T. UES-Capital Reliability Study 2019

U. UES-Seacoast Reliability Study 2019

APPENDIX A

UES-SEACOAST
2020-2024 CAPITAL BUDGET

Capital Budget 2020 UES Capital							
Code	#	Blankets:Electric	2020	2021	2022	2023	2024
BAB		T&D Improvements	1,088,981	1,079,598	1,198,371	1,421,526	1,466,228
BAC		T&D Improvements, Carryover	24,756	24,441	27,765	33,485	33,808
BBB		New Customer Additions	380,094	376,571	424,335	515,350	535,142
BBC		New Customer Additions, Carryover	29,420	29,213	33,181	40,087	40,690
BCB		Outdoor Lighting	96,196	93,189	104,980	125,913	128,038
BCC		Outdoor Lighting, Carryover	3,951	3,903	4,434	5,340	5,394
BDB		Emergency & Storm Restoration	615,397	611,647	675,318	796,943	825,651
BDC		Emergency & Storm Restoration, Carryover	10,063	10,160	11,316	13,369	13,921
BEB		Billable work	188,888	192,271	217,644	261,528	269,585
BEC		Billable work, Carryover	7,995	7,949	8,741	10,286	10,695
BFB		Transformers Company/Conversions	84,062	82,203	89,001	104,797	110,117
BFC		Transformers Company/Conversions, Carryover	10,856	0	0	0	0
BGB		Transformer Customer Requirements	741,404	727,361	789,652	932,728	987,129
BGC		Transformer Customer Requirements, Carryover	83,663	81,644	87,751	103,202	109,316
BHB		Meters Company Requirements	174,888	174,126	186,922	217,050	226,832
BIB		Meters Customer Requirements	466,553	454,150	486,137	565,532	591,211
		Sub-Total:	4,007,165	3,948,427	4,345,549	5,147,136	5,353,758
Code	#	Communications:Electric	2020	2021	2022	2023	2024
ECE	1	Two Way Radio Replacements	4,000	0	0	0	0
ECE	21	Two Way Radio Replacements	0	5,000	0	0	0
ECE	22	Replace and Upgrade Electric SCADA Master	0	259,948	0	0	0
ECE	41	Two Way Radio Replacements	0	0	5,000	0	0
ECE	61	Two Way Radio Replacements	0	0	0	5,000	0
EEC	1	Radio Upgrade Project	250000	0	0	0	0
EEC	2	Upgrade TS2 to PLX Infrastructure Carryover	173,900	0	0	0	0
EEC	21	Radio Upgrade Project	0	125,000	0	0	0
		Sub-Total:	427,900	389,948	5,000	5,000	0
Code	#	Distribution:Electric	2020	2021	2022	2023	2024
DAB		Overhead Line Extensions	39,291	0	0	0	0
DAB	20	Overhead Line Extensions	0	38,656	0	0	0
DAB	40	Overhead Line Extensions	0	0	44,303	0	0
DAB	60	Overhead Line Extensions	0	0	0	55,705	0
DAB	80	Overhead Line Extensions	0	0	0	0	58,129
DAC		Overhead Line Extensions, Carryover	4,901	0	0	0	0
DAC	20	Overhead Line Extensions - Carryover	0	4,771	0	0	0
DAC	40	Overhead Line Extensions - Carryover	0	0	5,497	0	0
DAC	60	Overhead Line Extensions - Carryover	0	0	0	6,979	0
DAC	80	Overhead Line Extensions - Carryover	0	0	0	0	7,235
DBB		Underground Line Extensions	99,765	0	0	0	0
DBB	20	Underground Line Extensions	0	102,370	0	0	0
DBB	40	Underground Line Extensions	0	0	120,128	0	0

DBB	60	Underground Line Extensions	0	0	0	155,167	0
DBB	80	Underground Line Extensions	0	0	0	0	161,949
DBC		Underground Line Extensions, Carryover	23,579	0	0	0	0
DBC	20	Underground Line Extensions, Carryover	0	22,715	0	0	0
DBC	40	Underground Line Extensions, Carryover	0	0	26,005	0	0
DBC	60	Underground Line Extensions, Carryover	0	0	0	33,256	0
DBC	80	Underground Line Extensions, Carryover	0	0	0	0	34,528
DCB		Street Light Projects	3,685	0	0	0	0
DCB	20	Street Light Projects	0	3,680	0	0	0
DCB	40	Street Light Projects	0	0	4,122	0	0
DCB	60	Street Light Projects	0	0	0	4,907	0
DCB	80	Street Light Projects	0	0	0	0	5,018
DCC		Street Light Projects, Carryover	564	0	0	0	0
DCC	20	Street Light Projects - Carryover	0	564	0	0	0
DCC	40	Street Light Projects - Carryover	0	0	635	0	0
DCC	60	Street Light Projects - Carryover	0	0	0	753	0
DCC	80	Street Light Projects - Carryover	0	0	0	0	771
DDB		Telephone Company Requests	15,364	0	0	0	0
DDB	20	Telephone Company Requests	0	15,347	0	0	0
DDB	40	Telephone Company Requests	0	0	17,245	0	0
DDB	60	Telephone Company Requests	0	0	0	20,516	0
DDB	80	Telephone Company Requests	0	0	0	0	20,948
DDC		Telephone Company Requests, Carryover	1,545	0	0	0	0
DDC	20	Telephone Company Request - Carryover	0	1,523	0	0	0
DDC	40	Telephone Company Request - Carryover	0	0	1,726	0	0
DDC	60	Telephone Company Request - Carryover	0	0	0	2,078	0
DDC	80	Telephone Company Request - Carryover	0	0	0	0	2,103
DEB		Highway Projects	71,757	0	0	0	0
DEB	20	Highway Projects	0	71,597	0	0	0
DEB	40	Highway Projects	0	0	79,735	0	0
DEB	60	Highway Projects	0	0	0	238,953	0
DEB	80	Highway Projects	0	0	0	0	789,795
DEC		Highway Projects, Carryover	7,216	0	0	0	0
DEC	20	Highway Projects, Carryover	0	7,200	0	0	0
DEC	40	Highway Projects, Carryover	0	0	8,071	0	0
DEC	60	Highway Projects, Carryover	0	0	0	9,601	0
DEC	80	Highway Projects, Carryover	0	0	0	0	225,422
DPB	1	Distribution Pole Replacement	646,838	0	0	0	0

DPB	2	Replace River Crossing Structures	354,495	0	0	0	0
DPB	3	37X1 Tap Pole Replacement	220,530	0	0	0	0
DPB	5	Manhole improvements MH 6	127,981	0	0	0	0
DPB	6	Extend Brown Hill Rd, Bow - 22W3	177,682	0	0	0	0
DPB	7	Conversion in Downtown Concord - Part 2	721,847	0	0	0	0
DPB	20	Distirbution Unspecified	0	1,500,000	0	0	0
DPB	21	Distribution Pole Replacement	0	654,852	0	0	0
DPB	22	Porcelain Cutout Replacements	0	200,599	0	0	0
DPB	23	37 Line - Reconductor Penacook to Maccoy St Tap	0	1,058,505	0	0	0
DPB	24	Create a loop in MH28 - Downtown UG	0	105,886	0	0	0
DPB	25	Replace Direct Buried URD Cable Rocky Point Dr, Bow	0	88,747	0	0	0
DPB	26	Perform Cable Injection Fairfield St. Concord	0	173,712	0	0	0
DPB	28	Cable Injection - 129 Fisherville Rd, Concord	0	77,215	0	0	0
DPB	29	Perform Cable Injection New Meadow Rd. Concord	0	86,866	0	0	0
DPB	30	Perform Cable Injection E.Ricker Rd. Chichester	0	28,556	0	0	0
DPB	31	38 Line Spacer Reconductoring	0	247,742	0	0	0
DPB	40	Distirbution Unspecified	0	0	2,400,000	0	0
DPB	41	Distribution Pole Replacement	0	0	747,995	0	0
DPB	42	Transfer Load from 24H1 to 8H1	0	0	71,779	0	0
DPB	43	374X1 Spacer Cable Replacement	0	0	45,927	0	0
DPB	44	Replace Direct Buried URD Cable Rocky Point Dr, Bow phase 2	0	0	154,455	0	0
DPB	45	Replace Direct Buried Cable - Profile Ave	0	0	37,797	0	0
DPB	46	2H2 Spacer Cable Replacement	0	0	467,260	0	0
DPB	60	Distirbution Unspecified	0	0	0	2,300,000	0
DPB	61	Distribution Pole Replacement	0	0	0	916,441	0
DPB	62	Replace spacer cable on 8H1	0	0	0	239,151	0
DPB	80	Distirbution Unspecified	0	0	0	0	2,300,000
DPB	81	Distribution Pole Replacement	0	0	0	0	940,591
DPB	82	15W2 Spacer Cable Replacement	0	0	0	0	287,120
DPC	1	Bridge St Switchgear Replacement	328,861	0	0	0	0
DRB		Reliabilty Projects	287,491	0	0	0	0
DRB	20	Reliability Projects	0	375,000	0	0	0
DRB	40	Reliability Projects	0	0	375,000	0	0
DRB	60	Reliability Projects	0	0	0	375,000	0
		Sub-Total:	3,133,390	4,866,104	4,607,679	4,358,507	4,833,607
Code	#	Tools, Shop, Garage:Electric	2020	2021	2022	2023	2024
EAE	1	Purchase and Replace Rubber Goods	5,500	0	0	0	0
EAE	2	Purchase and Replace Hot Line Tools	3,500	0	0	0	0

EAE	3	Tools, Shop & Garage - Normal Additions and Replacements	14,000	0	0	0	0
EAE	4	Normal additions & replacement - tools & equipment Metering	7,000	0	0	0	0
EAE	5	Normal Additions and Replacements - Tools and Equipment - Substation	10,000	0	0	0	0
EAE	6	Purchase Bierer PD - 50 All purpose Utility Meter	3,000	0	0	0	0
EAE	7	Purchase tools for new Bucket Truck # 24	5,000	0	0	0	0
EAE	8	Replace FC300 Handhelds	12,000	0	0	0	0
EAE	10	Purchase new Dig Safe Locating Machine	4,500	0	0	0	0
EAE	12	Purchase Milwaukee Force Logice 750 MCM Dieless Crimper	4,325	0	0	0	0
EAE	21	Purchase and Replace Rubber Goods	0	6,000	0	0	0
EAE	22	Purchase and Replace Hot Line Tools	0	4,000	0	0	0
EAE	23	Tools, Shop & Garage - Normal Additions and Replacements	0	14,500	0	0	0
EAE	24	Normal additions & replacement - tools & equipment Metering	0	7,000	0	0	0
EAE	25	Normal Additions and Replacements - Tools and Equipment - Substation	0	12,000	0	0	0
EAE	26	Tools - Unspecified	0	16,000	0	0	0
EAE	27	Purchase tools for new Digger Truck # 31	0	6,000	0	0	0
EAE	28	Purchase OMICRON ARCO Recloser Test Set	0	31,800	0	0	0
EAE	29	Purchase Power Factor Test Set	0	77,000	0	0	0
EAE	30	Purchase Omicron Power Factor Test Set	0	77,000	0	0	0
EAE	41	Purchase and Replace Rubber Goods	0	0	6,000	0	0
EAE	42	Purchase and Replace Hot Line Tools	0	0	4,000	0	0
EAE	43	Tools, Shop & Garage - Normal Additions and Replacements	0	0	14,500	0	0
EAE	44	Normal additions & replacement - tools & equipment Metering	0	0	7,000	0	0
EAE	45	Normal Additions and Replacements - Tools and Equipment - Substation	0	0	12,000	0	0
EAE	46	Tools - Unspecified	0	0	16,000	0	0
EAE	47	Purchase Oil Filter Unit	0	0	56,000	0	0
EAE	61	Purchase and Replace Rubber Goods	0	0	0	6,000	0
EAE	62	Purchase and Replace Hot Line Tools	0	0	0	4,500	0
EAE	63	Tools, Shop & Garage - Normal Additions and Replacements	0	0	0	14,500	0
EAE	64	Normal additions & replacement - tools & equipment Metering	0	0	0	7,000	0

EAE	65	Normal Additions and Replacements - Tools and Equipment - Substation	0	0	0	12,000	0
EAE	66	Tools - Unspecified	0	0	0	16,500	0
EAE	81	Normal additions & replacement - tools & equipment Metering	0	0	0	0	7,000
EAE	82	Normal Additions and Replacements - Tools and Equipment - Substation	0	0	0	0	12,000
EAE	83	Purchase and Replace Rubber Goods	0	0	0	0	6,500
EAE	84	Purchase and Replace Hot Line Tools	0	0	0	0	4,500
EAE	85	Tools, Shop & Garage - Normal Additions and Replacements	0	0	0	0	14,500
EAE	86	Tools - Unspecified	0	0	0	0	16,500
		Sub-Total:	68,825	251,300	115,500	60,500	61,000
Code	#	Tools, Shop, Garage:General	2020	2021	2022	2023	2024
EAC	41	Purchase tools for new Bucket trk # 22	0	0	6,000	0	0
EAC	81	Purchase tools for new Bucket trk # 21	0	0	0	0	6,000
		Sub-Total:	0	0	6,000	0	6,000
Code	#	Laboratory:General	2020	2021	2022	2023	2024
EBB	1	Lab Equipment - Normal Additions and Replacements	7,000	0	0	0	0
EBB	21	Lab Equipment - Normal Additions and Replacements	0	7,000	0	0	0
EBB	41	Lab Equipment - Normal Additions and Replacements	0	0	7,000	0	0
EBB	61	Lab Equipment - Normal Additions and Replacements	0	0	0	7,000	0
EBB	81	Lab Equipment - Normal Additions and Replacements	0	0	0	0	7,000
		Sub-Total:	7,000	7,000	7,000	7,000	7,000
Code	#	Office:Electric	2020	2021	2022	2023	2024
EDE	1	Office Furniture & Equipment-Normal Additions and Replacements	3,500	0	0	0	0
EDE	2	Furniture Replacements-Year 2 of 2 Year Program	13,000	0	0	0	0
EDE	21	Office Furniture & Equipment-Normal Additions and Replacements	0	3,500	0	0	0
EDE	41	Office Furniture & Equipment-Normal Additions and Replacements	0	0	3,500	0	0
EDE	61	Office Furniture & Equipment-Normal Additions and Replacements	0	0	0	3,500	0
EDE	81	Office Furniture & Equipment-Normal Additions and Replacements	0	0	0	0	3,500
		Sub-Total:	16,500	3,500	3,500	3,500	3,500
Code	#	Structures:General	2020	2021	2022	2023	2024
GPB	1	Normal Improvements to Capital Facility	18,000	0	0	0	0
GPB	3	Office Finishes Improvements	12,000	0	0	0	0

GPB	21	Normal Improvements to Capital Facility	0	18,000	0	0	0
GPB	26	HVAC/Boiler Replacements	0	850,000	0	0	0
GPB	41	Normal Improvements to Capital Facility	0	0	18,000	0	0
GPB	43	Building Electrical System Replacements	0	0	150,000	0	0
GPB	44	Building Intrusion Detection System Installation	0	0	50,000	0	0
GPB	46	Capital Fire Alarm System	0	0	105,000	0	0
GPB	47	Replace Dock Leveler - Capital	0	0	12,000	0	0
GPB	48	Replace Generator - Capital	0	0	50,000	0	0
GPB	61	Normal Improvements to Capital Facility	0	0	0	18,000	0
GPB	81	Normal Improvements	0	0	0	0	18,000
GPB	82	Window Replacements & Building Envelope Improvements	0	0	0	0	250,000
GPB	83	Improvements to Pole Yard Roadway & Pole Yard	0	0	0	150,000	0
GPB	83	Replace Asphalt Shingle Roof - Capital	0	0	0	0	25,000
GPB	84	Replace Front Entrance Doors - Capital	0	0	0	0	31,000
GPB	85	Site Lighting and Infrastructure Improvements	0	0	0	150,000	0
		Sub-Total:	30,000	868,000	385,000	318,000	324,000
Code	#	Substation:Electric	2020	2021	2022	2023	2024
SPB	1	Replace Substation Locks	10,000	0	0	0	0
SPB	6	Bridge St. Regulator Replacement	271,450	0	0	0	0
SPB	7	Substation Stone Installation at W Portsmouth and Bow Bog S/S	56,008	0	0	0	0
SPB	10	Bow Junction - Transformer High-Side Protection	253,554	0	0	0	0
SPB	20	Substation Projects, Unspecified	0	0	0	0	0
SPB	22	Garvins - Replace SCADA RTU	0	45,960	0	0	0
SPB	23	Terrill Park - Replace SCADA RTU and Upgrade Equipment	0	211,676	0	0	0
SPB	24	Replace Substation Locks	0	10,000	0	0	0
SPB	25	Langdon Street - Replace SCADA RTU	0	49,801	0	0	0
SPB	28	Penacook - Install Time Keeping System	0	15,365	0	0	0
SPB	29	5 MVA Mobile S/S - Upgrade Protective Relaying	0	46,094	0	0	0
SPB	31	Storrs Street Upgrades	0	357,730	0	0	0
SPB	32	Replace Fence Sections at Boscawen and Penacook S/S	0	68,873	0	0	0
SPB	40	Substation Projects, Unspecified	0	0	0	0	0
SPB	41	Substation Fence and Stone Installation	0	0	88,340	0	0

SPB	42	West Portsmouth Street - Replace RTU and Upgrade Equipment	0	0	229,096	0	0
SPB	43	Bow Bog Upgrades	0	0	125,911	0	0
SPB	44	Iron Works Road - Transformer High-Side Protection	0	0	251,930	0	0
SPB	60	Substation Projects, Unspecified	0	0	0	339,728	0
SPB	61	Substation Fence and Stone Installation	0	0	0	100,945	0
SPB	62	Pleasant Street - Replace RTU and Upgrade Equipment	0	0	0	208,668	0
SPB	80	Substation Projects, Unspecified	0	0	0	0	344,545
SPB	81	Substation Fence and Stone Installation	0	0	0	0	103,726
SPC	1	Gulf Street - 13kV Additions and Upgrades	1,846,742	0	0	0	0
SPC	2	West Concord - Replace RTU and Upgrade Equipment	229,094	0	0	0	0
SPC	27	Bridge St. Regulator Replacement	0	280,395	0	0	0
		Sub-Total:	2,666,847	1,085,895	695,277	649,341	448,271
Code	#	Transportation:Electric	2020	2021	2022	2023	2024
FEB	1	#14 - Electric Ops (Mgr) - SUV	1	0	0	0	0
FEB	2	#11 - Electric Ops (Line Supv) - Pick Up	1	0	0	0	0
FEB	3	#45 - Electrics Ops (Utility Mnt Wrkr) - Pick Up	1	0	0	0	0
FEB	4	#15 - Electric Ops (Field Svc Spvsr) - Pick Up	1	0	0	0	0
FEB	5	#24 - Electric Ops (Substation) - Line Truck	1	0	0	0	0
FEB	6	Forklift (Propane)	1	0	0	0	0
FEB	7	Purchase GPS Tracking Devices for Contractor Crews	2,100	0	0	0	0
FEB	8	Purchase Substation Work Trailer	1	0	0	0	0
FEB	21	Replace pickup #41- Meter Mechanic	0	1	0	0	0
FEB	22	Replace #51 - Plow Truck Substations	0	1	0	0	0
FEB	23	Replace pickup truck #48 - Substation	0	1	0	0	0
FEB	24	Replace Digger truck #31	0	1	0	0	0
FEB	25	Replace pickup truck #54 - Standby	0	1	0	0	0
FEB	41	Replace pick up #40 - Meter	0	0	1	0	0
FEB	42	Replace Bucket Truck #22	0	0	1	0	0
FEB	43	Replace pick up #41 - Meter	0	0	1	0	0
FEB	61	Replace plow/stockroom vehicle #52	0	0	0	1	0
FEB	62	Replace pickup #42-Meter Mechanic	0	0	0	1	0
FEB	81	Replace pick up #6	0	0	0	0	1
FEB	82	Replace pick up #55	0	0	0	0	1
FEB	83	Replace Bucket truck #21	0	0	0	0	1
		Sub-Total:	2,107	5	3	2	3
		Total:	**10,359,734**	**11,420,179**	**10,170,508**	**10,548,986**	**11,037,139**

APPENDIX B

UES-SEACOAST
2020-2024 SEACOAST BUDGET

Capital Budget 2020 UES Seacoast

Code	#	Blankets:Electric	2020	2021	2022	2023	2024
BAB		T&D Improvements	1,608,687	1,567,328	1,737,638	2,068,649	2,130,849
BAC		T&D Improvements, Carryover	44,244	43,283	48,592	58,325	59,563
BBB		New Customer Additions	437,591	443,567	503,315	607,926	632,319
BBC		New Customer Additions, Carryover	17,596	17,340	20,021	24,290	24,947
BCB		Outdoor Lighting	182,802	179,172	205,803	250,936	250,698
BCC		Outdoor Lighting, Carryover	10,474	10,449	11,691	13,974	14,511
BDB		Emergency & Storm Restoration	472,396	470,605	524,183	621,123	638,851
BDC		Emergency & Storm Restoration, Carryover	15,380	15,384	17,115	20,395	21,347
BEB		Billable work	403,997	404,885	450,725	531,870	547,969
BEC		Billable work, Carryover	0	0	0	0	0
BFB		Transformers Company/Conversions	393,226	227,387	244,786	287,815	303,760
BFC		Transformers Company/Conversions, Carryover	24,382	0	0	0	0
BGB		Transformer Customer Requirements	1,118,488	1,102,524	1,196,468	1,411,279	1,493,189
BGC		Transformer Customer Requirements, Carryover	138,163	134,519	144,401	169,585	179,400
BHB		Meters Company Requirements	332,139	317,411	331,942	393,074	409,503
BIB		Meters Customer Requirements	567,207	550,141	582,631	674,717	703,512
		Sub-Total:	5,766,770	5,483,994	6,019,310	7,133,959	7,410,420
Code	#	Communications:Electric	2020	2021	2022	2023	2024
ECE	1	Two Way Radio Replacements	6,000	0	0	0	0
ECE	21	Two Way Radio Replacements	0	6,000	0	0	0
ECE	41	Two Way Radio Replacements	0	0	6,000	0	0
ECE	61	Two Way Radio Replacements	0	0	0	6,000	0
ECE	81	Two Way Radio Replacements	0	0	0	0	6,000
		Sub-Total:	6,000	6,000	6,000	6,000	6,000
Code	#	Distribution:Electric	2020	2021	2022	2023	2024
DAB	20	Overhead Line Extensions - New Projects	29,427	0	0	0	0
DAB	20	Overhead Line Extensions - New Projects	0	29,296	0	0	0
DAB	40	Overhead Line Extensions - New Projects	0	0	34,608	0	0
DAB	60	Overhead Line Extensions - New Projects	0	0	0	44,661	0
DAB	80	Overhead Line Extensions - New Projects	0	0	0	0	46,821
DAC	20	Overhead Line Extensions, Carryover	22,416	0	0	0	0
DAC	20	Overhead Line Extensions, Carryover	0	22,110	0	0	0
DAC	40	Overhead Line Extensions, Carryover	0	0	25,828	0	0
DAC	60	Overhead Line Extensions, Carryover	0	0	0	31,408	0
DAC	80	Overhead Line Extensions, Carryover	0	0	0	0	32,276
DBB	20	Underground Line Extensions - New Projects	240,968	0	0	0	0

DBB	20	Underground Line Extensions - New Projects	0	242,391	0	0	0
DBB	40	Underground Line Extensions - New Projects	0	0	284,630	0	0
DBB	60	Underground Line Extensions - New Projects	0	0	0	364,888	0
DBB	80	Underground Line Extensions - New Projects	0	0	0	0	386,675
DBC	20	Underground Line Extensions, Carryovers	309,986	0	0	0	0
DBC	20	Underground Line Extensions, Carryovers	0	310,683	0	0	0
DBC	40	Underground Line Extensions, Carryovers	0	0	351,021	0	0
DBC	60	Underground Line Extensions, Carryovers	0	0	0	425,224	0
DBC	80	Underground Line Extensions, Carryovers	0	0	0	0	437,763
DCB	20	Street Light Projects	26,394	0	0	0	0
DCB	20	Street Light Projects	0	26,172	0	0	0
DCB	40	Street Light Projects	0	0	29,382	0	0
DCB	60	Street Light Projects	0	0	0	34,573	0
DCB	80	Street Light Projects	0	0	0	0	34,660
DCC	20	Street Light Projects, Carryover	0	0	0	0	0
DCC	20	Street Light Projects, Carryover	0	0	0	0	0
DCC	40	Street Light Projects, Carryover	0	0	0	0	0
DCC	60	Street Light Projects, Carryover	0	0	0	0	0
DCC	80	Street Light Projects, Carryover	0	0	0	0	0
DDB	20	Telephone Company Requests	0	0	0	0	0
DDB	20	Telephone Company Requests	0	0	0	0	0
DDB	40	Telephone Company Requests	0	0	0	0	0
DDB	80	Telephone Company Requests	0	0	0	0	0
DDB	80	Telephone Company Requests	0	0	0	0	0
DDC	20	Telephone Requests, Carryover	0	0	0	0	0
DDC	20	Telephone Requests, Carryover	0	0	0	0	0
DDC	40	Telephone Requests, Carryover	0	0	0	0	0
DDC	60	Telephone Requests, Carryover	0	0	0	0	0
DDC	80	Telephone Requests, Carryover	0	0	0	0	0
DEB	20	Highway Projects	196,335	0	0	0	0
DEB	20	Highway Projects	0	193,007	0	0	0
DEB	40	Highway Projects	0	0	214,299	0	0
DEB	60	Highway Projects	0	0	0	255,424	0
DEB	80	Highway Projects	0	0	0	0	262,827
DEC	20	Highway Projects, Carryover	0	0	0	0	0
DEC	20	Highway Projects, Carryover	0	0	0	0	0
DEC	40	Highway Projects, Carryover	0	0	0	0	0
DEC	60	Highway Projects, Carryover	0	0	0	0	0
DEC	80	Highway Projects, Carryover	0	0	0	0	0

DPB	1	Distribution Pole Replacements	1,071,613	0	0	0	0
DPB	3	Circuit 19H1 - Transfer to 27X1, Drinkwater Rd., Kensington	226,920	0	0	0	0
DPB	4	Circuit 22X1: Install Regulator Colby Road, Danville	45,170	0	0	0	0
DPB	5	Circuit 23X1: Install Voltage Regulator Wild Pasture Rd, Kensington	42,732	0	0	0	0
DPB	6	Circuit 58X1 - Convert Main Street, Plaistow	373,726	0	0	0	0
DPB	7	Town of Exeter, Sidewalk Installations, Relocate Poles	72,275	0	0	0	0
DPB	8	Replace Four (4) H- Structures on the 3350 Sub-Transmission Line	461,126	0	0	0	0
DPB	13	Circuit 47X1, Stratham - Add SCADA to 47X1R51X1 Intellirupters	8,893	0	0	0	0
DPB	14	Circuit 13W1, Convert Kelley Road, Plaistow	149,275	0	0	0	0
DPB	16	Circuit 56X1 - Convert Route 125, Kingston	224,922	0	0	0	0
DPB	20	Distribution Projects, Unspecified	0	0	0	0	0
DPB	21	Distribution Pole Replacements	0	1,045,264	0	0	0
DPB	22	Porcelain Cutout Replacements, Various Locations	0	200,599	0	0	0
DPB	23	3348/50 Lines - Rebuild	0	5,377,669	0	0	0
DPB	24	Circuit 23X1: Install Voltage Regulator, Old Amesbury Road, South Hampton	0	40,628	0	0	0
DPB	25	Circuit 13X3: Install Voltage Regulators Old County Road, Plaistow	0	104,217	0	0	0
DPB	26	Circuit 54X1: Install Voltage Regulator Main Street, Newton	0	41,397	0	0	0
DPB	27	Circuit 6W1 - Convert Main St. South Hampton to 8 kV	0	275,787	0	0	0
DPB	40	Distribution Projects, Unspecified	0	0	3,650,000	0	0
DPB	41	Distribution Pole Replacements	0	0	1,146,797	0	0
DPB	42	3342 & 3353 Lines - Replace Crossarms	0	0	377,660	0	0
DPB	43	20T1 Transformer: Transfer Load to 28X1	0	0	446,140	0	0
DPB	60	Distribution Projects, Unspecified	0	0	0	8,500,000	0
DPB	61	Distribution Pole Replacements	0	0	0	1,363,461	0
DPB	62	Circuit 19X3: Replace Cutouts with Switch	0	0	0	71,649	0
DPB	80	Distribution Projects, Unspecified	0	0	0	0	7,750,000
DPB	81	Distribution Pole Replacements	0	0	0	0	1,415,399
DPB	82	Circuit 23X1: Convert Portion of South Road	0	0	0	0	339,026
DPB	83	Circuit 5X3: Install Voltage Regulator Smith Corner Road	0	0	0	0	151,189

DPC	1	Establish 5X3/58X1 Distribution Circuit Tie, Main Street, Plaistow	41,144	0	0	0	0
DPC	21	Circuit 56X1 - Convert Route 125, Kingston	0	337,772	0	0	0
DPC	41	3348/50 Lines - Rebuild	0	0	5,604,574	0	0
DRB		Reliabilty Projects	323,594	0	0	0	0
DRB	20	Reliability Projects, Unspecified	0	375,000	0	0	0
DRB	40	Reliability Projects, Unspecified	0	0	375,000	0	0
DRB	60	Reliability Projects, Unspecified	0	0	0	375,000	0
DRB	80	Reliability Projects, Unspecified	0	0	0	0	375,000
DRC		Reliabilty Projects, Carryover	54,508	0	0	0	0
DRC	1	Circuit 13W2, Install Reclosers, Newton	256,747	0	0	0	0
DRC	21	Circuit 43X1 – Install Reclosers and Implement Distribution Automation	0	351,360	0	0	0
		Sub-Total:	4,178,171	8,973,353	12,539,939	11,466,287	11,231,635
Code	#	Tools, Shop, Garage:Electric	2020	2021	2022	2023	2024
EAE	1	Tools, Shop & Garage – Normal Additions and Replacements	14,500	0	0	0	0
EAE	2	Purchase and Replace Rubber Goods	6,000	0	0	0	0
EAE	3	Purchase and Replace Hot Line Tools	4,500	0	0	0	0
EAE	4	Normal additions & replacement - tools & equipment Meter and Services	7,000	0	0	0	0
EAE	5	Normal Additions and Replacements- Tools and Equipment Substation	10,000	0	0	0	0
EAE	6	Purchase and Replace Tools for New Truck #25	7,000	0	0	0	0
EAE	8	Replace Battery Operated Compression Tool	5,500	0	0	0	0
EAE	9	Replace FC300 Handhelds	16,000	0	0	0	0
EAE	21	Tools, Shop & Garage – Normal Additions and Replacements	0	14,500	0	0	0
EAE	22	Purchase and Replace Rubber Goods	0	6,000	0	0	0
EAE	23	Purchase and Replace Hot Line Tools	0	4,500	0	0	0
EAE	24	Normal additions & replacement - tools & equipment Meter and Services	0	7,000	0	0	0
EAE	25	Normal Additions and Replacements- Tools and Equipment Substation	0	12,000	0	0	0
EAE	26	Tools - Line Department, Unspecified	0	15,000	0	0	0
EAE	27	Purchase and Replace Tools for New Truck #11	0	6,000	0	0	0
EAE	28	Purchase Power Back	0	3,000	0	0	0
EAE	41	Tools, Shop & Garage – Normal Additions and Replacements	0	0	14,700	0	0
EAE	42	Purchase and Replace Rubber Goods	0	0	6,100	0	0
EAE	43	Purchase and Replace Hot Line Tools	0	0	4,700	0	0
EAE	44	Normal additions & replacement - tools & equipment Meter and Services	0	0	7,000	0	0

EAE	45	Normal Additions and Replacements- Tools and Equipment Substation	0	0	12,000	0	0
EAE	46	Tools - Line Department, Unspecified	0	0	15,000	0	0
EAE	47	Purchase and Replace Tools for New Truck #2	0	0	7,500	0	0
EAE	61	Normal additions & replacement - tools & equipment Meter and Field Services	0	0	0	7,000	0
EAE	62	Purchase and Replace Rubber Goods	0	0	0	6,100	0
EAE	63	Purchase and Replace Hot Line Tools	0	0	0	4,800	0
EAE	64	Tools, Shop & Garage – Normal Additions and Replacements	0	0	0	14,800	0
EAE	65	Tools - Line Department, Unspecified	0	0	0	15,000	0
EAE	66	Normal Additions and Replacements- Tools and Equipment Substation	0	0	0	12,000	0
EAE	81	Normal additions & replacement - tools & equipment Meter and Services	0	0	0	0	7,000
EAE	82	Purchase and Replace Hot Line Tools	0	0	0	0	4,900
EAE	83	Tools - Line Department, Unspecified	0	0	0	0	15,000
EAE	84	Tools, Shop & Garage – Normal Additions and Replacements	0	0	0	0	14,800
EAE	85	Purchase and Replace Rubber Goods	0	0	0	0	6,200
EAE	86	Normal Additions and Replacements- Tools and Equipment Substation	0	0	0	0	12,000
		Sub-Total:	70,500	68,000	67,000	59,700	59,900
Code	#	Laboratory:General	2020	2021	2022	2023	2024
EBB	1	Lab Equipment - Normal Additions and Replacements	7,000	0	0	0	0
EBB	21	Lab Equipment - Normal Additions and Replacements	0	7,000	0	0	0
EBB	41	Lab Equipment - Normal Additions and Replacements	0	0	7,000	0	0
EBB	61	Lab Equipment - Normal Additions and Replacements	0	0	0	7,000	0
EBB	81	Lab Equipment - Normal Additions and Replacements	0	0	0	0	7,000
		Sub-Total:	7,000	7,000	7,000	7,000	7,000
Code	#	Office:Electric	2020	2021	2022	2023	2024
EDE	1	Office Furniture & Equipment – Normal Additions and Replacements	3,500	0	0	0	0
EDE	21	Office Furniture & Equipment – Normal Additions and Replacements	0	3,500	0	0	0
EDE	41	Office Furniture & Equipment – Normal Additions and Replacements	0	0	3,500	0	0
EDE	61	Office Furniture & Equipment – Normal Additions and Replacements	0	0	0	3,500	0
EDE	81	Office Furniture & Equipment – Normal Additions and Replacements	0	0	0	0	3,500

Code	#		2020	2021	2022	2023	2024
		Sub-Total:	3,500	3,500	3,500	3,500	3,500
Code	#	Structures:General	2020	2021	2022	2023	2024
GPB	1	Normal Improvements to Seacoast DOC Facility	8,000	0	0	0	0
GPB	21	Normal Improvements to Seacoast DOC Facility	0	12,000	0	0	0
GPB	22	Plaistow Garage Improvements	0	27,000	0	0	0
GPB	41	Normal Improvements to Seacoast DOC Facility	0	0	12,000	0	0
GPB	61	Normal Improvements to Seacoast Facility	0	0	0	15,000	0
GPB	81	Normal Improvements to Seacoast DOC Facility	0	0	0	0	15,000
GPC	1	Construct New NH Seacoast Region Facility, Exeter	0	2,000,000	0	0	0
GPC	3	Construct New NH Seacoast Region Facility, Exeter	10,000,000	0	0	0	0
		Sub-Total:	10,008,000	2,039,000	12,000	15,000	15,000
Code	#	Substation:Electric	2020	2021	2022	2023	2024
SPB	1	Substation Stone Installation, Various Locations	36,131	0	0	0	0
SPB	3	Replace Multi-Drop Telephone Landline Service, Various Locations	48,764	0	0	0	0
SPB	4	Guinea Substation, Hampton - Upgrade Site Communications	78,504	0	0	0	0
SPB	20	Substation Projects, Unspecified	0	0	0	0	0
SPB	21	Exeter Substation, Exeter, Replace Fence	0	84,238	0	0	0
SPB	22	High Street Substation, Hampton - Replace 17W1 & 17W2 Relays	0	58,451	0	0	0
SPB	23	Replace Multi-Drop Telephone Landline Service	0	46,094	0	0	0
SPB	24	Guinea Substation, Hampton - Install Time Keeping System	0	14,289	0	0	0
SPB	26	Replace Fence at Gilman Lane Substation	0	84,238	0	0	0
SPB	27	Westville Substation, Plaistow - Replace SCADA RTU	0	54,960	0	0	0
SPB	40	Substation Projects, Unspecified	0	0	0	0	0
SPB	41	Substation Fence and Stone Installation	0	0	88,340	0	0
SPB	42	Replace Multi-Drop Telephone Landline Service	0	0	48,039	0	0
SPB	60	Substation Projects, Unspecified	0	0	0	0	0
SPB	61	Substation Fence and Stone Installation	0	0	0	100,945	0
SPB	62	Guinea - Replace EM Relaying	0	0	0	762,262	0
SPB	80	Substation Projects, Unspecified	0	0	0	0	0

SPB	81	Substation Fence and Stone Installation	0	0	0	0	103,726
SPB	82	Guinea - Replace EM Relaying	0	0	0	0	1,172,795
		Sub-Total:	163,398	342,270	136,379	863,207	1,276,521
Code	#	Transportation:Electric	2020	2021	2022	2023	2024
FEB	1	Replace Pick Up Truck #12 - Electric Ops (Prmry Stndby)	1	0	0	0	0
FEB	2	Replace Pick-up Truck #14 - Electric Ops (2nd Standby)	1	0	0	0	0
FEB	3	Replace Bucket Truck #25 - Electric Ops	1	0	0	0	0
FEB	4	Purchase New Forklift (Electric)	1	0	0	0	0
FEB	5	Replace Wire Reel Trailer #T12 - Electric Ops -	1	0	0	0	0
FEB	6	Replace Pole Trailer #T8 - Electric Ops - (Large Pole Trailer)	1	0	0	0	0
FEB	7	Purchase GPS Tracking Devices for Contractor Crews	2,100	0	0	0	0
FEB	21	Replace Pick up Truck #26 - Metering	0	1	0	0	0
FEB	22	Replace Pick Up Truck #30	0	1	0	0	0
FEB	23	Replace Pick Up Truck #24	0	1	0	0	0
FEB	24	Replace Pick Up Truck #22 - Metering	0	1	0	0	0
FEB	26	Replace Pick Up Truck #31 - Stock Room/Plow Truck	0	1	0	0	0
FEB	27	Replace Digger Truck #11	0	1	0	0	0
FEB	28	Replace Large Pole Trailer	0	1	0	0	0
FEB	41	Replace substation truck #5	0	0	1	0	0
FEB	42	Replace pick up #16	0	0	1	0	0
FEB	43	Replace Bucket Truck #2	0	0	1	0	0
FEB	44	Replace pick up #34	0	0	1	0	0
FEB	61	Replace Pick Up Truck #18- Project Leader	0	0	0	1	0
FEB	62	Replace Pick Up Truck #15-Field Services Supervisor	0	0	0	1	0
FEB	81	Replace pick up #3	0	0	0	0	1
FEB	82	Replace pick up #4	0	0	0	0	1
FEB	83	Replace pick up #7	0	0	0	0	1
FEB	84	Replace pick up #36	0	0	0	0	1
		Sub-Total:	2,106	7	4	2	4
		Total:	**20,205,445**	**16,923,124**	**18,791,132**	**19,554,655**	**20,009,980**

APPENDIX C

PLANNING AND BUDGET PROCESS FLOW

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 follows the process displayed in 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 three load projections (Average Peak Load, 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:

The forecasted loads are used to develop load flows and evaluate the constraints and limits of the Subtransmission System and Distribution Systems.

C) 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 is updated with system updates from the previous year and consolidate with the updated model from Eversource.

D) Distribution circuit models are created using the Milsoft Windmil software. The Milsoft software performs unbalanced voltage drop analysis (per phase load flow analysis). The loads used in these models are projected loads of the individual circuits allocated with historical consumer billing data. The model results are compared to the equipment ratings and system constraint criteria specified in Unitil's Distribution Planning Guideline (Appendix G). 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.

E) The Distribution Engineering Department then evaluates the system constraints identified by the load flow and circuit modelling process and generates alternate system upgrades. Alternatives are evaluated per Unitil's Project Evaluation Process (Appendix F). 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.

F) 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>

G) 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 load flow and circuit modelling result including loading and voltage violations and other system deficiencies. The report also describes the scope and benefits of alternatives and recommends the proposed project to resolve the identified constraints.

<u>Project Budgeting:</u>

H) After the planning studies are reviewed and approved by engineering management, the recommended projects are 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 levels 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.

APPENDIX D

UNITIL ELECTRIC SYSTEM PLANNING GUIDE

Unitil	Guidelines	Procedure No.	GL-DT-DS-01
	Distribution Engineering	Page No.	Cover
		Revision No.	5
	Electric System Planning Guide	Revision Date	11/20/2018
		Supersedes Date:	02/09/2016

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.

12/10/2018

Kevin E. Sprague — Date
Director, Engineering

Nov. 28, 2018

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
5	11/20/2018	Updated to reference project evaluation process and modifications to sections 1.2, 1.4 (removed), 1.5 (renumbered 1.4), 3.1, 3.2, 3.7, 3.9.1, 4.3, 4.5, A-1, B-1)

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 (New England Power Pool) 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.

This document does not apply to distribution circuits or distribution substation equipment, such as distribution substation transformers, distribution circuit terminal equipment, etc.

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 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.
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.

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 under frequency 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-06). 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. Typically, the single-non-repeating load cycle portion of this criterion is met by completing necessary repairs within twenty-four hours. In situations which require longer repair times (moving a system spare transformer, repairs along the salt marsh, etc.) elements may not exceed Normal Limits for consecutive days.

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.

Reference Appendix A for a summary of the electric system planning loading threshold criteria.

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 within the following limits. Steady state operating voltages at Non-Distribution Points shall have an upper threshold of 105% of nominal (126 V on a 120 V base) and a lower threshold to allow directly connected downline regulators to boost the voltage to the programmed float voltage under basecase conditions and to 95% of the float voltage under contingency scenarios. The lower steady state voltage threshold for Non-Distribution Points that do not directly supply voltage regulators is 90% of nominal (108 V on a 120 V base). Steady state operating voltages at Regulated Distribution Points shall have an upper threshold of 104.2% of nominal (125 V on a 120 V base) and a lower threshold equal to 99% of the float voltage of the directly connected up line regulation (typically 123 V on a 120 V base) under basecase conditions and 97.5% of the regulator float voltage under contingency scenarios. Unitil systems should be planned and designed to sustain steady state operating voltages at Unregulated 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). Additionally, Unitil systems should be planned and designed to sustain steady state operating voltages at Customer Primary Metering Points within a minimum limit of 95% of nominal (114 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 supplies for distribution loads or primary metered 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).

A Regulated Distribution Points indicate locations that supply distribution loads and have directly connected up line regulation. This may be, for example, at substation low-side buses where voltage regulation is provided by load-tap-changing power transformers or regulators at the transformer output.

Correspondingly, Unregulated Distribution Points indicate locations that directly supply distribution loads without directly connected up line regulation. This may be, for example, at unregulated distribution circuits or customer taps off of subtransmission lines.

Customer Primary Metering Points are locations that directly supply primary metered loads.

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.

Reference Appendix B for a summary of the electric system planning voltage threshold criteria.

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 one generating plant within the immediate vicinity of the Unitil system;
- largest distributed generation facility out of service and an outage of any one additional distributed generation facility within the immediate vicinity of the Unitil system.

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

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) is 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 protective relaying, 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.

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. 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.

For basecase modeling of the system, any one generating plant and the largest distributed generation facility, as well as any one additional distributed generation facility shall be modelled out of service for the future study period with all other elements in service.

This may result in evaluating the system under multiple generator dispatch cases. Remaining units may be modeled at their historical output during the season of study. 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).

For contingency modeling of the systems all distributed generation facilities shall be modeled at their historic output during the season of study with the largest facility modelled off-line. All generation that is expected to trip offline during the fault is considered to remain offline following restoration switching. In addition, the largest single generator interconnected to the source/line used for restoration of load is considered to be offline prior to the fault occurring and following restoration switching.

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 shall be developed and evaluated per Unitil's *Project Evaluation Procedure* (PR-DT-DS-11). 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 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.

4.5.3 Economics

Cost estimates should be prepared for each alternative identified during the course of a study. These estimates shall be used to perform a cost/benefit analysis per Unitil's Project Evaluation Procedure (PR-DT-DS-11). Cost comparisons between alternatives shall include a net present value analysis for multi-year solutions.

4.5.4 Recommendation

Every study that identifies potential violations of design criteria shall propose recommended actions.

4.5.5 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

			Allowable Element Loading		Allowable Loss of Load	
Design Condition	**Load Level**	**Generation**	**Limit[1]**	**Duration**	**Limit**	**Duration**
Normal Operation –						
all elements in service, or non-emergency configuration	≤ Peak Design Load	typical seasonal dispatch w/ largest generating plant and largest DG facility out of service as well as any one additional DG facility out of service	≤ Normal	Continuous	none	---
outage of generating plant			≤ Normal	Continuous	none	---
Contingency Operation –						
loss of non-radial line	≤ Peak Design Load	dispatch w/ largest generating plant and the largest DG facility out of service All generation that is expected to trip offline during the fault is considered to remain offline following restoration switching. In addition, the largest single generator interconnected to the source/line used for restoration of load is considered to be offline prior to the fault occurring and following restoration switching	≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---
loss of a 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
Extreme Peak – all elements in service	≤ Extreme Peak Load	typical seasonal dispatch w/ largest generating plant and largest DG facility out of service	≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---

(S) = Summer load cycle

(W) = Winter load cycle

[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

Design Condition	Location	% Boost of Downline Regulation Directly Connected to Bus [1]	Low Limit (p.u.)	High Limit (p.u.)
Normal Operation -				
a) all elements in service, or non-emergency configuration b) outage of generating plant	Non-Distribution Point	10%	0.94	1.05
		7.5%	0.962	1.05
		5%	0.985	1.05
		n/a	0.90	1.05
	Regulated Distribution Point	n/a	1.025[2]	1.042
	Unregulated Distribution Point	n/a	0.975	1.042
	Customer Primary Metering Point	n/a	0.95	1.042
Contingency Operation -				
a) loss of non-radial line, b) loss of a system supply transformer, c) loss of a radial line (no backup tie)	Non-Distribution Point	10%	0.91	1.05
		7.5%	0.93	1.05
		5%	0.95	1.05
		n/a	0.90	1.05
	Regulated Distribution Point	n/a	1.0	1.042
	Unregulated Distribution Point	n/a	0.975	1.042
	Customer Primary Metering Point	n/a	0.95	1.042
Extreme Peak - all elements in service	Non-Distribution Point	10%	0.91	1.05
		7.5%	0.93	1.05
		5%	0.95	1.05
		n/a	0.90	1.05
	Regulated Distribution Point	n/a	1.0	1.042
	Unregulated Distribution Point	n/a	0.975	1.042
	Customer Primary Metering Point	n/a	0.95	1.042

Non-Distribution Points are locations that do not directly supply distribution loads or primary metered loads.

Regulated Distribution Points are locations that supply distribution loads with directly connected up line regulation.

Unregulated Distribution Points are locations that directly supply distribution loads without directly connected up line regulation.

Customer Primary Metering Points are locations that directly supply primary metered loads.

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[1] Assumes regulator float voltage of 1.033 p.u. (124V on 120V base)

[2] Assumes regulation float voltage of 1.033 p.u. and 1V bandwidth (123V on 120V base, lower end of band)

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:

APPENDIX E

UNITIL ELECTRIC SYSTEM LOAD FORECASTING PROCEDURE

Unitil	Engineering Procedures	Procedure No.	PR-DT-DS-08
	Distribution Engineering	Page No.	Cover
		Revision No.	2
	Electric System Load Forecasting	Revision Date	11/5/18
		Supersedes Date:	2/10/16

FOREWORD

The purpose of this document is to define the process of developing the ten year electric system load forecasts.

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

11/27/2018

Kevin E. Sprague
Director, Engineering

Date

Nov. 26, 2018

John J. Bonazoli
Manager, Distribution Engineering

Date

REVISION HISTORY		
Revision #	**Date**	**Description of Changes**
0	May 26, 2009	Original Issue
1	February 10, 2016	Revised to Update Procedures
2	November 5, 2018	Revised Template, updated to reflect new spreadsheet tools, revised note in 4.1 and updated section 4.4.

Table of Contents

List of Appendices

1.0 Introduction

This document details the procedures to be followed during the process of developing the ten year electric system load forecasts.

1.1 Purpose

The purpose of this procedure is to assist Distribution Engineering personnel in the process of developing the ten year electric system load forecasts for use in planning system improvements in order to ensure the reliability of the electric system. The following procedure is to be used as a general guide in the mechanics of system load forecasting and outlines the process of data collection, file management, and the statistical analysis used to develop the forecasting models. This guideline is not intended to be an all-inclusive step-by-step procedure and may need to be modified where engineering judgment deems necessary.

1.2 Applicability & Scope

This document applies to the overall system load forecasts for the Unitil electric systems. This procedure is not applicable for forecasting individual distribution circuit loads.

1.3 Updating the Guideline

The Director, Engineering is responsible for maintaining this guideline to ensure the 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 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

2.1.1 Forecasting Study Period

Unitil has adopted the summer peak period for forecasting purposes. This period is defined as being June 1 – September 30.

2.1.2 Average Peak Load

The Average Peak Load levels are used as a guide for general load growth decisions not related to system infrastructure planning. The Average Peak Design Load forecasts are set at a 50% probability limit meaning there is an equal likelihood of that year's peak demand load being either higher or lower than the Average Peak Load level.

2.1.3 Peak Design Load

The Peak Design Load levels are used for the purpose of assessing the adequacy of system infrastructure when performing system planning and contingency studies for the loss of major system elements. The Peak Design Load projections are set at a 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.

2.1.4 Extreme Peak Load

The 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 Extreme Peak Load projections are set at a 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.

2.1.5 Statistical Outlier

A Statistical Outlier, for the purposes of this guideline, is considered to be any value greater than 3 standard deviations from the reference value.

3.0 Forecasting Methodology

The historical basis for each system is a series of yearly regression models developed to correlate actual daily loads to a weighted temperature-humidity index (WTHI) derived from the average temperature and average dew point temperature of each day and the previous two days. Once a model is established, an estimated peak load can be derived for that season for any value of WTHI. There are two dimensions of variability introduced with this modeling. First is the highest WTHI 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 WTHI. 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 WTHI is assumed to follow the discrete distribution of past historical highest WTHI. The random possibilities of peak load outcomes for any specific WTHI are assumed to follow a standard probability distribution model with a mean centered on the point estimate of the peak load at that WTHI 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 WTHI and random peak load estimates at those WTHI 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 WTHI possibilities and variability in loads versus WTHI. 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.

4.0 Forecasting Procedure

The Electric System load forecasts are performed using three distinct Excel models. Each model and the process of annual updates are described below. Each of the three models builds upon the previous model. Therefore, it is essential that this process be completed in the sequential order given below.

4.1 Peak Load vs. Weighted Temperature-Humidity Index Model

The first step in the process is to develop a model of peak load vs. WTHI for the previous year. Unitil utilizes the Boltzmann Curve to model this relationship. Each DOC has a separate Excel spreadsheet file to develop this model. Each file shall be named indicating the DOC and year (e.g. 'UES Seacoast 2015 - Boltzmann WTHI.xls'). Models are saved in the current year's forecast folder as shown in the example below:

S:\Departments\Engineering\DepartmentOnly\PLANNING\Electric System Design Forecasts\Electric System Design Forecasts - 2017-2026\Load vs WTHI models

The 'Data Analysis' tab of the 'Boltzmann WTHI' workbook performs the necessary calculations to develop the load vs. WTHI model and provide upper and lower peak load prediction limits for any given WTHI. Note that conditional formatting is applied to the 'residual' column whereby the cell will become highlighted magenta if the absolute value of the difference between the actual measured peak kW and the model's predicted peak kW for a given WTHI (residual value) is greater than 3 standard deviations of the residual values. The purpose of this formatting is to assist in identifying Statistical Outliers.

The following procedure shall be used as a guide in updating this model:

Obtain daily system peak data for the Forecasting Study Period:

- Tie point metering for each DOC is obtained from the Energy Measurement Information System (EMIS) accessed through WebOps. Data is entered throughout the year into EMIS Excel spreadsheets for Fitchburg Gas & Electric (FG&E) and Unitil Energy

Systems (UES). The path to the root directory for these spreadsheets are located in the following directory:

S:\Departments\Engineering\DepartmentOnly\LOADDATA\Load Data by DOC

FG&E and UES have separate sub-directories. Each EMIS spreadsheet file is named indicating the system and year (e.g. EMIS UES 2015.xls)

- A separate tab exists for each individual tie point meter. Peak load data from EMIS is entered into the tab for the respective tie point meter and hourly peak load data is totaled in the 'Summary' tabs of each workbook.
- Transpose the summer season daily peak kW load data into the 'Data' tab of the 'Boltzmann WTHI' workbook.

Obtain daily average temperature and average dew point temperature data for the Forecasting Study Period:

- Obtain daily average temperature and the average dew point temperature from weather stations local to each DOC. The following websites may be utilized to obtain this data:

  UES-Seacoast (Portsmouth)

  http://www.wunderground.com/history/airport/KPSM/2015/6/1/MonthlyHistory.html

  UES-Capital (Concord)

  http://www.wunderground.com/history/airport/KCON/2015/6/1/MonthlyHistory.html

  UES-FGE (Fitchburg)

  http://www.wunderground.com/history/airport/KFIT/2015/6/1/MonthlyHistory.html

- Data for the Forecasting Study Period is copied into the weather data spreadsheet for each DOC located in the following directory:

  S:\Departments\Engineering\DepartmentOnly\Weather Data

  One weather data spreadsheet file is utilized for all three DOCs (e.g. Weather Data 2018.xlsx). There are separate tabs for each DOC and two summary tabs within the spreadsheet. This spreadsheet is used to calculate a 3-day WTHI for each day. The basis for the daily WTHI is the average dry bulb temperature and average dew point temperature of the current day and the previous two days.

  The formula below is used to calculate each day's temperature-humidity index is as follows:

$$THI_d = (0.5 * Avg\ Dry\ Bulb\ Temp) + (0.3 * Avg\ Dew\ Point\ Temp) + 15$$

  The formula below is used to calculate each day's 3-day WTHI is as follows:

$$WTHI = \left[\frac{10 * THI_d + 5 * THI_{d-1} + 2 * THI_{d-2}}{17}\right] - 55$$

- Copy the daily WTHI from the 'Weather Data' spreadsheet into the 'Data' tab of the 'Boltzmann WTHI' workbook.

Update Boltzmann model to eliminate weekends and holidays and Statistical Outliers:

- Create a copy of the 'data analysis' tab and remove all weekends and holidays during the Forecasting Study Period.
- Copy the non-holiday weekday data in the date, daily peak kW, and daily WTHI columns into the 'Data Analysis' tab of the 'Boltzmann WTHI' workbook.
- Delete the previous year's outliers at the bottom of the workbook and confirm formula ranges refer to the entire data range.

Optimize Boltzmann constants to maximize r-squared (coefficient of determination):

- In the 'Data Analysis' tab of the 'Boltzmann WTHI' workbook, the constants a1, a2, dx, & x0 in the Boltzmann equation will be optimized by using the Excel Solver add-in to maximize the value SSR/SST (r-squared). The following procedure shall be followed in the sequence given below:
  1. Maximize SSR/SST by varying a1 & a2. Run multiple trials of Solver until the value is maximized.
  2. Maximize SSR/SST by varying dx. Run multiple trials of Solver until the value is maximized.
  3. Maximize SSR/SST by varying x0. Run multiple trials of Solver until the value is maximized.
  4. Maximize SSR/SST by varying all 4 constants. Run multiple trials of Solver until the value is maximized.
  5. Look at the 'residual' column of the data set and remove any outliers.
  6. Repeat steps 1-5 until constants are maximized and all outliers have been removed.

Inspect and update charts and graphs:

- Confirm the model's "goodness of fit" by inspecting charts and graphs.

  NOTE: The 'Residuals' tab in the 'Boltzmann WTHI' workbook shows a graphical depiction of the residual values vs. WTHI. Confirm the plotted residual values are a scatter plot that is generally centered the horizontal axis (approximately an equal number positive and negative points). A steeply sloped scatter plot (positive or negative) may indicate that the model may not represent an accurate load vs. WTHI correlation.
- Update chart titles and scales as necessary.

4.2 Ten Year Historical Boltzmann Peak WTHI Adjustment Model

The next step in the forecasting procedure is to consolidate the past ten years of Boltzmann load vs WTHI models, develop linear peak load growth rates for any given daily WTHI, and to trend changes in the Boltzmann constants. This is done using the 'Boltzmann peak WTHI adjustments' Excel workbook. Each DOC has a separate Excel spreadsheet file. Each file shall be named indicating the DOC and year (e.g. 'UES Seacoast 2006-2015 - Boltzmann WTHI.xlsx'). Models are saved in the current year's forecast folder as shown in the example below:

S:\Departments\Engineering\DepartmentOnly\PLANNING\Electric System Design Forecasts\Electric System Design Forecasts - 2017-2026

The following procedure shall be used as a guide in updating this model:

- Copy the 'analysis' tab from the 'Boltzmann WTHI' workbook to the 'Boltzmann Peak WTHI Adjustment' file. Rename tab to include year.
- Change the confidence interval in the analysis tab to 50%.
- Update cell references and column headings for the Boltzmann model constants a1, a2, dx, x0, and SSR/SST in the 'analysis summary' tab.
- Update cell references and column headings in the 'Growth Rates' tab as necessary.
- Update cell references and column headings for the upper, lower, and mean prediction limits in the 'application' tab.
- Update chart titles and confirm scaling as necessary.

4.3 Ten Year System Forecasting Model

The final step is forecasting the peak load levels for specific probability limits which define the Average Peak Load, Peak Design Load and Extreme Peak Load.

This is done using the 'Monte Carlo w WTHI adjustments' Excel workbook. Each DOC has a separate Excel spreadsheet file. Each file shall be named indicating the DOC and year (e.g. 'UES-Seacoast 2006-2015 Monte Carlo WTHI.xlsx'). Models are saved in the current year's forecast folder as shown in the example below:

S:\Departments\Engineering\DepartmentOnly\PLANNING\Electric System Design Forecasts\Electric System Design Forecasts - 2014-2023

The following procedure shall be used as a guide in updating this model:

- Update the formulas and cell references for the upper and lower predication limits in the 'Historical Model Average' tab.
- Update the formulas and cell references for the predicted model mean loads and standard deviations in the 'Load-vs-Temp Model Data 2' tab.
- Update the cell references for the model constants in the 'Load-vs-Temp Model Data 1' tab.

- Update historical WTHI data to include most recent year in the 'WTHI Data' tab.
- Run successive Monte Carlo trials to ensure the model solves and is stable.

Note: There are two Monte Carlo tabs in this workbook; 'Monte Carlo (working)' and 'Monte Carlo (frozen)'. The 'Monte Carlo (working)' tab actively updates when calculations are refreshed. All graphs and charts are based off the 'Trial Results' tab which references the 'Monte Carlo (frozen)' tab. When determining model stability, replace all cell references in the 'Trial Results' tab to the 'Monte Carlo (working)' tab. Once results are stable and satisfactory, copy the results from the 'Monte Carlo (working)' tab into the 'Monte Carlo (frozen)' tab and re-reference the 'Trial Results' tab to the 'Monte Carlo (frozen)' tab to lock the results.

- Update chart titles and confirm scaling as necessary.

4.4 Distributed Energy Resources and Standby Service Agreements

Distribution Energy Resources (DER) and Non-Utility Generators (NUG) that are operating during peak load conditions will offset system tie point power flows consequently reducing system load forecasts. Therefore, the power offset or produced from all known significant DER and NUG units must be accounted for in the load forecasts. The method on how this is accomplished will depend on the configuration of the interconnection. Some common examples are outlined below:

- A customer owned 1 MW natural gas NUG is found to be operational during peak load conditions at its full output rating. This interconnection is offsetting the customer's load only. The interconnection agreement does not allow export onto the distribution system but includes standby service of 1 MW.

  Load forecasts are completed based on the system tie point interchange. The standby service amount of 1MW is added to each year's forecast to account for the customer's 1MW load offset by the NUG.

- A 3 MW PV NUG is interconnected at the distribution circuit level and approved as a Qualified Facility permitting 100% export. Export power during the system peak hour was measured to be 2 MW.

  The 2MW output of the NUG is added to the system tie point interchange prior to forecasting future system loads. This ensures that the loads offset by the NUG included in the system forecast.

- A customer has a standby service agreement of 3 MW. The customer is found to be consuming 1 MW during peak load conditions. The 1 MW of load is subtracted from the system tie point interchange. The standby service amount of 3 MW is added to each year's forecast to account for the customer's standby service agreement.
- A customer has a standby service agreement of 1 MW and owns a 1.5 natural gas NUG. The generator is found to be generating during peak load conditions and is exporting 0.5 MW onto the Unitil system. The exported load of 0.5 MW is added to the system tie point interchange and the standby service amount of 1 MW is added to each year's forecast to account for the customer's standby service agreement.

- The aggregate amount of small scale "behind the meter" DER, such as residential inverter based PV interconnections, has significantly increased over the last couple of years. The effect that these interconnections have on future load projections tends to lag the actual load reduction experienced since the forecasting procedure is based on ten years of historical data. Historical comparison of peak day load cycles have shown a "flatting" of the curve during the peak hours in recent years that can be attributed to the amount of PV interconnections that have occurred. Prior to finalizing load projections, the impact of installed PV as well as the aggregate amount of applications being processed should be considered. Engineering judgement should be used to determine if load projections should be reduced due to PV on a case by case basis. It is not anticipated that this process will be required long term since the PV offset will become inherent in the forecasting process over time and once the amount of interconnection applications drops off.

5.0 Load Factor Forecasting

The final component of the ten year load forecasting procedure is to forecast the system load factor. Load factor defines the relationship between energy usage and peak load and is presented as the ratio of the average hourly equivalent of the annual energy usage for a given year divided by the peak hour load for that year. Energy usage is tracked separately for FG&E and for the UES system as a whole. Therefore, the evaluation for UES is relative to the coincident peaks for the combined UES-Capital and UES-Seacoast systems.

Load factor forecast is modeled using separate Excel workbooks for UES and FG&E. Each file shall be named indicating the DOC and year (e.g. 'FG&E 2017-2026 load factor - Peak Demand vs Energy (external BOD).xls'). Models are saved in the current year's forecast folder.

The following procedure shall be used as a guide in updating this model:

- Obtain the annual energy usage forecast from Finance. Forecasts for annual kWH as well as annual WTHI adjusted kWh are provided in an Excel spreadsheet for each UES & FGE. Both spreadsheets are located in a separate folder for each year as shown in the example below:

  S:\Common\Departments Shared\Finance\Data Transfer\UnitForecasts_2015

- Copy and insert kWH forecast data into the appropriate columns of the load factor forecasting spreadsheet indicated above.
- Copy and insert the forecast demand data developed previously into the appropriate columns of the load factor forecasting spreadsheet.
- Confirm and update all formula ranges and update chart data ranges.

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 2020-2029 ELECTRIC SYSTEM PLANNING STUDY

Unitil Energy Systems - Capital

Electric System Planning Study 2020-2029

Prepared By:

Jake Dusling
Unitil Service Corp.
October 25, 2019

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 2020 through 2029.

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

Year	Project Description	Justification	Cost
2020	Boscawen Substation – Take 13W1 and 13W2 Regulators Out of Load Bonus	Basecase Voltage	n/a
	West Concord Substation – Take 2H1, 2H2 and 2H4 Regulators Out of Load Bonus	Basecase Voltage	n/a
	37 Line, Penacook to MacCoy Street Tap – Reconductor	Contingency Loading	$725,000
	Penacook Substation – 4X1 Protection Setting Modifications	Contingency Loading	n/a

Note: cost estimates do not include 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 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 options were developed and tested to assess the impact they had on these deficiencies. Cost estimates were developed for each improvement option, and a cost-benefit comparison was made for the improvement plan options. Final recommendations represent the proposed system improvement plan.

Note that this study does not attempt to identify basecase distribution substation loading concerns. These concerns, including loading of substation transformers, are typically identified and addressed as part of the Distribution Planning Study.

3 SYSTEM DESCRIPTION

The UES–Capital electric power system is supplied from Eversource Energy (Eversource) 115kV transmission and 35kV subtransmission systems via three Eversource substations; Garvins, Oak Hill, and Curtisville.

The Eversource Garvins substation, located in Bow, is served from three 115 kV transmission lines; the H-137 originating from Merrimack Station, the G-146 from Deerfield substation, and the M-108 from Curtisville substation. Two 115 - 34.5 kV, 36/48/60/67.2 MVA transformers supply the Garvins 34.5kV bus. Three dedicated breaker positions at Garvins directly supply UES-Capital subtransmission lines (374, 375 & 396).

The Eversource Oak Hill substation, located in Concord, is served from two 115kV transmission lines; the B-15 and B-84 Lines from Farmwood substation. 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 substation. Three 34.5kV subtransmission lines emanate from Peancook substation (34, 35/36 & 37).

The Eversource Curstisville substation supplies the UES-Capital Broken Ground substation, located in Concord, with two incoming 115 kV transmission lines. Curtisville is supplied by an in-and-out loop of the Eversource C-189/M-108 line approximately mid-way between Garvins and Farmwood. Broken Ground consist of two 115 – 34.5 kV, 60 MVA transformers supplying three 34.5 kV subtransmission lines (38, 3376 & 3387).

The UES-Capital electric system consists of ten 34.5kV subtransmission lines interconnecting sixteen distribution substations. The 374 line operates radially between Garvins and Bow Junction substation. The 396 line supplies the 374 line beyond Bow Junction substation. From Bow Junction substation the 374 line operates in parallel with the 375 line Garvins to Bridge Street substation. The 34 operated radially from Penacook substation to Bridge Street substation and 35/36 lines operate radially from Bridge Street substation to Penacook substation. The 37 line operates radially from Penacook substation to Boscawen substation. The 33 line interconnects Bow Junction substation and West Concord substation with a normally open point at Pleasant Street substation. The 3376 and 3387 lines operate radially between Broken Ground and Hollis with a normally open point between the two lines at the Hollis bus. The 38 line operates radially from Broken Ground to a normally open tie with the 35 line at Horseshoe Pond tap.

In addition to the interconnections with Eversource, five non-utility generating plants connect internally, or at the 34.5 kV supply point, to 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. Finally, the Eversource Garvins Falls hydro-generation station interconnects directly at Garvins substation.

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 the linear trend projections from ten years of historical models of the summer season daily peak load versus the daily weighted temperature-humidity index (WTHI), which account for the correlation of daily loads to actual daily WTHI. This results in a range of peak load possibilities for each year, which vary due to annual highest WTHI. 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 UES-Capital system load projections developed in December, 2018 were used for this study and are provided in the table below.

UES-Capital System Loads Under Study

Projected Summer Season	Peak Design Load (MW)	Extreme Peak Load (MW)
2020	133.4	138.8
2021	134.7	141.2
2022	136.5	143.3
2023	137.3	146.3
2024	139.0	147.4
2025	140.0	148.8
2026	141.7	151.7
2027	142.4	153.2
2028	143.5	155.2
2029	145.1	157.3

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 34.5.0) 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 peak hour 2018. 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 August 29th, 2018 peak hour. 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 August 29th, 2018 peak hour.

Basecase models for study of future years were developed from this 2018 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 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 (LPF) for the UES system (Seacoast and Capital) is subject to the requirements specified in the 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 – 2020 Anticipated Load Power Factor Limits

Equivalent Load (% of Peak)	Minimum p.f.	Maximum p.f.
28%	n/a	1.000, leading
66%	0.9638, lagging	0.9974, leading
100%	0.9693, lagging	n/a

On August 29, 2018 at 16:00, the UES-Capital system reached a peak demand of 123.08 MW. The system was lagging by 16.44 MVAr during that peak hour, with a corresponding power factor of 0.9912. This met the minimum LPF requirement of 0.9693 in effect during 2018.

The following table shows the estimated UES-Capital system LPF over the time period of this study and the schedule of the minimum anticipated PF correction requirements.

UES-Capital System – Anticipated Power Factor Correction Requirements

Year	Uncorrected System Load[1,2,3] (MW)	(MVAr)	p.f. (115 kV)	Additional p.f. correction (MVAr)	Est. LPF w/ Improvements p.f. (115 kV)
2020	133.7	17.0	0.9921 lagging	n/a	n/a
2029	142.6	17.7	0.9924 lagging	n/a	n/a

At these load levels, the net power factor is expected to remain above the minimum LPF standard throughout the study period.

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.

Year	Load Level (MW)	System Constraint	Circumstances
2020	133.4	Boscawen 13.8 kV Bus 1 (13W1/13W2 Bus) Voltage @ 0.96 PU	Basecase
		West Concord 4.16 kV Bus Voltage @ 0.96 PU	
		Loading of 37 Line #1/0 ACSR Conductor @ 115% of Normal for more than 12 consecutive hours	Loss of 4X1 at Penacook
		Loading of 4X1 Overcurrent Protection Settings @ 89% of Pickup	Loss of 37 Line at Penacook
		33X2 Tap Voltage @ 0.97 PU	Loss of 33 Line at Bow Junction
2024	139.0	33X3 Tap Voltage @ 0.97 PU	Loss of 33 Line at Bow Junction

Exposure to the low voltage condition on the 33 line for loss of the 33 line at Bow Junction is limited to only a few customers[4] at summer peak load conditions with all internal generation offline. In the event that actual service voltage at the customer's point of interconnection drops below the ANSI C84.1 acceptable range, interruption of this customer load may be necessary until repairs are made or switching to isolated faulted equipment is completed and the system is restored to the extent possible. The duration of any interruption due to

[1] Transmission equivalent power import
[2] With all UES-Capital subtransmission and substation capacitor banks in-service with the exception of Broken Ground C2 and C4 and Boscawen 13C1.
[3] Loads were determined from future year basecase models, which were developed by growing MVAr at the same percentage at MW.
[4] 33X2 & 33X3 are single customer taps.

unacceptable service voltage is anticipated to be similar to a typical distribution system outage event. Therefore, no system improvement recommendations are proposed for these low voltage conditions on the 33 line.

The following contingencies require the loop between Penacook and Garvins be reestablished by closing the 34 breaker at Bridge Street and the 036 breaker at Penacook prior to restoring load during peak load conditions.

- Loss of a Garvins Transformer (TB39 or TB51)
- Loss of an Oak Hill Transformer (TB15 or TB84)
- Loss of the 3122 Line at Penacook
- Loss of the 317 Line at Penacook
- Loss of the 33 Line at Bow Junction

Additionally, the following contingencies require the 34 line to be transferred to Bridge Street substation by closing the 34 breaker at Bridge Street and opening the 034 breaker at Penacook in 2029 and beyond to address low voltage conditions.

- Loss of 1X7P Circuit at Bridge Street
- Loss of 1X7A Circuit at Bridge Street

8 SYSTEM IMPROVEMENT OPTIONS

The following sections describe details of system improvement options 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.

Improvement options are developed and evaluated per Unitil's *Project Evaluation Procedure* (PR-DT-DS-11). The project evaluation workflow description and detailed cost/benefit analyses (if applicable) for the improvement options below can be found in Appendix G – Project Evaluations.

8.1 Boscawen 13.8 kV Bus 1 Voltage – 2020

Low voltage conditions were identified at the Boscawen substation 13.8 kV bus 1, 13W1 and 13W2 bus, under basecase conditions in 2020. This voltage violation is due to the 13W1 and 13W2 regulators being in load bonus, reducing the regulation range to +/- 5%.

The following options were examined to avoid voltage violations identified at Boscawen substation.

8.1.1 Take Regulators Out of Load Bonus

Summary:
Take the 13W1 and 13W2 regulators at Boscawen substation out of load bonus to allow the full regulation range of +/- 10%.

Cost Estimate: no capital investment

Results:
From the time of taking the regulators out of load bonus through 2029 and beyond it is expected that voltage at the Boscawen 13.8 kV bus 1 will remain within planning criteria limits under basecase and contingency configurations.

Loading of the 13W1 and 13W2 circuit positions under 2024 summer distribution load projections with the regulators out of load bonus is expected to be:

Circuit	2024 Projected Load (kVA)	Proposed Summer Normal Rating (kVA)	% Loading	Proposed Limiting Element	Existing Summer Normal Rating (kVA)	Existing Limiting Element
13W1	1,521	4,302	35%	Regulator	4,953	Relay Setting
13W2	2,650	4,302	62%	Regulator	4,953	Relay Setting

The overall rating of taking the regulators out of load bonus reduces the overall circuit ratings of 13W1 and 13W2 by approximately 650 kVA and makes the regulators the limiting element. In the event additional capacity is needed to carry both 13W1 and 13W2 the regulators could be placed back into load bonus as part of the switching to restore/transfer the load.

8.1.2 Replace 13W1 and 13W2 Regulators with Larger Units

Summary:
Replace the 13W1 and 13W2 regulators with 438A units that will not be placed in load bonus.

Cost Estimate:

Replace 13W1 and 13W2 Regulators	$350,000
Total (w/o OHs)	$350,000

Results:
From the time of installation through 2029 and beyond it is expected that voltage at the Boscawen 13.8 kV bus 1 will remain within planning criteria limits under basecase and contingency configurtions.

8.1.3 Install Capacitor Bank at Boscawen 13.8 kV Bus 1

Summary:
Install a 1,200 kVAr, switched capacitor bank with local and remote control on the 13.8 kV bus 1 at Boscawen substation. Additional study will be required to confirm this installation will not cause switching concerns with the existing 3,600 kVAr bank installed on the 37 line at Boscawen.

Cost Estimate:

Install Capacitor on the 13.8 kV Bus 1 at Boscawen	$100,000
Total (w/o OHs)	$100,000

Results:
From the time of installation through 2029 and beyond it is expected that voltage at the Boscawen 13.8 kV bus 1 will remain within planning criteria limits under basecase and contingency configurations.

The exisitng 34.5 kV capacitor bank at Boscawen is typically out of service due to switching surges that cause issues for a primary metered customer supplied via circuit 13X4. It is possible that the proposed 13.8 kV capacitor bank could cause similar issues for the primary metered customer.

8.1.4 Reconductor the 37 Line from Penacook to MacCoy Street Tap

Reconductoring the 37 line from Penacook to the MacCoy Street Tap was reviewed as an option to the projects described above. The reconductoring the 37 line did not improve voltages to within planning criteria.

8.1.5 Recommended Traditional Option

Taking the 13W1 and 13W2 regulators out of load bonus is the recommended traditional option to the identified voltage constraint.

8.1.6 Non-wires Alternatives

This project was evaluated per Unitil's Project Evaluation Procedure. Per the procedure non-wires alternatives were not required to be evaluated, because the proposed traditional option is estimated to cost less than $250,000.

8.1.7 Recommended Project

Taking the 13W1 and 13W2 regulators out of load bonus is the recommended solution to the identified voltage constraint.

8.2 West Concord 4.16 kV Bus Voltage – 2020

Low voltage conditions were identified at the West Concord substation 4.16 kV bus under basecase conditions in 2020. This voltage violation is due to the 2H1, 2H2 and 2H4 regulators being in load bonus, reducing the regulation range to +/- 5%.

The following options were examined to avoid voltage violations identified at West Concord substation.

8.2.1 Take Regulators Out of Load Bonus

Summary:
Take the 2H1, 2H2 and 2H4 regulators at West Concord substation out of load bonus to allow the full regulation range of +/- 10%.

Cost Estimate: no capital investment

Results:
From the time of taking the regulators out of load bonus through 2029 and beyond it is expected that voltage at the West Concord 4.16 kV bus will remain within planning criteria limits under basecase and contingency configurations.

Loading of the 2H1, 2H2 and 2H4 circuit positions under 2024 summer distribution load projections with the regulators out of load bonus is expected to be:

Circuit	2024 Projected Load (kVA)	Proposed Summer Normal Rating (kVA)	% Loading	Proposed Limiting Element	Existing Summer Normal Rating (kVA)	Existing Limiting Element
2H1	1,505	2,039	74%	Wire	2,039	Wire
2H2	1,935	2,594	75%	Regulator	3,199	Relay Set
2H4	1,244	2,133	58%	Relay Setting	2,133	Relay Set

Circuit 2H2 is the only circuit in which taking the regulators out of load bonus caused the regulators to be the limiting element of the circuit. The regulators on circuits 2H1 and 2H4 are expected to be load to 58% and 48% of their summer normal rating respectively.

8.2.2 Replace 2H1, 2H2 and 2H4 Regulators with Larger Units

Summary:
Replace the 2H1, 2H2 and 2H4 regulators with 668A units that will not be placed in load bonus.

Cost Estimate:

Replace 2H1, 2H2 and 2H4 Regulators	$450,000
Total (w/o OHs)	$450,000

Results:
From the time of installation through 2029 and beyond it is expected that voltage at the West Concord 4.16 kV bus will remain within planning criteria limits under basecase and contingency configurations.

8.2.3 Install Capacitor Bank at West Concord

Summary:
Install a 1,200 kVAr, switched capacitor bank with local and remote control on the 4.16 kV bus at West Concord substation. Additional study will be required to confirm this installation will not cause switching concerns with the existing 2,400 kVAr bank installed on the 33 line at West Concord.

Cost Estimate:

Install Capacitor on the 4.16 kV Bus at West Concord	$100,000
Total (w/o OHs)	$100,000

Results:
From the time of installation through 2029 and beyond it is expected that voltage at the West Concord 4.16 kV bus will remain within planning criteria limits under basecase and contingency configurations.

8.2.4 Recommended Traditional Option
Taking the 2H1, 2H2 and 2H4 regulators out of load bonus is the recommended traditional option to the identified voltage constraint.

8.2.5 Non-wires Alternatives
This project was evaluated per Unitil's Project Evaluation Procedure. Per the procedure non-wires alternatives were not required to be evaluated, because the proposed traditional option is estimated to cost less than $250,000.

8.2.6 Recommended Project
Taking the 2H1, 2H2 and 2H4 regulators out of load bonus is the recommended solution to the identified voltage constraint.

8.3 37 Line Loading Violation - 2020
The 37 line is a radial subtransmission line that is used to restore circuit 4X1 for a fault between Penacook substation and pole 12 Village Street. The existing conductor on the 37 line is expected to exceed its normal rating for more than 12 consecutive hours as early as 2020 with all 4X1/37 line generation off-line[5].

The following options were examined to avoid conductor overloads identified on the 37 line.

8.3.1 Reconductor the 37 Line

Summary:
Reconductor the 37 Line from pole 8 in the vicinity of Penacook to MacCoy Street tap (pole 34) with 556 ACSR phase conductor and 266 ASCR neutral conductor.

Cost Estimate:

Reconductor 37 Line from Penacook to MacCoy Street	$725,000
Total (w/o OHs)	$725,000

Results:
From the time of reconductoring through 2029 and beyond, after switching to restore all load, loading on the 37 line between Penacook and MacCoy Street tap with 556 ACSR conductor is expected to remain below its normal rating.

[5] Wheelabrator/SES is the largest generator in the area and is modelled offline per planning criteria. All three hydroelectric generators are modelled offline because they are typically offline during summer conditions due to low river flow.

8.3.2 Construct New 34.5 kV Line – Penacook to MacCoy Street Tap

Summary:
Construct a new 34.5 kV line from Penacook to MacCoy Street tap. Construction to include 336 AA phase conductors on separate structures from the 37 line, the addition of a new 34.5 kV line terminal at Penacook, and modifications to MacCoy Street tap. The proposed new configuration would have the new line carrying the 37 line from MacCoy Street tap to Boscawen and the existing 37 lines feeding a portion of 4X1.

Due to the limited right-of-way width of portions of the 37 line and that portions of the line are constructed along the street from Penacook to MacCoy Street tap the construction of a second line would likely require the acquisition of additional land rights.

Cost Estimate:

Penacook Substation Modification to Accommodate 3rd Line	\$500,000
Construct new 2nd Line – Penacook to MacCoy Street Tap	\$750,000
Total (w/o General Construction OHs)	\$1,250,000

Results:
From the time of construction through 2029 and beyond, loading on both the new line and the existing 37 line are expected to remain below their normal ratings.

8.3.3 Recommended Traditional Option
Reconductoring the 37 line from Penacook to the MacCoy Street tap is the recommended traditional option to the identified conductor constraint.

8.3.4 Non-wires Alternatives
The recommended traditional option is to reconductor the 37 line from Penacook to MacCoy Street tap in 2020. This project was evaluated per Unitil's Project Evaluation Procedure. Per the procedure non-wires alternatives were not required to be evaluated, because the implementation date of the proposed traditional option is less than three years in the future.

However, it was determined that Unitil will obtain information regarding non-wire alternative projects to defer this project.

The 37 line/4X1 load area is approximately 18 MW. To defer the need for the traditional options above non-wires alternative project(s) would need to reduce load[6] in the 37 line/4X1 area by approximately 3 MW in 2020 to reduce line load below its normal rating[7] and approximately 175 kVA to 275 kVA per year until 2029.

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[6] Load estimates are based on UES-Capital peak design load projections and five year distribution load projections. The load estimates provided do not include any margin for unforeseen large customer additions.
[7] Achieving an expected load that is below the normal conductor rating provides some margin for unforeseen future load growth.

Unitil issued a request for information (RFI) for non-wires alternatives to nineteen vendors on March 29th, 2019 with 11 bidders expressing interest in submitting information. After receiving and responding to multiple bidder questions Unitil received four responses to the RFI. All four responses were for this installation of battery storage with one proposal including the installation of a photovoltaic facility in conjunction with the battery storage. The pricing of these proposals ranged from $7 million to $11.5 million over a ten year period.

A cost benefit analysis determined that the NWA alternatives did not provide the necessary benefits to justify the additional cost over the traditional option.

8.3.5 Recommended Project

Reconductoring the 37 line from Penacook to the MacCoy Street tap is the recommended option to the identified conductor constraint.

9 OTHER CONSIDERATIONS

In addition to the traditional basecase and N-1 contingency evaluations the following items were also reviewed:

9.1 Loss of a Unitil Owned Supply Transformer and Loss a 2nd Supply Transformer

Unitil does not currently own a 115-34.5 kV mobile transformer and it is expected that the spare 115-34.5 kV transformer could take up to two weeks to disassemble, transport and place in-service in the event of an in-service transformer failure at Broken Ground.

9.1.1 Loss of Both Broken Ground Transformers

For loss of the second Broken Ground transformer while waiting for the spare transformer to be placed into service the 38 line is restored from Horseshoe Pond. Approximately 10 MW of Hollis load can be restore from the 38 line via the Broken Ground Bus (after restoring the loop between Garvins and Penacook), leaving approximately 14 MW out of service until transformer capacity can be placed in-service at Broken Ground.

To restore all load for loss of both Broken Ground transformers additional subtransmission line capacity needs to be constructed between Broken Ground and the Garvins to Bridge Street portion of the system (374 and 375 lines). See section 10.1 below for additional details on the Broken Ground Master Plan.

Another option to restore all load for loss of both Broken Ground transformers is to purchase and store a spare transformer at Broken Ground or purchase a mobile 115-34.5 kV transformer. The necessary infrastructure will need to be constructed at Broken Ground to allow the spare or mobile to be installed in a timely manner.

9.1.2 Loss of One Broken Ground Transformer and Loss of One Garvins Transformer or One Oak Hill Transformer

All load can be restored following the loss of one Broken Ground transformer and one Garvins or Oak Hill transformer throughout the study period.

9.2 Split Oak Hill/Penacook 34.5 kV Buses

Due to the normal configuration of Oak Hill and Penacook Unitil was informed by the ESCC that anytime a Farmwood substation breaker was open or out of service an Oak Hill Transformer had to be removed from service or the Oak Hill bus tie and one of the lines between Oak Hill and Penacook (317 or 3122) had to be open at Penacook or Oak Hill to avoid the 34.5 kV system becoming a transmission path following a V182 or P145 outage.

A preliminary review of the UES-Capital system was performed under 2029 project peak loads with the 4XBT2 bus tie at Penacook and the BT54 bus tie at Oak Hill open. No new loading or voltage concerns were identified as part of this analysis however it would be desirable to install a second capacitor bank on Penacook bus 3 (3122 Bus) to provide voltage support for the 34 line and to reduce the times during the year that the Oak Hill and Garvins loop needs to be established. To allow the Penacook bus tie to be closed remotely the 4XBT2 will be replaced with a bus tie breaker.

Additionally, this review assumed that the Oak Hill and Penacook bus ties would be closed prior to reestablishing the loop between Garvins and Penacook. Additional load flow and protection reviews will need to be completed to determine if the Oak Hill and Penacook bus ties need to be closed prior to reestablishing the loop.

The possibility of splitting the Oak Hill and Penacook 34.5 kV will be discussed in more detail as part of the Joint Planning Process with Eversource. However, due to the limited frequency in which a Farmwood substation breaker is expected to be out of service it is not recommended that the Oak Hill and Penacook buses be split at this time.

9.3 Radial Subtransmission Lines

UES-Capital has two radial subtransmission lines with no ties to other subtransmission lines. Neither radial subtransmission line violates planning criteria as they serve less than 30 MW of load at peak design load levels and it is reasonable to assume that repairs can be made within twenty-four hours.

Neither line currently has viable distribution switching options to restore load. The following sections describe possible upgrades to restore load via the distribution system. For both lines an option to the distribution projects described below is to construct 2nd subtransmission lines adjacent to the existing lines.

Additional study will be required to determine the feasibility and ultimate scope of work required to increase capacity to restore additional load.

9.3.1 <u>396X1 Line</u>

The 396X1 line is a radial line that is a tap off the 396 line at Garvins and supplies Bow Bog substation and a 34.5 kV primary customer. 396X1 serves approximately 5 MW of load. There is no distribution switching that can be utilized during peak conditions to restore load. Portions of Bow Bog substation can be restored via Iron Works and Bow Junction substation during off-peak conditions.

To restore additional load via distribution circuits, capacity additions will be required at both Iron Works and Bow Junction substations. Additionally, upgrades to circuits 22W3, 18W2 and 7W3 will also be needed.

Even with the upgrades described the primary metered 34.5 kV customer would remain out of service until repairs are made.

9.3.2 <u>37 Line</u>

The 37 line is a radial line that runs from the MacCoy Street tap to Boscawen substation and serves approximately 12 MW of load. There is currently a circuit tie between circuit 13W2 and 4W3 that can be used to restore a portion of circuit 13W2.

To restore additional load the 4W3J13W2 circuit will need to be reinforced. This would include rebuilding circuit 4W3 and 13W2 and installing additional 13.8 kV capacity at Penacook substation.

Even with the upgrades described above portions of the Boscawen substation circuits and the 34.5 kV primary metered customers will remain out of service until repairs to the 37 line can be completed.

10 FUTURE CONSIDERATIONS

A 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 loads greater than the 2029 projected peak[8]. The review is completed under basecase configuration with all elements in service.

For total system loads up to 175 MW the following additional conditions have been identified for basecase conditions:

- Garvins TB15 transformer loading at 93% of Normal
- Garvins TB84 transformer loading at 90% of Normal
- 33 Line Voltage (Iron Works 13.8 kV Bus, 33X4, 33X5 and 33X6)
- Penacook 13.8 kV bus voltage

The following table summarizes system elements that are anticipated to be loaded above 90% of their normal rating under basecase or contingencies conditions in 2029.

[8] UES-Capital Extreme Peak Load was grown by 10%

System Constraint	Circumstances
Oak Hill TB15 Transformer at 104% of Normal[9]	Loss of TB51 (or TB39) Transformer at Garvins
Oak Hill TB84 Transformer at 101% of Normal[9]	Loss of TB51 (or TB39) Transformer at Garvins
Oak Hill TB15 (or TB84) Transformer at 108% of Normal[9]	Loss of TB84 (or TB15) Transformer at Oak Hill
396 Line from Garvins to the 396X1 Tap at 98% of Normal	Loss of the 374 Line at Garvins
375 Line From Garvins to Terrill Park at 93% of Normal	Loss of the 396 Line at Garvins
33 Line from West Concord to the State Prison Tap at 98% of Normal	Loss of the 33 Line at Bow Junction
3122 Line from Oak Hill to Penacook at 101% of Normal	Loss of the 317 Line at Penacook
317 Line from Oak Hill to the Penacook Tap at 94% of Normal	Loss of the 3122 Line at Penacook
33 Line from Iron Works to Pleasant Street at 95% of Normal	Loss of the 33 Line at West Concord

These high level reviews are used to identify potential system problems which occur beyond the 10 year planning horizon or may occur in the event of large unforeseen load growth. These reviews are used to develop a long term vision of the system which is used to guide incremental improvements.

10.1 Broken Ground Master Plan
In the summer of 2017 Unitil completed construction of the Broken Ground system supply substation which consists of two 60 MVA, 115-34.5 kV transformers and three new subtransmission lines from Broken Ground to Hollis.

In the basecase configuration loading of the three UES-Capital system supplies is as follows:

System Supply Substation	**Transformer**	**2029 Projected Load (MVA)**	**Summer Normal Rating (MVA)**	**% Loading**
Garvins	TB39	43.0	67	64%
	TB51	43.2	67	64%
Oak Hill	TB15	39.6	45	88%
	TB84	36.5	44	83%
Broken Ground	28T1	23.7	60	40%
	28T2	13.9	60	23%

9 Prior to Eversource switching Eversource Oak Hill load to other supplies.

A review was performed to develop a master plan to utilize the Broken Ground capacity and offload the Oak Hill and Garvins supplies. This plan consists of the following:

- Construct a new line from Hollis to the 375 line corridor between Bridge Street substation and Terrill Park substation with 795 AA conductor.
- Rebuild the 38 line or construct a new line from Broken Ground/Hollis to the 35 line corridor between at West Portsmouth substation.
- Construct a new subtransmission line between the 35 line in the vicinity of West Portsmouth and the 34 line at West Concord.
- Install a bus tie breaker and second 34.5 kV capacitor bank at Penacook substation.
- Install a bus tie breaker and second 34.5 kV capacitor bank at Bridge Street substation.

This will allow the new line between Hollis and the 375 line to normally supply 375 line load and the southern Bridge Street substation bus. The new line/38 line will supply the 34 line and the northern Bridge Street bus. The 396/374 line will operate radially from Garvins and the 35/36 line will operate radially from Penacook.

This configuration allows all lines to be operated radially and all load can be restored following an N-1 contingency without the need to re-establish the loop between Penacook and Bridge street. Also, this configuration will allow all Broken Ground load to be restored via Garvins and Oak Hill following the loss of both Broken Ground transformers. Garvins and Oak Hill will also be utilized to restore load for loss of the new line between Hollis and the 375 corridor and the new line between Broken Ground/Hollis and the 35 corridor.

11 FINAL RECOMMENDATIONS

The following summarizes final recommendations given in this report.

Year	Project Description	Justification	Cost
2020	Boscawen Substation – Take 13W1 and 13W2 Regulators Out of Load Bonus	Basecase Voltage	n/a
	West Concord Substation – Take 2H1, 2H2 and 2H4 Regulators Out of Load Bonus	Basecase Voltage	n/a
	37 Line, Penacook to MacCoy Street Tap – Reconductor	Contingency Loading	$725,000
	Penacook Substation – 4X1 Protection Setting Modifications	Contingency Loading	n/a

Note: cost estimates do not include overheads.

APPENDICES

APPENDIX A

EVALUATION CRITERIA

The following tables summarize the application of electric system planning guidelines as used in this study. These criteria are based on Unitil's Electric System Planning Guide Revision 5 (November 20, 2018).

VOLTAGE CRITERIA

Design Condition	Location	% Boost of Downline Regulation Directly Connected to Bus [10]	Low Limit (p.u.)	High Limit (p.u.)
Normal Operation -				
a) all elements in service, or non-emergency configuration b) outage of generating plant	Non-Distribution Point	10%	0.94	1.05
		7.5%	0.962	1.05
		5%	0.985	1.05
		n/a	0.90	1.05
	Regulated Distribution Point	n/a	1.025[11]	1.042
	Unregulated Distribution Point	n/a	0.975	1.042
	Customer Primary Metering Point	n/a	0.95	1.042
Contingency Operation -				
a) loss of non-radial line, b) loss of a system supply transformer, c) loss of a radial line (no backup tie)	Non-Distribution Point	10%	0.91	1.05
		7.5%	0.93	1.05
		5%	0.95	1.05
		n/a	0.90	1.05
	Regulated Distribution Point	n/a	1.0	1.042
	Unregulated Distribution Point	n/a	0.975	1.042
	Customer Primary Metering Point	n/a	0.95	1.042
Extreme Peak - all elements in service	Non-Distribution Point	10%	0.91	1.05
		7.5%	0.93	1.05
		5%	0.95	1.05
		n/a	0.90	1.05
	Regulated Distribution Point	n/a	1.0	1.042
	Unregulated Distribution Point	n/a	0.975	1.042
	Customer Primary Metering Point	n/a	0.95	1.042

[10] Assumes regulator float voltage of 1.033 p.u. (124V on 120V base)
[11] Assumes regulation float voltage of 1.033 p.u. and 1V bandwidth (123V on 120V base, lower end of band)

LOADING CRITERIA

			Allowable Element Loading		Allowable Loss of Load	
Design Condition	**Load Level**	**Generation**	**Limit[12]**	**Duration**	**Limit**	**Duration**
Normal Operation –						
all elements in service, or non-emergency configuration	≤ Peak Design Load	typical seasonal dispatch w/ largest generating plant and largest DG facility out of service as well as any one additional DG facility out of service	≤ Normal	Continuous	none	---
outage of generating plant			≤ Normal	Continuous	none	---
Contingency Operation –						
loss of non-radial line	≤ Peak Design Load	dispatch w/ largest generating plant and the largest DG facility out of service All generation that is expected to trip offline during the fault is considered to remain offline following restoration switching. In addition, the largest single generator interconnected to the source/line used for restoration of load is considered to be offline prior to the fault occurring and following restoration switching	≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---
loss of a 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
Extreme Peak – all elements in service	≤ Extreme Peak Load	typical seasonal dispatch w/ largest generating plant and largest DG facility out of service	≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---

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

APPENDIX B

UES-CAPITAL LINE & SUBTRANSMISSION SUBSTATION RATINGS

UES-Capital Transmission Substation Ratings

Substation Element	Voltage Base	Breaker or Recloser ontinuous Rating (Amp		Breaker or Recloser Trip Level (Amps)		Breaker or Recloser Load Encroachment		CTs Present Tap Selection		Switches Continuous Rating		Fuses		Regulator Rating		Conductor Rating		Transformer Rating		Overall Rating		Overall Rating		Limiting Element	
	(kV)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (kVA)	LTE (kVA)	Normal (Amps)	LTE (Amps)	Normal	LTE
Garvins TB-39	34.5																	1,121	1,322	66,921	78,906	1,121	1,322	Xfmr	Xfmr
Garvins TB-51	34.5																	1,121	1,322	66,921	78,906	1,121	1,322	Xfmr	Xfmr
374	34.5	2,000	2,000					1,000	1,000	1,200	1,200					730	891			43,570	53,179	730	891	Wire	Wire
375	34.5	2,000	2,000					1,000	1,000	1,200	1,200					739	902			44,107	53,836	739	902	Wire	Wire
396	34.5	1,200	1,200					1,200	1,200	1,200	1,200					915	1,121			54,612	66,907	915	1,121	Wire	Wire
Bow Jct.	34.5																								
374	34.5							1,200	1,200	1,200	1,200					1,324	1,683			71,622	71,622	1,200	1,200	CT	CT
Bus Tie 7XBT1	34.5									600	600					1,324	1,683			35,811	35,811	600	600	Switch	Switch
Langdon	34.5																								
374	34.5									600	600					1,324	1,683			35,811	35,811	600	600	Switch	Switch
Gulf Street	34.5																								
374	34.5									1,200	1,200					1,103	1,395			65,833	71,622	1,103	1,200	Wire	Switch
Terrill Park	34.5																								
375	34.5							1,200	1,200	1,200	1,200					1,324	1,683			71,622	71,622	1,200	1,200	CT	CT
Bridge Street	34.5																								
34	34.5	1,200	1,200	429	512			800	800	600	600					531	645			25,593	30,559	429	512	Trip	Trip
35	34.5	1,200	1,200	429	512			800	800	600	600					531	645			25,593	30,559	429	512	Trip	Trip
374	34.5	1,200	1,200	429	512			800	800	1,200	1,200					730	891			25,593	30,559	429	512	Trip	Trip
375	34.5	1,200	1,200	429	512			800	800	1,200	1,200					730	891			25,593	30,559	429	512	Trip	Trip
1X7A	34.5											180	180			174	174			10,385	10,385	174	174	Wire	Wire
1X7P	34.5	560	560	322	384			100	100					160	160	174	174			5,969	5,969	100	100	CT	CT
Bus Tie 1XBT1	34.5									600	600									35,811	35,811	600	600	Switch	Switch
Oak Hill TB-15	34.5																	736	887	43,948	52,937	736	887	Xfmr	Xfmr
Oak Hill TB-84	34.5																	753	820	44,947	48,942	753	820	Xfmr	Xfmr
Penacook	34.5																								
317	34.5	1,200	1,200	322	384			1,200	1,200							670	818			19,195	22,919	322	384	Trip	Trip
3122	34.5	1,200	1,200	322	384			1,200	1,200							670	818			19,195	22,919	322	384	Trip	Trip
34	34.5	1,200	1,200	322	384			1,200	1,200	600	600					739	902			19,195	22,919	322	384	Trip	Trip
36	34.5	1,200	1,200	322	384			1,200	1,200	600	600					531	645			19,195	22,919	322	384	Trip	Trip
37	34.5	1,200	1,200	279	333			400	400							739	902			16,635	19,863	279	333	Trip	Trip
Bus Tie 4XBT1	34.5									600	600									35,811	35,811	600	600	Switch	Switch
Bus Tie 4XBT2	34.5									600	600									35,811	35,811	600	600	Switch	Switch
Maccoy Tap	34.5																								
37R1	34.5	800	800	188	224	288	288	1,000	1,000	900	900					463	562			17,189	17,189	288	288	Load Enc	Load Enc
37R4X1	34.5	800	800	188	224	288	288	1,000	1,000	900	900					463	562			17,189	17,189	288	288	Load Enc	Load Enc
Bow Jct.	34.5																								
33	34.5	1,200	1,200	375	448											730	891			22,394	26,739	375	448	Trip	Trip
West Concord	34.5																								
33	34.5	1,120	1,120	392	468					1,200	1,200					463	562			23,394	27,933	392	468	Trip	Trip
Hollis	34.5													668	668	531	645			31,693	38,497	531	645	Wire	Wire
38R1	34.5	800	800					1,000	1,000	900	900					531	645			31,693	38,497	531	645	Wire	Wire
Horseshoe Pond Tap	34.5																								
38	34.5	800	800	295	352	432	432	1,000	1,000	900	900					537	653			25,784	25,784	432	432	Load Enc	Load Enc
Broken Ground T1	115	2,000	2,000							1,200	1,200					945	1,159			188,008	230,583	945	1,159	Wire	Wire
Broken Ground 28T1	34.5	2,000	2,000	1,233	1,472			2,200	2,200	2,000	2,000							1,205	1,205	71,915	71,915	1,205	1,205	Xfmr	Xfmr
38	34.5	1,200	1,200	375	448			800	800	1,200	1,200					945	1,159			22,394	26,739	375	448	Trip	Trip
3376	34.5	1,200	1,200	375	448			800	800	1,200	1,200					945	1,159			22,394	26,739	375	448	Trip	Trip
Bus Tie BT28A	34.5	2,000	2,000	981	1,171			2,400	2,400	2,000	2,000									58,544	69,903	981	1,171	Trip	Trip
Broken Ground T2	115	2,000	2,000							1,200	1,200					945	1,159			188,008	230,583	945	1,159	Wire	Wire
Broken Ground 28T2	34.5	2,000	2,000	1,233	1,472			2,200	2,200	2,000	2,000							1,205	1,205	71,915	71,915	1,205	1,205	Xfmr	Xfmr
3387	34.5	1,200	1,200	375	448			800	800	1,200	1,200					945	1,159			22,394	26,739	375	448	Trip	Trip

UES-Capital Summary of Line Ratings and Impedances

Line	Section No.	Section From	Section To	Switch Rating (Amps)	Phase Conductor	Neutral Conductor	Ampere Ratings Summer Normal	Summer Emergency	Winter Normal	Winter Emergency	Distance Miles	Phase GMD (ft)	Neutral GMD (ft)	Section Impedance (PU on 100 MVA, 34.5 kV base) R1	X1	R0	X0	Section Impedance (ohms) R1	X1	R0	X0
33	1	Bow Junction	Iron Works	600	556 AA	266 ACSR	730	891	956	1074	1.767	5.22	7.47	0.02755	0.09337	0.07881	0.27675	0.32787	1.11135	0.93807	3.29402
	2	Iron Works	Pleasant		#2 CU	266 ACSR	240	289	312	348	0.733	5.22	7.47	0.05938	0.04763	0.08062	0.12364	0.70678	0.56692	0.95963	1.47164
	3	continued	continued	1200	#2 CU	052 AWA	240	289	312	348	0.214	5.22	7.47	0.01734	0.01391	0.02731	0.03991	0.20634	0.16553	0.32501	0.47502
	4	Pleasant	St. Paul	900	556 ACSR	266 ACSR	739	902	968	1087	0.379	5.22	7.47	0.00591	0.02003	0.01690	0.05936	0.07032	0.23837	0.20120	0.70652
	5	St. Paul	33X4 Tap	1200	266 ACSR	1/0 AA	463	562	605	677	1.741	5.22	7.47	0.05577	0.09696	0.13743	0.30879	0.66375	1.15405	1.63580	3.67534
	6	33X4 Tap	Jefferson Pilot Tap		266 ACSR	1/0 AA	463	562	605	677	0.791	5.22	7.47	0.02534	0.04405	0.06244	0.14029	0.30157	0.52433	0.74320	1.66984
	7	Jefferson Pilot Tap	W. Concord		266 ACSR	1/0 AA	463	562	605	677	0.710	5.22	7.47	0.02274	0.03954	0.05605	0.12593	0.27069	0.47064	0.66710	1.49885
34	1	Bridge Street S/S	(p.148)		266 ACSR	1/0 ACSR	463	562	605	677	0.044	5.22	7.47	0.00570	0.00991	0.01393	0.03272	0.06786	0.11799	0.16581	0.38941
		(p.148)	Storrs St. Tap (p.142)		266 ACSR	1/0 ACSR	463	562	605	677	0.134	5.22	7.47								
	2	Storrs St. Tap (p.142)	Montgomery St. Tap (p.139)		266 ACSR	1/0 ACSR	463	562	605	677	0.133	5.22	7.47	0.00426	0.00741	0.01041	0.02445	0.05070	0.08816	0.12389	0.29097
	3	Montgomery St. Tap (p.139)	Concord Center Tap (p.131)		266 ACSR	1/0 ACSR	463	562	605	677	0.275	5.22	7.47	0.00881	0.01532	0.02152	0.05055	0.10484	0.18229	0.25617	0.60162
	4	Concord Center Tap (p.131)	W. Concord S/S		266 ACSR	266 ACSR	463	562	605	677	1.198	5.22	7.47	0.03837	0.06671	0.07311	0.19101	0.45675	0.79403	0.87013	2.27351
	5	W. Concord S/S	Crowley Foods (p.27)	1200	266 ACSR	1/0 ACSR	463	562	605	677	0.651	5.22	7.47	0.02085	0.03626	0.05095	0.11966	0.24819	0.43154	0.60642	1.42419
	6	Crowley Foods (p.27)	Sewalls Falls (p.90)	1200	266 ACSR	1/0 ACSR	463	562	605	677	1.534	5.22	7.47	0.04913	0.08543	0.12006	0.28195	0.58482	1.01685	1.42897	3.35595
	7	Sewalls Falls (p.90)	(p.124)		336 AA	336 ACSR	531	645	694	777	0.909	5.22	7.47	0.02351	0.05086	0.04062	0.14302	0.27986	0.60537	0.48347	1.70230
	8	continued	continued		336 AA	336 ACSR	531	645	694	777	0.654	5.22	7.47	0.01692	0.03659	0.03311	0.10290	0.20135	0.43555	0.39409	1.22476
	9	(p.124)	(p.125)		336 ACSR	336 ACSR	537	653	702	787	0.204	5.22	7.47	0.00533	0.01144	0.01053	0.03273	0.06345	0.13611	0.12533	0.38952
	10	(p.125)	Penacook S/S		336 AA	336 ACSR	531	645	694	777	0.170	5.22	7.47	0.00440	0.00951	0.00861	0.02675	0.05234	0.11322	0.10243	0.31836
35	1	Bridge Street S/S	(p.71)		266 ACSR	266 ACSR	463	562	605	677	0.745	5.22	7.47	0.02386	0.04149	0.04546	0.11878	0.28403	0.49379	0.54111	1.41383
	2	(p.71)	Line 38 Tap (p.65)	600	336 ACSR	266 ACSR	537	653	702	787	0.284	5.22	7.47	0.00721	0.01547	0.01544	0.04494	0.08579	0.18416	0.18381	0.53492
	3	Line 38 Tap (p.65)	(p.61)	600	336 ACSR	266 ACSR	537	653	702	787	0.172	5.22	7.47	0.00437	0.00937	0.00935	0.02722	0.05195	0.11154	0.11132	0.32396
	4	(p.61)	(p.49)		336 ACSR	1/0 ACSR	537	653	702	787	0.415	5.22	7.47	0.01053	0.02261	0.02972	0.07578	0.12536	0.26914	0.35377	0.90200
	5	(p.49)	(p.46)		336 ACSR	1/2" CW	537	653	702	787	0.155	5.22	7.47	0.00635	0.01362	0.01800	0.04402	0.07552	0.16214	0.21420	0.52390
		(p.46)	(p.43)		336 ACSR	052 AWA	537	653	702	787	0.095	5.22	7.47								
	6	(p.43)	W. Portsmouth Street S/S		266 ACSR	052 AWA	463	562	605	677	0.191	5.22	7.47	0.00612	0.01064	0.01502	0.03386	0.07282	0.12661	0.17875	0.40298
	7	W. Portsmouth Street S/S	(p.31)		266 ACSR	1/0 ACSR	463	562	605	677	0.430	5.22	7.47	0.01377	0.02395	0.03365	0.07904	0.16393	0.28504	0.40055	0.94071
	8	(p.31)	Locke Rd. Tap (p.26)	600	336 ACSR	1/0 ACSR	537	653	702	787	0.193	5.22	7.47	0.00490	0.01052	0.01382	0.03524	0.05830	0.12517	0.16453	0.41948
	9	Locke Rd. Tap (p.26)	(p.4)	600	336 ACSR	1/0 ACSR	537	653	702	787	0.980	5.22	7.47	0.02487	0.05340	0.07019	0.17896	0.29603	0.63557	0.83540	2.13002
	10	(p.4)	(p.2)		556 ACSR	1/0 ACSR	739	902	968	1087	0.076	5.22	7.47	0.00457	0.01548	0.01183	0.04520	0.05436	0.18427	0.14076	0.53793
		(p.2)	(p.1A,1B,1C)		556 ACSR	336 ACSR	739	902	968	1087	0.041	5.22	7.47								
		(p.1A,1B,1C)	(p.3A,3B,3C)		556 ACSR	2-336 ACSR	739	902	968	1087	0.120	5.22	7.47								
		(p.3A,3B,3C)	Sewalls Falls	600	556 ACSR	336 AA	739	902	968	1087	0.056	5.22	7.47								
36	1	Sewalls Falls	(tower #2)		266 ACSR	1/0 ACSR	463	562	605	677	0.074	5.22	7.47	0.00237	0.00412	0.00579	0.01360	0.02821	0.04905	0.06893	0.16189
	2	(tower #2)	(tower #3)		336 ACSR	1/0 ACSR	537	653	702	787	0.041	5.22	7.47	0.00104	0.00223	0.00294	0.00749	0.01239	0.02659	0.03495	0.08911
	3	(tower #3)	(p.27)		336 ACSR	---	537	653	702	787	0.931	5.22	35.43	0.02307	0.04951	0.04095	0.17910	0.27455	0.58923	0.48744	2.13174
	4	(p.27)	(p.41A,41B)		336 AA	---	531	645	694	777	0.654	5.22	35.43	0.01691	0.03660	0.02978	0.12904	0.20130	0.43562	0.35447	1.53586
	5	(p.41A,41B)	Penacook S/S		336 ACSR	---	537	653	702	787	0.210	5.22	35.43	0.00533	0.01144	0.00946	0.04138	0.06343	0.13613	0.11261	0.49248
	6	continued	continued		336 ACSR	---	537	653	702	787	0.170	5.22	35.43	0.00431	0.00926	0.00766	0.03350	0.05135	0.11019	0.09116	0.39867
37	1	Penacook	Pole 1		556 ACSR	266 ACSR	739	902	968	1087	0.013	5.22	7.47	0.00034	0.00073	0.00076	0.00215	0.00400	0.00867	0.00903	0.02560
	2	Pole 1	Pole 2		556 ACSR	266 ACSR	739	902	968	1087	0.027	5.22	7.47	0.00229	0.00194	0.00307	0.00474	0.02728	0.02309	0.03659	0.05642
	3	Pole 2	Pole 8		556 ACSR	266 ACSR	739	902	968	1087	0.267	5.22	7.47	0.00416	0.01411	0.01191	0.04182	0.04954	0.16793	0.14175	0.49774
	4	Pole 8	Maccoy Tap	800	1/0 AA	1/0 ACSR	253	305	330	368	1.240	5.22	7.47	0.10169	0.07740	0.15900	0.23618	1.21031	0.92124	1.89249	2.81113
	5	Maccoy Tap	Lower Falls		266 ACSR	1/0 ACSR	463	562	605	677	0.186	5.22	7.47	0.00596	0.01036	0.01456	0.03419	0.07092	0.12330	0.17326	0.40691
	6	Lower Falls	37X1 Tap		266 ACSR	1/0 ACSR	463	562	605	677	0.352	5.22	7.47	0.01128	0.01960	0.02755	0.06470	0.13420	0.23334	0.32790	0.77008
	7	37X1 Tap	Boscawen		266 ACSR	1/0 ACSR	463	562	605	677	2.294	5.22	7.47	0.07348	0.12776	0.17954	0.42164	0.87456	1.52064	2.13693	5.01861
38	1	Broken Ground	Hollis	900	795 AA	336 ACSR	915	1121	1201	1351	0.550	5.22	7.47	0.00554	0.02912	0.01355	0.07659	0.06600	0.34663	0.16130	0.91157
	2	Hollis	38R1	600	336 AA	1/0 ACSR	531	645	694	777	1.297	5.22	7.47	0.03354	0.07262	0.09352	0.23879	0.39925	0.86432	1.11311	2.84214
	3	38R1	Hazen	800	336 AA Spacer	052 AWA	500	620	696	778	0.371	1.17	1.21	0.00868	0.01468	0.03699	0.07431	0.10333	0.17468	0.44026	0.88449
	4	Hazen	State		336 AA Spacer	052 AWA	500	620	696	778	0.180	1.17	1.21	0.00421	0.00712	0.01795	0.03605	0.05013	0.08475	0.21361	0.42913
	5	State	River Crossing (P.27)	600	336 AA Spacer	052 AWA	500	620	696	778	0.248	1.17	1.21	0.00580	0.00981	0.02473	0.04967	0.06907	0.11677	0.29430	0.59125
	6	River Crossing (P.27-26)			336 ACSR	052 AWA	537	653	702	787	0.166	17.64	15.24	0.00427	0.01102	0.01073	0.02248	0.05079	0.13118	0.12771	0.26760
	7	River Crossing (P.26)	Fort Eddy Road Tap	900	336 ACSR	266 ACSR	537	653	702	787	0.351	5.22	7.47	0.00891	0.01912	0.01909	0.05554	0.10603	0.22761	0.22718	0.66112
	8	Fort Eddy Road Tap	Horseshoe Pond Tap	600	336 ACSR	266 ACSR	537	653	702	787	0.566	5.22	7.47	0.01437	0.03084	0.03078	0.08957	0.17098	0.36702	0.36633	1.06607
374	1	Garvins	Bow Junction		556 AA	266 ACSR	730	891	956	1074	0.300	5.22	7.47	0.00331	0.01120	0.00832	0.02987	0.03935	0.13333	0.09897	0.35555
	2	continued	continued	1200	556 ACSR	266 ACSR	739	902	968	1087	1.435	5.22	7.47	0.02040	0.07437	0.06204	0.22330	0.24281	0.88515	0.73838	2.65778
	3	Bow Junction	(p.32)	1200	556 AA	266 ACSR	730	891	956	1074	0.490	5.22	7.47	0.00771	0.02615	0.02193	0.07701	0.09179	0.31129	0.26101	0.91655
	4	Pond Crossing			556 ACSR	556 ACSR	739	902	968	1087	0.199	14.54	10.08	0.00285	0.01226	0.00606	0.02752	0.03393	0.14589	0.07215	0.32752
	5	(p.22)	Langdon	600	556 AA	266 ACSR	730	891	956	1074	0.194	5.22	7.47	0.00301	0.01035	0.00868	0.03049	0.03577	0.12324	0.10334	0.36288
	6	Langdon	Gulf Street	600	556 AA	266 ACSR	730	891	956	1074	0.490	5.22	7.47	0.00771	0.02615	0.02193	0.07701	0.09179	0.31129	0.26101	0.91655

UES-Capital Summary of Line Ratings and Impedances

	7	Gulf Street	Bridge Street	1200	556 AA	034 AWA	730	891	956	1074	0.934	5.22	7.47		0.01470	0.04986	0.05825	0.16342	0.17499	0.59342	0.69326	1.94514
375	1	Garvins	Terrill Park		556 ACSR	266 ACSR	739	902	968	1087	0.210	5.22	7.47		0.00427	0.01554	0.01142	0.04221	0.05078	0.18494	0.13595	0.50242
	2	continued	continued	1200	556 AA	266 ACSR	730	891	956	1074	2.580	5.22	7.47		0.04061	0.13770	0.11546	0.40545	0.48334	1.63902	1.37429	4.82589
	3	Terrill Park	Bridge Street	1200	556 AA	266 ACSR	730	891	956	1074	1.330	5.22	7.47		0.02093	0.07099	0.05952	0.20901	0.24916	0.84492	0.70845	2.48777
396X1	1	396X1 tap	Z-Tech	1200	266 ACSR	1/0 ACSR	463	562	605	677	0.644	5.22	7.47		0.02063	0.03587	0.05040	0.11837	0.24551	0.42690	0.59991	1.40889
	2	Z-Tech	Bow Bog		266 ACSR	1/0 ACSR	463	562	605	677	2.100	5.22	7.47		0.06726	0.11695	0.16435	0.38599	0.80060	1.39204	1.95621	4.59419
396	1	Garvins	396X1 tap		795 AA	336 AA	915	1121	1201	1351	0.030	5.22	7.47		0.00030	0.00145	0.00098	0.00493	0.00360	0.01727	0.01172	0.05868
	2	396X1 tap	P #10 Garvins Rd	1200	795 AA	336 AA	915	1121	1201	1351	0.050	5.22	7.47		0.00050	0.00259	0.00160	0.00815	0.00600	0.03083	0.01909	0.09705
	3	P #10 Garvins Rd	P #4 Garvins Rd		795 AA Spacer[1]	4/0 ACSR	852	1069	1206	1351	0.170	1.80	1.80		0.00172	0.00682	0.00868	0.02414	0.02047	0.08119	0.10333	0.28736
	4 [2]	P #4 Garvins Rd	33 Line Pole #4		795 AA Spacer[1]	4/0 ACSR	852	1069	1206	1351	1.270	1.80	1.80		0.01288	0.05095	0.06553	0.16505	0.15329	0.60641	0.77997	1.96450
	5 [3]	33 Line Pole #4	Bow Junction	1200	795 AA	336 AA	915	1121	1201	1351	0.140	5.22	7.47		0.00141	0.00712	0.00439	0.02394	0.01680	0.08472	0.05224	0.28495
3387	1	Broken Ground	Hollis	1200	795 AA	336 ACSR	915	1121	1201	1351	0.620	5.22	7.47		0.00626	0.03287	0.01548	0.08490	0.07451	0.39126	0.18430	1.01053
3376	1	Broken Ground	Hollis	1200	795 AA	336 ACSR	915	1121	1201	1351	0.615	5.22	7.47		0.00621	0.03254	0.01514	0.08134	0.07387	0.38735	0.18026	0.96818

Note[1]: Messenger Wire 0000127 AWA

Note[2]: Section #4 is double circuit w/ 7W3 (336AA spacer w/052 AWA messenger)

Note[3]: Section # 5 is double circuit w/ 33 Line (556 ACSR open wire)

APPENDIX C

UES-CAPITAL SYSTEM SUPPLY TRANSFORMER RATINGS

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

System Supply Transformers	Voltage	Summer Capacity		Winter Capacity	
		Normal (MVA)	LTE (MVA)	Normal (MVA)	LTE (MVA)
TB-39 Garvins[13]	115 – 34.5 kV	67	79	86	96
TB-51 Garvins[13]	115 – 34.5 kV	67	79	86	96
TB-15 Oak Hill[13]	115 – 34.5 kV	44	53	60	67
TB-84 Oak Hill[13]	115 – 34.5kV	45	49	57	66
Broken Ground T1	115 – 34.5kV	60	72	60	72
Broken Ground T2	115 – 34.5kV	60	72	60	72

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.

[13] Property of Eversource.

APPENDIX D

Ten-Year System Load Forecasts
Summer 2020 - 2029

Projection Methodology

The historical basis for each system is a series of yearly regression models developed to correlate actual daily loads to a weighted temperature-humidity index (WTHI) derived from the average temperature and average dew point temperature of each day and the previous two days. Once a model is established, an estimated peak load can be derived for that season for any value of WTHI. There are two dimensions of variability introduced with this modeling. First is the highest WTHI 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 WTHI. 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 WTHI is assumed to follow the discrete distribution of past historical highest WTHI. The random possibilities of peak load outcomes for any specific WTHI are assumed to follow a standard probability distribution model with a mean centered on the point estimate of the peak load at that WTHI 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 WTHI and random peak load estimates at those WTHI values 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 WTHI possibilities and variability in loads versus WTHI. 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.

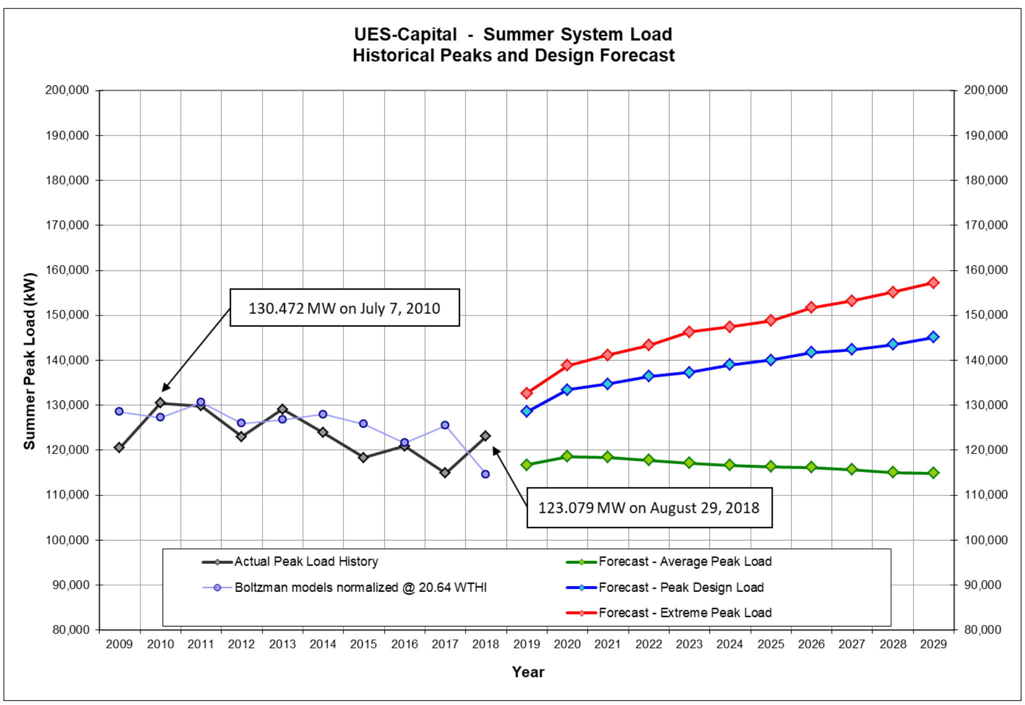
It is important to recognize that with this level of study, constraints and reinforcements are not necessarily associated with major contingencies occurring only at the highest peak hour of the year. Instead, they are associated with contingencies occurring any time during broader stretches of heavy 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 2018 of 123.079 MW on August 29, 2018 at 4:00 PM[14]. The 3-day weighted temperature index (WTHI) was 21.62 on this peak day. The highest peak load for the UES-Capital system during the previous ten years was 130.472 MW set on July 7, 2010 at 3:00 PM coinciding with the highest WTHI of 21.95 during the same time period. The historical mean of annual highest WTHI values for the past thirteen years is 20.55. The linear trend of the mean point estimates at this value from the annual load-versus-WTHI models is -1.10 MW per year with an average standard deviation of ±5.09 MW.

UES-Capital Ten-Year Summer Design Forecasts

Projected Summer Season	Average Peak Load (MW)	Peak Design Load (MW)	Extreme Peak Load (MW)
2020	118.6	133.4	138.8
2021	118.4	134.7	141.2
2022	117.8	136.5	143.3
2023	117.2	137.3	146.3
2024	116.6	139.0	147.4
2025	116.3	140.0	148.8
2026	116.1	141.7	151.7
2027	115.7	142.4	153.2
2028	115.1	143.5	155.2
2029	114.9	145.1	157.3



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

[14] peak hourly consumption of 123,079 kWhr

APPENDIX E

BASECASE STUDIES

The information provided in this section describes details of power flow simulation results for the UES-Capital system in its normal and/or proposed normal 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.

The basecase UES-Capital system was modeled as summarized below:

- All local area generation offline
  - Wheelabrator Concord (SES) is largest generators directly connected to the UES-Capital system and is assumed off-line.
  - All hydro-electric generators are assumed off-line as they are typically off-line during summer conditions due to low river flow.
- 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
- 396J374 switch normally open at Garvins
- 25J374switch normally open at Garvins

- 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 at Garvins
- 374J4 switch normally open at Bow Junction

- Distribution loads normally supplied:
  - Langdon S/S circuits 14H1, 14H2, and 14X3
  - 374X1 (Industrial Park tap)
  - Gulf Street S/S circuits 3W1, 3H3, and 3H4

- Bridge Street circuits 1H1, 1H2, 1H6 and 1X7P (in parallel with 375 line)[15]
- Montgomery Street S/S circuits 21W1A, 21W1P, Elderly Housing, Nelson Plaza

<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
- 25J375 switch normally open at Garvins

- 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) [16]
  - Storrs Street S/S circuits 21W1A, 21W1P, and Holiday Inn[1]

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

The 396X1 line is tapped off the 396 line from Garvins at the 396X1J1 and operates radially to supply Bow Bog substation.

- 396X1J1 normally closed at the 396X1 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
- 33J2 switch normally open at Pleasant St S/S

- Distribution loads normally supplied:
  - 33X2 (Donovan Street 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 normally operates radially between Penacook and Bridge Street and supplies the 33 line at West Concord.

- 034 breaker normally closed at Penacook
- 34 breaker normally open at Bridge Steet

[15] These circuits are fed from the 374 Line side of the normally closed 1XBT1 bus tie switch at Bridge Street
[16] These circuits are fed from the 375 Line side of the normally closed 1XBT1 bus tie switch at Bridge Street

- 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)

<u>35 and 36 Lines – Bridge Street to Penacook</u>[17]
The 35/36 line normally operates radially between Bridge Street and Penacook.
- 35 breaker normally closed at Bridge St.
- 036 breaker normally open at Penacook

- Distribution loads normally supplied:
  - West Portsmouth St. S/S circuits 15W1, 15W2 and 15H3
  - 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>3376 Line – Broken Ground to Hollis</u>
The 3376 line operates radially from Broken Ground to Hollis with a normally open tie to the 3387 line at Hollis.
- 8XBT1 normally open at Hollis

- Distribution loads normally supplied:
  - Hollis S/S circuits 8H1, 8H2, and 8X5

<u>3387 Line – Broken Ground to Hollis</u>
The 3387 line operates radially from Broken Ground to Hollis with a normally open tie to the 3376 line at Hollis.
- 8XBT1 normally open at Hollis

- Distribution loads normally supplied:
  - Hollis S/S circuit 8X3

[17] This line is designated the 35 Line on the Bridge Street side of Sewalls Falls and the 36 Line on the Penacook side.

<u>38 Line – Broken Ground to 35 Line (Horseshoe Pond)</u>
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:
  - 38A tap (Alton Woods)
  - 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
  - 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 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)
• Iron Works 13.8kV bus	2.4 MVAr (13.8kV)
• Broken Ground – Bus 1 – 28C1	4.8 MVAr (34.5kV)
• Broken Ground – Bus 1 – 28C3	4.8 MVAr (34.5kV)

The following system capacitor banks are modeled as being switch out during summer peak conditions.

• Broken Ground – Bus 1 – 22C2	4.8 MVAr (34.5 kV)
• Broken Ground – Bus 2 – 22C4	4.8 MVAr (34.5 kV)
• Boscawen S/S	3.6 MVAr (34.5 kV)

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 option 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
2020	133.4	*	Boscawen 13.8 kV Bus 1 (13W1/13W2 Bus)	Voltage 0.96 PU	Voltage < 0.985 PU
		*	West Concord 4.16 kV Bus	Voltage 0.96 PU	Voltage < 0.985 PU

Extreme (Extreme Peak Load) Planning Flags

None

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:
1A) Loss of Garvins TB39 Transformer
1B) Loss of Garvins TB51 Transformer
2A) Loss of Oak Hill TB15 Transformer (or B15 – Farmwood to Oak Hill)
2B) Loss of Oak Hill TB84 Transformer (or B84 – Farmwood to Oak Hill)
3) Loss of Broken Ground 28T1 Transformer (or T1 line Curtisville to Broken Ground)
4) Loss of Broken Ground 28T2 Transformer (or T2 line Curtisville to Broken Ground)
5) Loss of 374 Line at Garvins
6) Loss of 375 Line at Garvins
7) Loss of 375 Line at Bridge Street
8) Loss of 396 Line at Garvins
9) Loss of 374 Line at Bridge Street
10) Loss of 33 Line at Bow Junction
11) Loss of 317 Line at Penacook
12) Loss of 3122 Line at Oak Hill (or Penacook)
13) Loss of 34 Line at Penacook
14) Loss of 35 Line at Bridge Street
15) Loss of 33 Line at West Concord
16) Loss of 1X7P Circuit at Bridge Street
17) Loss of 1X7A Circuit at Bridge Street
18) Loss of 37 Line at Penacook
19) Loss of 37 Line beyond Maccoy Tap
20) Loss of Circuit 4X1 at Penacook
21) Loss of 3376 Line at Broken Ground
22) Loss of 3387 Line at Broken Ground
23) Loss of the 38 Line at Broken Ground

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 option 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	*
2020	133.4	Loss of 37 Line at Penacook	Loading @ 89% of 4X1 Overcurrent Protection Setting		Loading > 80% of Pickup	*
		Loss of Circuit 4X1	Loading @ 115% Normal Rating of 37 Line #1/0 ACSR Conductor	> 12 hrs	Loading > Normal for > 12 consecutive hrs	*
		Loss of 33 Line at Bow Jct	Voltage at 33X2 Tap 0.97 PU[18]		Voltage < 0.975 PU	*
2021	134.7	Loss of Garvins TB39 Transformer of TB51 Transformer	Loading @ 100% Normal Rating of TB15 Transformer		Loading > Normal	
2023	137.3	Loss of Circuit 4X1	Loading @ 101% LTE Rating of 37 Line #1/0 ACSR Conductor		Loading > LTE	*
2024	139.0	Loss of 33 Line at Bow Jct	Voltage at 33X3 Tap 0.97 PU[18]		Voltage < 0.975 PU	*
2028	143.5	Loss of 33 Line at Bow Jct	Voltage at Iron Works S/S 13.8 kV bus 0.94 PU		Voltage < 0.95 PU	*
		Loss of Garvins TB39 Transformer of TB51 Transformer	Loading @ 100% Normal Rating of TB85 Transformer		Loading > Normal	

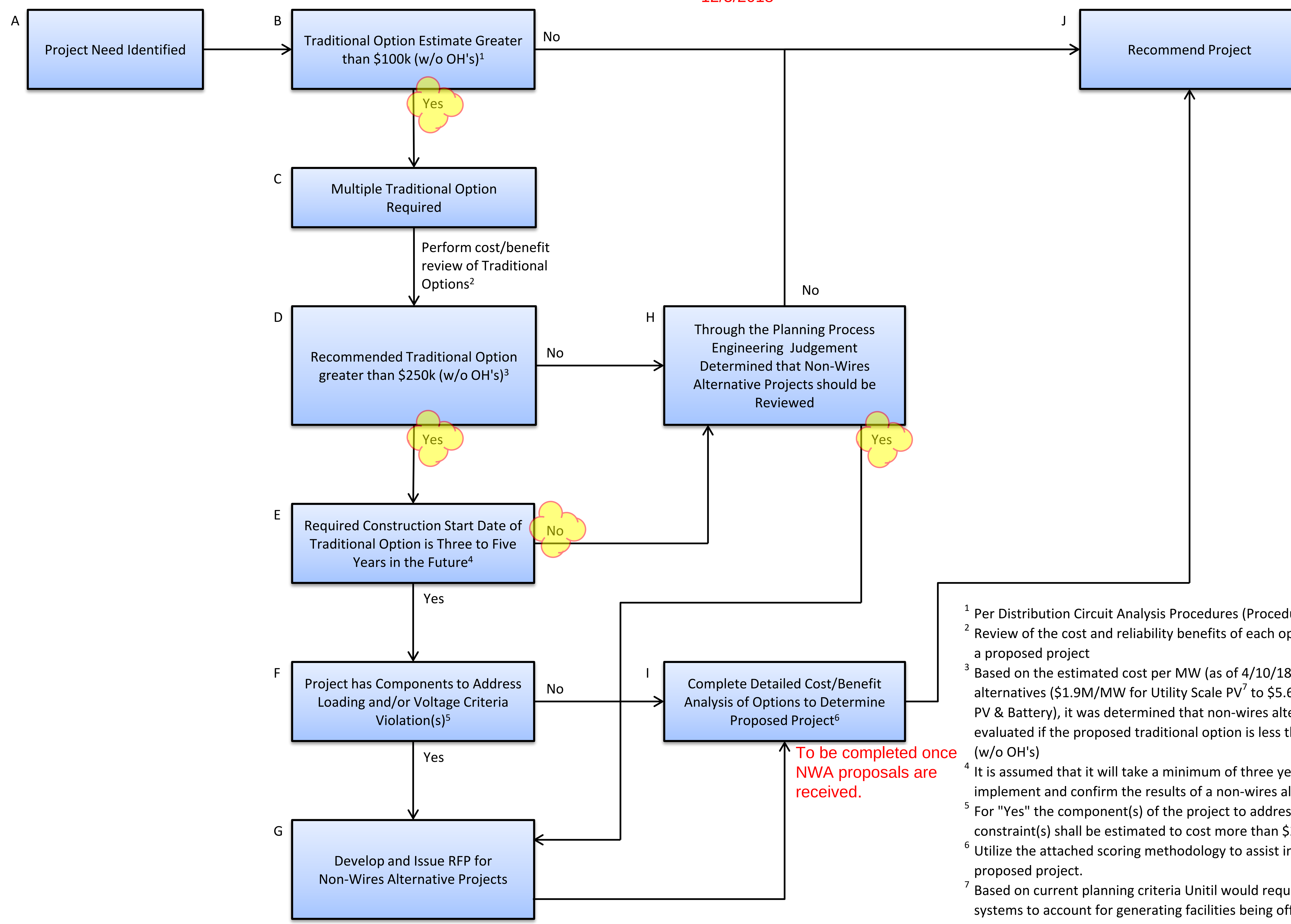
[18] Marginal low voltage conditions are limited to a small number of customers.

APPENDIX G

PROJECT EVALUATIONS

Project Evaluation Workflow

37 Line Loading Violation
12/5/2018



1 Per Distribution Circuit Analysis Procedures (Procedure No. PR-DT-DS-03).

2 Review of the cost and reliability benefits of each option to determine a proposed project

3 Based on the estimated cost per MW (as of 4/10/18) to implement non-wires alternatives ($1.9M/MW for Utility Scale PV[7] to $5.6M/MW for Roof Top PV & Battery), it was determined that non-wires alternatives would not be evaluated if the proposed traditional option is less than $0.25M (w/o OH's)

4 It is assumed that it will take a minimum of three years to evaluate, implement and confirm the results of a non-wires alternative project.

5 For "Yes" the component(s) of the project to address loading and/or voltage constraint(s) shall be estimated to cost more than $250k (w/o OH's).

6 Utilize the attached scoring methodology to assist in selecting a proposed project.

7 Based on current planning criteria Unitil would require multiple utility scale systems to account for generating facilities being off-line.

Constraint / Need for Project: 37 Line Loading Violation

Project Need Year: 2020
Date Evaluation Performed: 6/18/2019
Traditional Alternative Construction Start Year: 2020

	Project Scope
Option 1	Reconductor 37 Line - Traditional
Option 2	Battery Storage LiO - NWA
Option 3	Battery Storage LiO/PV - NWA
Option 4	
Option 5	

Number of Alternatives **3**

User Input (cell will turn white once value is enetered)

Evaluation Criteria	Weight Factor	**Ranked Score (N Best, 1 Worst, N= # of Options)** Option 1	Option 2	Option 3	Option 4	Option 5
Functionality *(See Below)*	15%	3	2	1	0	0
Environemental *(See Below)*	10%	2	3	1	0	0
Reliability *(See Below)*	15%	3	2	2	0	0
Feasibility *(See Below)*	25%	3	2	1	0	0
Unitil Cost	30%	3	2	1		
Value Added Benefit of DG	5%	1	2	3		
Totals	100%	**2.8**	**2.1**	**1.25**	**0**	**0**

Overall Rankings	1	2	3	4	4

Functionality Evaluation Criteria	Weight Factor	**Ranked Score (N Best, 1 Worst, N= # of Options)** Option 1	Option 2	Option 3	Option 4	Option 5
Operating Flexibility	15%	3	1	2		
Availability	30%	3	2	1		
Maintenance	10%	3	2	1		
Load Servicing Capacity	20%	3	3	1		
DG Interconnect Capacity	10%	3	2	1		
System Master Plan	15%	3	2	2		
Totals	100%	**3**	**2.05**	**1.3**	**0**	**0**
Rankings		1	2	3	4	4

Environmental Evaluation Criteria	Weight Factor	**Ranked Score (N Best, 1 Worst, N= # of Options)** Option 1	Option 2	Option 3	Option 4	Option 5
Wetland Impact	25%	1	3	2		
Tree Clearing	25%	3	3	1		
Residential Area Impacts	25%	2	3	1		
Municipal Considerations	25%	2	3	1		
Totals	100%	**2**	**3**	**1.25**	**0**	**0**
	Rankings	2	1	3	4	4

Reliability Evaluation Criteria	Weight Factor	**Ranked Score (N Best, 1 Worst, N= # of Options)** Option 1	Option 2	Option 3	Option 4	Option 5
Customer Exposure	30%	3	1	2		
Miles / Equipment Exposure	30%	2	2	1		
Automatic Restoration	20%	1	1	1		
Power Quality	20%	1	3	3		
Totals	100%	**1.9**	**1.7**	**1.7**	**0**	**0**
	Rankings	1	2	2	4	4

Feasibility Evaluation Criteria	Weight Factor	**Ranked Score (N Best, 1 Worst, N= # of Options)** Option 1	Option 2	Option 3	Option 4	Option 5
Likelihood of Completion	50%	3	2	1		
Long Term Solution	25%	3	2	2		
Life Span	20%	3	2	2		
Design Standards	5%	3	2	2		
Totals	100%	**3**	**2**	**1.5**	**0**	**0**
	Rankings	1	2	3	4	4

Note: Weight factors and evaluation criteria shall be adjusted as needed

APPENDIX H

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.

1A) Loss of Garvins TB39 Transformer
(Garvins TB39 transformer fault)

(Reference part 1B) 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.

1B) Loss of Garvins TB51 Transformer
(Garvins TB51 transformer fault)

Initial Event:

- G1460, H1370 and M1080 trip at Garvins S/S
- TB36, TB39, TB51, 318, 374, 375, 396, 3340 and 3350 trip at Garvins S/S
- 0374 and 0375 trip at Bridge Street S/S via transfer trip from Garvins S/S
- J51 opens at Garvins S/S

- 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 3W1, 3H3, 3H4
  - Bridge Street 1H1, 1H2, 1H3, 1H4, 1H5, 1H6, 1X7A, 1X7P
  - Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
  - West Portsmouth 15W1, 15W2, 15H3
  - Storrs Street 21W1A
  - Montgomery Street 21W1P
  - 33X2 (Donovan St Tap)
  - Iron Works Road 22W1, 22W2, 22W3
  - 375X1(Flanders Tap)
  - 35X1, 35X2, 35X3, 35X4 (Locke Road)

Automatic Restoration:

- H1370 recloses at Garvins S/S
- TB39 recloses at Garvins S/S
- 374, 375 and 396 reclose at Garvins S/S
- 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 3W1, 3H3, 3H4
  - Terrill Park 16H1, 16H3, 16X4, 16X5, 16X6
  - 33X2 (Donovan St Tap)
  - Iron Works Road 22W1, 22W2, 22W3
  - 375X1(Flanders Tap)

Switching Procedures:

1. Penacook S/S – Close 036 Breaker
2. Bridge Street S/S – Close 34 Breaker

- Load restored:
  - Bridge Street 1H1, 1H2, 1H3, 1H4, 1H5, 1H6, 1X7A, 1X7P
  - Storrs Street 21W1A
  - Montgomery Street 21W1P
  - West Portsmouth 15W1, 15W2, 15H3
  - 35X1, 35X2, 35X3, 35X4 (Locke Road)
- All **Unitil** load restored

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)
- All load restored

System Concerns:
At system loads of 133.4 MW (2020):
- Oak Hill TB-15 transformer at 99% of its Normal Rating
- Oak Hill TB-84 transformer at 96% of its Normal Rating

At system loads of 145.1 MW (2029):
- Oak Hill TB-15 transformer at 104% of its Normal Rating (87% of LTE)
- Oak Hill TB-84 transformer at 101% of its Normal Rating (93% of LTE)
- Storrs Street 13.8 kV Bus 0.98 PU Voltage

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

2A) Loss of Oak Hill TB15 Transformer
(Oak Hill TB15 transformer fault or fault on B15 line between J315 switch at Farmwood and 15J1 circuit switcher at Oak Hill)

(Reference part 2B) Loss of Oak Hill TB84 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.

2B) Loss of Oak Hill TB84 Transformer
(Oak Hill TB84 transformer fault or fault on B84 line between J484 switch at Farmwood and J84 circuit switcher at Oak Hill)

Initial Event:
- J84 and TB84 trips and locks out at Oak Hill S/S
- No load out of service

System Concerns:
At system loads of 133.4 MW (2020):
* - Oak Hill TB15 transformer at 156% of its Normal Rating (143% of LTE)

At system loads of 145.1 MW (2029):
* - Oak Hill TB15 transformer at 163% of its Normal Rating (150% of LTE)

Possible lockout of J15 and TB15 on overcurrent.
Up to 74 MW of load shed in 2029

Switching Procedures:
1. Penacook S/S – Close 036 Breaker
2. Bridge Street S/S – Close 34 Breaker

System Concerns:
At system loads of 133.4 MW (2020):
- Oak Hill TB15 transformer at 102% of its Normal Rating (93% of LTE)

At system loads of 145.1 MW (2029):
- Oak Hill TB15 transformer at 108% of its Normal Rating (99% of LTE)

Switching Procedures:
Eversource to transfer load from Oak Hill to other supply transformers as needed to alleviate loading concerns.

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

3) Loss of Broken Ground Transformer 28T1
(Broken Ground transformer 28T1 fault or loss of 115kV line Curtisville to Broken Ground)

Initial Event:
- Broken Ground S/S – 28T1 opens and locks out
- Broken Ground S/S – 28XT1 opens and locks out
- Load out of service:
  Hollis 8X5, 8H1 & 8H2
  Hazen Drive 24H1, 24H2, 24H3
  38 Line distribution loads

Switching Procedures:
1. Broken Ground S/S – Close BT28A
   - Load restored:
     Hollis 8X5, 8H1 & 8H2
     Hazen Drive 24H1, 24H2, 24H3
     38 Line distribution loads
   - All load restored

System Concerns:
- None

4) Loss of Broken Ground Transformer 28T2
(Broken Ground transformer 28T2 fault or loss of 115kV line Curtisville to Broken Ground)

Initial Event:
- Broken Ground S/S – 28T2 opens and locks out
- Broken Ground S/S – 28XT2 opens and locks out

- Load out of service:
  Hollis 8X3

Switching Procedures:
1. Broken Ground S/S – Close BT28A
   - Load Restored:
     Hollis 8X3
   - All load restored

System Concerns:
- None

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

Initial Event:
- 374 trips at Garvins S/S
- 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:
- None

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

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:
- None

7) 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 S/S
- 375 trips to lockout at Garvins S/S
- 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:
- None

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

Initial Event:
- 396 trips to lockout out at Garvins S/S
- 0374 trips to lockout at Bridge St S/S
- Load out of service:
    Bow Bog 18W2
    Langdon Street 14H1, 14H2, 14X3
    Gulf Street 3W1, 3H3, 3H4
    17X1 (Z-Tech Corporation)
    374X1 (Industrial Park Tap)

Switching Procedures:
1. Garvins S/S – open 96DX1 Switch
2. Bridge Street S/S – close 0374 Breaker
   - Load restored:

Bow Bog 18W2	17X1 (Z-Tech Corporation)
Langdon Street 14H1, 14H2, 14X3	374X1 (Industrial Park Tap)
Gulf Street 3W1, 3H3, 3H4	

   - All load restored

System Concerns:
At system loads of 133.4 MW (2020):
- 0375 protection settings at Penacook at 80% of pickup
  (This is not a planning violation due to directional element of protection setting)

At system loads of 145.1 MW (2029):
- 0375 protection settings at Penacook at 87% of pickup
  (This is not a planning violation due to directional element of protection setting)
- Storrs Street 13.8 kV Bus 0.98 PU Voltage

9) 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 S/S
- 396 trips to lockout at Garvins S/S
- Load out of service:

Langdon Street 14H1, 14H2, 14X3	17X1 (Z-Tech Corporation)
374A Industrial Park Drive Tap	Gulf Street 3W1, 3H3, 3H4
Bow Bog 18W2	

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

Langdon Street 14H1, 14H2, 14X3	17X1 (Z-Tech Corporation)
374A Industrial Park Drive Tap	Gulf Street 3W1, 3H3, 3H4
Bow Bog 18W2	

   - All load restored

System Concerns:
- None

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

Initial Event:
- 33 recloser trips to lockout at Bow Junction S/S
- Load out of service:
  Iron Works Road 22W1, 22W2, 22W3
  Pleasant Street 6X3
  33X2 (NH State Tap)

Switching Procedures:
1. Penacook S/S – close 034 Breaker
2. Bridge Street S/S – close 35 Breaker
3. Donovan St Tap 33X2 – open 33J4 switch
4. Pleasant Street S/S – close 33J2 switch
   - Load restored:
     Iron Works Road 22W1, 22W2, 22W3
     Pleasant Street 6X3
     33X2 (NH State Tap)
   - All load restored

System Concerns:
At system loads of 133.4 MW (2020):
* - Marginal voltage on 33 Line – 33X2 0.97 PU

At system loads of 145.1 MW (2029):
* - Irons Works 13.8 kV Bus Voltage 0.94 PU
* - Marginal voltage on 33 Line – 33X2 0.96 PU, 33X3 0.97 PU

11) Loss of 317 Line at Penacook (fault on the 317 Line between Penacook and 317 tap)

Initial Event**:**
- 317 trips to lockout at Oak Hill S/S
- 3170 trips to lockout at Penacook S/S
- Load out of service:
  Eversource 317 Line to Davisville

Switching Procedures:
1. Eversource to isolate fault and restore 317 Line from Oak Hill or from Davisville (to the extent as possible)

System Concerns:
At system loads of 133.4 MW (2020):
- None

At system loads of 145.1 MW (2029):
- 3122 Line from Oak Hill to Penacook at 101% of Normal Rating (80% LTE)
- Boscawen 13X4 voltage 0.97 PU

Switching Procedures:
2. Penacook S/S – close 036 Breaker
3. Bridge Street S/S – close 34 Breaker

System Concerns:
- None

12) Loss of 3122 at Penacook (fault on the 3122 Line)

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

Load out of service:
- None

System Concerns:
At system loads of 133.4 MW (2020):
* - 317 Line from Oak Hill to the 317 Line Tap at 129% of Normal Rating (103% LTE)

At system loads of 145.1 MW (2029):
* - 317 Line from Oak Hill to the 317 Line Tap at 138% of Normal Rating (110% LTE)
- 317 Line from the 317 Line Tap to Penacook at 101% of Normal Rating (80% LTE)

Switching Procedures:
1. Penacook S/S – close 036 Breaker
2. Bridge Street S/S – close 34 Breaker

System Concerns:
- None

13) Loss of 34 Line at Penacook
(fault between 034 breaker at Penacook and 34J6 switch at the 34X4 Tap

Initial Event:
- 034 trips to lockout at Penacook S/S
- 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. 34X4 (Crowley Foods) Tap – open 34J4 switch
2. Bridge Street S/S – close 34 breaker
   - Load restored:

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

   - All load restored

System Concerns:
- None

14) Loss of 35 Line at Bridge Street
(fault between 35 breaker at Bridge Street and 35J1 Switch at Horseshoe Pond Tap)

Initial Event:
- 35 trips to lockout at Bridge Street S/S
- Load out of service:
  West Portsmouth 15W1, 15W2, 15H3
  35X1, 35X2, 35X3, 35X4(Locke Rd)

Switching Procedures:
1. West Portsmouth Street S/S – open 35J3 switch
2. Penacook S/S – close 036 breaker
   - Load restored:
     West Portsmouth 15W1, 15W2, 15H3
     35X1, 35X2, 35X3, 35X4 (Locke Rd)
   - All load restored

System Concerns:
- None

15) 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 S/S
- Load out of service:

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

1. 33X6 (NH State Prison) – open 33J12 Line GOAB
2. Pleasant Street S/S – close 33J2 switch
    - Load restored:
        33X3 (St Pauls)
        33X4 (Little Pond Road Tap)
        33X5 (Jefferson Pilot)
        33X6 (NH State Prison)
    - All load restored

System Concerns:
- None

16) 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 S/S
- Load out of service:
    Montgomery Street 21W1P
    Nelson Plaza
    Eelderly Housing

Switching Procedures:
1. Montgomery Street S/S – open DS-17P switch
2. Montgomery Street S/S – close DS-17A switch
    - Load restored:
        Montgomery Street 21W1P
        Nelson Plaza
        Elderly Housing
    - All load restored

System Concerns:
At system loads of 133.4 MW (2020):
- Montgomery Street 13.8 kV Bus 0.98 PU Voltage

At system loads of 145.1 MW (2029):
* - Montgomery Street 13.8 kV Bus 0.97 PU Voltage

Switching Procedures:
3. Bridge Street S/S – close 34 Breaker
4. Penacook S/S – open 034 Breaker

System Concerns:
- None

17) 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 S/S
- 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 system loads of 133.4 MW (2020):
- Storrs Street 13.8 kV Bus 0.98 PU Voltage

At system loads of 145.1 MW (2029):
* - Storrs Street 13.8 kV Bus 0.97 PU Voltage

Switching Procedures:
3. Bridge Street S/S – close 34 Breaker
4. Penacook S/S – open 034 Breaker

System Concerns:
- None

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

Initial Event:
- 37 trips to lockout at Penacook S/S
- 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:

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

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

System Concerns:
At system loads of 133.4 MW (2020):
* - 4X1 protection settings at Penacook at 89% of pickup

At system loads of 145.1 MW (2029):
* - 4X1 protection settings at Penacook at 96% of pickup

19) 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 S/S
- Penacook Lower Falls Hydro generation trips off line
- SES Concord generation trips off line
- Load remaining out of service:
  37X1 Tap
  Boscawen 13W1, 13W2, 13W3, 13X4
  Penacook Lower Falls Hydro
  SES Concord
- No switching available

System Concerns:
At system loads of 133.4 MW (2020):
- Up to 11.5 MW of load remains out of service

At system loads of 145.1 MW (2029):
- Up to 12.5 MW of load remains out of service

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

Initial Event:
- 4X1 trips to lockout at Penacook S/S
- 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 Street Tap
   - Load restored:
     Penacook 4X1
     Penacook Upper Falls Hydro
     Briar Hydro
   - All load restored

System Concerns:
At system loads of 133.4 MW (2020):
* - 37 Line 115% Normal Rating Penacook to Maccoy Street Tap (96% LTE)

At system loads of 145.1 MW (2029):
* - 37 Line 126% Normal Rating Penacook to Maccoy Street Tap (105% LTE)

21) Loss of 3376 Line at Broken Ground

Initial Event**:**
- 3376 trips to lockout at Broken Ground S/S
- Load out of service:
  Hollis 8H1, 8H2, 8X5

Switching Procedures:
1. Hollis S/S - Open 3376J1 switch
2. Hollis S/S - Close 8XBT1 Bus Tie Switch
   - Load restored:
     Hollis 8H1, 8H2, 8X5
   - All load restored

System Concerns:
- None

22) Loss of 3387 Line at Broken Ground

Initial Event**:**

- 3387 trips to lockout at Broken Ground S/S

- Load out of service:
  Hollis 8X3

Switching Procedures:

1. Hollis S/S - Open 3387J1 switch
2. Hollis S/S - Close 8XBT1 Bus Tie Switch
   - Load restored:
     Hollis 8X3
   - All load restored

System Concerns:

- None

23) Loss of 38 Line at Broken Ground

Initial Event:

- 038 trips to lockout at Broken Ground S/S

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

Switching Procedures:

1. Hollis S/S – open 38J6 Switch
2. Horseshoe Pond Tap – close 38 Recloser
   - Load restored:
     Hazen Drive 24H1, 24H2
     38 Line distribution loads
   - All load restored

System Concerns:

- None

APPENDIX I

REFERENCES

1. Electric System Planning Guide Unitil Service Corporation rev 5, November 20, 2018

2. Electrical Equipment Rating Procedures Unitil Service Corporation rev 6, December 20, 2018

APPENDIX J

DIAGRAMS

APPENDIX G

UES-SEACOAST 2020-2029 ELECTRIC SYSTEM PLANNING STUDY

Unitil Energy Systems – Seacoast

Electric System Planning Study 2020-2029

Prepared By:

Jake Dusling
Unitil Service Corp.
October 25, 2019

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 2020 through 2029.

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

Year	Project Description	Justification	Cost
2024	Implement Alternate System Configuration	Basecase Loading Great Bay TB141	n/a

Note: cost estimates do not include overheads.

2 INTRODUCTION

The purpose of this study is to plan for recommended system improvements to meet system design and performance objectives. It evaluates the adequacy of the UES-Seacoast electric system with respect to its external system supply interconnection and internal 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 comparison was made for the improvement plan options. Final recommendations represent the proposed system improvement plan.

Note that this study does not attempt to identify basecase distribution substation loading concerns. These concerns, including loading of substation transformers, are typically identified and addressed as part of the Distribution Planning Study.

3 SYSTEM DESCRIPTION

The UES–Seacoast electric power system is supplied from Eversource Energy (Eversource) 345 kV and 115 kV transmission systems via three 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.

Peaslee 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 UES-Seacoast 34.5 kV subtransmission lines exit Great Bay substation.

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 the linear trend projections from ten years of historical models of the summer season daily peak load versus the daily weighted temperature-humidity index (WTHI), which account for the correlation of daily loads to actual daily WTHI. This results in a range of peak load possibilities for each year, which vary due to annual highest WTHI. 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 UES-Seacoast system load projections developed in December, 2018 were used for this study and are provided in the table below.

UES Seacoast System Loads Under Study

Projected Summer Season	Peak Design Load (MW)	Extreme Peak Load (MW)
2020	186.0	192.4
2021	188.3	195.7
2022	191.1	199.0
2023	193.4	202.4
2024	195.3	204.7
2025	197.9	208.6
2026	200.2	210.6
2027	203.0	212.4
2028	204.3	215.7
2029	206.1	217.4

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 34.5.0) 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 2018 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 August 29th, 2018 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 August 29th, 2018 summer peak hour.

Basecase models for study of future years were developed from this 2018 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 (LPF) for the UES system (Seacoast and Capital) is subject to the requirements specified in 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 – 2020 Anticipated Load Power Factor Limits

Equivalent Load (% of Peak)	Minimum p.f.	Maximum p.f.
28%	n/a	1.000, leading
66%	0.9638, lagging	0.9974, leading
100%	0.9693, lagging	n/a

On August 29, 2018 at 17:00, the UES-Seacoast system reached a peak demand of 166.80 MW. The system was lagging by 23.10 MVAr during that peak hour, with a corresponding power factor of 0.9905. This met the minimum LPF requirement of 0.9693 in effect during 2018.

The following table shows the estimated UES-Seacoast system LPF over the time period of this study and the schedule of the minimum anticipated PF correction requirements.

UES-Seacoast System – Anticipated Power Factor Correction Requirements

Year	Uncorrected System Load[1,2,3] (MW)	(MVAr)	p.f. (115 kV)	Additional p.f. correction (MVAr)	Est. LPF w/ Improvements p.f. (115 kV)
2020	186.7	33.8	0.9840 lagging	n/a	n/a
2029	206.7	48.5	0.9735 lagging	n/a	n/a

At these load levels, the net power factor is expected to remain above the minimum LPF standard throughout the study period.

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

[1] Transmission equivalent power import
[2] With all UES-Seacoast subtransmission and substation capacitor banks in-service with the exception Kingston C2 and C4.
[3] Loads were determined from future year basecase models, which were developed by growing MVAr at the same percentage at MW.

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

Year	**Load Level (MW)**	**System Constraint**	**Circumstances**
2024	204.7	Great Bay TB141 Transformer Loading above Normal for two consecutive days	Extreme Peak

The following contingencies require subtransmission or distribution switching to be performed to reduce loading prior to restoring load during peak load conditions.

Contingency	Switching Required Prior to Restoring Load	Year Required
Loss of 3342 Line – Guinea to Hampton	Cemetery Lane S/S – Close 3359J5 Switch Hampton S/S – Open 3348 Recloser	Prior to 2020
Loss of 3353 Line – Guinea to Hampton	Cemetery Lane S/S – Close 3359J5 Switch Hampton S/S – Open 3348 Recloser	Prior to 2020
Loss of 3359 Line – Guinea to Mill Lane	Hampton Beach S/S – Close J042 Switch Hampton Beach S/S – Open J053 Switch	Prior to 2020
Loss of Kingston 22T1 or 22T2	Guinea Sw/S – Close 3354 Breaker Kingston S/S – Open 03354 Breaker	2029

8 SYSTEM IMPROVEMENT OPTIONS

The following sections describe details of system improvement options 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.

Improvement options are developed and evaluated per Unitil's *Project Evaluation Procedure* (PR-DT-DS-11). The project evaluation workflow description and detailed cost/benefit analyses (if applicable) for the improvement options below can be found in Appendix G – Project Evaluations.

8.1 Great Bay TB141 Transformer Loading - 2024

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

- Close J041 Switch at Gilman Lane S/S
- Open BT-1A Switch at Gilman Lane S/S
- Close BT-1B at Exeter S/S
- Open DS1T2S at Exeter S/S
- Close 03341 Recloser at Wolf Hill Tap
- Open 3351J1 Switch at Dow's Hill S/S

In this configuration the Great Bay TB141 transformer is expected to exceed its normal rating during basecase conditions in 2025 at a system load level of 195 MW. TB141 is also projected to exceed its normal rating for two consecutive days at a system load level of 204 MW (2029 during basecase conditions and 2024 during summer extreme peak conditions).

To reduce loading of the Great Bay TB141 transformer the following switching is proposed instead of the switching that is currently being performed during summer load conditions.

- Close J041 Switch at Gilman Lane S/S
- Open BT-1A Switch at Gilman Lane S/S
- Close BT-1B at Exeter S/S
- Open DS1T2S at Exeter S/S
- Close 3352 Recloser at Wolf Hill Tap
- Open 3362J1 Switch at Dow's Hill S/S
- Close 3347B Recloser at the 3347 Line Tap
- Open 3347A Recloser at the 3347 Line Tap

Cost Estimate: no capital investment

From the year of implementation, of the switching procedure above, through 2029 and later, basecase and extreme peak loading on the Great Bay TB141 transformer is expected to be within planning guidelines. Additionally, equipment loading and bus voltages are expected to be within planning guidelines through 2029 after switching to restore all load for the following contingencies.

- Loss of 3362 Line
- Loss of the 3351 Line
- Loss of the 3352 Line
- Loss of the 3341 Line
- Loss of Timber Swamp TB25 or TB69 Transformers

9 OTHER CONSIDERATIONS

In addition to the traditional basecase and N-1 contingency evaluations the following items were also reviewed:

9.1 Loss of a Unitil Owned Supply Transformer and Loss of a 2nd Supply Transformer

Unitil does not currently own a 115-34.5 kV mobile transformer and it is expected that the spare 115-34.5 kV transformer could require up to one week to place in-service at Kingston in the event of an in-service transformer failure at Kingston.

9.1.1 Loss of Both Kingston Transformers

On loss of the second Kingston transformer, approximately 48 MW of Kingston load can be restored by supplying the 3343 and 3354 lines from Guinea Station, leaving approximately 26 MW out of service until transformer capacity can be placed in-service at Kingston following the loss of both Kingston transformers.

To restore all load for loss of both Kingston transformers the necessary infrastructure to allow the system spare transformer to be placed in-service in a timely manner will need to be constructed.

An alternative to the system spare transformer is purchasing a mobile 115-34.5 kV transformer and installing the necessary infrastructure to allow it be placed in service in a timely manner.

Switching options were reviewed to restore all load for loss of both Kingston transformers. Additional subtransmission line capacity and supply transformer capacity will be required to restore all load following the loss of both Kingston transformers. The 3343 and 3354 lines do not have the necessary capacity to restore all load and the existing TB25 transformer would be loaded above normal after switching to restore all load. Additional study will be required to develop a master system plan that will allow switching to be performed to restore all load following the contingent loss of both Kingston transformers.

9.1.2 Loss of One Kingston Transformer and Loss of One Timber Swamp Transformer

For loss of one Kingston transformer and one Timber Swamp transformer it is expected that either the remaining Kingston transformer or Timber Swamp Transformer will be loaded above normal.

Eversource transferring approximately 10 MW of their Timber Swamp Load to Ocean Road elevates this concern throughout the study period.

Another option to address this concern is to install additional transformer capacity at Great Bay to allow the load shifted to Timber Swamp during the summer months to be switched back to Great Bay. This could be done with the mobile following the loss of the first transformer.

9.1.3 Loss of One Kingston Transformers and Loss of the Great Bay Transformer

All Great Bay load and 3343/3354 line load can be restored via Timber Swamp for Loss of one Kingston transformer and loss of the Great Bay transformer.

9.2 Loss of Both Timber Swamp Transformers

Timber Swamp is equipped with two 140 MVA 345-34.5kV in-service transformers with no on-site spare unit. For the contingent loss of one transformer at Timber Swamp all load can be restored by closing the 34.5 kV bus tie breaker. It is assumed that a repair and/or replacement for a transformer failure could take up to one year. Eversource does have an in-service unit that could be moved to Timber Swamp in the event of a transformer failure, but the process of disassembling, moving, reassembling and testing a transformer of this size could take more than a month.

In the event of a failure of the second 140 MVA transformers, while preparing to install the replacement to the first transformer, at Timber Swamp Eversource can restore all the Eversource Timber Swamp load from Ocean Road and Unitil can restore approximately 25

MW of their load from Ocean Road, leaving approximately 55 MW of Unitil load out of service under peak conditions. There is not sufficient transformer or line capacity to restore all the remaining Unitil load from Great Bay or Kingston.

Of the configurations reviewed the one that allowed for the most Unitil load to be restored required the installation of the Eversource 35 MVA, 115-34.5 kV mobile at Great Bay and utilizing the following system configuration:

- Via the 3362 Line Great Bay TB141 supplies:
    - 51X1
    - 47X1
    - Portsmouth Ave S/S
    - 19X3
    - 19H1
- Via the 3351/3341 Line the Eversource Mobile at Great Bay supplies (17 MW restored, 3 MW out of service):
    - 19X2
    - Exeter S/S
    - Dow's Hill S/S
    - 18X1
    - 2X2
- Via the 3354 Line Kingston supplies (20 MW restored, 6 MW out of service):
    - 2H1
    - 2X3
    - 46X1
    - High Street S/S
    - Hampton Beach S/S
- Via the Guinea Strain Bus the 3112 Line supplies (25 MW restored, 8 MW out of service)
    - 23X1
    - 59X1
    - 15X1
    - Seabrook Station
    - Seabrook S/S

Based on preliminary analysis this configuration can be used to restore all load up to a total system load level of approximately 170 MW. Under 2020 peak design loads this would leave approximately 17 MW of load out of service. The exposure to load levels of 170 MW is 8 days in 2020 and 23 days in 2029.

This configuration will need to be reviewed by both the Eversource and Unitil planning and protection groups to determine its feasibility. Additionally, Unitil and Eversource will work on more detailed contingency plans for loss of both Timber Swamp transformer as part of the joint planning process.

9.3 Radial Subtransmission Lines

UES-Seacoast has four radial subtransmission lines with no ties to other subtransmission lines. All four radial subtransmission lines do not violate planning criteria as they serve less than 30 MW of load at peak design load levels and all load can be restored via distribution ties or repairs made within twenty-four hours throughout the study period.

The following sections detail the available distribution switching[4] that can be utilized to restore as much load as possible and describes possible upgrades to restore additional load. For all four lines an alternative to the distribution options described below is to construct a 2nd subtransmission line adjacent to the existing line.

Additional study will be required to determine the feasibility and ultimate scope of work required to increase capacity to restore additional load.

9.3.1 3347 Line

The 3347 line is a radial line that runs from 3351/3362 subtransmission corridor to Portsmouth Ave substation and serves approximately 18 MW of load. The 47X1J51X1 circuit tie can be utilized to restore circuit 47X1 from circuit 51X1 and the 11X2J19X2 circuit tie can be used to restore circuit 11X1 and 11X2 from circuit 19X2.

The 47X1J51X1 tie and the 11X2J19X2 tie have the capacity to restore all 3347 line load throughout the study period.

9.3.2 3350 Line

The 3350 line is a radial line that runs from 3348/3359 subtransmission corridor to Seabrook substation and serves approximately 10 MW of load. The 3350 line runs across the salt marsh in Seabrook and cannot typically be repaired within twenty-four hours due to access concerns during high-tide. The 15X1J7X2 circuit tie can be utilized to restore circuits 7X2 and 7W1 from 7X2 via circuit 15X1.

The 15X1J7X2 tie has the capacity to restore all Seabrook substation load throughout the study period.

9.3.3 3358 Line

The 3358 line is a radial line that runs from Plaistow substation to Westville substation and serves approximately 24 MW of load. The 5X3J58X1 circuit tie has the capacity to restore approximately 10 MW of load.

The additional 14 MW of load can be restored via the 5X3J58X1 tie by upgrading the 5X3 regulators at Plaistow S/S with larger units. This would provide 5X3 the necessary capacity to restore Westville S/S from 5X3 via 58X1.

It is expected that upgrading the 5X3 regulators will provide sufficient capacity to restore the entire 3358 line from 5X3 until approximately 2029 at which time a new

[4] Distribution switching review was done utilizing 2024 distribution projections and circuit models.

circuit from Plaistow substation to Westville substation along route 125 would be needed to allow Westville substation to be restored via the new circuit.

9.3.4 3346 Line

The 3346 line is a radial line that runs from the 3342/3353 subtransmission corridor to High Street substation and serves approximately 10 MW of load. This line has no subtransmission or distribution switching that can be utilized during peak conditions to restore load. A small portion of High Street S/S circuit 17W1 can be restored via circuit 3W1 during off-peak conditions.

To restore additional load via distribution switching new circuit ties will need to be created between circuit 2X2 and 46X1. This will require significant voltage conversion and reconductoring projects. Additionally, new transformation and an additional 13.8 kV circuit position will need to be installed at Hampton Beach S/S and circuit 2X2 will need to upgraded and extended to supply the Waste Water Treatment Plant and Brazonics.

Even with the upgrades described above portions of the High Street S/S circuits will remain out of service until repairs to the 3346 line can be completed.

10 FUTURE CONSIDERATIONS

A 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 loads greater than the 2029 projected peak[5]. The review is completed under basecase conditions with all elements in service.

For total system loads up to 240 MW no additional planning violations have been identified under basecase conditions.

The following table summarizes system elements that are anticipated to be loaded above 90% of their normal rating under basecase or contingencies conditions in 2029.

[5] UES-Seacoast Extreme Peak Load was grown by 10%

System Constraint	Circumstances
Timber Swamp TB25 or TB69 Transformer at 91% of Normal	Loss of TB69 or TB25 Transformer at Timber Swamp
Kingston 22T2 97% of Nameplate	Loss of 3343 Line
3356 Line, Kingston to Hunt Road at 110% of Normal	Loss of 3345 Line
3356 Line, Hunt Road to Dorre Road at 105% of Normal	
3356 Line, Dorre Road to Timberlane at 99% of Normal	
Kingston 22T2 97% of Nameplate	
3345 Line, Kingston to Hunt Road at 110% of Normal	Loss of 3356 Line
3345 Line, Hunt Road to Dorre Road at 105% of Normal	
3345 Line, Dorre Road to Timberlane at 99% of Normal	
Kingston 22T1 95% of Nameplate	
3359 Line, Guinea to Mill Lane at 106% of Normal	Various
3359 Line, Mill Lane to Stard Road at 95% of Normal	
3353 Line, Guinea to Hampton at 90% of Normal prior to transferring 2X2 to 18X1	Loss of the 3342 Line from Guinea to Hampton
3342 Breaker at Guinea at 99% of Rating prior to transferring 2X2 to 18X1	Loss of 3353 Line from Guinea to Hampton
3342J1 Switch at Hampton at 99% of Rating prior to transferring 2X2 to 18X1	
3342 Line, Guinea to Hampton at 90% of Normal prior to transferring 2X2 to 18X1	
3348 Line at 107% of Normal	Loss of 3359 Line from Guinea to Mill Lane
3353 Line, Guinea to Hampton at 104% of Normal	
3353 Line from Guinea to Hampton at 95% of Normal	Loss of the 3342 Line from Hampton to Hampton Beach

These high level reviews are used to identify potential system problems which occur beyond the 10 year planning horizon or may occur in the event of large unforeseen load growth. These reviews are used to develop a long term vision of the system which is used to guide incremental improvements.

11 FINAL RECOMMENDATIONS

The following summarizes final recommendations given in this report.

Year	Project Description	Justification	Cost
2020	Implement Alternate System Configuration	Basecase Loading Great Bay TB141	n/a

Note: cost estimates do not include overheads.

APPENDICES

APPENDIX A

EVALUATION CRITERIA

The following tables summarize the application of electric system planning guidelines as used in this study. These criteria are based on Unitil's Electric System Planning Guide Revision 5 (November 20, 2018).

VOLTAGE CRITERIA

Design Condition	Location	% Boost of Downline Regulation Directly Connected to Bus [6]	Low Limit (p.u.)	High Limit (p.u.)
Normal Operation -				
a) all elements in service, or non-emergency configuration b) outage of generating plant	Non-Distribution Point	10%	0.94	1.05
		7.5%	0.962	1.05
		5%	0.985	1.05
		n/a	0.90	1.05
	Regulated Distribution Point	n/a	1.025[7]	1.042
	Unregulated Distribution Point	n/a	0.975	1.042
	Customer Primary Metering Point	n/a	0.95	1.042
Contingency Operation -				
a) loss of non-radial line, b) loss of a system supply transformer, c) loss of a radial line (no backup tie)	Non-Distribution Point	10%	0.91	1.05
		7.5%	0.93	1.05
		5%	0.95	1.05
		n/a	0.90	1.05
	Regulated Distribution Point	n/a	1.0	1.042
	Unregulated Distribution Point	n/a	0.975	1.042
	Customer Primary Metering Point	n/a	0.95	1.042
Extreme Peak - all elements in service	Non-Distribution Point	10%	0.91	1.05
		7.5%	0.93	1.05
		5%	0.95	1.05
		n/a	0.90	1.05
	Regulated Distribution Point	n/a	1.0	1.042
	Unregulated Distribution Point	n/a	0.975	1.042
	Customer Primary Metering Point	n/a	0.95	1.042

[6] Assumes regulator float voltage of 1.033 p.u. (124V on 120V base)
[7] Assumes regulation float voltage of 1.033 p.u. and 1V bandwidth (123V on 120V base, lower end of band)

LOADING CRITERIA

			Allowable Element Loading		Allowable Loss of Load	
Design Condition	**Load Level**	**Generation**	**Limit[8]**	**Duration**	**Limit**	**Duration**
Normal Operation –						
all elements in service, or non-emergency configuration	≤ Peak Design Load	typical seasonal dispatch w/ largest generating plant and largest DG facility out of service as well as any one additional DG facility out of service	≤ Normal	Continuous	none	---
outage of generating plant	≤ Peak Design Load	typical seasonal dispatch w/ largest generating plant and largest DG facility out of service as well as any one additional DG facility out of service	≤ Normal	Continuous	none	---
Contingency Operation –						
loss of non-radial line	≤ Peak Design Load	dispatch w/ largest generating plant and the largest DG facility out of service All generation that is expected to trip offline during the fault is considered to remain offline following restoration switching. In addition, the largest single generator interconnected to the source/line used for restoration of load is considered to be offline prior to the fault occurring and following restoration switching	≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---
loss of a system supply transformer	≤ Peak Design Load	dispatch w/ largest generating plant and the largest DG facility out of service All generation that is expected to trip offline during the fault is considered to remain offline following restoration switching. In addition, the largest single generator interconnected to the source/line used for restoration of load is considered to be offline prior to the fault occurring and following restoration switching	≤ LTE	Per transformer rating summary	none	---
loss of radial line (no backup tie)	≤ Peak Design Load	dispatch w/ largest generating plant and the largest DG facility out of service All generation that is expected to trip offline during the fault is considered to remain offline following restoration switching. In addition, the largest single generator interconnected to the source/line used for restoration of load is considered to be offline prior to the fault occurring and following restoration switching	≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	≤ 30 MW	≤ 24 hours
Extreme Peak – all elements in service	≤ Extreme Peak Load	typical seasonal dispatch w/ largest generating plant and largest DG facility out of service	≤ LTE	≤ 12 hours (S) ≤ 4 hours (W)	none	---

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

APPENDIX B

UES–SEACOAST LINE & SUBTRANSMISSION RATINGS

UES-Seacoast Transmission Substation Ratings

Substation Element	Voltage Base	Breaker or Recloser Continuous Rating		Breaker or Recloser Trip Level		Breaker or Recloser Load Enchroachment		CTs Present Tap Selection		Switches Continuous Rating		Fuses		Regulator Rating		Conductor Rating		Transformer Rating		Overall Rating		Overall Rating		Limiting Element	
	(kV)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (Amps)	LTE (Amps)	Normal (kVA)	LTE (kVA)	Normal (Amps)	LTE (Amps)	Normal	LTE
Great Bay TB-141	34.5									1,200	1,200							736	853	44,000	51,000	736	853	Xfmr	Xfmr
3351	34.5	2,000	2,000	555	662			1,200	1,200	2,000	2,000					915	1,121			33,150	39,582	555	662	Trip	Trip
3362	34.5	2,000	2,000	555	662			1,200	1,200	2,000	2,000					915	1,121			33,150	39,582	555	662	Trip	Trip
3347 Line Tap	34.5																								
3351	34.5							1,200	1,200	1,200	1,200					915	1,121			54,677	66,986	915	1,121	Wire	Wire
3362	34.5							1,200	1,200	1,200	1,200					915	1,121			54,677	66,986	915	1,121	Wire	Wire
3347	34.5	800	800	507	605			600	600	900	900					531	645			30,267	35,853	507	600	Trip	CT
Timber Swamp TB-25	34.5																	2,343	3,012	140,000	180,000	2,343	3,012	Xfmr	Xfmr
3360	34.5	3,000	3,000	1,883	2,248			3,000	3,000	2,000	2,000					3,600	3,600			112,502	119,512	1,883	2,000	Trip	Switch
3371	34.5	3,000	3,000	1,883	2,248			3,000	3,000	2,000	2,000					3,600	3,600			112,502	119,512	1,883	2,000	Trip	Switch
Wolf Hill	34.5																								
3341	34.5	800	800	536	640			1,000	1,000	900	900					663	808			32,029	38,244	536	640	Trip	Trip
3352	34.5	800	800	536	640			1,000	1,000	900	900					663	808			32,029	38,244	536	640	Trip	Trip
Guinea Switching	34.5																								
3112	34.5	600	600	268	320			500	500	1,200	1,200					537	653			16,015	19,122	268	320	Trip	Trip
3165	34.5	1,200	1,200	268	320			500	500	1,200	1,200					537	653			16,015	19,122	268	320	Trip	Trip
3172	34.5	600	600	268	320			500	500	1,200	1,200					500	607			16,015	19,122	268	320	Trip	Trip
3342	34.5	600	600	482	576	680	680	600	600	600	600					663	808			35,853	35,853	600	600	Brkr/Rclsr	Brkr/Rclsr
3343	34.5	1,200	1,200	402	480			500	500	600	600					531	645			24,022	28,683	402	480	Trip	Trip
3353	34.5	1,200	1,200	536	640	906	906	800	800	1,200	1,200					663	808			39,618	47,805	663	800	Wire	CT
3354	34.5	600	600	402	480			500	500	1,200	1,200					663	808			24,022	28,683	402	480	Trip	Trip
3359	34.5	1,200	1,200	536	640	906	906	800	800	1,200	1,200					531	645			31,730	38,542	531	645	Wire	Wire
3360	34.5	2,000	2,000					2,000	2,000	2,000	2,000					2,174	2,174			119,512	119,512	2,000	2,000	Brkr/Rclsr	Brkr/Rclsr
3371	34.5	2,000	2,000					2,000	2,000	2,000	2,000					2,174	2,174			119,512	119,512	2,000	2,000	Brkr/Rclsr	Brkr/Rclsr
Bus Tie BT-18	34.5									1,600	1,600									95,609	95,609	1,600	1,600	Switch	Switch
Hampton	34.5																								
3342	34.5	800	800	322	384			1,000	1,000	900	900					915	1,121			19,217	22,946	322	384	Trip	Trip
3353	34.5	800	800	322	384			1,000	1,000	900	900					915	1,121			19,217	22,946	322	384	Trip	Trip
3348	34.5	800	800	624	746			1,000	1,000	900	900					531	645			31,730	38,542	531	645	Wire	Wire
Bus Tie BT-2	34.5									600	600									35,853	35,853	600	600	Switch	Switch
High Street Tap	34.5																								
3346	34.5									600	600					531	645			31,730	35,853	531	600	Wire	Switch
Seabrook Tap	34.5																								
3350	34.5									600	600					531	645			31,730	35,853	531	600	Wire	Switch
3359	34.5							600	600	600	600					531	645			31,730	35,853	531	600	Wire	CT
Kingston T10	115	2,000	2,000							1,200	1,200					945	1,159			188,231	230,856	945	1,159	Wire	Wire
Kingston 22T1	34.5	2,000	2,000	1,233	1,472			2,200	2,200	2,000	2,000							1,205	1,205	72,000	72,000	1,205	1,205	Xfmr	Xfmr
3343	34.5	1,200	1,200	375	448	972	972	800	800	1,200	1,200					1,025	1,259			47,805	47,805	800	800	CT	CT
3345	34.5	1,200	1,200	375	448	972	972	1,000	1,000	1,200	1,200					1,025	1,259			58,083	58,083	972	972	Load Enc	Load Enc
Bus Tie BT22A	34.5	2,000	2,000	981	1,171			2,400	2,400	2,000	2,000									58,613	69,986	981	1,171	Trip	Trip
Kingston T20	115	2,000	2,000							1,200	1,200					945	1,159			188,231	230,856	945	1,159	Wire	Wire
Kingston 22T2	34.5	2,000	2,000	1,233	1,472			2,200	2,200	2,000	2,000							1,205	1,205	72,000	72,000	1,205	1,205	Xfmr	Xfmr
3354	34.5	1,200	1,200	375	448	972	972	800	800	1,200	1,200					1,025	1,259			47,805	47,805	800	800	CT	CT
3356	34.5	1,200	1,200	375	448	972	972	1,000	1,000	1,200	1,200					1,025	1,259			58,083	58,083	972	972	Load Enc	Load Enc
Plaistow	34.5																								
3358	34.5	800	800	355	424	540	540	1,000	1,000	900	900					531	645			31,730	32,268	531	540	Wire	Load Enc

UES-Seacoast Summary of Line Ratings and Impedances

Line	Section No.	Section From	Section To	Switch Rating (Amps)	Phase Conductor	Neutral Conductor	Ampere Ratings Summer Normal	Summer Emergency	Winter Normal	Winter Emergency	Distance Miles	Phase GMD (ft)	Neutral GMD (ft)	Section Impedance (PU on 100 MVA, 34.5 kV base) R1	X1	R0	X0	Section Impedance (ohms) R1	X1	R0	X0
3341	1	Wolf Hill Tap	Wolf Hill	900	477 AA	1/0 ACSR	663	808	868	974	0.020	5.22	7.47	0.00033	0.00109	0.00112	0.00318	0.00394	0.01299	0.01332	0.03788
	2	Wolf Hill	Merrills Pit Tap	1200	477 AA	1/0 ACSR	663	808	868	974	1.930	5.22	7.47	0.03195	0.10530	0.09182	0.30117	0.38032	1.25333	1.09285	3.58465
	3	Merrills Pit Tap	PEA Tap	1200	795 AA	1/0 ACSR	915	1121	1201	1351	2.240	5.22	7.47	0.02259	0.11600	0.09207	0.34333	0.26893	1.38072	1.09590	4.08651
	4	PEA Tap	Exeter Switching	600	795 AA	1/0 ACSR	915	1121	1201	1351	0.240	5.22	7.47	0.00242	0.01243	0.00987	0.03679	0.02881	0.14793	0.11742	0.43784
	5	Exeter Switching	Exeter Sub.	400	#1 CU	1/0 ACSR	271	327	353	393	0.040	5.22	7.47	0.00233	0.00258	0.00407	0.00753	0.02775	0.03070	0.04847	0.08964
3342	1	Guinea Sw/S	Hampton Sub.	600	477 AA	1/0 ACSR	663	808	868	974	1.770	5.22	7.47	0.02931	0.09658	0.09901	0.28167	0.34884	1.14953	1.17844	3.35252
	2	Hampton Sub.	High St. Tap	900	795 AA	336 AA	915	1121	1201	1351	0.920	5.22	7.47	0.00928	0.04764	0.02614	0.12801	0.11045	0.56707	0.31113	1.52366
	3	High St. Tap	Route 101	900	795 AA	336 AA	915	1121	1201	1351	0.230	5.22	7.47	0.00232	0.01191	0.00654	0.03200	0.02761	0.14177	0.07778	0.38092
	4 [2]	Route 101 Crossing	Route 101 Riser Pole	600	477 AA Spacer[1]	336 AA	622	776	876	976	0.620	1.90	2.44	0.00176	0.00466	0.00603	0.01396	0.02093	0.05548	0.07178	0.16619
	5	Route 101 Riser Pole	Hampton Beach Sub	600	500 CU UG	---	470	515	470	515	0.170	---	---	0.03231	0.03680	0.00987	0.03321	0.38461	0.43803	0.11752	0.39530
3343	1	Guinea Sw/S	Kingston Tap	600	336 AA	---	531	645	694	777	0.640	5.22	33.50	0.01495	0.03605	0.03550	0.13271	0.17796	0.42909	0.42259	1.57953
	2	Kingston Tap	Munt Hill Tap		2/0 CU SOLID	---	373	451	486	543	1.050	5.22	33.50	0.03820	0.06523	0.07191	0.22381	0.45462	0.77643	0.85595	2.66387
	3	Munt Hill Tap	Shaw's Hill Tap		2/0 CU SOLID	---	373	451	486	543	2.910	5.22	33.50	0.10585	0.18079	0.19930	0.62027	1.25994	2.15183	2.37221	7.38273
	4	Shaw's Hill Tap	Willow Rd		2/0 CU SOLID	---	373	451	486	543	3.210	5.22	33.50	0.11677	0.19943	0.21985	0.68421	1.38983	2.37367	2.61677	8.14384
	5	Willow Rd	E.Kingston Tap		336 AA	---	531	645	694	777	1.200	5.22	30.60	0.02803	0.06760	0.06657	0.24882	0.33368	0.80455	0.79235	2.96163
	6	E.Kingston Tap	New Boston Rd		336 AA	1/0 ACSR	531	645	694	777	0.090	5.22	7.47	0.00210	0.00507	0.00602	0.01621	0.02502	0.06035	0.07163	0.19296
	7	Continued			477 AA	1/0 ACSR	663	808	868	974	1.270	5.22	7.47	0.02102	0.06931	0.07627	0.22652	0.25019	0.82495	0.90784	2.69621
	8	New Boston Rd	Kingston Sub		477 AA	1/0 ACSR	663	808	868	974	2.240	5.22	7.47	0.03708	0.12225	0.13453	0.39954	0.44129	1.45503	1.60123	4.75552
	9	Continued			954 AA	477 AA	1025	1259	1346	1516	0.070	6.13	8.92	0.00060	0.00363	0.00118	0.00795	0.00709	0.04323	0.01401	0.09459
3345	1	Kingston Sub	56X1 Tap		954 AA	477 AA	1025	1259	1346	1516	0.040	6.13	8.92	0.00034	0.00208	0.00072	0.00492	0.00405	0.02474	0.00862	0.05861
	2	Continued			477 AA	---	663	808	868	974	0.700	5.22	30.60	0.01159	0.03820	0.03407	0.14391	0.13795	0.45462	0.40550	1.71292
	3	56X1 Tap	56X2 Tap		477 AA	---	663	808	868	974	1.100	5.22	30.60	0.01821	0.06002	0.05354	0.22615	0.21678	0.71441	0.63722	2.69172
	4	56X2 Tap	Timberlane Sub.		477 AA	---	663	808	868	974	1.260	5.22	30.60	0.02086	0.06875	0.06132	0.25904	0.24831	0.81832	0.72991	3.08325
	5	Timbrlane Sub.	Plaistow Sub.	900	477 AA	---	663	808	868	974	0.820	5.22	30.60	0.01358	0.04474	0.03991	0.16858	0.16160	0.53256	0.47502	2.00656
3346	1	Hampton Tap	Tide Mill		336 AA	1/0 ACSR	531	645	694	777	0.630	5.22	7.47	0.01471	0.03549	0.04212	0.11348	0.17514	0.42246	0.50138	1.35072
	2	Tide Mill	46X1 Tap		336 AA	1/0 ACSR	531	645	694	777	0.630	5.22	7.47	0.01471	0.03549	0.04212	0.11348	0.17514	0.42246	0.50138	1.35072
	3	46X1 Tap	High St. Sub.	600	336 AA	---	531	645	694	777	0.780	5.22	---	0.01822	0.04394	0.03651	0.19404	0.21684	0.52305	0.43461	2.30961
3347	1	3347 Line Tap	47X1 Tap		336 AA	4/0 ACSR	531	645	694	777	0.490	5.22	7.47	0.01144	0.02761	0.02598	0.08173	0.13622	0.32858	0.30921	0.97283
	3	47X1 Tap	Sylvania Tap		336 AA	4/0 ACSR	531	645	694	777	1.160	5.22	7.47	0.02709	0.06535	0.06150	0.19349	0.32248	0.77786	0.73201	2.30303
	4	Sylvania Tap	Portsmouth Ave. Sub.		336 AA	4/0 ACSR	531	645	694	777	0.180	5.22	7.47	0.00420	0.01014	0.00954	0.03002	0.05004	0.12070	0.11359	0.35737
3347 Sylvania Tap	1	Sylvania Tap	Sylvania Sub.		336 AA	---	531	645	694	777	0.430	5.22	---	0.01004	0.02423	0.02013	0.10697	0.11954	0.28835	0.23959	1.27325
3348	1	Hampton Sub.	Seabrook Tap	900	336 AA	1/0 ACSR	531	645	694	777	2.390	7.00	8.14	0.05587	0.14049	0.15891	0.42071	0.66500	1.67223	1.89139	5.00749
3350	1	Seabrook Tap	Seabrook Sub.	600	336 AA	1/0 ACSR	531	645	694	777	0.120	7.00	7.64	0.00281	0.00705	0.00831	0.02037	0.03343	0.08389	0.09896	0.24248
	2	Continued			#1 CU	1/0 ACSR	271	327	353	393	2.100	7.00	7.64	0.12251	0.14046	0.21886	0.37362	1.45822	1.67182	2.60502	4.44703
3351	1	Great Bay	3347 Line Tap	1200	795 AA	336 AA	915	1121	1201	1351	2.680	5.22	7.47	0.02702	0.13883	0.08878	0.41498	0.32161	1.65240	1.05673	4.93933
	2	3347 Line Tap	Dow's Hill	1200	795 AA	336 AA	915	1121	1201	1351	0.140	5.22	7.47	0.00141	0.00725	0.00464	0.02168	0.01680	0.08632	0.05520	0.25802
	3	Dow's Hill	Merrills Pit	1200	795 AA	336 AA	915	1121	1201	1351	0.770	5.22	7.47	0.00777	0.03988	0.02575	0.10958	0.09246	0.47466	0.30651	1.30426
3352	1	Wolf Hill Tap	Wolf Hill	900	477 AA	1/0 ACSR	663	808	868	974	0.020	5.22	7.47	0.00033	0.00109	0.00112	0.00318	0.00394	0.01299	0.01332	0.03788
	2	Wolf Hill	Merrills Pit Tap	1200	477 AA	336 AA	663	808	868	974	2.130	5.22	7.47	0.03527	0.11622	0.08501	0.30903	0.41979	1.38332	1.01188	3.67817
	3	Merrills Pit Tap	PEA Tap	1200	795 AA	336 AA	915	1121	1201	1351	2.010	5.22	7.47	0.02028	0.10410	0.06722	0.28604	0.24137	1.23906	0.80010	3.40462
	4	PEA Tap	Exeter Switching	600	795 AA	336 AA	915	1121	1201	1351	0.240	5.22	7.47	0.00242	0.01243	0.00803	0.03415	0.02882	0.14795	0.09553	0.40652
	5	Exeter Switching	Exeter Sub.	400	#1 CU	---	271	327	353	393	0.040	5.22	30.60	0.00233	0.00258	0.00362	0.00862	0.02775	0.03070	0.04304	0.10260
3353	1	Guinea Sw/S	Hampton Sub.	1200	477 AA	1/0 ACSR	663	808	868	974	1.770	5.22	7.47	0.02931	0.09658	0.09901	0.28167	0.34884	1.14953	1.17844	3.35252
	2	Hampton Sub.	Hampton Tap	900	795 AA	336 AA	915	1121	1201	1351	0.910	5.22	7.47	0.00918	0.04713	0.02586	0.12662	0.10925	0.56091	0.30775	1.50710
	3	High St. Tap	Route 101	900	795 AA	336 AA	915	1121	1201	1351	0.240	5.22	7.47	0.00242	0.01243	0.00682	0.03339	0.02881	0.14793	0.08116	0.39748
	4 [3]	Route 101 Crossing	Route 101 Riser Pole	600	477 AA Spacer[1]	336 AA	622	776	876	976	0.620	1.90	2.44	0.00176	0.00466	0.00603	0.01396	0.02093	0.05548	0.07178	0.16619
	5	Route 101 Riser Pole	Hampton Beach Sub	600	500 CU UG	---	470	515	470	515	0.170	---	---	0.03231	0.03680	0.00987	0.03321	0.38461	0.43803	0.11752	0.39530
3354	1	Guinea Sw/S	Kingston Tap	1200	477 AA	1/0 ACSR	663	808	868	974	0.630	5.22	7.47	0.01043	0.03438	0.03784	0.11237	0.12411	0.40923	0.45035	1.33749
	2	Kingston Tap	Munt Hill Tap		336 AA	1/0 ACSR	531	645	694	777	1.040	5.22	7.47	0.02429	0.05859	0.06954	0.18734	0.28912	0.69739	0.82767	2.22976
	3	Munt Hill Tap	Shaw's Hill Tap		336 AA	1/0 ACSR	531	645	694	777	2.940	5.22	7.47	0.06867	0.16564	0.19658	0.52958	0.81733	1.97147	2.33976	6.30336
	4	Shaw's Hill Tap	Willow Road		336 AA	1/0 ACSR	531	645	694	777	3.180	5.22	7.47	0.07427	0.17916	0.21262	0.57281	0.88405	2.13241	2.53076	6.81792
	5	Willow Road	E.Kingston Tap		336 AA	1/0 ACSR	531	645	694	777	1.180	5.22	7.47	0.02756	0.06648	0.07890	0.21255	0.32804	0.79127	0.93909	2.52992
	6	E.Kingston Tap	New Boston Rd		336 AA	---	531	645	694	777	1.350	5.22	30.60	0.03154	0.07604	0.07489	0.27993	0.37539	0.90512	0.89140	3.33183
	7	New Boston Rd	Kingston Sub		336 AA	---	531	645	694	777	2.240	5.22	30.60	0.05233	0.12618	0.12426	0.46447	0.62287	1.50183	1.47906	5.52837
	8	Continued			954 AA	477 AA	1025	1259	1346	1516	0.070	6.13	8.92	0.00060	0.00363	0.00121	0.00813	0.00709	0.04325	0.01443	0.09672

UES-Seacoast Summary of Line Ratings and Impedances

Line	Section No.	Section From	Section To	Switch Rating (Amps)	Phase Conductor	Neutral Conductor	Ampere Ratings Summer Normal	Summer Emergency	Winter Normal	Winter Emergency	Distance Miles	Phase GMD (ft)	Neutral GMD (ft)	Section Impedance (PU on 100 MVA, 34.5 kV base) R1	X1	R0	X0	Section Impedance (ohms) R1	X1	R0	X0
3356	1	Kingston Sub	56X1 Tap		954 AA	477 AA	1025	1259	1346	1516	0.060	6.13	8.92	0.00051	0.00311	0.00100	0.00681	0.00608	0.03705	0.01188	0.08104
	2	Continued			477 AA	1/0 ACSR	663	808	868	974	0.700	5.22	7.47	0.01159	0.03820	0.04204	0.12486	0.13790	0.45470	0.50039	1.48610
	3	56X1 Tap	56X2 Tap		477 AA	1/0 ACSR	663	808	868	974	1.110	5.22	7.47	0.01837	0.06058	0.06666	0.19799	0.21867	0.72102	0.79347	2.35653
	4	56X2 Tap	Timberlane Sub.		477 AA	1/0 ACSR	663	808	868	974	1.260	5.22	7.47	0.02085	0.06876	0.07567	0.22474	0.24822	0.81846	0.90069	2.67498
	5	Timberlane Sub.	Plaistow Sub.	900	477 AA	1/0 ACSR	663	808	868	974	0.810	5.22	7.47	0.01341	0.04421	0.04865	0.14448	0.15957	0.52615	0.57902	1.71963
3357 PEA Tap	1	PEA Tap	PEA		336 AA	---	531	645	694	777	0.270	5.22	---	0.00631	0.01521	0.01264	0.06717	0.07506	0.18105	0.15044	0.79948
3358	1	Plaistow Tap	Process Engineering	900	336 AA	1/0 ACSR	531	645	694	777	0.600	5.22	7.47	0.01401	0.03380	0.04012	0.10808	0.16680	0.40234	0.47750	1.28640
	2	Process Engineering	58X1 Tap		336 AA	1/0 ACSR	531	645	694	777	0.400	5.22	7.47	0.00934	0.02254	0.02675	0.07205	0.11120	0.26823	0.31833	0.85760
	3	58X1 Tap	Westville Sub.		336 AA	1/0 ACSR	531	645	694	777	0.080	5.22	7.47	0.00187	0.00451	0.00535	0.01441	0.02224	0.05365	0.06367	0.17152
3359	1	Guinea SW	Mill Lane Tap	1200	336 AA	1/0 ACSR	531	645	694	777	3.710	5.22	7.47	0.08665	0.20902	0.24806	0.66828	1.03139	2.48781	2.95255	7.95424
	2	Mill Lane	Stard Road		336 AA	1/0 ACSR	531	645	694	777	1.100	5.22	7.47	0.02569	0.06197	0.07355	0.19814	0.30580	0.73763	0.87542	2.35840
	3	Stard Road	Cemetery Lane	1200	336 AA	1/0 ACSR	531	645	694	777	0.570	5.22	7.47	0.01331	0.03211	0.03811	0.10267	0.15846	0.38222	0.45363	1.22208
	5	Cemetery Lane	Seabrook Tap	600	336 AA	1/0 ACSR	531	645	694	777	1.320	5.22	7.47	0.03083	0.07437	0.08826	0.23777	0.36696	0.88515	1.05050	2.83008
	6	Continued		1200	477 AA	1/0 ACSR	663	808	868	974	0.870	5.22	7.47	0.01440	0.04748	0.05225	0.15518	0.17139	0.56512	0.62191	1.84701
	7	Continued			336 AA	1/0 ACSR	531	645	694	777	0.090	5.22	7.47	0.00210	0.00507	0.00602	0.01621	0.02502	0.06035	0.07163	0.19296
3360	1	Timber Swamp	Wolf Hill Tap	2000	1113 ACSS/TW	477 AA	2174	2174	2342	2342	0.200	5.22	7.47	0.00139	0.01011	0.00507	0.03026	0.01658	0.12031	0.06033	0.36021
	2	Wolf Hill Tap	Guinea Sw/S	2000	1113 ACSS/TW	477 AA	2174	2174	2342	2342	0.150	5.22	7.47	0.00105	0.00758	0.00316	0.02040	0.01244	0.09021	0.03767	0.24286
3362	1	Great Bay	3347 Line Tap	2000	795 AA	---	915	1121	1201	1351	2.680	5.22	40.41	0.02703	0.13879	0.07818	0.51327	0.32171	1.65199	0.93057	6.10922
	2	3347 Line Tap	Dow's Hill	1200	795 AA	---	915	1121	1201	1351	0.140	5.22	40.41	0.00141	0.00725	0.00408	0.02681	0.01681	0.08630	0.04861	0.31914
	3	Dow's Hill	Merrills Pit	1200	336 AA	1/0 ACSR	531	645	694	777	0.770	5.22	7.47	0.01799	0.04337	0.04187	0.12151	0.21411	0.51620	0.49838	1.44632
3371	1	Timber Swamp	Wolf Hill Tap	2000	1113 ACSS/TW	---	2174	2174	2342	2342	0.210	5.22	16.13	0.00146	0.01061	0.00487	0.03972	0.01742	0.12630	0.05798	0.47276
	2	Wolf Hill Tap	Guinea Sw/S	2000	1113 ACSS/TW	477 AA	2174	2174	2342	2342	0.180	5.22	7.47	0.00125	0.00909	0.00380	0.02449	0.01493	0.10825	0.04520	0.29144

APPENDIX C

UES-SEACOAST SYSTEM SUPPLY TRANSFORMER RATINGS

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

System Supply Transformers	Voltage	Summer Capacity		Winter Capacity	
		Normal (MVA)	LTE (MVA)	Normal (MVA)	LTE (MVA)
Great Bay[9]	115 – 34.5 kV	44	51	58	66
Timber Swamp TB25[9]	345 – 34.5 kV	140	180	197	210
Timber Swamp TB69[9]	345 – 34.5 kV	140	163	173	205
Kingston 22T1	115 – 34.5kV	60	72	60	72
Kingston 22T2	115 – 34.5kV	60	72	60	72

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.

[9] Property of Eversource

APPENDIX D

Ten-Year System Load Forecasts
Summer 2020 - 2029

Projection Methodology

The historical basis for each system is a series of yearly regression models developed to correlate actual daily loads to a weighted temperature-humidity index (WTHI) derived from the average temperature and average dew point temperature of each day and the previous two days. Once a model is established, an estimated peak load can be derived for that season for any value of WTHI. There are two dimensions of variability introduced with this modeling. First is the highest WTHI 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 WTHI. 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 WTHI is assumed to follow the discrete distribution of past historical highest WTHI. The random possibilities of peak load outcomes for any specific WTHI are assumed to follow a standard probability distribution model with a mean centered on the point estimate of the peak load at that WTHI 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 WTHI and random peak load estimates at those WTHI values 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 WTHI possibilities and variability in loads versus WTHI. 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.

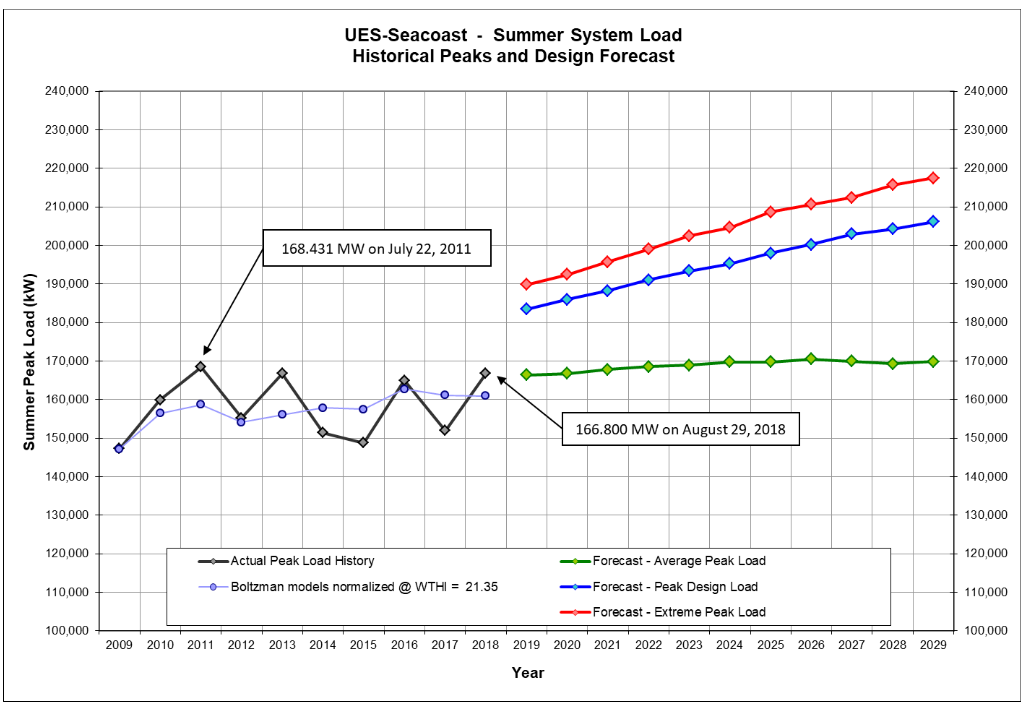
It is important to recognize that with this level of study, constraints and reinforcements are not necessarily associated with major contingencies occurring only at the highest peak hour of the year. Instead, they are associated with contingencies occurring any time during broader stretches of heavy 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-Seacoast system reached a peak load for the summer of 2018 of 166.800 MW on August 29, 2018 at 5:00 PM[10]. The 3-day weighted temperature index (WTHI) was 22.42 on this peak day. The highest peak load for the UES-Seacoast system during the previous ten years was 168.431 MW set on July 22, 2011 at 4:00 PM coinciding with the highest WTHI of 23.74 during the same time period. The historical mean of annual highest WTHI values for the past thirteen years is 21.25. The linear trend of the mean point estimates at this value from the annual load-versus-WTHI models is +1.15 MW per year with an average standard deviation of ±7.86 MW.

UES-Seacoast Ten-Year Summer Design Forecasts

Projected Summer Season	Average Peak Load (MW)	Peak Design Load (MW)	Extreme Peak Load (MW)
2020	166.8	186.0	192.4
2021	167.8	188.3	195.7
2022	168.6	191.1	199.0
2023	169.0	193.4	202.4
2024	169.7	195.3	204.7
2025	169.8	197.9	208.6
2026	170.5	200.2	210.6
2027	169.9	203.0	212.4
2028	169.3	204.3	215.7
2029	169.9	206.1	217.4



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

[10] peak hourly consumption of 166,800 kWhr.

APPENDIX E

BASECASE STUDIES

The information provided in this section describes details of power flow simulation results for the UES–Seacoast system in its normal and/or proposed normal 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>
The 3360 line operates in parallel with the 3371 line from Timber Swamp to Guinea

- 43J60 switch normally open at Guinea

<u>3371 Line, Timber Swamp to Guinea</u>
The 3371 line operates in parallel with the 3360 line from Timber Swamp to Guinea

- 54J71 switch normally open at Guinea
- 3352 recloser normally open at Wolf Hill

<u>3343 Line, Guinea to Kingston</u>
The 3343 line is a double ended line between Guinea and Kingston that normally operated radially from Kingston. The 3343 line is also backed up by the 3354 line.

- 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>
The 3354 line is a double ended line between Guinea and Kingston that normally operated radially from Kingston. The 3354 line is also backed up by the 3343 line.

- 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 54X1and 54X2

<u>3342 Line, Guinea to Hampton Beach</u>
The 3342 line operates radially between Guinea and Hampton Beach and is backed up by the 3353 line.

- 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>
The 3353 line operates radially between Guinea and Hampton Beach and is backed up by the 3342 line.

- 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 3W1 and 3W4

<u>3359/48 Lines, Guinea to Hampton</u>
The 3359/48 lines is a double ended line between Guinea and Hampton that normally operates radially from each source with an open point at Cemetery Lane. The 3348 line runs from Hampton to the 48J50 Switch and the 3359 line from Guinea to the 48J50 switch.

- 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
    - Seabrook Station

<u>3346 Line, 3346 Line Tap to High Street</u>
The 3346 line is a radial line that originates at the 3346 line tap and in the 3342/3353 line corridor and is normally supplied via the 3342 line. There is an automatic transfer scheme that transfers the 3346 line to the 3353 line for a sustained outage in the 3342 line. There are no alternative subtransmission lines that supply 3346 line load.

- 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>

The 3350 line is a radial line that originates at the 3350 line tap in the 3348/3359 line corridor. There are no alternative subtransmission lines that supply 3350 line load.

- Distribution loads normally supplied:
  - Seabrook S/S circuits 7W1 and 7X2

<u>3345 Line, Kingston to Plaistow</u>

The 3345 line operates radially between Kingston and Plaistow and is backed up by the 3356 line.

- 45J56X1 switch normally open at the Hunt Road tap
- 45J56X2 switch normally open at the Dorre Road tap
- 3358B recloser normally open at Plaistow
- Distribution loads normally supplied:
  - Timberlane S/S circuits 13W1, 13W2, and 13X3
  - Plaistow S/S circuit 5X3

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

The 3356 line operates radially between Kingston and Plaistow and is backed up by the 3345 line.

- 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>

The 3358 line is a radial line that originates at Plaistow substation and is normally supplied via the 3356 line. There is an automatic transfer scheme that transfers the 3358 line to the 3345 line for a sustained outage in the 3356 line. There are no alternative subtransmission lines that supply 3358 line load.

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

<u>3351/3341 Lines, Great Bay to Wolf Hill and Exeter</u>

The 3351/3341 lines is a double ended line between Great Bay and Wolf Hill that normally operates radially from each source with an open point at Dow’s Hill. The 3351/3341 lines is also backed up by the 3362/3352 lines.

- 3351J1 switched normally open at Dow’s Hill
- 03341 recloser normally closed at Wolf Hill
- 41J57 switch normally open at P.E.A. tap
- J041 switch normally closed at Exeter Switching
- BT-1A switch normally open at Exeter Switching
- DS1T2 switch normally open at Exeter Switching

- BT-1B switch normally closed at Exeter
- DS1T2S switch normally open at Exeter
- Distribution loads normally supplied:
  - Winnicutt Road tap circuit 51X1
  - Dow's Hill S/S circuit 20H1
  - Exeter Switching S/S circuit 19X2
  - Exeter S/S circuit 1H3 and 1H4

<u>3362/3352 Lines, Great Bay to Wolf Hill and Exeter</u>
The 3362/3352 lines is a double ended line between Great Bay and Wolf Hill that normally operates radially from Great Bay. The 3362/3352 lines is also backed up by the 3351/3341 lines.

- 62J51X1 switch normally open at Winnicutt Road tap
- 3347B recloser normally open at 3347 line tap
- J2062 switch normally open at Dow's Hill
- 3352 recloser normally open at Wolf Hill
- Distribution loads normally supplied:
  - P.E.A.
  - Exeter Switching S/S circuit 19H1 and 19X3

<u>3347 Line, 3347 Line Tap to Portsmouth Avenue</u>
The 3347 line is a radial line that originates at the 3347 line tap in the 3351/3362 line corridor and is normally supplied via the 3351 line. There is an automatic transfer scheme that transfers the 3347 line to the 3362 line for a sustained outage in the 3351 line. There are no alternative subtransmission lines that supply 3347 line load.

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

The following system capacitor banks are modeled as being switched in during summer peak conditions

• Guinea S/S (2-3.6 MVAr banks)	7.2 MVAr (34.5 kV)
• Kingston S/S – Bus 1 – 22C1	4.8 MVAr (34.5 kV)
• Kingston S/S – Bus 2 – 22C3	4.8 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)
• Seabrook S/S	2.4 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 (2-0.90 MVAr banks)	1.8 MVAr (13.8 kV)
• High Street S/S	2.4 MVAr (34.5 kV)

The following system capacitor banks are modeled as being switch out during summer peak conditions.

• Kingston S/S – Bus 1 – 22C2	4.8 MVAr (34.5 kV)
• Kingston S/S – Bus 2 – 22C4	4.8 MVAr (34.5 kV)

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
2020	186.0		Great Bay 44.8 MVA Transformer	95% of Normal Rating	Loading > Normal
2025	197.9	*	Great Bay 44.8 MVA Transformer	101% of Normal Rating	Loading > Normal

Extreme (Extreme Peak Load) Planning Flags

Year	Load Level (MW)	*	Location/Element	Condition	Planning Criteria or Rating
2022	199.0		Great Bay 44.8 MVA Transformer	101% of Normal Rating	Loading > Normal
2024	204.7	*	Great Bay 44.8 MVA Transformer	105% of Normal Rating	Loading > Normal for 2 consecutive days
2025	197.9		Great Bay 44.8 MVA Transformer	91% of LTE Rating	Loading > LTE

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 22T1 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	*
2021	188.3	Loss of 3356 Line, Kingston to Hunt Road	3345 Line, Kingston to Hunt Road @ 101% of Normal	< 12 hrs	Loading > 100% Normal	
		Loss of 3345 Line, Kingston to Hunt Road	3356 Line, Kingston to Hunt Road @ 101% of Normal	< 12 hrs	Loading > 100% Normal	
2023	193.4	Loss of 3359 Line, Guinea to Mill Lane	3348 Line, Hampton to 3350/3359 Tap @ 101% of Normal	< 12 hrs	Loading > 100% Normal	
2026	200.2	Loss of 3342 Line, Guinea to Hampton	3359 Line, Guinea to Mill Lane @ 101% of Normal	< 12 hrs	Loading > 100% Normal	
		Loss of 3353 Line, Guinea to Hampton				
		Loss of 3348 Line				
		Loss of 3359 Line, Guinea to Mill Lane	3353 Line, Guinea to Hampton @ 101% of Normal	< 12 hrs	Loading > 100% Normal	

APPENDIX G

PROJECT EVALUATIONS

No Capital improvement projects were identified as part of this study.

APPENDIX H

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 3W1, 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
  - Exeter Switching 19X2
  - Exeter 1H3 and 1H4

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

- Load restored:

Guinea 18X1	Seabrook 7W1 and 7X2
Hampton 2H1, 2X2 and 2X3	Mill Lane Tap 23X1
Hampton Beach 3W1, 3W4	Stard Road Tap 59X1
Winnacunnet Road Tap 46X1	Cemetery Lane 15X1
High Street 17W1 and 17W2	Seabrook Station
Brazonics	Exeter Switching 19X2
Hampton sewer treatment plant	Exeter 1H3 and 1H4

- All load restored

System Concerns:

At a system load level of 186.0 MW (2020):
- None

At a system load level of 206.1 MW (2029):
- Guinea B-Bus (18X1) 34.5 kV voltage 0.98 PU

2) Loss of 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 5X3

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 5X3

- All load restored

System Concerns:

At a system load level of 186.0 MW (2020):
- 22T2 Transformer at 110% of its Nameplate Rating
- 22T2 Transformer at 92% of its Emergency Rating

At a system load level of 206.1 MW (2029):
- 22T2 Transformer at 122% of its Nameplate Rating
- 22T2 Transformer at 102% of its Emergency Rating

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

2. Guinea Sw/S – close 3354 breaker
3. Kingston S/S – open 03354 breaker
4. Guinea Sw/S – close 3343 breaker
5. Kingston S/S – open 03343 breaker

System Concerns:
- None

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

Initial Event:
- 22T2 breaker trips and locks out at Kingston
- 22XT2 low-side protection trips and locks out at Kingston

- Load out of service:
  East Kingston 6W1, 6W2
  Kingston 22X1
  Dorre Road 56X2
  Westville Road Tap 58X1
  New Boston Road 54X1, 54X2
  Hunt Road 56X1
  Westville 21W1, 21W2

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

- Load restored:
  East Kingston 6W1, 6W2
  Kingston 22X1
  Dorre Road 56X2
  Westville Road Tap 58X1
  New Boston Road 54X1, 54X2
  Hunt Road 56X1
  Westville 21W1, 21W2
- All load restored

System Concerns:
At a system load level of 186.0 MW (2020):
- 22T1 Transformer at 110% of its Nameplate Rating (92% Emergency)

At a system load level of 206.1 MW (2029):
* - 22T1 Transformer at 122% of its Nameplate Rating (102% Emergency)

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

2. Guinea Sw/S – close 3354 breaker
3. Kingston S/S – open 03354 breaker
4. Guinea Sw/S – close 3343 breaker
5. Kingston S/S – open 03343 breaker

System Concerns:
- None

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.
Portsmouth Ave. 11X1, 11X2	Exeter Switching 19H1, 19X3

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	Dow's Hill 20H1
Guinea Rd. Tap 47X1	Portsmouth Ave. 11X1, 11X2

4. Wolf Hill – close 3352 recloser
   - Load restored:

Exeter Switching 19H1, 19X3	P.E.A

   - All load restored

System Concerns:
At a system load level of 186.0 MW (2020):
- None

At a system load level of 206.1 MW (2029):
- Winnacutt Road Tap (51X1) 34.5 kV voltage 0.98 PU

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 Exeter 1H3, 1H4

Switching Procedures:
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 Exeter 1H3, 1H4
   - All load restored

System Concerns:
- None

6) Loss of 3371 Line, Timber Swamp to Guinea
(fault between 03371 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 Concerns:
- None

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
  - Munt Hill Tap 28X1
  - Shaw's Hill Tap 27X1, 27X2

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 Concerns:

At a system load level of 186.0 MW (2020):
- None

At a system load level of 206.1 MW (2029):
- 22T2 Transformer at 94% of its Nameplate Rating

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, 54X2
  - 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, 54X2
3. East Kingston S/S – open J654 switch
4. East Kingston S/S – close J643switch
   - Load restored:
     - East Kingston 6W1, 6W2
   - All load restored

System Concerns:
- None

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 5X3

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

System Concerns:
At a system load level of 186.0 MW (2020):
- 3356 Line from Kingston to Hunt Road at 99% of its Normal Rating
- 3356 Line from Hunt Road to Dorre Road at 93% of its Normal Rating
- 22T2 Transformer at 92% of its Nameplate Rating

At a system load level of 206.1 MW (2029):
- 3356 Line from Kingston to Hunt Road at 111% of its Normal Rating (91% LTE)
- 3356 Line from Hunt Road to Dorre Road at 105% of its Normal Rating
- 22T2 Transformer at 103% of its Nameplate Rating (92% Emergency)

... reconfigure system as necessary to reduce 22T2 loading concern ...

5. Guinea Sw/S – close 3354 breaker
6. Kingston S/S – open 03354 breaker

System Concerns:
At a system load level of 186.0 MW (2020):
- 3356 Line from Kingston to Hunt Road at 99% of its Normal Rating
- 3356 Line from Hunt Road to Dorre Road at 93% of its Normal Rating

At a system load level of 206.1 MW (2029):
- 3356 Line from Kingston to Hunt Road at 111% of its Normal Rating (91% LTE)
- 3356 Line from Hunt Road to Dorre Road at 105% 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 — Westville 21W1, 21W2
  Dorre Rd. Tap 56X2 — Process Engineering
  Westville Rd. Tap 58X1

Automated Switching
- Plaistow S/S – 3358A opens
- Plaistow S/S – 3358B closes
- Load restored:
  Westville Rd Tap 5X1 — Westville 21W1, 21W2

Switching Procedures:
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 Concerns:
At a system load level of 186.0 MW (2020):
- 3345 Line from Kingston to Hunt Road at 99% of its Normal Rating
- 3345 Line from Hunt Road to Dorre Road at 93% of its Normal Rating

At a system load level of 206.1 MW (2029):
- 3345 Line from Kingston to Hunt Road at 111% of its Normal Rating (91% LTE)
- 3345 Line from Hunt Road to Dorre Road at 105% of its Normal Rating
- 22T1 Transformer at 95% of its Nameplate Rating

11) Loss of 3358 Line at Plaistow
(fault between 3358A recloser at Plaistow and DS21 at Westville)

Initial Event:
- 3358A trips and locks out at Plaistow
- Load out of service:

Hunt Rd. Tap 56X1	Westville Rd Tap 58X1
Dorre Rd. Tap 56X2	Westville 21W1, 21W2

Switching Procedures:
No subtransmission switching available

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

1. Route 125, Plaistow – open disconnects at pole 117/81
2. Main Street, Plaistow – close 5X3J58X1 switch
   - Load restored:
     Portion of Westville Rd. Tap 58X1

System Concerns:
At a system load level of 186.0 MW (2020):
- Up to 12 MW remain out of service.

At a system load level of 206.1 MW (2029):
- Up to 14 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	Portsmouth Ave 11X1, 11X2
Guinea Rd. Tap 47X1	Dow's Hill 20H1

Automated Switching
- 3347 Line Tap – 3347A opens
- 3347 Line Tap – 3347B closes
- Load restored:

Guinea Rd. Tap 47X1	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 Concerns:
At a system load level of 186.0 MW (2020):
* - 3810X overcurrent protection at 85% of its minimum pick-up setting.

At a system load level of 206.1 MW (2029):
* - 3810X overcurrent protection at 95% of its minimum pick-up setting.

... reconfigure system as necessary to reduce 22T2 loading concern ...

5. Wolf Hill – close 3352 breaker
6. Dow's Hill S/S – open 3362J1 switch

System Concerns:
- None

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.

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

System Concerns:
- None

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:
  Portsmouth Ave. 11X1, 11X2 | Guinea Rd Tap 47X1

Switching Procedures:

No Subtransmission switching available

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

1. Portsmouth Ave S/S – open 11X recloser (automated)
2. Portsmouth Ave, Exeter – close 11X2J19X2 recloser (automated)
   - Load restored:
     Portsmouth Ave. 11X1, 11X2
3. Guinea Rd, Exeter – open 47X1R1 Intellirupter (automated)
4. Union Rd, Stratham – close 47X1J51X1 Intellirupter (automated)
5. Guinea Rd Tap – open 47X1 Recloser
6. Guinea Rd, Exeter – close 47X1R1 Intellirupter
   - Load restored:
     Guinea Rd Tap 47X1
   - All load restored

System Concerns:

- None

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:
  Exeter Sw/S 19X2 | Exeter 1H3, 1H4

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, 1H4
   - All load restored

System Concerns:
- None

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.

Switching Procedures:
1. Exeter Sw/S – open J052 switch
2. Exeter Sw/S – close BT-1A switch
   - Load restored:
     Exeter Switching 19H1, 19X3
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 Concerns:
- None

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

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 Concerns:
At a system load level of 186.0 MW (2020):
- 3353 Line at 108% of its Normal Rating
- 3353 Breaker 800:5 CT tap at 90% of their thermal limit

At a system load level of 206.1 MW (2029):
* - 3353 Line at 121% of its Normal Rating (100% LTE)
* - 3353 Breaker 800:5 CT tap at 101% of their thermal limit

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

3. Cemetery Lane S/S – close 3359J5 switch
4. Hampton S/S – open 3348 recloser

System Concerns:
At a system load level of 186.0 MW (2020):
- None

At a system load level of 206.1 MW (2029):
- 3359 Line at 106% of its Normal 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 3W1, 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 3W1, 3W4	Seabrook Station

   - All load restored

System Concerns:
At a system load level of 186.0 MW (2020):
* - 3342 Breaker at Guinea at 120% of its Thermal Limit
* - 3342J1 Switch at Hampton at 120% of its Thermal Limit
- 3342 overcurrent protection at 83% of its load encroachment setting
* - 3342 Line at 108% of its Normal Rating

At a system load level of 206.1 MW (2029):
* - 3342 Breaker at Guinea at 134% of its Thermal Limit
* - 3342J1 Switch at Hampton at 134% of its Thermal Limit
* - 3342 overcurrent protection at 95% of its load encroachment setting
* - 3342 Line at 1211% of its Normal Rating (100% LTE)

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

3. Cemetery Lane S/S – close 3359J5 switch
4. Hampton S/S – open 3348 recloser

System Concerns:
At a system load level of 186.0 MW (2020):
- None

At a system load level of 206.1 MW (2029):
- 3342 Breaker at Guinea at 99% of its Thermal Limit
- 3342J1 Switch at Hampton at 99% of its Thermal Limit
- 3359 Line at 106% of its Normal 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 Concerns:
At a system load level of 186.0 MW (2020):
* - 3353 Line at 116% of its Normal Rating
  - 3353 Breaker 800:5 CT tap at 97% of their thermal limit
  - 3348 Line at 97% of its Normal Rating

At a system load level of 206.1 MW (2029):
* - 3353 Line at 129% of its Normal Rating (105% LTE)
* - 3353 Breaker 800:5 CT tap at 107% of their thermal limit
  - 3348 Line at 108% of its Normal Rating

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

3. Hampton Beach S/S – close J042 switch
4. Hampton Beach S/S – open J053 switch

System Concerns:
At a system load level of 186.0 MW (2020):
  - 3348 Line at 97% of its Normal Rating

At a system load level of 206.1 MW (2029):
  - 3348 Line at 108% of its Normal Rating
  - 3353 Line at 105% of its Normal Rating

20) Loss of 3348 Line at Hampton
(fault between 3348 recloser 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 Concerns:
At a system load level of 186.0 MW (2020):
- None

At a system load level of 206.1 MW (2029):
- 3359 Line at 106% of its Normal Rating

21) Loss of 3342 Line, Hampton to Hampton Beach
(fault between 3342R1 recloser 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 Concerns:
- None

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

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

- Load out of service:
  Hampton Beach 3W1, 3W4

Switching Procedures:
1. Hampton Beach S/S – open J053 switch
2. Hampton Beach S/S – close J042 switch
   - Load restored:
     Hampton Beach 3W1, 3W4
   - All load restored:

System Concerns:
- None

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 Concerns:
At a system load level of 186.0 MW (2020):
- Up to 9 MW remain out of service.

At a system load level of 206.1 MW (2029):
- 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 ...

3. Seabrook S/S – open 3350J1 switch
4. Walton Rd, Seabrook – close 7X2J15X1 switch
   - Load restored:
     - Seabrook 7W1, 7X2
   - All load restored

System Concerns:
- None

APPENDIX I

REFERENCES

1. Electric System Planning Guide Unitil Service Corporation rev 5, November 20, 2018

2. Electrical Equipment Rating Procedures Unitil Service Corporation rev 6, December 20, 2018

APPENDIX J

DIAGRAMS

APPENDIX H

UNITIL ELECTRICAL EQUIPMENT RATING PROCEDURES

Unitil	Engineering Procedure	Procedure No.	PR-DT-DS-06
	Electrical Engineering	Page No.	Cover
		Revision No.	6
	Electrical Equipment Rating Procedures	Revision Date	12/20/17
		Supersedes Date:	4/29/16

FOREWORD

The purpose of this document is to define the process for rating electrical lines and equipment.

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

KC Sprague — 12/28/2017

Kevin Sprague — Date

Director, Engineering

John Bonazoli — Dec. 28, 2017

John Bonazoli — Date

Manager, Distribution Engineering

REVISION HISTORY

Revision #	Date	Description of Changes
1	04/04/2000	Revision 1
2	03/16/2012	Update to Power Transformer Rating Procedures and Guideline Consolidation
3	11/06/2012	Update to Ambient Conditions and Circuit Breaker Ratings
4	02/09/2016	Revised document number. This document supersedes PR-DT-TC-01
5	04/29/2016	Revised to include category for Facility Ratings
6	12/20/17	Updated to clarify compliance with NERC FAC-008-3

Table of Contents

List of Appendices

1. Introduction

All electrical equipment have limits at which they can operate. The limits are based on current and length of time that cause the equipment to heat up to a point that the equipment may become damaged. In operating and planning the electric system it is important to create and know the ratings of all types of equipment.

1.1. Purpose

The purpose of this document is to serve as a guide for rating equipment and conductors under various conditions applied on the Unitil electrical system.

1.2. Applicability & Scope

This document provides detailed rating procedures for the following series-connected equipment:

- Transmission and Distribution Conductors
- Substation Power Transformers
- Relay Protection Settings
- Terminal Equipment[1]
  - Current Transformers
  - Switches
  - Breakers
  - Primary Fuses
- Series Reactors

All equipment installed on Unitil transmission/sub-transmission systems and within distribution substations shall be rated in accordance with these procedures. Alternate ratings may be assigned only if accordance with the manufacturer's recommendations and following approval from the Manager, Distribution Engineering.

1.3. Updating the Procedure

The Director of Engineering is responsible for approving this guideline and the Manager of Distribution Engineering is responsible for implementing this guideline. Material in the guideline will be updated or revised, as needed, in an attempt to stay current with changes in the company’s organization, policies or to capture good utility practices. All revisions and/or

[1] Unitil does not own or operate any wave traps.

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 an update and supersedes all previous revisions of Unitil Electrical Equipment Rating Procedures. This revision also expands on the previous version incorporating the requirements of other stand-alone rating guidelines and consolidates these requirements into one comprehensive document. As a result, the following documents are now obsolete and shall no longer be referenced:

- *Power Transformer Rating Methodologies* – no revision date
- *Procedure for Rating Transformers* – 7/24/96
- *Overhead Conductor Rating Methodologies* – no revision date
- *Conductor Rating Procedure* – 7/24/96

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.

1.6. References

IEEE C57.91- Guide for Loading Mineral-Oil-Immersed Transformers

IEEE 738 - IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors

IEEE C37.010 - Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis

ISO NE Planning Procedure No. 7 - Procedures for Determining and Implementing Transmission Facility Ratings in New England

Code of Massachusetts Regulations 220 CMR 125.00 - Installation and Maintenance of Electric Transmission Lines

NERC Standard FAC-008 – Facility Ratings

2. General Information

2.1. Acronyms/Abbreviations

The following is a list of commonly used acronyms:

DAL – Drastic Action Limit

LTE – Long Time Emergency

STE – Short Term Emergency

2.2. Definitions

Facility – a set of electrical equipment that operates as a single system element.

Equipment Rating – The maximum current on individual equipment under steady state conditions as permitted or assigned by the equipment owner.

Normal Rating – equipment rating adjusted for ambient conditions, which will allow maximum equipment loading without incurring loss of life above design criteria.

Emergency Ratings – equipment rating above normal rating, which may involve loss of life or loss of tensile strength in excess of design criteria.

3. Responsibilities

3.1. Department Responsibilities

- Use only current versions of guidelines
- Ensure guideline updates, revisions, or corrections are conducted as needed
- When assigned to write or review guidelines, use only appropriate references

4. Rating Categories

This section describes the required ratings to be assigned to specified electrical components.

4.1. Equipment Ratings

All transmission/sub-transmission line elements (conductors, breakers, switches, terminal equipment, etc.) and substation power transformers shall be assigned normal and LTE ratings for winter and summer operating conditions. Facility ratings shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that facility. The Winter Period is defined as November 1 to March 31. The Summer Period is defined as April 1 to October 31.

STE and DAL ratings will be assigned to transmission/sub-transmission elements that interface with systems under the jurisdiction of ISO-NE. Typically, STE and DAL equipment ratings will be equivalent.

Electrical equipment shall be operated at these ratings in accordance with the limitations described in the Unitil Electric System Planning Guide and as summarized in the table below:

Season	Rating	Operational Limitation
Summer	Normal	Continuous (normal load cycle)
	LTE/Emergency	12 Hours (one non-repeating load cycle)
	STE	15 Minutes
	DAL	Requires immediate action
Winter	Normal	Continuous (normal load cycle)
	LTE/Emergency	4 Hours (one non-repeating load cycle)
	STE	15 Minutes
	DAL	Requires immediate action

NOTES:

1. In practice, operating equipment at load levels above its Normal rating but below LTE rating shall be considered operation at LTE. Similarly, operation above LTE but below the STE rating should be considered operation at STE. Operation at or above the STE limit should be considered operation at DAL.

2. Equipment operating above the Short Term Emergency limit for more than five minutes may suffer unacceptable damage.

4.2. Facility Ratings

Transmission Facility Ratings shall be determined per ISO NE Planning Procedure No. 7 and shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility per latest NERC Standard FAC-008. Each rating (Normal/LTE/STE/DAL) shall be determined separately such that the limiting equipment may differ for each rating assigned to that facility.

4.3. Temporary Ratings

Temporary ratings of newly installed equipment may be used until permanent rating calculations are established. The temporary ratings will be based on the manufacturers' continuous ratings.

5. Calculation Assumptions

5.1. Ambient Conditions

Normal and Emergency ratings shall be established for both summer and winter seasons based on a wind velocity of 3 feet per second (fps), where applicable, and the ambient temperatures outlined in the table below.

	Overhead Conductors		Power and Current Transformer		All other Equipment	
Season	Normal	Emergency	Normal	Emergency	Normal	Emergency
Winter (11/1 to 3/31)	10ºC	10ºC	10ºC	10ºC	10ºC	10ºC
Summer (4/1 to 10/31)	37.8ºC	37.8ºC	25ºC	32ºC	28ºC	28ºC

These ambient temperatures listed above were developed based on recommendations from the following IEEE guidelines, ISO-NE PP7, and state regulations:

A. Power and Current Transformers

IEEE C57.91 – Guide for Loading Mineral-Oil-Immersed Transformers recommends the use of either the average temperature2 or the maximum daily temperature3 for the month involved in determining Normal and Emergency ratings. C57.91 also recommends the use of a 5ºC adder for conservatism. The ambient temperatures indicated in the preceding table are based on historical temperatures experienced throughout Unitil service territories and these recommendations.

B. Overhead Transmission and Distribution Line Conductor

IEEE 738 – Standard for Calculating the Current-Temperature of Bare Overhead Conductors. Massachusetts Department of Public Utilities, CMR 220, 125.23 (3)

5.2. Equipment Temperature

Equipment temperatures for normal loading shall be in accordance with industry standards or loading guides where applicable. In cases where no industry approved guides exist for emergency loading, maximum equipment temperatures higher than design values may be allowed for emergency operation, at the discretion of Unitil Service Corp. It is noted that operation at total temperatures above design values may violate manufacturers' warranties and/or may result in undesirable changes in operating characteristics.

5.3. Temperature Measurements

The temperature of line terminal equipment which experience maximum rated loads may be measured with infrared equipment or other appropriate devices during these maximum rated loads.

Ratings based on reliable infrared observations, or any other reliable temperature measurements, obtained under operating conditions, will be considered to take precedence over all other ratings.

5.4. Nonconforming Equipment

Equipment not designed, not manufactured, not installed, or not maintained in accordance with these Procedures is assigned ratings in accordance with the manufacturer's recommendations.

[2] IEEE C57.91 defines *Average Temperature* as the average daily temperature for the month involved, averaged over several years.

[3] IEEE C57.91 defines *Maximum Daily Temperature* as the maximum daily temperatures for the month involved averaged over several years.

5.5. Assumed Loading Conditions

Where time-temperature relationships for annealing characteristics have been applied, the following estimated hours of operation at allowable equipment temperatures have been assumed, over a 30-year equipment life:

Normal Rating	13,200 hours
Emergency (4-12 hour) Rating	500 hours
Emergency (15 minute) Rating	20 hours
Drastic Action Limit	N/A

These estimates are based on the fact that annealing and loss of strength occur only when a device is operating at or near its emergency rated temperature limits. For most locations on the transmission system, ambient temperature variations together with daily and seasonal cycling of load current will result in conditions where the equipment operates at temperatures considerably lower than rated values, most of the time.

The total duration of operation at emergency temperatures reflects a conservative estimate for the time that the rated elements are expected to operate under contingency conditions. In regards to conductors, the common rule of thumb for loss of tensile strength is to limit the loss to 10 % over the 30-yr equipment life.

6. Equipment Rating Procedures

6.1. Substation Power Transformers

The ratings described in this section apply substation power transformers with nameplate ratings of 100 MVA and below. Substation power transformers shall be rated in accordance with the following standards and noted exceptions.

a. Transformers are to be rated in accordance with ANSI Standards and IEEE loading guidelines. Transformers not conforming to ANSI Standards shall be assigned ratings in accordance with the manufacturer's recommendations.

b. Transformers shall be rated within the following operational limitation derived directly from ANSI C57.91 – 1995.

Criteria	55°C Rise Transformers		65°C Rise Transformers	
	Normal	LTE	Normal	LTE
Acceptable Loss of Life (% per day)	No Limit[4]	No Limit[3]	No Limit[3]	No Limit[3]
Top Oil Temperature	100°C	100°C	110°C	110°C
Hottest-Spot Temperature	115°C	125°C	130°C	140°C
Max Loading (P.U. of nameplate)	2	2	2	2

6.2. Current Transformers

Current transformers are to be rated in accordance with the following procedures outlined in the example below:

6.2.1. Independent Current Transformers

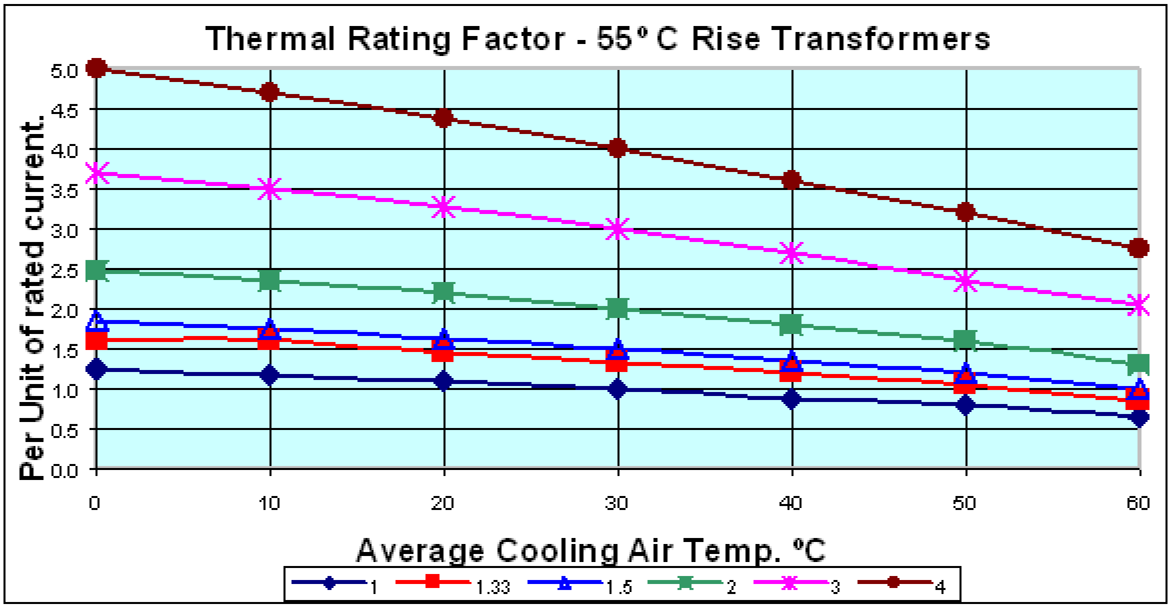
These are current transformers which are purchased and installed as independent units.

A. Normal and Emergency Continuous Capability – The normal and emergency continuous capability of a current transformer depends on its thermal rating factor and the average cooling air temperature. At the present time the normal and emergency ratings are the same. The rating can be found by choosing the appropriate thermal rating factor and average ambient temperature in Figure 1, (reproduction of Figure 6 of IEEE Standard C57.13-1978) and then reading the per unit of rated current at the left of the curve.

Design temperature limits will not be exceeded if this loading procedure is followed.

[4] The following loss of life values shall be used to quantify excessive loss of life: Normal Loading = 0.0369 per day, LTE Loading = 1% per day

Figure #1: Independent CT Thermal Rating Factors



6.2.2. Internal Bushing Current Transformers

These are current transformers which use the current-carrying parts of major equipment as their primary windings and are usually purchased as integral parts of such equipment. On a multi-ratio transformer, the secondary winding is tapped.

A. Normal Continuous Capability - Most manufacturers state that internal bushing current transformers furnished with a piece of equipment have thermal capabilities which equal the capability of the equipment.

1) For a single-ratio or multi-ratio internal bushing current transformer operating at a nominal primary current rating equal to the nameplate rating of the equipment with which it is used, the current transformer should be considered to have the same thermal capability as the equipment.

2) For a single-ratio internal bushing current transformer with a rating less than that of the equipment in which it is installed, the calculated equipment capability should be reduced by the factor

$$\sqrt{I_{ct} / I_e}$$

Where Ict is the current transformer nameplate primary current rating and Ie is the equipment nameplate current rating.

3) For a multi-ratio internal bushing current transformer with a maximum rating equal to the nameplate rating of the equipment in which it is installed, but which is operating on a reduced tap, the calculated equipment capability should be reduced by the factor

$$\sqrt{I_t / I_n}$$

Where It is the reduced tap current rating, and In is the maximum current rating of the current transformer.

Information is not readily available on the continuous thermal rating factor of a bushing current transformer, the manufacturer should be consulted.

6.2.3. External Bushing Current Transformers

These are current transformers which use the current-carrying parts of major equipment as their primary windings, and are not usually purchased as integral parts of such equipment. These current transformers are to be assigned ratings in accordance with the manufacturer's recommendations.

6.2.4. Loading of Secondary Devices

In all cases devices connected to the secondary circuit of a current transformer shall be checked with respect to both accuracy and thermal capability.

6.2.5. CT Rating Example

The following example is provided to illustrate these procedures:

1. The sample current transformer is an independent, oil filled, current transformer, with thermal rating factor of 1.5.

2. Ambient temperatures:

	Normal	Emergency
Winter	10˚C	N/A
Summer	32˚C	N/A

3. Loadability Multipliers Observed From Figure 1

	Winter	Summer
Normal	1.7	1.5
Emergency	N/A	N/A

4. devices connected to the secondary circuit of a current transformer shall be checked with respect to both accuracy and thermal capability.

6.3. Overhead Line Conductors

6.3.1. Rating Procedure

The capacity rating calculation procedures are designed to achieve uniformity. All ratings shall be determined using the ambient air temperature and wind velocity described in Section 5. Ratings shall be developed using the following procedures:

a. Conductor ratings shall be calculated in accordance with IEEE 738 - IEEE Standard for Calculating the Current-Temperature of Bare Overhead Conductors.

b. Conductor ratings should include:

Summer Normal
Summer Long-term Emergency
Summer Short-term Emergency
Winter Normal
Winter Long-term Emergency
Winter Short-term Emergency

c. The following values for equation parameters are specified below:

Parameter	Name	Value
D	Conductor Diameter	As required
E	Emissivity Factor	0.75
A	Absorbtivity Factor	0.50
R	Conductor AC Resistance @ 75ºC/25ºC	As required
Ta	Ambient Temperature	37.8ºC/10ºC
Tc	Conductor Temperature	
	(Normal Rating)	80ºC
	(Long-time Emergency Rating)	100ºC
	(Short-time Emergency Rating)	120ºC
V	Wind Velocity (perpendicular to line)	3.0 fps
	Atmosphere	Clear
	Local Sun Time	2:00PM
	Latitude	42.5 degrees
	Elevation	1000ft

6.3.2. Line Constants

Line constants are developed using LineProp software developed by Siemens Power Technologies International. This program is used to determine positive and zero sequence by
section of each transmission line currently within the Unitil System. It was determined by USC-Engineering and Planning that the ground resistance would beset to an average of 100 ohm-meters and resistance and reactance values are used at 50 degrees Celsius. All summer and winter conductor ratings are developed as stated above and entered into the program. This program will serve to be the database for all transmission conductors within the Unitil System.

6.4. Underground Line Conductors

Underground line conductors are assigned ratings in accordance with the manufacturer's recommendations.[5]

[5] Unitil does not own or operate any underground primary conductors that are directly connected to the New England transmission system and under the jurisdiction of ISO-NE.

6.5. Breakers, switches, circuit switchers, regulators, and series reactors

Breakers, switches, circuit switchers, regulators, and series reactors are to be assigned ratings in accordance with the manufacturer's recommendations. These ratings are typically the nameplate ratings of the device.

Breakers, and any associated internal bushing CTs, operating at 69kV and above that are directly connected to the New England transmission system and under the jurisdiction of ISO-NE shall be rated based on ANSI C37.010 adjusted for the ambient conditions detailed in Section 5.1.

6.6. Relay Protective Settings

Whenever possible protective device settings and fuses do not limit the loadability of a Facility. Loading of protective devices is reviewed during the annual planning process to determine if any protective settings or fuses exceed the following limits.

Fuses - 90% of continuous current rating or 67% of minimum melt, whichever is lower.

Relay Protection Setting – 67% of pick-up in normal configurations and 80% of pickup in contingency configurations.

Any device that exceeds these ratings shall be reviewed in more detail to determine if settings or fusing should be modified.

In the event that a protection setting is the most limiting element the facility rating shall be limited to the reflect the protection setting limitations.

Appendix A: Request for Procedure/Change Form

Requestor: ______________________ Item(s)/Section to be changed (if applicable):
Title: ______________________ Section: ____________________
Department: ______________________ Page: ____________________
Location/DOC: ______________________ Figure: ____________________
Date: ______________________ Appendix ____________________
Procedure No.: ______________________ 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 J

UNITIL DISTRIBUTION PLANNING GUIDELINE

Unitil	Guidelines	Procedure No.	GL-DT-DS-02
	Distribution Engineering	Page No.	Cover
		Revision No.	5
	Distribution Planning Guide	Revision Date	09/17/2018
		Supersedes Date:	08/22/2017

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.

KES

Kevin E. Sprague
Director, Engineering

11/27/2018
Date

John J. Bonazoli
Manager, Distribution Engineering

Nov. 26, 2018
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
4	8/22/2017	Removed procedure for projecting loads of circuits with DG from Sec 3.2
5	09/17/2018	Revisions to entire document and title change

Table of Contents

List of Appendices

1.0 Introduction

1.1 Purpose

The intent of this guideline is to define study methods and design criteria used to assess the adequacy of Unitil's distribution circuits and distribution substation equipment. The purpose is to ensure appropriate and consistent planning and design practices to satisfy applicable criteria and reasonable performance expectations.

1.2 Applicability & Scope

This document applies to the planning of distribution circuits and distribution substation equipment (distribution substation transformers, distribution circuit terminal equipment, etc.) 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 should 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 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 Criteria

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

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 seasonal Normal rating.
- Loading on substation transformers should not exceed their seasonal Normal rating.
- Loading on distribution stepdown transformers should not exceed 120% of their nameplate rating.
- 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[1].
- Loading on breakers, switches, CTs and isolating devices should not exceed their nameplate rating.
- Protective devices (fuse, relays, etc.) should not exceed the follow:
  - Fuses – continuous current rating or 74%[2] of minimum melt, whichever is lower.
  - Relay Protection Settings - 74%[3] of phase pick-up or 100% of the load encroachment limit, whichever is lower.

3.2 Current Unbalance

All distribution circuits and distribution substation transformers shall be reviewed for phase balance on an annual basis. In general, the goal for phase balancing is 10%. Circuits or transformers with an average phase imbalance greater than 20% are considered severe and shall be reviewed to determine if remediation is required.

3.3 Steady State 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 should be performed in order to determine corrective measures.

3.3.1 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:

[1] ANSI/IEEE C57.95-1984 is used as a guide for determining the maximum allowable loading of regulators for normal loss of life. 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

[2] 110% of 67% of minimum melt.

[3] 110% of 67% of pick-up.

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.

3.3.2 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.

3.3.3 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.

3.3.4 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.

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

3.4 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.

3.4.1 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 Visibility1 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.

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

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: 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 should 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 one standard size than is required to serve the steady state load. If the resulting condition still violates this guideline, the customer should 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 options for the most economical solution such as reconductoring, voltage conversion, static VAR compensation, etc.

4.0 Planning of the Distribution Study

The goal of distribution planning is to forecast projected peak loads and to perform circuit analysis on a routine basis to ensure the overall objectives of this guideline are met.

4.1 Distribution Load Projections

The Unitil distribution system shall be planned and designed to meet applicable criteria up to projected peak load levels. Five year summer and winter peak load projections shall be created for each distribution circuit and substation transformer per Unitil's *Distribution Load Projection Guideline* (GL-DT-DS-09).

The five year distribution load projections shall be compared to the distribution substation transformer and circuit position ratings. The transformers and circuit positions that are projected to reach 90% of their rating shall be reviewed in more detail and have project scope(s) developed and evaluated per Unitil's *Project Evaluation Procedure* (PR-DT-DS-11).

4.2 Distribution Circuit Analysis

Distribution circuit analysis shall be performed per Unitil's *Distribution Circuit Analysis Procedures* (PR-DT-DS-03) on an annual basis and as needed to review customer additions and other ad hawk needs.

4.2.1 DG Facilities and DER

The distribution planning process shall include the impact of interconnected DG facilities as well as the output or load offset by other DER projects.

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 common coupling is ≥ 500kW.

DG facilities that are proposed for new installation are studied under a separate effort during the application process.

4.2.2 Peak Load Analysis

All circuits on the Unitil system will be evaluated annually for primary voltage, equipment load and protection sensitivity violations using project peak loads. Circuits that are summer peaking are evaluated using summer projected loads and summer ratings. Circuits that are winter peaking will be evaluated under summer peak and winter peak conditions.

4.2.2.1 DG Dispatch

When performing peak load circuit analysis of any circuit with only one large DG interconnection, the DG interconnection shall be modelled offline. 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 Large DG facilities shall be modeled at their typical historical AC output at the point of interconnection during the circuit peak hour.
- Voltage analysis shall be performed with all combinations of possible DG site status (online/offline, peak load/light load)
- Substation equipment loading constraints shall be analyzed with at least 100% of the cumulative output of all DG interconnections offline.

Small DG is inherent in peak load projections and small DG facilities shout not be or be modelled off-line in peak load models.

4.2.3 Minimum Load Analysis

All circuits on the Unitil system with DG facilities (large and/or small) shall be evaluated annually under minimum load conditions for voltage and loading violations. PV facilities shall be evaluated using minimum daytime load (30% of annual peak), unless otherwise specifically known. Other DG facilities will be evaluated using circuit minimum load (25% of annual peak).

4.2.3.1 DG Dispatch

When performing minimum load circuit analysis all large and small DG interconnections shall be modeled at 100% of their AC rating at the point of interconnection.

4.2.4 Other Analysis

4.2.4.1 Customer Load Addition

Peak load models shall be used to evaluate new customer additions to confirm the distribution circuit can accommodate the added load.

4.2.4.2 Protection Review

Peak load models shall be used to review protective device coordination. These reviews will be performed at the request of the manager of Distribution Engineering or as needed due to load additions, reliability improvements, etc.

4.2.4.3 Circuit Tie Analysis

Analysis shall be performed on all mainline distribution circuit ties on a regular basis. Circuit ties shall be evaluated using projected summer peak loads for the first year of the study period. Circuit ties shall be assessed for loading, voltage and protection sensitivity violations.

It is understood that marginal low voltage and protection coordination concerns may exist while circuits are tied. For the purposes of this review all elements may be operated up to their long term emergency ratings while circuits are tied.

4.3 Addressing System Constraints

Distribution planning should clearly identify results that fail to satisfy criteria. All identified constraints should be reviewed in additional detail and verified against available field measurements to determine the severity of the concern.

System modification options shall be evaluated when any of the following planning thresholds are reached:

- Loading of substation transformers, stepdown transformers, protective devices and other distribution circuit elements are anticipated to reach 90% of their respective limits outlined within this guideline.
- Current imbalance at the distribution circuit supply point is recorded to be greater than 20%.
- 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 Unitil's *Distribution Protection Guideline* (Guideline #GL-DT-TC-09).

4.4 Development and Evaluation of Options

If the performance of the system does not or is not projected to conform to applicable criteria then alternative solutions shall be developed and evaluated per Unitil's *Project Evaluation Procedure* (PR-DT-DS-11).

4.4.1 Performance

The system performance with the proposed options should meet or exceed all applicable planning criteria for the duration of the five-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.

4.4.2 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.

4.4.3 Recommendation

Every identified violation of design criteria should have a proposed recommended action.

5.0 Distribution Planning Studies

Distribution planning study reports shall be created to document the results of distribution load projections, annual distribution circuit analysis and circuit tie analysis. The studies should detail modelling assumptions, analysis procedures, identified constraints, options for system upgrades or modifications considered and final recommendations.

In additional to reporting on the results of distribution load projections and circuit analysis distribution planning studies should contain the following:

5.1 Master Plan

A long range master plan should be included in the distribution planning studies. The purpose of this plan is to provide strategic direction for the development of the electric distribution system as a whole. It is not intended to be a cost-benefit justification for major system investments, but is meant to guide design decisions for various individual projects to work towards comprehensive system objectives.

The master plan should consist of the following:

- Master Plan Map

  - Existing and future mainline backbone.
  - Existing and future sectionalizing devices to work towards achieving the requirements detailed in Unitil's *Reliability Construction Guidelines* (GL-DT-DS-11).
  - Vision (including device locations) for the implementation of distribution automation and "self-healing" of existing and future mainline backbones.
- Detailed Description of the Master Plan by area

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 K

UNITIL DISTIRBUTION PROJECTION GUIDELINE

Unitil	Guidelines	Procedure No.	GL-DT-DS-09
	Distribution Engineering	Page No.	1
		Revision No.	2
	Distribution Load Projection Guideline	Revision Date	08/01/18
		Supersedes Date:	08/22/17

FOREWORD

The purpose of this document is to outline the distribution load projection process.

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

KES 9/1/2018

Kevin E. Sprague
Director, Engineering

Date

SEP. 1, 2018

John J. Bonazoli
Manager, Distribution Engineering

Date

REVISION HISTORY

Date of Review:

Revision #	Date	Description of Changes
0	05/22/09	Initial Issue
1	08/22/17	Revised to update procedure
2	08/01/18	Updated section 4.1 paragraph 2

Unitil	Guidelines	Procedure No.	GL-DT-DS-09
	Distribution Engineering	Page No.	2
		Revision No.	2
	Distribution Load Projection Guideline	Revision Date	08/01/18
		Supersedes Date:	08/22/17

Table of Contents

List of Appendices

1.0 Introduction

1.1 Purpose

The intent of this document is to provide a guideline to assist Distribution Engineering personnel in the process of projecting the five year distribution circuit and substation transformer load levels for use in planning system improvements in order to ensure the reliability of the electric system.

This guideline is not intended to be an all-inclusive, step-by-step procedure and should not replace sound engineering judgment.

1.2 Applicability

This document applies to the projection of load for distribution circuits operating at nominal primary voltages of 34.5kV or less and substation transformers operating at nominal primary voltages of 69kV or less.

This guideline does not apply to the projection of loads for the subtransmission systems and/or system supply transformers.

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.

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 Scope / Background

As part of the annual Distribution System Planning process, a five year load forecast is developed for each distribution circuit and substation transformer utilizing a linear trend analysis, wherever possible. The linear trend is based on the historical monthly peak data from the previous five years obtained from monthly thermal readings, SCADA archives, and/or actual customer billing load data. In some cases, historical load data may reflect incidences of unusual loading due to, for example, maintenance or contingency switching. Where these abnormalities are apparent, the data is removed from the analysis. In addition, future load projections reflect all permanent circuit reconfigurations, load transfers, and any known changes in key account customers (load additions or reductions). Separate forecasts are developed for the summer (May – September) and winter (November – March) seasons.

These projected load levels are then compared to equipment ratings in order to identify all required distribution system improvements over the five year distribution planning period. It is important to note that these load projections are considered a determination of future capacity requirements that serve as the basis for directing system modifications and not a “prediction” of specific load levels that will ultimately be experienced.

4.0 Forecasting Methodology

4.1 Distribution Circuit Load Projections

Linear regression analysis is used to establish a ‘best fit’ trend line of the previous five year historical circuit load data. The slope of this line is then projected forward as the potential growth rate for a given circuit to yield the base load projection. One standard error is added to the projection for each year in order to provide a design margin for weather related variations and other forecasting uncertainties. This method is used when the growth rate is reasonable and positive and the standard error is 10% or less of the base load projection.

In some instances, linear regression analysis will result in an unreasonable growth rate, a negative growth rate or a standard error greater than 10%. In these instances, the linear regression trend line should be recalculated after dropping the values furthest away from the mean or using the previous three or four years of historical circuit load data. If an unreasonable growth rate, negative growth rate or unacceptable standard error still results, this method will be modified based on the following cases:

4.1.1 Positive Growth Rate with Standard Error >10%

Where a reasonable increasing trend results but the addition of standard error projects an unrealistic growth rate, the trend line shall be used to project the five year load forecast and the standard error should not be included.

4.1.2 Negative Growth Rate or Unreasonable Positive Growth Rate

Where an unreasonable positive growth rate or a decreasing trend is the result of the linear trend analysis the circuit growth rate shall be set equal the system growth rate. The formula used to project the circuit is as follows:

Projected Peak $_{\text{Year } n}$ = (Circuit Peak Previous 3 years) * {1 + [rate * (n+1)]}

n+1 is used in the projection formula to provide a design margin for weather related variations and other forecasting uncertainties.

This formula was derived on the basis that circuit load growth is more accurately estimated by projecting constant year-to-year incremental growth expressed in kVA. The typical compounding growth method will over estimate circuit load growth due to the compounding factor.

4.2 Distribution Substation Transformer Load Projections

Load projections for distribution transformers with historical peak data shall be calculated in the same manner as distribution circuit load projections described in section 4.1.

Sound engineering judgement shall be used to make sure the transformer projections are reasonable and that they correlate with historical loads and projections of circuits supplied by the transformer.

In the event the transformer projections are unreasonable or their is no historical peak data available the following methods shall be used:

4.2.1 Unreasonable Distribution Transformer Projection

Where an unreasonable distribution transformer projection is the result of using the methods described in section 4.1 the load projections for the transformer shall be calculated based on the sum of the peak projected distribution circuit loads served by the transformer multiplied by a coincident circuit load factor. The historical coincident load factor for each year shall be determined using the following formula:

$$\text{Coincident Load Factor} = \frac{\text{Distribution Substation Transform Load}}{\sum \text{Distribution Circuit Loads}}$$

The maximum historical coincident load factor from the previous three years shall be used for projecting future loads. The coincident load factor used shall always be a number between 0 and 1. In some instances, such as years with missing or invalid circuit load data, the calculated coincident load factor may be a value greater than 1. These cases shall be discarded from the evaluation.

4.2.2 Transformers without Historical Data Supplying Circuits with SCADA Data

Transformer loading for units without historical monthly peak data which supply circuits that all have historical, coincident SCADA telemetry data shall be calculated using the procedure outlined below:

- The interval demand at each circuit supplied from the distribution substation transformer shall be obtained from SCADA.
- The interval data obtained from each circuit position shall be correlated to calculate an estimated aggregate peak load on the transformer.

The transformer loading shall then be projected in the same manner as transformers with historical data.

4.2.3 Transformers without Historical Data Supplying Circuits without SCADA Data

Projections for transformer that do not have historical monthly peak data and supply circuits that do not have historical, coincident SCADA telemetry data shall be calculated based on the sum of the peak projected distribution circuit loads served by the transformer multiplied by a coincident circuit load factor of 1.

It is understood that this method is conservative. In the event units projected in this manner are projected to be overloaded, field measurements (application of load loggers, installation of transformer metering, etc.) shall be taken to determine the severity of the loading concern.

4.3 Special Considerations

In all the following cases, care should be taken to properly document the methodology and reasoning used for all distribution circuit and distribution substation transformer load projections.

4.3.1 Large Interconnected DG Facilities and DER

The distribution load projection process shall include the impact of interconnected large scale DG facilities as well as the output or load offset by other DER projects. 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 development of load projections for circuits and distribution substation transformers with large DG facilities shall follow section 4.1 and 4.2 with all large DG facilities assumed to be offline.

The method for determining the previous circuit peak shall follow the procedure outlined below:

- The hourly interval demand at the substation circuit position and substation transformer shall be obtained from monthly substation inspection records, SCADA, or relay interrogation.
- The hourly interval DG interconnection(s) output shall be obtained from EMIS data, SCADA or relay interrogation.
- The hourly interval data obtained at the circuit position, transformer and DG interconnection(s) shall be correlated to calculate an estimated aggregate peak load on the circuit.

  Note: 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.

4.3.2 Reserved Capacity Customers

The impact of customers with "reserved capacity contracts" shall be accounted for in the distribution load projection process. The development of load projections for circuits and substation transformers with reserved capacity customers shall follow section 4.1 and 4.2. The load associated with the reserved capacity service shall be removed from the historical load. Once the base projection of the remaining load is determined, the reserved capacity shall be added to each year of the projection.

The method for determining the previous circuit peak shall follow the procedure outlined below:

- The hourly interval demand at the substation circuit position and substation transformer shall be obtained from monthly substation inspection records, SCADA, or relay interrogation.
- The hourly interval demand at the reserved capacity service(s) shall be obtained from EMIS data, SCADA or relay interrogation.
- The hourly interval data obtained at the circuit position, transformer and reserved capacity service(s) shall be correlated to calculate an estimated aggregate peak load on the circuit without serving any load at the reserved capacity service.

4.3.3 Known Future Customer Additions

Any future large customer additions that are determined not to be part of "normal" load growth shall be added to each year of the circuit and substation transformer projections from which the new load will be served.

4.3.4 Load Transfers

Where load is transferred from one circuit to another in the previous year, the slope of the linear regression trend line and the standard error for each circuit shall be calculated based on the years prior to the transfer. However, the slope of the trend line represents the growth rate for the circuit prior to the load transfer. This will result in an annual growth rate that does not account for the transferred load. In order to correct this, the slope is scaled by a "load share multiplier" calculated using the following formula:

$$\text{Load Share Multiplier} = \frac{\text{Peak Load After Transfer}}{\text{Peak Load Before Transfer}}$$

The application of this method should be used with sound engineering judgment and all factors such as the amount and type (industrial vs. residential) of load being transferred shall be considered when determining if this method is applicable.

4.3.5 Winter Projections

Care should be taken such that circuits and distribution substation transformers that are historically summer peaking are not projected to become winter peaking unless sound engineering judgement determines this should be the case.

In the event linear regression analysis results in unreasonable winter load projections the winter projection shall be determined based on the summer projection multiplied by the proportion of the previous winter and summer peak circuit demands. The formula used to project the circuit is as follows:

$$\text{Projected Peak}_{\text{Year n/Year n+1}} = (\text{Summer Peak}_{\text{year n}}) * \frac{\text{Winter Peak Previous Year}}{\text{Summer Peak Previous Year}}$$

Appendix A - Request for Procedure/Change Form

Requestor: ____________________ Item(s)/Section to be changed (if applicable):
Title: ____________________ Section: ____________________
Department: ____________________ Page: ____________________
Location/DOC: ____________________ Figure: ____________________
Date: ____________________ Appendix ____________________
Procedure No.: ____________________ 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 N

2019 JOINT PLANNING REPORT

Eversource / Unitil Energy Systems

2019 Joint Planning Report

September 20, 2019

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1 EXECUTIVE SUMMARY

Eversource and Unitil have conducted the annual joint planning meeting(s) and completed the joint planning process for 2019. Planning departments from both companies were represented at the meeting(s) and loading of joint facilities under basecase and contingency configurations were reviewed.

This report summarizes the findings of the joint planning process. The Eversource 2019-2023 Loadflow Study and the Unitil 2020-2029 Electric System Planning Studies were used as the basis for identifying constraints for the years 2020-2029. Alternatives are developed and evaluated per each company's planning and design guidelines. Evaluation criteria include total cost in today's dollars, net present value, system benefit and technical preference.

The 2019 Eversource and UES joint planning process identified one Capital system improvement project.

- To provide time to develop and implement a long-term solution to the identified Oak Hill transformer Short Term Emergency loading constraint Unitil will transfer its 34 line (approx. 10MW) from Penacook to Bridge Street at the request of the ESCC for ISO-NE load levels above 23,300 MW. In order to accommodate this transfer Unitil will need to make modifications to AMI infrastructure at Penacook.

  Estimate Cost: $150,000

Additionally, the following non-capital modifications are recommended as a result of the joint planning effort:

- Starting in 2025 Unitil will switch an additional 7.5 MW from Great Bay to Timber Swamp during the summer load season.

2 INTRODUCTION

Unitil is a transmission customer of Eversource in New Hampshire. Unitil is provided 34.5 kV service at four Eversource distribution substations; Oak Hill and Garvins in Concord, Timber Swamp in Hampton, and Great Bay in Stratham. Additionally, Unitil is supplied 115 kV service at Unitil's Kingston substation in Kingston and Broken Ground substation in Concord. Three of the distribution substations supply both Unitil and Eversource distribution load. Due to the joint nature of the Eversource distribution and transmission facilities that supply Unitil, Eversource and Unitil participate in a joint planning process to develop short term and long term plans for these areas that represent the best interests of all customers as a whole.

Although transmission needs are discussed, the joint planning process is a distribution planning effort and any recommendations that have transmission implications need to be reviewed by Eversource Transmission Planning and ISO-NE.

The joint planning process is an annual process that typically consists of Unitil and Eversource developing independent system load projections and loadflow models. Unitil and Eversource exchange load projections and incorporate them into their loadflow models. As needed Eversource will provide Unitil with an updated transmission loadflow model that Unitil will incorporate the Unitil distribution model into and return to Eversource for use in their studies. Unitil and Eversource complete separate planning studies (Eversource Loadflow Study and Unitil Electric System Planning Studies). With the study work complete joint meetings are held to discuss the results and project scopes and estimates are developed for any identified constraints that affect joint facilities.

3 RELEVANT SYSTEM CHANGES

Relevant system changes since the release of the previous Joint Planning Report are described below:

3.1 Broken Ground Load Limitation

The necessary modifications to Eversource's Farmwood substation are complete and Unitil's load limitation at Broken Ground substation is no longer required and has been removed.

3.2 Great Bay 3810X and 3260X Protection Settings

Eversource confirmed that the protection settings of the 3810X and the 3260X breakers at Great Bay have a load encroachment setting that allows for up to 1,500 amps of loadability.

4 TRANSFORMER RATINGS

The following table listed the summer ratings of the Eversource transformers that supply UES:

Transformers	Nameplate Capacity (MVA)	Summer Ratings		
		Normal (MVA)	LTE (MVA)	STE/DAL (MVA)
Garvins TB39	67.2	67	79	100
Garvins TB51	67.2	67	79	100
Oak Hill TB15	44.8	44	53	67
Oak Hill TB84	45	45	49	61
Timber Swamp TB25	140	140	180	210
Timber Swamp TB69	140	140	163	200
Great Bay TB141	44.8	44	51	67

5 BASECASE REVIEW

The following table summarizes the percent loading of the jointly used transformers.

Year	Location/Element	Percent Loading
2025	Great Bay TB141 Transformer	101% of Normal (44.2 MVA)
2029	Garvins TB39 Transformer[1]	64% of Normal (42.7 MVA)
	Garvins TB51 Transformer[1]	64% of Normal (42.9 MVA)
	Oak Hill TB15 Transformer[1]	84% of Normal (36.8 MVA)
	Oak Hill TB84 Transformer[1]	81% of Normal (36.5 MVA)
	Great Bay TB141 Transformer	105% of Normal (46.1 MVA)
	Timber Swamp TB25	63% of Normal (88.2 MVA)
	Timber Swamp TB69	28% of Normal (39.4 MVA)

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

- Close J041 Switch at Gilman Lane S/S
- Open BT-1A Switch at Gilman Lane S/S
- Close BT-1B at Exeter S/S
- Open DS1T2S at Exeter S/S
- Close 03341 Recloser at Wolf Hill Tap
- Open 3351J1 Switch at Dow’s Hill S/S

In this configuration the Great Bay TB141 transformer is expected to exceed its normal rating during basecase conditions in 2025. To reduce loading of the Great Bay TB141 transformer the following switching is proposed instead of the switching that is currently being performed during summer load conditions.

- Close J041 Switch at Gilman Lane S/S
- Open BT-1A Switch at Gilman Lane S/S
- Close BT-1B at Exeter S/S
- Open DS1T2S at Exeter S/S
- Close 3352 Recloser at Wolf Hill Tap
- Open 3362J1 Switch at Dow’s Hill S/S
- Close 3347B Recloser at the 3347 Line Tap
- Open 3347A Recloser at the 3347 Line Tap

6 CONTINGENCY EVALUATION

The following section describes the power flow simulation results for contingent loss of jointly used power transformers, any contingency that is expected to load jointly used infrastructure over its normal rating, and contingencies which identify deficiencies that have alternatives requiring modifications to jointly used facilities in the next ten years.

[1] Assumes SES Concord and all area hydroelectric generators are off-line

The following planning violations were identified:

- Remaining Oak Hill transformer expected to be loaded above its STE limit immediately following the loss of the other Oak Hill transformer.

The switching described below is a guide and is not meant as step by step switching procedures to be implemented in the field.

All scenarios below assume SES Concord and all area hydroelectric generators are off-line

6.1 Loss of Garvins TB51 Transformer
(Garvins TB51 transformer fault)

Initial Event:
- G1460, H1370 and M1080 trip at Garvins S/S
- TB36, TB39, TB51, 318, 374, 375, 396, 3340 and 3350 trip at Garvins S/S
- 0374 and 0375 trip at Bridge Street S/S via transfer trip from Garvins S/S
- J51 opens at Garvins S/S

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

Unitil Switching Procedures:
1. Penacook S/S – Close 036 Breaker
2. Bridge Street S/S – Close 34 Breaker
   - All **Unitil** load restored

Eversource perform switching to restore load:
1. Garvins – Close 318 Breaker
2. China Mills 334 Line – Close 334J15
   - All **Eversource** Load restored

System Concerns:

2020:
- Oak Hill TB15 transformer at 43.7 MVA (99% of Normal) 44
- Oak Hill TB84 transformer at 43.1 MVA (96% of Normal) 45
- Garvins TB39 transformer at 52.4 MVA (78% of Normal) 67

2029:
- Oak Hill TB15 transformer at 45.9 MVA (104% of Normal)
- Oak Hill TB84 transformer at 45.5 MVA (101% of Normal)
- Garvins TB39 transformer at 57.1 MVA (85% of Normal)

… install Eversource 35MVA mobile at Garvins S/S and reconfigure system to reduce loading at Oak Hill and Garvins...

6.2 Loss of Garvins TB39 Transformer
(Garvins TB39 transformer fault)

Reference section 5.1 above, Loss of Garvins TB51 transformer. 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.

6.3 Loss of Oak Hill TB84 Transformer
(Oak Hill TB84 transformer fault or fault on B84 line between J484 switch at Farmwood and J84 circuit switcher at Oak Hill)

Initial Event:
- J84 and TB84 trips and lock out at Oak Hill S/S
  Note: Possible lockout of J15 and TB15 on overcurrent at Oak Hill S/S.

System Concerns:
2020:
- Oak Hill TB15 transformer at 70.3 MVA (115% of STE)

2029:
- Oak Hill TB15 transformer at 73.3 MVA (120% of STE)

Unitil Switching Procedures:
1. Penacook S/S – Close 036 Breaker
2. Bridge Street S/S – Close 34 Breaker
   - All load restored

Note: Additional switching required if J15 and TB15 lockout on overcurrent.

System Concerns:
2020:
- Oak Hill TB15 transformer at 45.7 MVA (104% of Normal)
- Garvins TB39 transformer at 52.6 MVA (79% of Normal)
- Garvins TB51 transformer at 52.3 MVA (78% of Normal)

2029:
- Oak Hill TB15 transformer at 48.5 MVA (110% of Normal)
- Garvins TB39 transformer at 55.8 MVA (83% of Normal)
- Garvins TB51 transformer at 55.5 MVA (83% of Normal)

Eversource Switching Procedures:

1. Eversource to transfer 317 line load from Oak Hill substation to Jackman substation as needed to alleviate loading concerns.

… install Eversource 35MVA mobile at Oak Hill S/S and reconfigure system to reduce loading at Oak Hill and Garvins...

6.4 Loss of Oak Hill TB15 Transformer
(Oak Hill TB15 transformer fault or fault on B15 line between J315 switch at Farmwood and 15J1 circuit switcher at Oak Hill)

Reference section 5.3 above, Loss of Oak Hill TB84 transformer. 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.

6.5 Various UES-Capital Contingencies
The following contingencies require the loop between Penacook and Bridge Street be reestablished by closing the 034 breaker at Penacook and the 35 breaker at Bridge Street to restore all load during peak load conditions.

- Loss of a Garvins Transformer (TB39 or TB51)
- Loss of an Oak Hill Transformer (TB15 or TB84)
- Loss of the 3122 Line at Oak Hill (do not need to restore loop if Eversource transfers 317 line load to Jackman and North Road)
- Loss of the 317 Line at Oak Hill (do not need to restore loop if Eversource transfers 317 line load to Jackman and North Road)
- Loss of the 33 Line at Bow Junction

6.6 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

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

No Manual Switching Required
- No load out of service

System Concerns:
2020:
- Timber Swamp TB69 Transformer at 117.0 MVA (84% of Normal)

2029:
- Timber Swamp TB69 Transformer at 126.2.0 MVA (90% of Normal)

6.7 Loss of Timber Swamp TB69 Transformer
(Timber Swamp TB69 transformer fault)

Reference section 5.6 above, Loss of Timber Swamp TB25 Transformer. Details on initial event, automatic restoration, follow-on switching procedures, and associated system concerns are effectively the same.

6.8 Loss of Great Bay TB141 Transformer
(Great Bay TB141 transformer fault)

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

Unitil 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
4. Wolf Hill – close 3352 recloser
   - All load restored

System Concerns:
2020:
- Timber Swamp TB25 Transformer at 121.4 MVA (87% of Normal)

2029:
- Timber Swamp TB25 Transformer at 135.0 MVA (96% of Normal)

6.9 Line Contingencies
There are no line contingencies that cause elements to exceed their normal ratings.

7 SYSTEM IMPROVEMENT OPTIONS
The following sections describe details of system improvement options examined to address the deficiencies identified earlier in this report.

7.1 Oak Hill Transformer Loading - 2020
The remaining Oak Hill transformer is expected to be loaded above its STE (Short Term Emergency) limit for loss of the other Oak Hill transformer during summer peak conditions in 2020. This requires remedial action to be implemented within five minutes following the failure.

In order to alleviate the drastic action concern Unitil will transfer its 34 line (approximately 10MW) from Penacook substation to Bridge Street substation during summer peak conditions. To accommodate this transfer Unitil will need to make modifications to the AMI infrastructure at Penacook substation. The estimated cost of this investment is $150,000.

This switching solution will provide Eversource and Unitil the time to develop and implement a long-term solution by the summer of 2021.

8 ADDITIONAL ITEMS DISCUSSED

In addition to the traditional basecase and N-1 contingencies the joint planning group also discussed the following items.

8.1 Offloading of Great Bay to Timber Swamp

Unitil has receives requests on multiple occasions to be ready to offload all of Great Bay due to higher than anticipated loads. It was confirmed by the ESCC that this could occur at any load level and is dependent on generation capabilities vs load. The ESCC plans on the switching of distribution load following a first contingency in preparation of a second contingency occurring.

Response to such an event includes the following actions taking place within 120 minutes.

- Offloading:
  - Eversource's Ocean Road substation
  - Eversource's Brentwood substation
  - Eversource's Great Bay substation
  - Central Maine Power's Bolt Hill Substation
- Starting of Schiller Jet
- Starting of other Schiller generation as needed
- Recall of any out of service transmission lines

During such an event the Great Bay system supply will be unavailable to Unitil to restore load for other system contingencies. Additionally, this switching ability needs to be maintained by Unitil and if it is unavailable the ESCC shall be notified and scheduled work that would defeat this switching capability shall be scheduled with the ESCC.

The completion of Seacoast Reliability Project F107, which is expected to be completed in June of 2020, will reduce the exposure to this situation, but not eliminate it.

At this time there are no projects planned to eliminate the need to perform distribution system switching to resolve transmission system constraints.

8.2 Timber Swamp Substation – Loss of Both the TB25 and TB69 Transformers

Timber Swamp is equipped with two 140 MVA 345-34.5kV in-service transformers with no on-site spare unit. For the contingent loss of one transformer at Timber Swamp all load can be restored by closing the 34.5 kV bus tie breaker. It is assumed that a repair and/or replacement for a transformer failure could take up to one year. Eversource does have an in-service unit that could be moved to Timber Swamp in the event of a transformer failure, but the process of disassembling, moving, reassembling and testing a transformer of this size could take more than a month.

In the event of a failure of the remaining 140 MVA transformer Eversource can restore all the Eversource Timber Swamp load from Ocean Road and Unitil can restore approximately 25 MW of their load from Ocean Road, leaving approximately 50 MW of Unitil load out of service under peak conditions. There is not sufficient transformer or line capacity to restore all the remaining Unitil load from Great Bay or Kingston.

Unitil and Eversource began evaluating plans to restore all load for loss of both Timber Swamp transformers in 2019. Analysis to date has indicated that without significant capital investment Unitil will have load out of service until a spare transformer can be installed at Timber Swamp. Unitil estimates that the exposure to system load levels that would leave load out of service is 8 days in 2020 and 23 days in 2029.

Unitil and Eversource will continue to develop a plan to restore all load following the loss of both Timber Swamp transformers.

9 <u>CONCLUSION</u>

The 2019 joint planning process one capital improvement project and non-capital modification:

- To provide time to develop and implement a long-term solution to resolve the Oak Hill transformer Short Term Emergency loading constraint Unitil will transfer its 34 line (approx. 10MW) from Penacook to Bridge Street at the request of the ESCC for ISO-NE load levels above 23,300 MW. In order to accommodate this transfer Unitil will need to make modifications to AMI infrastructure at Penacook.

  Estimate Cost: $150,000

- Starting in 2025 Unitil will switch an additional 7.5 MW from Great Bay to Timber Swamp during the summer load season. The need for this additional switching is due to the new ratings of the Great Bay TB141 transformer.

  Estimate Cost: no capital investment

Additionally, two items were identified as requiring additional study:

- Loading above STE for loss of an Oak Hill transformer.
- Loss of both Timber Swamp 345-115 kV transformers.

10 ACCEPTANCE

This joint planning report is accepted by both Eversource and Unitil as meeting the needs for the long term planning of jointly used distribution facilities.

___Russel Johnson________ _9/26/2019_____
Manager – System Planning, Eversource Date

___Kevin Sprague________ _9/20/2019____
Vice President – Engineering, Unitil Date

APPENDIX P

UNITIL RELIABILITY ANALYSIS GUIDELINE

Unitil	Guidelines	Guideline No.	GL-DT-DS-05
	Distribution Engineering	Page No.	Cover
		Revision No.	2
	Reliability Analysis Guideline	Revision Date	3/15/19
		Supersedes Date:	2/9/16

FOREWORD

The purpose of this document is to outline the annual distribution reliability analysis process.

This document also serves as a guide when calculating the recurring annual reduction in Customer-Minutes (CMI) of interruption and in the number of Customer-Interruptions (CI) anticipated for a specific reliability improvement project proposal.

Any questions or inquiries regarding information provided in this document should be referred to the Manager, Distribution Engineering.

5/23/2019

Kevin Sprague — Date

Vice President, Engineering

MAY 13, 2019

John Bonazoli — Date

Manager, Distribution Engineering

REVISION HISTORY

Date of Review:

Revision #	Date	Description of Changes
0	08/16/2010	Initial Issue
1	02/09/2016	Revised document number. This document supersedes GL-DT-0-1
2	03/15/2019	Revisions to entire document

Table of Contents

1.0 Introduction

1.1 Purpose

This guideline has been developed to detail the requirements of the DOC annual reliability studies.

This document will also serve as a guide when calculating the recurring annual reduction in Customer-Minutes (CMI) of interruption and in the number of Customer-Interruptions (CI) anticipated for a specific reliability improvement project proposal.

1.2 Applicability & Scope

This document applies to the Distribution Engineering department annual reliability studies and reports. This guideline summarizes the requirements of the reports and defines how each component shall be calculated and presented. This document is not intended to be a template for the reports; however effort shall be made to have the report for each of the DOC be as similar in content and structure as possible.

This document also applies to the method of calculation of the annual reliability benefit ($/CI and $/CMI) of proposed projects or portions of projects that are being proposed on the justification of reliability benefit alone.

1.3 Updating the Procedure

The Manger, Distribution Engineering is responsible for maintaining this guideline to ensure the 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 and addressed to the Manger, Distribution 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 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 & Acronyms

Annualized Reliability Improvement (ARI)	Metric that represents the anticipated reduction in CMI (ARI_{CMI}) or CI (ARI_{CI}) of the circuit, or portion thereof, recurring annually which will be achieved by implementing a proposed project. Any/all projects are to be annualized in six month increments, using no less than eighteen months.
Customer-Interruptions (CI)	The sum of the customers interrupted for any given Sustained Interruption or an aggregate quantity due to several Sustained Interruptions over a given time period.
Customer-Minutes of Interruption (CMI)	The product of Customer-Interruptions and the respective Interruption Duration measured in minutes for any given Sustained Interruption or an aggregate quantity due to several Sustained Interruptions over a given time period.
Permanent Fault (PF)	All other trouble causes not classified as TF or PTF shall be considered permanent faults.
Potential Temporary Fault (PTF)	Trouble causes that can be classified as potentially temporary are troubles where an identifiable cause was found but resulted in no physical damage to Unitil facilities. Examples of this type of fault include Animal Contact, Broken Limb, etc. related outages. Note 1: "Tree/Limb Contact - Growth into Line" shall not be considered a PTF. Note 2: "Lightning" shall not be considered a PTF. "Lightning" is only identified as the root-cause when there is concrete evidence of a strike such as equipment damage. Note 3: A "suspected" lightning strike leaving no equipment damage should be identified as "Patrolled, Nothing Found".

Temporary Fault (TF)	The only documented trouble cause that can always be classified as a temporary fault is Patrolled, Nothing Found
Year of Study	Main year of interest for the annual reliability report. Typically this is the last full calendar year.

2.2 Reference Documents and Databases

The following documents and databases are available and shall be used to assist in the creation of annual reliability reports and calculating project reliability benefits. These references will assist in the determination of the historical performance of a circuit and can provide details of a specific outage.

2.2.1 Electric Distribution System Reliability Procedure (PR-DT-DS-04)

Unitil's Electric Distribution System Reliability Procedure details the Company's overall objectives for electric service reliability. It also describes the indices used for benchmarking performance as well as the metrics used for project planning and justification when developing the annual and five year capital budget.

As part of the budget process, the annualized reliability improvements for all proposed projects are compared and ranked against each other per Unitil' Electric Distribution System Reliability Procedure.

2.2.2 SIENA OMS Reports

All outage information is stored in Unitil's Outage Management System. This information is easily accessed through a webpage based set of reports. By using a variety of queries, a user is able to gather historical outage data and sort the date, time, location, circuit number, outage cause, excludable event, etc. in order to analyze reliability performance for each DOC and the Unitil System as a whole.

Archived data contained in the SIENA OMS reports dates back to 2013.

From 1998 through the end of 2013 all Unitil interruption information was stored in Unitil's Outage Database.

2.2.3 GIS

Unitil's GIS system is a tool to assist in identifying the exact location where outages have occurred. GIS provides details about the number of customers affected, the total number of customer-minutes of interruption, location, date, and outage cause of historical outage.

2.2.4 Annual Reliability Project Savings Calculator

Unitil's Annual Reliability Project Savings Calculator is a spreadsheet used to calculate annual reliability benefit ($/CMI and $/CI) of proposed reliability projects for various types of projects. This spreadsheet utilizes past historical reliability data to calculate assumed annual reliability savings.

3.0 Annual Reliability Report Requirements

Annual reliability reports shall be created for each DOC. The reports shall report on the historical reliability performance of the DOC and focus on the previous calendar year. In addition to historical performance the annual reliability reports will propose reliability improvement projects that will be compared to other proposed reliability projects to determine which projects will be accepted into the following year's capital budget.

The following sections detail the requirements on the annual reliability reports. This section describes the required content of the report, but is not intended to detail all aspects of the report, define the structure of the report, or act a template for the report.

Effort shall be made to have the reports for each DOC be as similar in content and structure as possible.

3.1 Historical Reliability Performance

The annual reliability reports shall report on the historical performance of the DOC. Required content regarding historical reliability performance is described below.

All reliability data referenced in this section is with all exclusions removed from the data unless otherwise noted below. Additionally, all tree/limb related causes (broken limb, broken trunk, growth into line, uprooted tree and vines) shall be grouped into one cause, tree related outages.

3.1.1 Reliability Performance and Targets

The annual reliability study shall report on the previous reliability performance for the DOC, including:

- Previous calendar year DOC system SAIDI and how is compares to the target
- Charts displaying DOC system SAIDI, SAIFI and CAIDI over the past five year.
- Upcoming DOC reliability targets.

3.1.2 Excluded Events

The report shall include a list that details the excluded major events for the previous calendar year. For the purposes of this list an excluded major event is considered to be a MED for UES-Seacoast and/or UES-Capital and a Major Event (reference Unitil's *Electric Distribution System Reliability Procedure*, PR-DT-DS-04 for the FG&E Major Event definition) in FG&E. The Excluded Event list shall include the following:

- Date
- Type of Event

- Number of interruptions
- CI
- CMI

3.1.3 Worst Performing Circuits

The report shall include the following regarding worst performing distribution circuits.

3.1.3.1 Worst Distribution Circuits by CMI

A listing of the ten worst performing distribution circuits by CMI during the previous calendar year. For the purposes of this item subtransmission outages shall be removed from the data set and any circuit having one outage contributing more than 80% of CMI shall be removed from the ranking. The list(s) shall include the following:

- Circuit
- CI
- Worst event percent of CI of circuit
- CMI
- Worst event percent of CMI of circuit
- Circuit SAIDI, SAIFI and CAIDI
- CMI and number of outages for the six most prevalent outage causes for the DOC during the previous calendar year.

3.1.3.2 SAIDI and SAIFI Worst Performing Circuits

Listing of the ten worst performing circuits in terms of SAIDI and SAIFI for each of the past five years. This item is with the removal of exclusions, but shall include circuits having one outage contributing more than 80% of CMI.

Note 1: the removal of exclusions will exclude outages on the FG&E 69kV system.

Note 2: subtransmission outages on the UES system are included in the data for this item. Unless they are part of a MED.

3.1.3.3 Worst Performing Circuit past Five Years

List of the ten worst performing circuits in terms of SAIDI and SAIFI for the past five years. This list shall be created utilizing the average number of customers served, CI and CMI for each circuit over the five year period. This can be a direct data pull out of OMS SIENA report tool.

- The listing shall also indicate the number of times the circuit has been on the annual top ten list for each index over the past five years.

3.1.4 Subtransmission and Substation Outages

The report shall include the following data regarding subtransmission and substation outages. Excludable events shall be included when reporting on the subtransmission and substation outages. Any outage that occurred during a major event or MED shall be footnoted.

- For each outage:
  - Trouble location (line/substation)
  - Date of Outage
  - Cause
  - CI
  - CMI
  - Contribution to DOC SAIDI
  - Contribution to DOC SAIFI
  - Number of outages on the line/substation in the four years prior to the previous calendar year
- For each circuit affected by a subtransmission or substation outage:
  - Circuit
  - Trouble location(s) (line/substation)
  - Number of Events
  - CMI
  - Percent of Total Circuit CMI
  - Contribution to Circuit SAIDI

3.1.5 Worst Distribution Outages

The report shall include a table that details the ten worst outages that occurred on distribution circuits for the previous calendar year. The table shall include the following:

- Circuit
- Date of Outage
- Cause
- CI
- CMI
- Contribution to DOC SAIDI
- Contribution to DOC SAIFI

3.1.6 Outages by Cause

The report shall include the following data on outage causes:

- Charts displaying number of interruptions by cause, number of CI by cause and number of CMI by cause over the previous calendar year. The chart shall include data labels for the total number of each as well as the percentage of total for any cause than accounted for more than 3% of the total.
- Table showing the number of interruptions for the top three trouble causes in each year for the previous five years.

3.1.6.1 Tree Related Outages

- Table displaying the ten worst performing circuits due to tree related outages
- Table displaying any street with three or more tree related outages during the previous calendar year including the number of interruptions, CMI and CI for each location on the list.

3.1.6.2 Company Equipment Failures

- Table showing the number of interruptions caused by each type of equipment failure.
- Chart showing company equipment failures by percentage of total failures. Chart shall include data labels for the total number of each as well as the percentage of total for any cause than accounted for more than 3% of the total.
- Table showing the number of interruptions for the top three company equipment failure types in each year for the previous five years.

3.1.7 Multiple Device Operations

The report shall include a list of any protective device that has operated four or more times in the previous calendar. The list shall include the follow:

- Circuit
- Device Type
- Location
- Number of operations in previous calendar year
- CMI in previous calendar year
- CI in previous calendar year
- Number of times the device has been on this list in the four years prior to the previous calendar year.

3.1.8 Locations Experiencing the Highest Number of Outages

The report shall include a list that indicates the streets of the operating system that had customers that experienced seven or more non-exclusion events in the previous calendar year. The list shall include the following:

- Circuit
- Street
- Maximum number of outages experience by a single customer in previous calendar year
- Number of times the location has been on this list in the four years prior to the previous calendar year.

3.1.9 Previous System Reliability Projects

The report shall include a list that details the budgeted vegetation management and capital improvements projects that were not complete at the start of the previous calendar year and are expected to improve reliability for the following:

- Worst performing circuits identified in section 3.1.3 and the ten worst performing circuit due to tree related outages.
- Devices on the Multiple Device Operations List
- Locations identified in sections 3.1.8 and any street that experienced three or more tree related outages in the previous calendar year.

3.2 Reliability Improvement Recommendations

The annual reliability reports shall also propose reliability improvement projects that will be ranked per *Electric Distribution System Reliability Procedure* (PR-DT-DS-04) and evaluated based on cost, schedule, workload and other factors to determine what projects will be accepted in to the capital budget.

All reliability based projects proposed during the development of the annual reliability reports must include a justification that describes the scope of the project, estimated cost, and the anticipated number of CMI's and CI's saved annually. The method for calculating the anticipated annual CMI's and CI's is described in section 4 below.

The reliability improvement recommendations in the annual reliability report should focus on improving the circuits and areas below:

- Worst performing circuits over the past five years (Section 3.1.3.3)
- Subtransmission lines and/or substations that experienced an outage in the study year and two or more outages in the four years prior to the study year (Section 3.1.4).
- Devices on the multiple device operations list for the study year and that were on the list in any of the four years prior to the study year (Section 3.1.7).

- Locations on the locations experiencing the highest numbers of operations list for the study year and that were on the list in any of the four years prior to the study year (Section 3.1.8).
- Other areas of the system that engineering and/or operational judgement determines the need to develop a reliability improvement project(s).

Many of the areas above may have or will benefit from past or currently budgeted reliability projects. In these cases engineering judgement may be used to determine that no project will be proposed as part of the annual reliability study. In these cases a footnote should be added to the appropriate list indicating as such.

4.0 Calculating the Anticipated Annual CMI's and CI's

All reliability based projects proposed during the development of the annual and five year capital budget should include a justification that describes the scope of the project, estimated cost, and the anticipated number of CMI's and CI's saved annually. In general, the causes documented in the SIENA OMS reports for the previous five full calendar years shall be used as the basis for calculating the estimated future reliability benefits for any given project being considered. This methodology assumes that future reliability performance on any given circuit, or portion thereof, is accurately represented by its past performance. For example, this implies that it is anticipated that a circuit experiencing a high frequency of tree related outage troubles will continue to experience similar issues unless modifications are made to prevent these troubles from occurring or action is taken to reduce the number of customers affected.

A five year history was chosen to try to capture the full vegetation management cycle of five year. However, in some cases five years could be too long due to other improvements and modifications to the circuit(s). In these cases engineering judgement shall be used to determine the historical timeframe to be used for the development of the anticipated savings.

Since future reliability performance will be based on the previous five years and different improvement project will result in different benefits Unitil's Annual Reliability Projects Savings Calculators should be used when calculating anticipated annual reliability savings.

The calculated saving shall be included in the justification of the reliability project and documented in the annual reliability reports. A copy of each project's calculation spreadsheet shall be archived in the reliability study directory for the given year.

APPENDIX Q

DER PROJECTION GUIDELINE

Unitil	Guidelines	Procedure No.	GL-DT-DS-12
	Distribution Engineering	Page No.	Cover
		Revision No.	0
	Distributed Energy Resources Projection Guideline	Revision Date	3/12/2020
		Supersedes Date:	n/a

FOREWORD

The purpose of this document is to outline the Distributed Energy Resource (DER) projection process.

Any questions or inquiries regarding information provided in this document should be referred to the Manager, Distribution Engineering.

KES

3/16/2020

Kevin E. Sprague
Vice President, Engineering

Date

John J. Bonazoli

MAR. 16, 2020

John J. Bonazoli
Manager, Distribution Engineering

Date

REVISION HISTORY

Date of Review:

Revision #	Date	Description of Changes
0	3/12/2020	Initial Issue

Unitil	Guidelines	Procedure No.	GL-DT-DS-12
	Distribution Engineering	Page No.	TOC
		Revision No.	0
	Distributed Energy Resources Projection Guideline	Revision Date	3/12/2020
		Supersedes Date:	n/a

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Unitil	Guidelines	Procedure No.	GL-DT-DS-12
	Distribution Engineering	Page No.	1
		Revision No.	0
	Distributed Energy Resources Projection Guideline	Revision Date	3/12/2020
		Supersedes Date:	n/a

1.0 Introduction

1.1 Purpose

The intent of this document is to provide a guideline to assist Distribution Engineering personnel in the process of projecting the five year installed capacity of distributed energy resources for each distribution operating center and each distribution circuit and substation transformer.

The results of the DER projections should not be used as the sole justification for system upgrades, instead they are intended to be used as a tool to assist in determining when system upgrades could be needed.

This guideline is not intended to be an all-inclusive, step-by-step procedure and should not replace sound engineering judgment.

1.2 Applicability

This document applies to the projection of the capacity of distributed energy resources on distribution circuits operating at nominal primary voltages of 34.5kV or less and substation transformers operating at nominal primary voltages of 69kV or less. Additionally, this document details the procedure for projecting the capacity of distributed energy resources on each distribution operating system as a whole.

1.3 Responsibilities

This procedure is written and maintained by the Distribution Engineering Department to whom any questions relating to its content or application should be addressed.

1.4 Availability

Current copies of this procedure can be found on the Engineering Department Only Drive. Hard copies are not version controlled.

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

2.0 General Information

2.1 Abbreviations and Acronyms

DER	Distributed Energy Resources

2.2 Definitions

Utility Scale DER Facility	Any DER facility with a nameplate capacity of 1,000kW or more
Large DER Facility	Any DER facility with a nameplate capacity between 1,000kW and 250kW (including 250kW)
Medium DER Facility	Any DER facility with a nameplate capacity between 250kW and 60kW
Small DER Facility	Any DER facility with a nameplate capacity of 60kW or less

3.0 Scope

To assist with the analysis of DER interconnection application review and support the need for system upgrades due to DER penetration five year DER forecasts shall be developed annually for each distribution operating company. DER forecast shall include forecasts for each distribution circuit and distribution substation transformer as well as overall system forecasts.

The process for forecasting DER penetration requires the development of five year projections for the installations of small DER facilities. These projections are then added to all sizes of DER facilities that are installed or approved for installation at the time the projections are developed to create an overall DER capacity projection for each distribution circuit, distribution substation transformer and the overall system. Overall system DER capacity projections also include the projected penetration of medium and large DER facilities.

Due to the limited number of medium and large facilities and the uncertainty of where these facilities may be located it was determined that these would not be included in the circuit and substation transformer DER projections. Similarly, circuit, substation transformer and system projections will not include the forecasting of utility scale facilities. Instead these facilities will be treated similarly to how new large customer load additions are incorporated into distribution load projections in that they will be added to the DER projections per the customer schedule and engineering judgement.

The DER forecasts are then compared to the rating of the limiting equipment to assist in determining when system upgrades could be needed.

It is important to note that these projections are utilized for planning purposes to assist in the direction of system improvements and are not a “prediction” of specific DER capacity levels that will ultimately be experienced.

4.0 Forecasting Methodology

It is understood that the DER forecasting methodology described below is conservative. In the event that these projections indicate the need for system improvements, additional analysis shall be performed and field measurements (application of load loggers, installation of additional metering, etc.) taken to determine the severity of the identified concern.

4.1 Distribution Circuit DER Projections

Distribution DER projections are developed using two similar methods and utilizing the higher result of the two methods as the ultimate DER projection for each circuit.

<u>Method 1 – Projection Based on Nominal DER Capacity:</u>

Method 1 utilizes the nominal capacity of small DER facilites installed on the circuit and "normalizes" this to the three year historical circuit peak load. A five year and three year historical slope is calculated based on the five year normalized DER capacity growth on the circuit. This is done for all distribution circuits on each of Unitil's distribution operating systems.

Based on the calculated slopes engineering judgement is used to create four growth rate ranges for each distribution operating company.

- N – slope of zero
- L – flat slope
- M – moderate slope
- A – aggressive slope

Each circuit is assigned a historical growth rate. Based on the historical growth rates future growth rates are calculated for each of the rate types. The future rate for each type is the maximum of the three year average and five year average of each historical rate of that rate type.

After reviewing the assigned historical rate type for both the three year and five year slopes engineering judgement is used to assign the desired future growth rate (slope) to each circuit. This slope is then used to calculate the additional amount of small DER that is projected on each circuit. This is added to the total amount of DER installed and approved for installation on each circuit to get the final method 1 projection.

<u>Method 2 – Projection Based on Number of DER Facilities Installed:</u>

Method 2 is very much the same as method 1 with one exception.

Method 2 Utilizes the number of small DER facilities on each circuit and "normalizes" this to the average number of customers supplied by each circuit. The same process described in method 1 is then used to forecast the number of small units that will be installed on the circuit. The projected number of units is then multiplied by the five year average size of a small unit to determine the forecasted capacity of small DER facilities for each circuit. This is added to the total amount of DER installed and approved for installation on each circuit to get the final method 2 projection.

4.2 Distribution Substation Transformer DER Projections

DER projections for distribution substation transformers should be calculated for both method 1 and method 2 above by summing the DER projections or each of the circuits supplied by the transformer. The ultimate substation transformer DER projection shall be the higher of the method 1 and method 2 projections.

4.3 System DER Projections

DER projections for each distribution operating system shall be calculated in the same manner as distribution circuit DER projections utilizing system-wide data opposed to individual circuit information.

Once the projection of small DG facilities in determine and added to the total amount of installed and approved for installation DER facilities the projected capacity of medium and large DER facilities is added to the projection determine the ultimate system projection.

The projected yearly capacity of medium and large DER facilities should be growth rate (slope) calculated from the previous five years of medium and large facility installations. In the event five years of data establishes an unrealistic or negative slope then engineering judgement shall be used to determine if a three year slope, yearly historical average or other method is used to calculate the projected yearly capacity of medium and large DER facilities that will be added to each year to get the ultimate system projection.

APPENDIX R

UES-CAPITAL DER PROJECTIONS

UES-Capital
DER Projections 2020-2024

Circuit/Xfmr	DER Nominal Capacity Projection (kW)				
	2020	2021	2022	2023	2024
1T1	29	39	50	61	71
1H3	25	34	43	51	60
1H4	3	4	6	7	8
1H5	5	7	9	12	14
1T2	129	142	156	169	182
1H1	54	59	64	69	74
1H2	8	11	15	19	23
1H6	68	72	76	81	85
1X7P	6	10	13	16	19
2T1	112	136	159	182	206
2H1	14	21	28	35	42
2H2	90	106	121	137	152
2H4	10	12	13	15	17
3T1	43	59	75	91	106
3H1	26	33	40	48	55
3H2	17	26	34	43	51
3T2	43	45	46	48	49
3H3	43	45	46	48	49
4X1	7,944	7,973	8,001	8,029	8,058
4T3	585	675	765	855	945
4W3	347	407	467	528	588
4W4	238	268	298	327	357
6X3	128	184	239	295	350
7X1	5	7	9	12	14
7T2	220	322	425	528	630
7W3	185	272	359	445	532
7W4	35	51	67	82	98
8T1	37	51	64	78	91
8H1	18	27	36	46	55
8H2	19	23	28	32	36
8X3	679	747	815	883	951
8X5	469	482	495	507	520
13T1	477	519	561	603	645
13W1	366	387	409	430	452
13W2	117	141	164	188	212
13T2	469	540	611	681	752
13W3	469	540	611	681	752
13X4	0	0	0	0	0
14T1	68	80	91	102	113
14H1	3	4	6	7	9
14H2	65	75	85	95	105
14X3	0	0	0	0	0
15T1	280	322	365	407	449
15W1	245	283	320	358	395

UES-Capital
DER Projections 2020-2024

Circuit/Xfmr	DER Nominal Capacity Projection (kW) 2020	2021	2022	2023	2024
15W2	35	40	45	49	54
15T2	35	36	37	38	38
15H3	35	36	37	38	38
16T1	61	77	92	108	124
16H1	37	43	50	56	63
16H3	24	33	43	52	61
16X4	121	129	138	146	154
16X5	0	0	0	0	0
16X6	0	0	0	0	0
18T2	431	480	529	578	627
18W2	431	480	529	578	627
21T1	28	28	28	28	28
21W1P	28	28	28	28	28
21W1A	0	0	0	0	0
22T1	473	547	620	693	767
22W1	95	102	110	117	124
22W2	4	5	6	6	7
22W3	379	447	515	583	650
23T1	28	28	28	28	28
21W1P	28	28	28	28	28
21W1A	0	0	0	0	0
24T1	9	14	18	23	28
24H1	9	14	18	23	28
24T2	11	16	22	27	33
24H2	11	16	22	27	33
24H3	5	7	9	12	14
33X4	60	63	65	68	70
37X1	4,981	4,987	4,992	4,998	5,003
38E	217	233	249	265	282

System	35,258	35,952	36,647	37,341	38,036

APPENDIX S

UES-SEACOAST DER PROJECTIONS

UES-Seacoast
DER Projections 2020-2024

Circuit/Xfmr	DER Nominal Capacity Projection (kW)				
	2020	2021	2022	2023	2024
15X1	145	159	173	187	201
56X2	8	12	16	20	24
20T1	24	29	34	40	45
20H1	24	29	34	40	45
6T1	449	491	533	575	617
6W1	311	338	364	391	417
6W2	138	154	169	184	200
1T1	57	67	78	88	99
1T2	57	67	78	88	99
1H3	36	41	46	51	56
1H4	21	26	32	38	44
19T1	41	45	50	55	59
19H1	41	45	50	55	59
19X2	26	36	45	55	64
19X3	771	836	902	967	1,032
47X1	304	356	408	459	511
18X1	245	279	313	347	381
2T1	18	23	28	33	39
2H1	18	23	28	33	39
2X2	93	110	128	146	163
2X3	60	70	81	91	101
3T3	96	115	133	151	170
3W1	49	57	65	73	81
3W4	47	58	68	79	89
17T1	124	140	155	170	186
17W1	98	110	121	133	144
17W2	26	30	34	38	42
56X1	52	56	61	66	70
22X1	371	409	448	486	525
22X2	24	27	29	32	35
23X1	455	470	486	501	517
28X1	115	119	122	125	128
54X	248	283	319	354	390
54X1	112	125	138	150	163
54X2	148	177	206	235	264
5X3	80	87	95	102	110
11X	410	472	533	594	656
11X1	266	314	363	411	459
11X2	177	206	236	265	295
7T1	53	61	69	77	85
7W1	53	61	69	77	85
7X2	120	132	143	154	165
27X	216	236	256	275	295
27X1	134	149	164	179	193

UES-Seacoast
DER Projections 2020-2024

Circuit/Xfmr	DER Nominal Capacity Projection (kW)				
	2020	2021	2022	2023	2024
27X2	82	87	92	97	102
59X1	166	181	196	210	225
13T1	329	356	383	409	436
13W1	68	76	83	91	98
13W2	261	280	299	318	338
13X3	227	229	231	234	236
21T1	129	140	152	163	174
21W1	129	140	152	163	174
21T2	119	129	138	148	158
21W2	119	129	138	148	158
58X1	244	266	288	309	331
43X1	484	554	624	694	764
46X1	51	59	66	73	81
51X1	294	318	342	366	390

System	7,349	8,097	8,845	9,594	10,342

APPENDIX T

UES-CAPITAL RELIABILITY STUDY 2019

UES Capital

Reliability Study

2019

Prepared By:
T. Glueck
Unitil Service Corp.
10/28/2019

Table of Contents

1 Executive Summary

The purpose of this document is to report on the overall reliability performance of the UES Capital system from January 1, 2018 through December 31, 2018. The scope of this report will also evaluate individual circuit reliability performance over the same time period. The outage data used in this report excludes the data in Section 5 (sub-transmission and substation outages), as well as outage data from IEEE Major Event Days (MEDs). UES-Capital MEDs are listed in the table below:

Date	Type of Event	Interruptions	Customer Interruptions	Cust-Min of Interruption
5/4/2018	Thunderstorm	33	3082	1,438,447
6/18/2018	Thunderstorm	27	11351	1,726,076

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 2020 budget development process.

Circuit / Line / Substation	Proposed Project	Cost ($)
15W1	Install Recloser on Mountain Rd	$32,401
8X3	Replace Hydraulic Recloser on Main St	$35,967
8X5	Install Recloser on Regional Dr	$34,531
6X3	Install Recloser on Pleasant St	$31,492
4W4	Install Recloser and Switches on Fisherville Rd	$85,802
Various	Fusesaver Installations	$143,506

Note: estimates do not include general construction overheads

UES Capital SAIDI was 127.48 minutes in 2018 after removing Major Event Days. The UES Capital target was 130 minutes. Charts 1, 2, and 3 below show UES Capital SAIDI, SAIFI, and CAIDI, respectively, over the past five years.

Chart 1
Annual Capital SAIDI

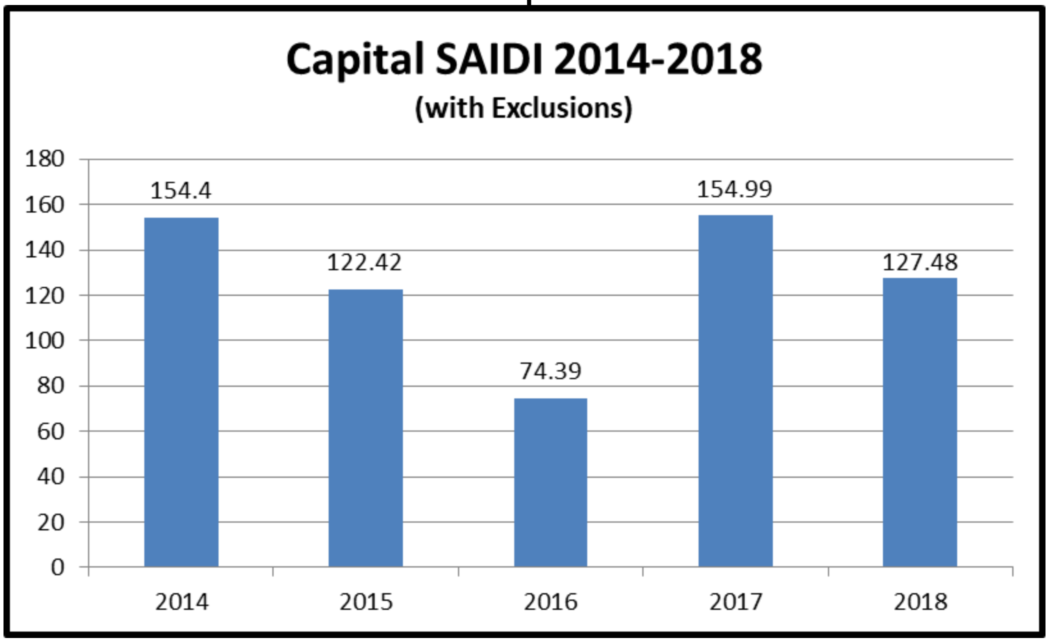


Chart 2
Annual Capital SAIFI

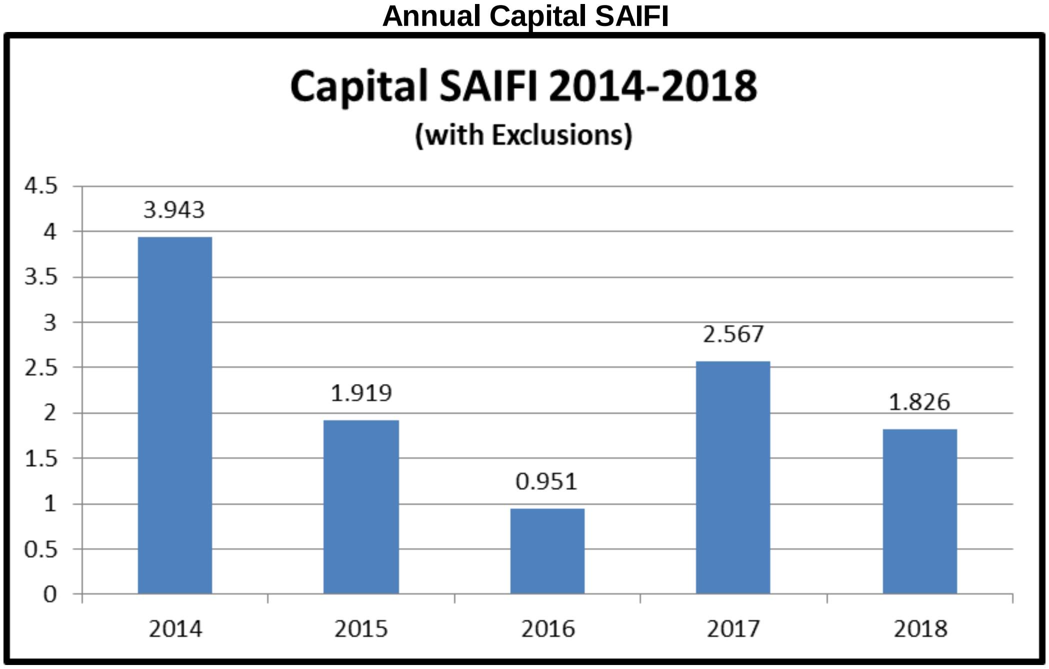
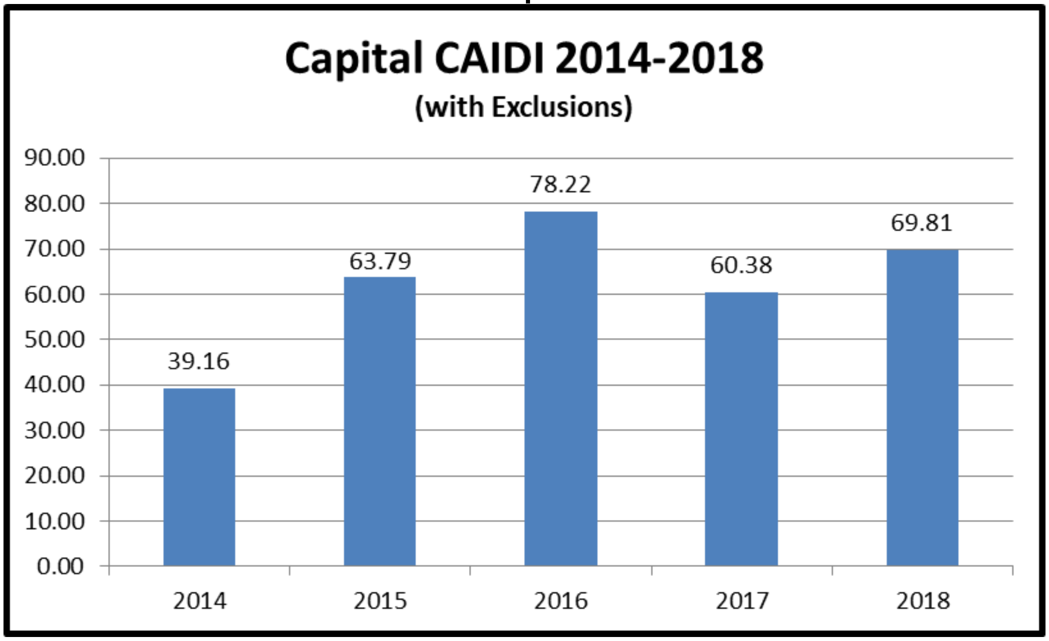


Chart 3
Annual Capital CAIDI



2 Reliability Goals

The annual UES Capital system reliability goal for 2019 has been set at 147.45 SAIDI minutes. This was developed by calculating the contribution of UES Capital to the Unitil system performance using the past five year average. The contribution factor was then set against the 2019 Unitil System goal. The 2019 Unitil System goal was developed through benchmarking the Unitil system performance with nationwide utilities.

Individual circuits will be analyzed based upon circuit SAIDI, SAIFI, and CAIDI. Analysis of individual circuits along with analysis of the entire UES 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 2018. Charts 4, 5, and 6 show the number of interruptions, the number of customer interruptions, and total customer-minutes of interruptions due to each cause, respectively. Only the causes contributing 3% or greater of the total are labeled. Table 1 shows the number of interruptions for the top three trouble causes for the previous five years.

Chart 4
Number of Interruptions by Cause

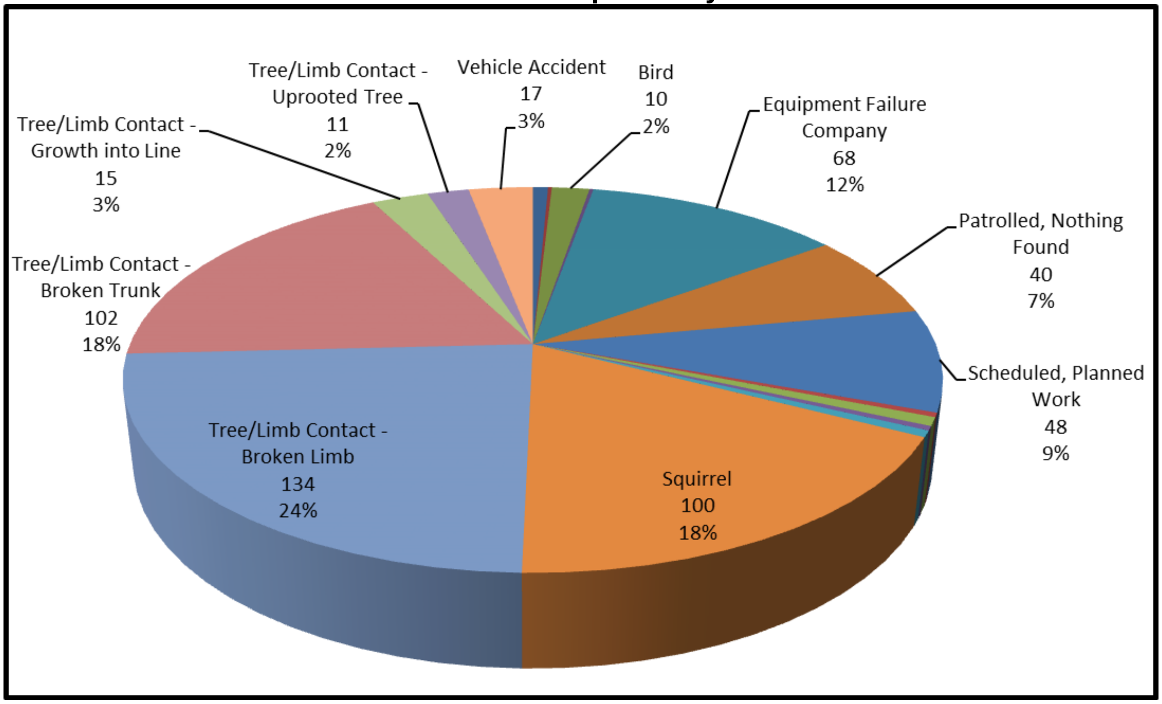


Chart 5
Number of Customer Interrupted by Cause

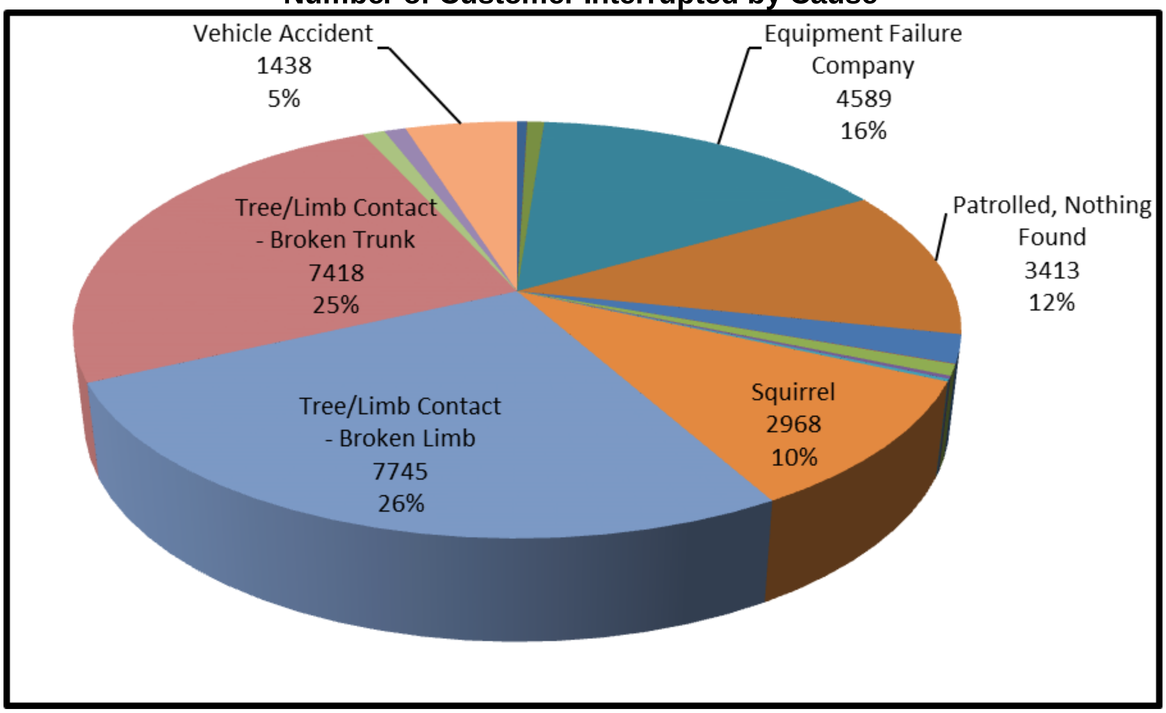


Chart 6
Percent of Customer-Minutes of Interruption by Cause

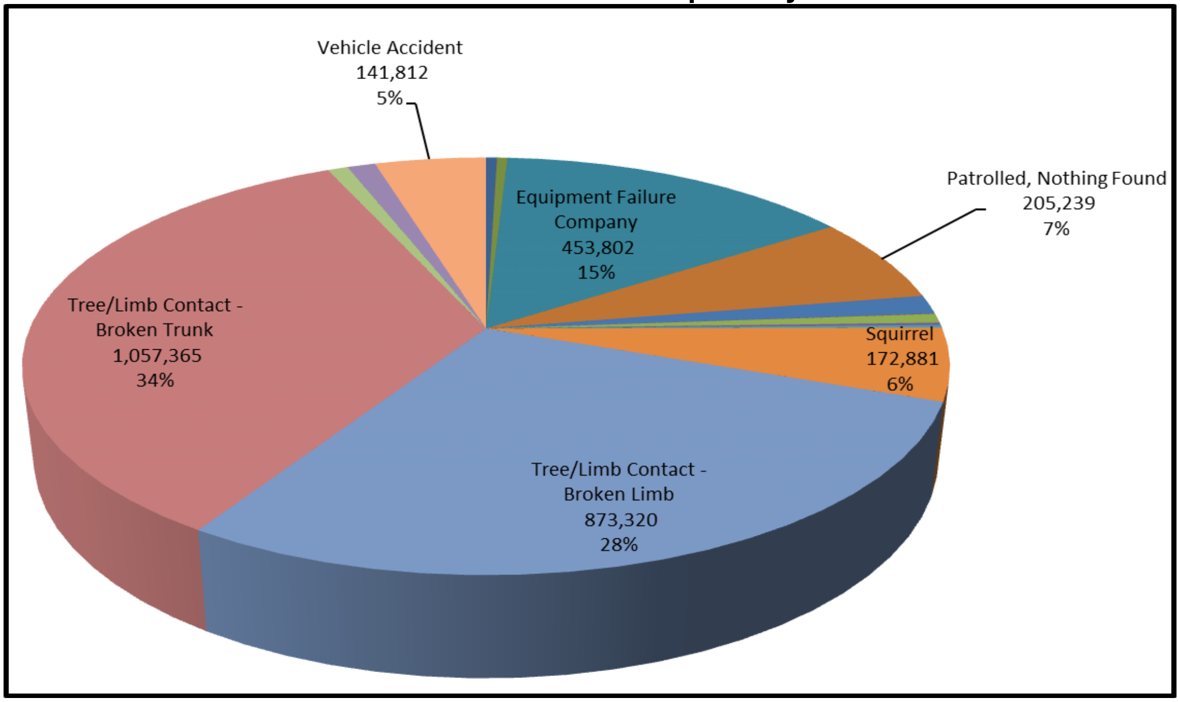


Table 1
Five-Year History of the Number of
Interruptions for the Worst Three Trouble Causes

Year	Tree/Limb Contact - Broken Limb	Tree/Limb Contact - Broken Trunk	Squirrel
2014	117	37	53
2015	134	44	53
2016	117	34	93
2017	86	37	112
2018	134	102	100

4 10 Worst Distribution Outages

The ten worst distribution outages ranked by customer-minutes of interruption during the time period from January 1, 2018 through December 31, 2018 are summarized in Table 2 below.

Table 2
Worst Ten Distribution Outages

Circuit	Description (Date/Cause)	No. of Customers Affected	No. of Customer Minutes	Capital SAIDI (min.)	Capital SAIFI
C13W3	11/10/2018 Tree/Limb Contact - Broken Trunk	1,615	155,709	5.13	0.053
C8X3	04/16/2018 Tree/Limb Contact - Broken Limb	1,139	140,192	4.62	0.038
C22W3	07/15/2018 Tree/Limb Contact - Broken Trunk	915	133,491	4.40	0.030
C13W3	07/10/2018 Tree/Limb Contact - Broken Trunk	401	92,484	3.05	0.013
C8X3	02/17/2018 Equipment Failure Company	892	70,914	2.34	0.029
C13W2	05/22/2018 Patrolled, Nothing Found	1,480	68,198	2.25	0.049
C38	07/21/2018 Equipment Failure Company	155	66,082	2.18	0.005
C13W2	07/10/2018 Tree/Limb Contact - Broken Limb	240	63,600	2.09	0.008
C13W3	01/23/2018 Tree/Limb Contact - Broken Limb	585	59,085	1.95	0.019
C15W2	12/17/2018 Tree/Limb Contact - Broken Trunk	251	57,547	1.90	0.008

Note: This table does not include outages that occurred at substations or on the subtransmission system, scheduled/planned work outages, or outages that occurred during excludable events.

5 Subtransmission and Substation Outages

This section describes the contribution of sub-transmission line and substation outages on the UES Capital system.

All substation and sub-transmission outages ranked by customer-minutes of interruption during the time period from January 1, 2018 through December 31, 2018 are summarized in Table 3 below.

Table 4 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 24% of the total customer-minutes of interruption for UES Capital.

Table 3
Subtransmission and Substation Outages

Trouble Location	Description (Date/Cause)	No. Customers Affected	No. of Customer Minutes	UES CAPITAL SAIDI (min)	UES Capital SAIFI	No. Times on List (past 4 yrs)
Line 38	12/17/2018 Tree/Limb Contact - Broken Limb	1,804	253,850	8.39	0.059	4
Line 34	11/06/2018 Tree/Limb Contact - Uprooted Tree	1,715	246,325	8.11	0.056	2
Line 35	02/16/2018 Equipment Failure Company	1,279	122,558	4.04	0.042	1
Line 34	07/04/2018 Tree/Limb Contact - Broken Trunk	1,710	90,674	2.99	0.056	2
Line 36	02/16/2018 Equipment Failure Company	10	410	0.01	0.000	0

Table 4
Contribution of Subtransmission and Substation Outages

Circuit	Trouble Location	Customer-Minutes of Interruption	% of Total Circuit Minutes	Circuit SAIDI Contribution	Number of Events
C2H4	Line 33 / Line 34	43,483	90%	836.21	2
C2H1	Line 33 / Line 34	69,631	100%	144.76	1
C33X4	Line 33 / Line 34	9,536	99%	146.71	2
C2H2	Line 33 / Line 34	211,208	88%	198.69	2
C33X5	Line 33 / Line 34	447	100%	149.00	2
C33X3	Line 33 / Line 34	149	100%	149.00	2
C33X6	Line 33 / Line 34	149	73%	3.73	2
C34X2	Line 33 / Line 34	2,025	100%	225.00	2
C34X4	Line 33 / Line 34	372	100%	371.80	2
C1X7P	Line 1X7P	349	100%	43.57	1
C21W1P	Line 1X7P	18,656	82%	43.49	3
C35X2	Line 36 / Line 35	644	100%	161.00	2
C35X3	Line 36 / Line 35	805	100%	161.00	2
C35X4	Line 36 / Line 35	161	100%	161.00	2
C15W2	Line 35	23,940	21%	72.33	1
C15W1	Line 35	94,145	74%	94.90	1
C15H3	Line 35	1,425	100%	95.00	1
C35X1	Line 35	1,848	100%	123.20	1

*Note that 2H1 and 2H4 were tied during some of the outages, which effects their event totals.

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 sub-transmission or substation supply outages unless noted otherwise.

6.1 Worst Performing Circuits in Past Year (1/1/18 – 12/31/18)

A summary of the worst performing circuits during the time period between January 1, 2018 and December 31, 2018 is included in the tables below.

Table 5 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 6 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 during 2018.

Circuits having one outage contributing more than 80% of the Customer-Minutes of interruption were excluded from this analysis.

Table 5
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
C13W3	8,906	18%	857,816	18%	532.47	5.528	96.32
C8X3	4,223	27%	470,644	30%	164.27	1.474	111.45
C22W3	4,679	34%	387,272	34%	242.20	2.926	82.77
C13W2	3,881	38%	359,001	19%	327.56	3.541	92.50
C38	754	21%	142,781	46%	128.52	0.679	189.37
C7W3	1,248	14%	129,571	27%	142.86	1.376	103.82
C4W3	1,541	30%	116,834	29%	73.62	0.971	75.82
C18W2	1,061	20%	97,330	16%	83.62	0.912	91.73
C15W2	517	49%	88,754	65%	268.14	1.562	171.67
C13W1	801	16%	75,936	13%	155.29	1.638	94.80

Note: all percentages and indices are calculated on a circuit basis

Table 6
Circuit Interruption Analysis by Cause

Circuit	Customer – Minutes of Interruption / # of Outages					
	Tree/Limb Contact - Broken Trunk	Tree/Limb Contact - Broken Limb	Equipment Failure Company	Patrolled, Nothing Found	Vehicle Accident	Squirrel
C13W3	490,316 / 29	218,235 / 37	2,483/ 6	54,908 / 10	29,058 / 4	12,812 / 13
C8X3	69,595 / 20	244,196 / 33	94,108/ 12	14,261 / 7	411 / 1	29,420 / 24
C22W3	245,240 / 9	79,321 / 16	22,258 / 9	9,999 / 3	0 / 0	7,452 / 9
C13W2	73,965 / 12	184,454 / 10	4,375 / 2	68,312 / 2	0 / 0	8,176 / 4
C38	1,408 / 2	1,602 / 2	131,284 / 6	7,065 / 1	0 / 0	0 / 0
C7W3	17,177 / 4	25,329 / 4	18,643 / 4	335 / 1	59,533 / 2	7,280 / 4
C4W3	0 / 0	17,452 / 4	40,990 / 4	68 / 1	36,204 / 4	14,067 / 4
C18W2	50,273 / 8	12,296 / 5	135 / 1	1,192 / 1	0 / 0	33,056 / 13
C15W2	57,546 / 1	3,296 / 1	4,017 / 2	0 / 0	0 / 0	7,292 / 4
C13W1	25,406 / 9	18,208 / 7	1450 / 3	7,839 / 4	13,955 / 2	2,764 / 6

6.2 Worst Performing Circuits of the Past Five Years (2014 – 2018)

The annual performance of the ten worst circuits in terms of circuit SAIDI and SAIFI for each of the past five years is shown in the tables below. Table 7 lists the ten worst performing circuits ranked by SAIDI and Table 8 lists the ten worst performing circuits ranked by SAIFI. Table 9 lists the ten worst performing circuits ranked by SAIDI and SAIFI over the past five years.

The data used in this analysis includes all system outages except those outages that occurred during the 2016 July Wind/Thunder storm, 2014 November Cato Snowstorm, 2017 March Windstorm, 2017 October Tropical Storm, 2018 May Windstorm, and 2018 June Thunderstorm.

The data used in this analysis includes all distribution circuits except those that do not have an interrupting device, e.g. fuse or recloser, at their tap location.

Table 7

Circuit SAIDI

Circuit Ranking (1 = worst)	2018		2017		2016		2015		2014	
	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI
1	C13W3	532.47	C13W2	577.74	C21W1A	892.82	C21W1A	803.71	C15W2	794.83
2	C13W2	327.55	C18W2	560.64	C7W3	272.49	C34X2	399.45	C22W3	729.57
3	C15W2	268.13	C13W1	555.75	C34X2	244.80	C13W3	357.44	C35X1	573.63
4	C22W3	242.19	C13W3	496.50	C37X1	176.22	C375X1	318.05	C24H1	570.48
5	C21W1A	166.73	C396X2	454.70	C18W2	155.42	C14H2	288.10	C24H2	545.14
6	C8X3	164.27	C17X1	410.37	C15W1	147.96	C16X4	281.37	C22W1	534.36
7	C13W1	155.28	C16H3	403.03	C4X1	146.38	C16H1	281.30	C22W2	512.65
8	C7W3	142.85	C8X3	326.03	C13W1	140.76	C7W3	281.18	C15W1	499.87
9	C38	128.51	C33X4	246.98	C22W3	136.51	C16H3	280.82	C7W3	444.56
10	C2H4	87.84	C8H2	246.67	C13W3	117.09	C16X5	280.05	C38W	441.97

Table 8
Circuit SAIFI

Circuit Ranking (1 = worst)	2017		2016		2015		2014		2013	
	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI
1	C2H4	10.981	C13W2	6.694	C21W1A	3.993	C21W1A	6.356	C24H1	7.143
2	C13W3	5.528	C13W1	5.818	C37X1	2.418	C16X4	5.023	C24H2	6.987
3	C13W2	3.541	C13W3	5.267	C18W2	1.995	C16H1	5.020	C15W2	6.597
4	C22W3	2.926	C16H3	4.693	C15W1	1.938	C16X5	5.000	C22W3	5.832
5	C8X5	1.795	C18W2	4.131	C13W1	1.785	C16X6	5.000	C3H1	4.251
6	C13W1	1.638	C8H2	3.122	C1X7P	1.778	C375X1	5.000	C22W1	4.034
7	C15W2	1.562	C8X3	3.108	C4X1	1.738	C16H3	4.998	C38W	4.022
8	C8X3	1.474	C17X1	3.000	C22W3	1.509	C7W3	4.850	C22W2	4.000
9	C7W3	1.376	C396X2	3.000	C7W3	1.396	C13W3	4.567	C7W3	3.982
10	C21W1A	1.239	C37X1	2.770	C13W3	1.348	C18W2	4.127	C14X3	3.500

Table 9

Worst Performing Circuit past Five Years

SAIDI			SAIFI		
Circuit Ranking	**Circuit**	**# Appearances**	**Circuit Ranking**	**Circuit**	**# Appearances**
1	C13W3	4	**1**	C21W1A	3
2	C21W1A	3	**2**	C13W1	3
3	C13W2	2	**3**	C13W3	4
4	C15W2	2	**4**	C13W2	2
5	C22W3	3	**5**	C22W3	3
6	C34X2	2	**6**	C18W2	3
7	C7W3	4	**7**	C15W2	2
8	C13W1	3	**8**	C16H3	2
9	C18W2	2	**9**	C24H1	1
10	C15W1	2	**10**	C2H4	1

6.3 System Reliability Improvements (2018 and 2019)

Vegetation management projects completed in 2018 or planned for 2019 that are expected to improve the reliability of the 2018 worst performing circuits are included in table 10 below. Table 11 below details electric system upgrades that are scheduled to be completed in 2019, or were completed in 2018, that were performed to improve system reliability.

Table 10
Vegetation Management Projects on Worst Performing Circuits

Circuit(s)	Year of Completion	Project Description
C13W3	2018	Planned Cycle Pruning
C13W2	2018	Planned Cycle Pruning & Hazard Tree Mitigation
C38	2019	Planned Cycle Pruning
C7W3	2018	Planned Hazard Tree Mitigation / Mid-Cycle Pruning
C4W3	2018 / 2019	Planned Reliability Analysis / Planned Mid-Cycle Pruning
C18W2	2019	Planned Mid-Cycle Pruning
C15W2	2018	Planned Mid-Cycle Pruning & Hazard Tree Mitigation
C13W1	2018 / 2019	Planned Reliability Analysis / Planned Cycle Pruning

Table 11
Electric System Improvements Performed to Improve Reliability

Circuit(s)	Year of Completion	Project Description
18W2	2018	Microprocessor Controlled Recloser Installation
13W3	2018	Sectionalizer Replacement (increased zone of protection)
8X3	2018	Fusesaver Installation
18W2	2019	Microprocessor Controlled Recloser Installation
18W2	2019	Fusesaver Installation
13W3	2019	Hydraulic Recloser Replacement (for coordination)
VARIOUS	2019	Porcelain Cutout Replacements
8X3 and 8X5	2019	New Circuit Tie
38	2019	UG Cable Injection
16H3	2019	UG Cable Injection
2H2	2019	Spacer Cable Replacement
1H2 and 1H3	2019	Replace Switchgear and add Tie
VARIOUS	2019	Animal Guard Installation
396X1	2019	Microprocessor Controlled Recloser Installation

7 Tree Related Outages in Past Year (1/1/18 – 12/31/18)

This section summarizes the worst performing circuits by tree related outage during the time period between January 1, 2018 and December 31, 2018.

Table 12 shows the ten worst circuits ranked by the total number of Customer-Minutes of interruption. The number of customer-interruptions and number of outages are also listed in this table.

All streets on the UES CAPITAL system with three or more tree related outages are shown in Table 13 below. The table is sorted by number of interruptions and customer-minutes of interruption.

Table 12
Worst Performing Circuits – Tree Related Outages

Circuit	Customer-Minutes of Interruption	Number of Customers Interrupted	No. of Interruptions
C13W3	714,927	5,624	72
C22W3	327,711	3,945	27
C8X3	321,818	2,399	55
C13W2	269,881	2,177	25
C15W2	63,370	303	5
C18W2	62,570	558	13
C13W1	44,275	392	17
C7W3	42,656	492	10
C7W4	32,542	505	3
C15W1	26,856	391	4

Table 13
Multiple Tree Related Outages by Street

Circuit	Street, Town	# Outages	Customer-Minutes of Interruption	No. of Customer Interruptions
C13W3	Old Turnpike Rd, Salisbury	10	210,337	1,278
C13W3	Daniel Webster Hwy, Boscawen	6	36,500	221
C13W1	Borough Rd, Canterbury	6	20,531	145
C13W3	Battle St, Webster	5	58,423	545
C8X3	New Orchard Rd, Epsom	4	32,119	98
C8X3	Swamp Rd, Epsom	4	19,503	218
C13W3	Mutton Rd, Webster	4	9,865	88
C38	Curtisville Rd, Concord	4	3,011	48
C13W3	High St, Boscawen	3	158,343	1,624
C13W3	White Plains Rd, Webster	3	37,120	324
C13W3	Corn Hill Rd, Boscawen	3	33,806	226
C18W2	Morse Rd, Dunbarton	3	33,728	263
C13W1	Pickard Rd, Canterbury	3	18,139	135
C13W3	Warner Rd, Salisbury	3	15,494	101
C22W3	Page Rd, Bow	3	15,220	118
C13W2	Elm St, Penacook	3	14,904	154
C13W1	Morrill Rd, Canterbury	3	14,497	121
C13W3	Whittemore Rd, Salisbury	3	5,839	67
C13W3	Battle St, Salisbury	3	5,469	84
C15W2	W. Portsmouth St, Concord	3	5,095	45
C13W1	Hackleboro Rd, Canterbury	3	2,986	46
C8X3	Sanborn Hill Rd N., Epsom	3	2,591	21
C13W1	Wilson Rd, Canterbury	3	2,410	22
C22W3	Brown Hill Rd, Bow	3	965	4

During 2018, 13W1, 13W2, and 13W3 was undergoing cycle pruning. These circuits will be re-evaluated in next years' study now that forestry has completed the work in these areas. In the meantime, all of these streets have been given to the forestry team to do hazard tree mitigation. Additionally, a new outage mapping program has been created. This will assist the forestry group to identify problem areas, particularly for hazard tree mitigation. Finally, projects to add reclosing to heavily treed circuits are being proposed for the 2020 budget.

8 Failed Equipment

This section is intended to clearly show all equipment failures throughout the study period from January 1, 2018 through December 31, 2018. Chart 7 shows all equipment failures throughout the study period. Chart 8 shows each equipment failure as a percentage of the total failures within this same study period. The number of equipment failures in each of the top three categories of failed equipment for the past five years are shown below in Chart 9.

Chart 7
Equipment Failure Analysis by Cause

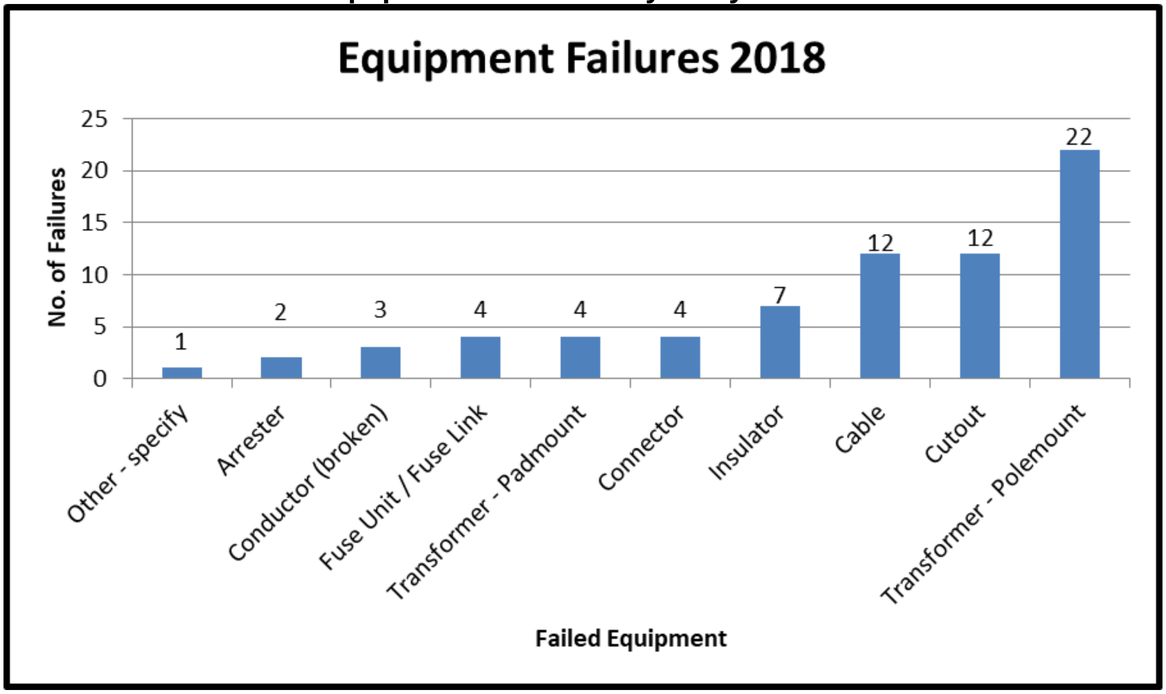


Chart 8
Equipment Failure Analysis by Percentage of Total Failures

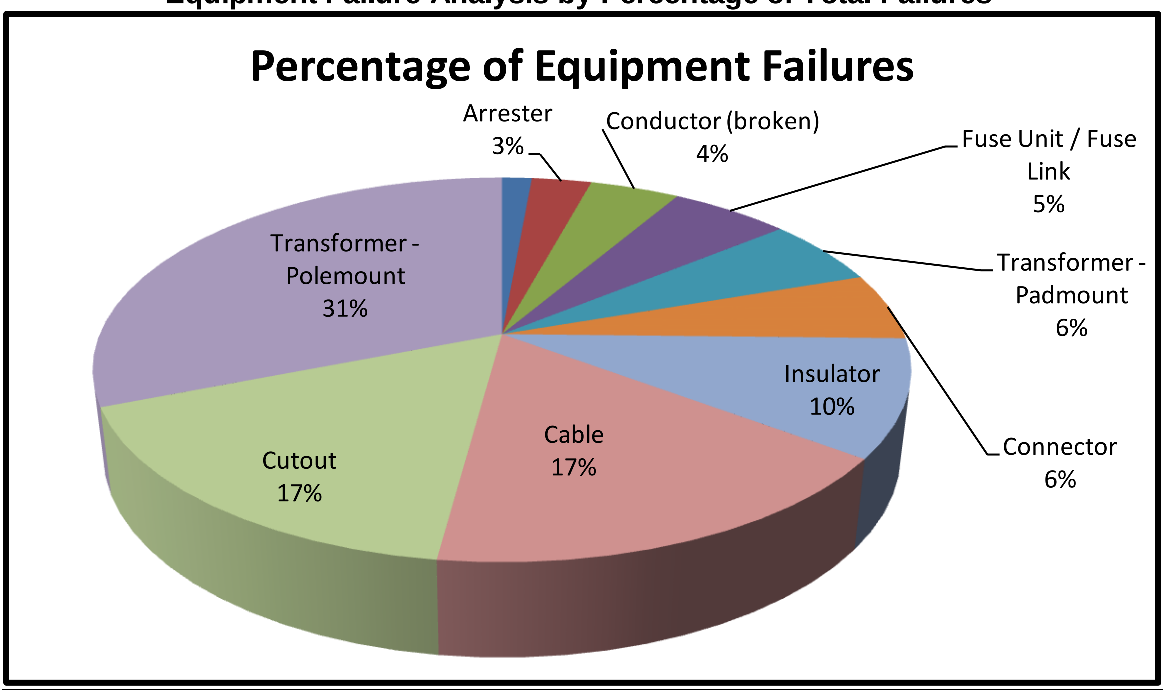
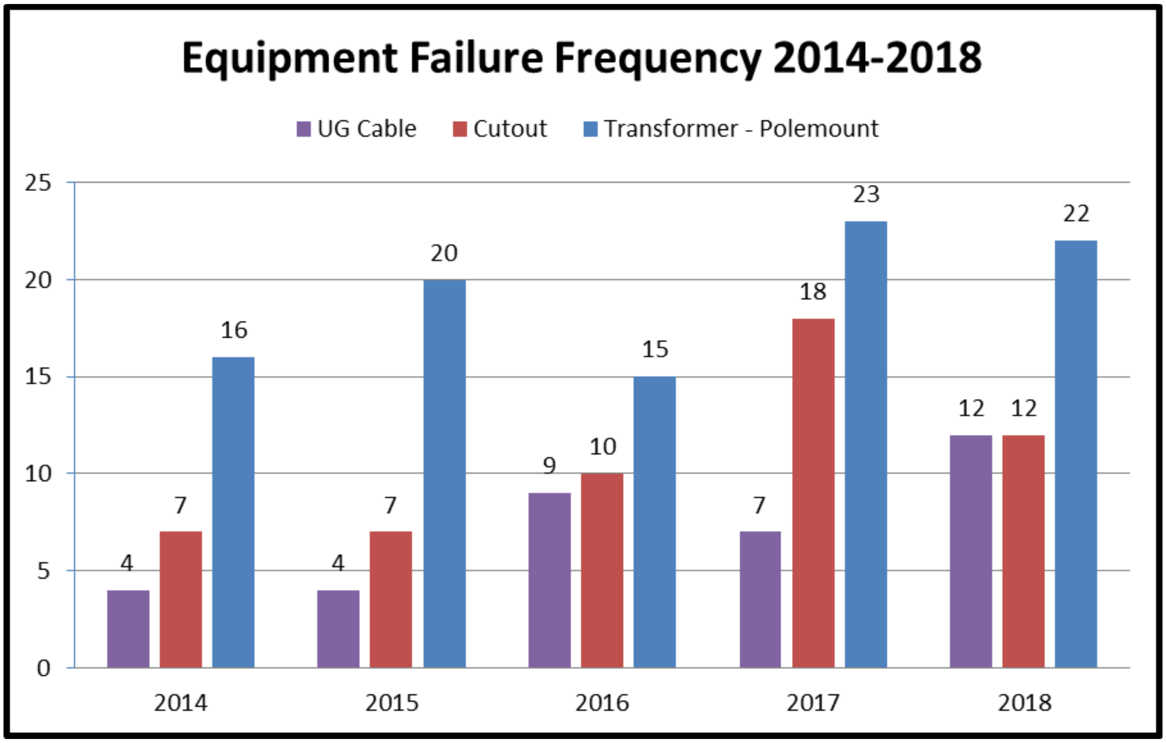


Chart 9
Annual Equipment Failures by Category (top three)

The top three equipment failures continue to be underground cable, cutouts, and polemount transformers. Underground cable failures have generally increased over the last five years. Two life-extending cable injections were executed in 2019. Additional cable injections and direct-buried cable replacement projects are planned for 2020-2021. Cutout failures experienced a slight reprieve in 2018; however they have trended upward over the course of five years. A porcelain cutout replacement program is planned for 2019-2021. Polemount transformer failures continue to be the highest rate of failure with a general, five-year upward trend. There is no planned program to address the transformer failure.



9 Multiple Device Operations and Streets with Highest Number of Outages

A summary of the devices that have operated four or more times from January 1, 2018 to December 31, 2018 are included in table 14 below. Refer to section 11 for project recommendations that address some of the areas identified.

A summary of the streets on the UES Capital system that had customers with 7 or more non-exclusionary outages in 2018 is included in Table 15 below. The table is sorted by circuit and then the maximum number of outages seen by a single customer on that street.

Table 14
Multiple Device Operations

Circuit	Device	Number of Operations	Customer Minutes	Customer Interruptions	# of Times on List in Previous 4 Years
C38	Fuse, Pole 25, Line 38 - East, Concord	5	121,042	716	0
C13W2	Fuse, Pole 50, Borough Rd, Canterbury	5	18,209	98	0
C13W3	Fuse, Pole 145, Old Turnpike Rd, Salisbury	5	10,234	105	0
C15W2	Fuse, Pole 8, W. Portsmouth St, Concord	5	6,564	75	1
C13W3	Recloser, Pole 84, High St, Boscawen	4	133,773	1130	1
C13W3	Fuse, Pole 75, Old Turnpike Rd, Salisbury	4	112,580	812	0
C15W2	Recloser, Pole S/S, Foundry St, Concord	4	71,664	834	0
C13W1	Recloser, Pole 1, Morrill Rd, Canterbury	4	21,599	240	0
C8X3	Fuse, Pole 2, Swamp Rd, Epsom	4	16,858	164	0
C13W2	Fuse, Pole 1, Randall Rd, Canterbury	4	15,579	80	0
C13W3	Fuse, Pole 30, Long St, Webster	4	9,865	88	0
C8X3	Fuse, Pole 1, Sanborn Hill Rd North, Epsom	4	5,347	40	1
C38	Fuse, Pole 7, Curtisville Rd, Concord	4	3,011	48	0

Table 15
Streets with the Highest Number of Outages

Circuit	Street	Max Number of Outages Seen by a Single Customer	Number of Times on List in Previous 4 Years
C13W3	OLD TURNPIKE RD	13	1
C13W3	WHITE PLAINS RD	12	2
C13W1	BOROUGH RD	11	2
C13W3	LITTLE HILL RD	9	2
C13W3	BATTLE ST	8	2
C13W3	MUTTON RD	8	2
C15W2	W PORTSMOUTH ST	8	1
C13W2	ELM ST	7	1
C13W1	TIOGA RD	7	1
C13W1	RANDALL RD	7	1
C13W1	MORRILL RD	7	1
C13W1	OLD TILTON RD	7	1
C8X3	SANBORN HILL RD	7	0
C22W3	BEAVER BROOK DR	7	0
C22W3	TONGA DR	7	1

10 Other Concerns

This section is intended to identify other reliability concerns that would not necessarily be identified from the analysis above.

10.1 13.8kV Underground Electric System Improvements

There are condition concerns in the 13.8kV Concord Downtown Underground. Portions of the cable have been replaced due to faults. There is historical evidence of connector failure as well. Transformers with primary switches are still in the process of being installed in place of the existing transformers. By the end of 2019, 18 of 21 transformers will have switches in them. A 2020 proposed budget project will address three more of these transformers. The same project will also create a loop out of manhole 25, allowing for additional restoration switching. A 2020 proposed budget project will allow switching all times of the year. This is expected to reduce outage duration and allow time for condition-based replacement as opposed to a quick fix to restore customers quickly.

10.2 URD Cable Failure

URD cables are failing at an average rate of 10 failures per year, from 2016 through 2018. There is a trend of increasing cable failures each year from 2015 to 2018. When a direct buried cable fails, Unitil splices in a small section of new cable into the existing cable. Generally, cable failures in conduit result in cable replacement. The remaining aged cable in the area is still susceptible to failure. Options to decrease the number of failures include: direct replacement, rejuvenation, and replacement with conduit (for existing direct buried options). Projects for rejuvenation and replacement with conduit are underway in 2019 and further proposed for the 2020 budget.

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 2020 capital budget. All project costs are shown without general construction overheads.

11.1. Circuit 13W3: Create a Loop between Water St and High St

11.1.1. Identified Concerns

Circuit 13W3 had three of the worst distribution outages in 2018, including the number one worst outage. It has been on the list of worst performing circuits four out of the last five years, ranked by SAIDI and SAIFI.

11.1.2. Recommendations

Build N. Water St, Boscawen from single phase to three phase spacer cable. Extend the phases through to P.50 Old Turnpike Rd, Salisbury.

Install two Reclosers and one three-phase, remote and motor operated switch. Implement an auto transfer scheme.

Estimated Project Cost (without construction overheads): $1,200,000

Estimated Annual Savings:

Customer Minutes: 144,600
Customer Interruptions: 673

11.1.3. Alternate Option

Install a recloser at P.49 Old Turnpike Rd, Salisbury.

Estimate Project Cost (without construction overheads): $50,000

Estimated Annual Savings:

Customer Minutes: 1,746
Customer Interruptions: 21

11.2. Circuit 15W1: Install Recloser on Mountain Rd

11.2.1. Identified Concerns

15W1 has experienced several operations on the fuses at P.5 Mountain Rd. Replacing the fuses with a recloser allows reclosing to eliminate some of the outages; particularly the patrolled, nothing found outages, squirrel and animal-related outages, and some broken limb outages.

11.2.2. Recommendations

Replace cutouts and fuses at P.5 Mountain Rd, Concord with a Recloser.

Estimated Project Cost (without construction overheads): $32,401

Estimated Annual Savings:

Customer Minutes: 27,838
Customer Interruptions: 335

11.3. Circuit 8X3: Replace Hydraulic Recloser with Digital Relay/Recloser

11.3.1. Identified Concern

The hydraulic recloser at P.167 Main St, Chichester does not coordinate well with downline devices. As such, there is low-side fusing for the step down transformers at P.164 and 166. These low-side fuses have operated multiple times in the last three years. The hydraulic recloser does allow for fuse savings downline. Replacing the hydraulic recloser and low-side fuses with a microprocessor-based recloser will allow reclosing for the 451 exposed customers.

11.3.2. Recommendation

Install a Recloser at P.168 Main St, Chichester.

Estimated Project Cost (without construction overheads): $35,967

Estimated Annual Savings:
Customer Minutes of Interruption: 33,655
Customer Interruptions: 405

11.4. Circuit 13W2: Reconductor N. Main St, Boscawen with Spacer

11.4.1. Identified Concern

The master plan is to create a backup for the 37 Line, as it radially feeds the Boscawen S/S. The 13W2 circuit will be converted to 34.5kV and tie with 4X1 from Penacook. This project is expected to provide increased reliability for 13W2 right now, but also establish the back bone for even greater reliability at the sub-transmission and distribution levels.

11.4.2. Recommendation

Reconductor 13W2 mainline from the S/S, down N. Main St, Boscawen, and end at the Village St bridge in Penacook. The reconductoring and reinsulating will be done to system planning capacity and 34.5kV construction. This construction is approximately 2.5 miles of spacer cable construction.

Estimated Project Cost (without construction overheads): $674,174

Estimated Annual Savings:
Customer Minutes of Interruption: 107,510
Customer Interruptions: 1,294

11.4.3 Alternate Option

Reconductor 13W2 mainline with open construction instead of spacer construction.

Estimated Project Cost (without construction overheads):

Estimated Annual Savings:
Customer Minutes of Interruption: 44,348
Customer Interruptions: 534

11.5 Circuit 13W1: Reconductor Morrill Rd, Canterbury

11.5.1 Identified Concern

A number of tree related outages on this single phase lateral occurred in 2018. There are limited trimming abilities in the area. Reconductoring with insulated wire will reduce the number of outages.

11.5.2 Recommendation

Reconductor approximately 14,000 ft of #6 Cu with insulated 1/0 ACSR on Morrill Rd, Canterbury.

Estimated Project Cost (without construction overheads): $445,000

Estimated Annual Savings:
Customer Minutes of Interruption: 7,630
Customer Interruptions: 84

11.6 Circuit 8X5: Install a Recloser on Regional Dr.

11.6.1 Identified Concern

A number of motor vehicle accidents and large tree related outages occurred in 2018 that caused the substation recloser to trip to lockout. A mid-line recloser will be another sectionalizing point with reclosing that will help lessen the effect of a mainline fault beyond the recloser.

11.6.2 Recommendation

Install a Recloser at P.5 Regional Dr., Concord.

Estimated Project Cost (without construction overheads): $34,531

Estimated Annual Savings:
Customer Minutes of Interruption: 27,429
Customer Interruptions: 330

11.7 Circuit 6X3: Install a Recloser on Pleasant St

11.7.1 Identified Concern

6X3 exits the Pleasant St S/S and branches to the left and right. In order to limit the scale of the outage, a sectionalizing device in each direction will prevent a full circuit outage. This project is for a recloser in the east direction of Pleasant St. It will replace a set of fuses on P.78.

11.7.2 Recommendation

Install a Recloser at P.78 Pleasant St, Concord.

Estimated Project Cost (without construction overheads): $31,492

Estimated Annual Savings:
Customer Minutes of Interruption: 27,774
Customer Interruptions: 334

11.8 Circuit 13W3: Reconductor Long St, Webster with Spacer Cable

11.8.1 Identified Concern

The sectionalizers on P.138 Long St, Boscawen operated several times in 2018, most as patrolled, nothing found outages. Reconductoring approximately 1.6 miles of three phase mainline will reduce the number of outages normally associated with trees and animals.

11.8.2 Recommendation

Reconductor approximately 1.6 miles of three-phase mainline on Long St, Boscawen and Webster with 13.8kV, 336AAC spacer.

Estimated Project Cost (without construction overheads): $533,935.83

Estimated Annual Savings:
Customer Minutes of Interruption: 23,315
Customer Interruptions: 281

11.9 Circuit 13W1: Reconductor West Rd, Canterbury and Install Recloser

11.9.1 Identified Concern

13W1 does not have a circuit tie that can back feed the circuit for restoration. This project aims to harden the stand alone system, lessen overall outage impact with an additional reclosing point, and prepare for a potential future tie, according to the master plan.

11.9.2 Recommendation

Reconductor approximately 4 miles of three phase mainline on West Rd, Canterbury with 13.8kV, 336AAC spacer.

Install a Recloser at P.31 North West Rd, Canterbury.

Estimated Project Cost (without construction overheads): $750,000

Estimated Annual Savings:
Customer Minutes of Interruption: 73,583
Customer Interruptions: 886

11.10 Circuit 8X3: Install a Recloser on Dover Rd, Epsom

11.10.1 Identified Concern

8X3 does not currently have a circuit backup to restore load for an outage outside of the substation. Adding sectionalizing points will limit the impact of outages beyond the new recloser.

11.10.2 Recommendations

Install a Recloser at P.5 Dover Rd, Epsom.

Estimated Project Cost (without construction overheads): $50,000

Estimate Annual Savings:
Customer Minutes of Interruption: 50,025
Customer Interruptions: 602

11.11 Fusesaver Installation Locations

11.11.1 Identified Concern

In an effort to continually improve upon reliability, fusesavers have been identified as capable to eliminate most momentary outages by allowing for a single trip clearing time. The following is a list of locations in which fusesavers have been identified as beneficial additions.

11.11.2 Recommendations

1) Install a fusesaver at P.22 N. Main St, Boscawen.

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 13,095
Customer Interruptions: 195

2) Install a fusesaver at P.1 New Orchard Rd, Epsom.

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 10,111
Customer Interruptions: 31

3) Install a fusesaver at P.16 Stickney Hill Rd, Hopkinton

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 7,565
Customer Interruptions: 120

4) Install a fusesaver at P.56 Knox Rd, Bow.

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 5,720
Customer Interruptions: 30

5) Install three fusesavers at P.4 King Rd, Chichester.

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 5,565
Customer Interruptions: 67

6) Install three fusesavers at P.1 Rocky Point Dr., Bow.

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 5,073
Customer Interruptions: 61

7) Install a fusesaver at P.62 Elm St, Boscawen.

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 4,733
Customer Interruptions: 57

8) Install a fusesaver at P.145 Old Turnpike Rd, Salisbury.

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 4,271
Customer Interruptions: 35

9) Install a fusesaver at P.50 Borough Rd, Canterbury.

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 4,200
Customer Interruptions: 20

10) Install a fusesaver at P.8 W. Portsmouth St, Concord.

Estimated Project Cost (without construction overheads): Minimal

Estimated Annual Savings:
Customer Minutes of Interruption: 2,166
Customer Interruptions: 25

11.12 Circuit 37X1: Install a Recloser at the 37X1 Tap

11.12.1 Identified Concern

37X1 is a lateral on the radial 37 line that is unprotected. This recloser will prevent 37 line outages when the fault occurs somewhere on 6,615 feet of unprotected lateral. Outages that occur here would no longer affect the Boscawen S/S and its 2,253 customers.

11.12.2 Recommendation

Install a Recloser on transmission Pole 42 of the 37 line, i.e. the 37X1 tap.

Estimated Project Cost (without construction overheads):

Estimated Annual Savings:
Customer Minutes of Interruption: 187,095
Customer Interruptions: 2,253

11.13. Miscellaneous Circuit Improvements to Reduce Recurring Outages

11.13.1. Identified Concerns & Recommendations

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 2018. It is recommended that a forestry review of these areas be performed in 2019 in order to identify and address any mid-cycle growth or hazard tree problems.

- C13W1
  - Borough Rd, Canterbury
  - Pickard Rd, Canterbury
  - Morrill Rd, Canterbury
  - Hackleboro Rd, Canterbury
  - Wilson Rd, Canterbury
- C13W2
  - Elm St, Penacook
- C13W3
  - Battle St, Salisbury
  - Old Turnpike Rd, Salisbury
  - Warner Rd, Salisbury
  - White Plains Rd, Salisbury
  - Whittemore Rd, Salisbury
  - Battle St, Webster
  - Mutton Rd, Webster
  - White Plains Rd, Webster
  - Corn Hill Rd, Boscawen
  - Daniel Webster Hwy, Boscawen
  - High St, Boscawen
- C15W2
  - W. Portsmouth St, Concord
- C18W2
  - Morse Rd, Dunbarton
- C22W3

  - Brown Hill Rd, Bow
  - Page Rd, Bow
- C38
  - Curtisville Rd, Concord
- C8X3
  - New Orchard Rd, Epsom
  - Sanborn Hill Rd N., Epsom
  - Swamp Rd, Epsom

Animal Guard Installation Recommendations

The areas identified below experienced three or more patrolled nothing found / animal outages in 2018.

- Woodhill Rd, Bow
- Stickney Hill Rd, Hopkinton
- Allen Rd, Bow
- Mountain Rd, Concord
- Morrill Rd, Canterbury

12 Conclusion

During 2018, tree related outages still present one of the largest problems in the UES-Capital System, 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.

Squirrel related outages saw a sharp decrease in outages in 2018, which is expected to continue into 2019. Animal guards were installed during 2018. A further project to target specific areas is in progress in 2019. Animal guards are continually being placed on equipment whenever an animal causes an outage. In addition, when there is an animal-related outage, any equipment in the vicinity will be checked. If nearby equipment does not have animal guards, the animal guards will be installed at that location. Also, all streets and circuits identified as having high numbers of animal related outages will be checked and proper animal protection will be installed where applicable.

Recommendations developed from this study are mainly focused on reducing the impact of multiple permanent outages and improving reliability of the sub transmission system. 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 measures to be taken. In addition, new ideas and solutions to reliability problems are always being explored in an attempt to provide the most reliable service possible.

APPENDIX U

UES-SEACOAST RELIABILITY STUDY 2019

Unitil Energy Systems – Seacoast

Reliability Study
2019

Prepared By:

Jake Dusling
Unitil Service Corp.
October 25, 2019

Table of Contents

1 Executive Summary

The purpose of this document is to report on the overall reliability performance of the Unitil Energy Systems – Seacoast (UES-Seacoast) system from January 1, 2018 through December 31, 2018. The scope of this report will also evaluate individual circuit reliability performance over the same time period. The outage data used in this report excludes the data in Section 5 (sub-transmission and substation outages), as well as the outage data from IEEE Major Event Days (MEDs). UES-Seacoast MEDs are listed in the table below:

# MEDs in Event	Dates of MEDs	Interruptions	Customer Interruptions	Cust-Min of Interruption
3	3/7/18 – 3/9/18	186	40,438	24,792,654

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 2020 budget development process.

Circuit / Line / Substation	Proposed Project	Cost ($)
6W1	Re-conductor portion of South Road with Spacer Cable	$250,000
43X1	Install Reclosers and Implement Distribution Automation	$350,000
3343 and 3354	Install Reclosers	$150,000
58X1	Install Reclosing Devices	$120,000

Note: estimates do not include general construction overheads

The 2018 annual UES-Seacoast system reliability goal was set at 105.61 SAIDI minutes, after removing exclusionary outages. UES-Seacoast's SAIDI performance in 2018 was 108.28 minutes. Charts 1, 2, and 3 below show UES-Seacoast's SAIDI, SAIFI, and CAIDI performance over the past five years.

Chart 1
Annual UES-Seacoast SAIDI

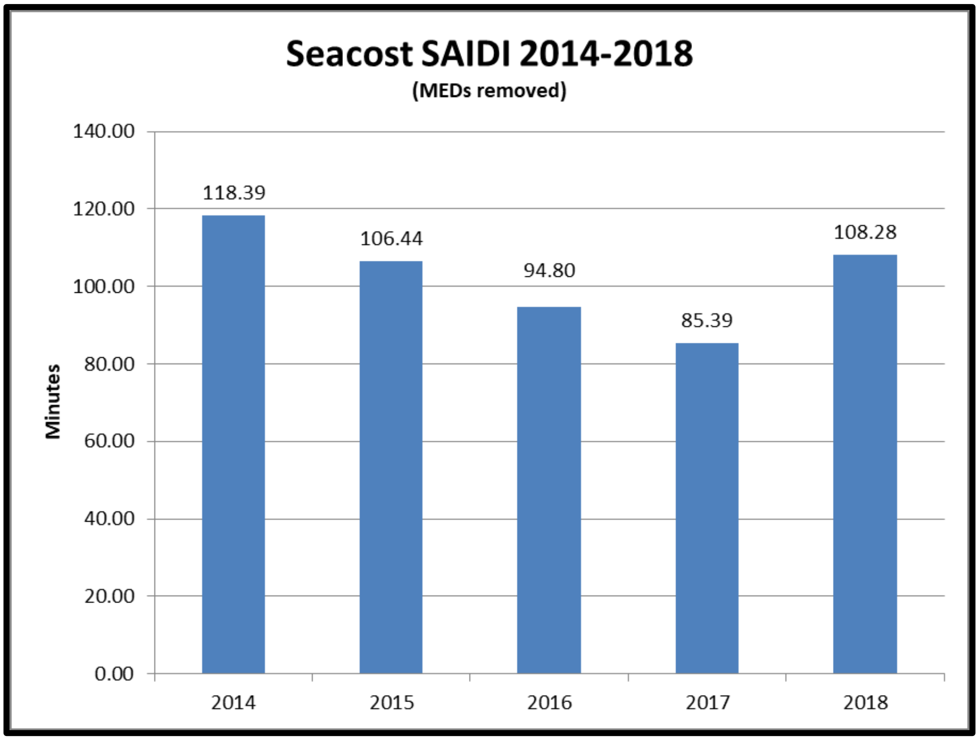


Chart 2
Annual UES-Seacoast SAIFI

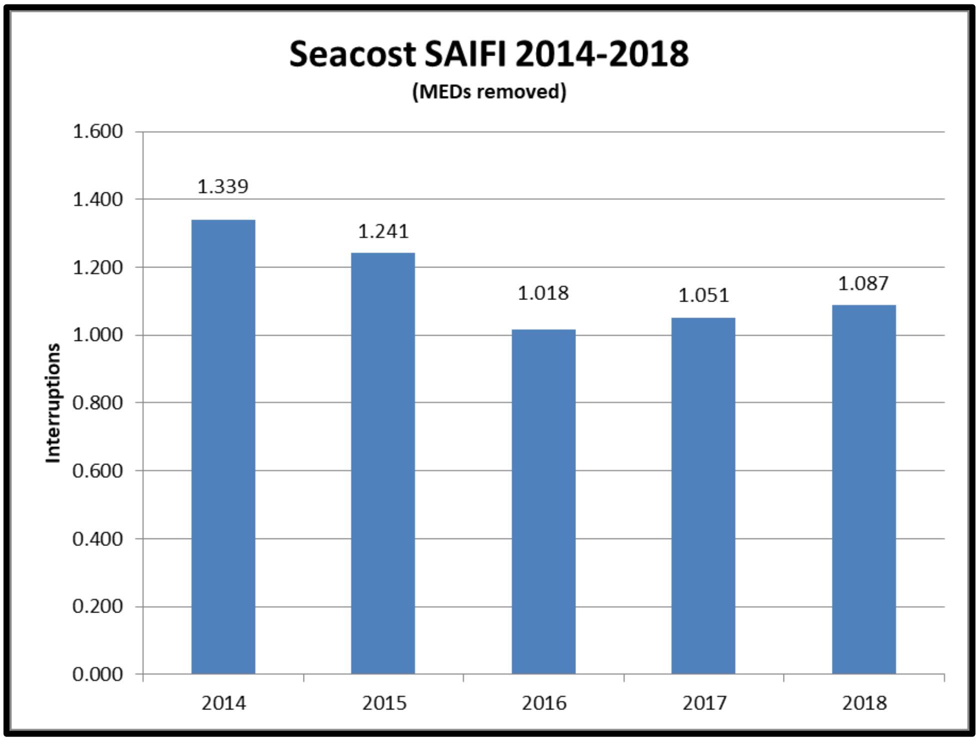
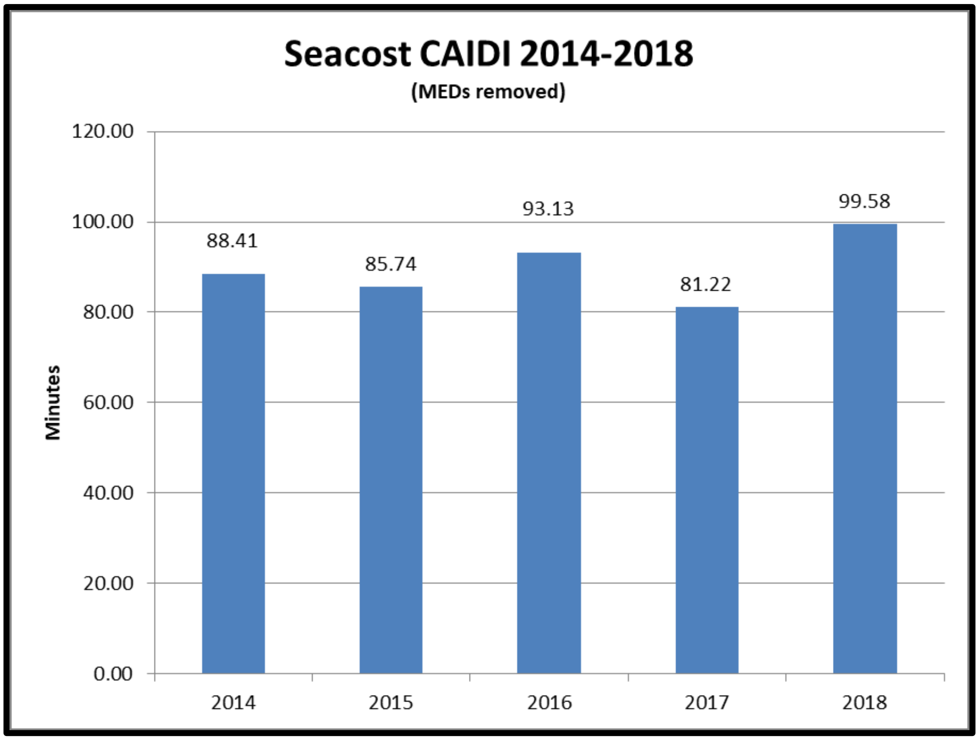


Chart 3
Annual UES-Seacoast CAIDI



2 Reliability Goals

The new annual UES-Seacoast system reliability goal for 2019 has been set at 113.25 SAIDI minutes. This was developed by calculating the contribution of UES-Seacoast to the Unitil system performance using the past five year average. The contribution factor was then set against the 2019 Unitil system goal. The 2019 Unitil system goal was developed through benchmarking the Unitil system performance with nationwide utilities.

Individual circuits will be analyzed based upon circuit SAIDI, SAIFI, and CAIDI. Analysis of individual circuits along with analysis of the entire UES-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 2018. Charts 4, 5, and 6 list the number of interruptions, the number of customer interruptions, and total customer-minutes of interruption due to each cause respectively. Only the causes contributing 3% or greater of the total are labeled. Table 1 shows the number of interruptions for the top three trouble causes for the previous five years.

Chart 4
Number of Interruptions by Cause

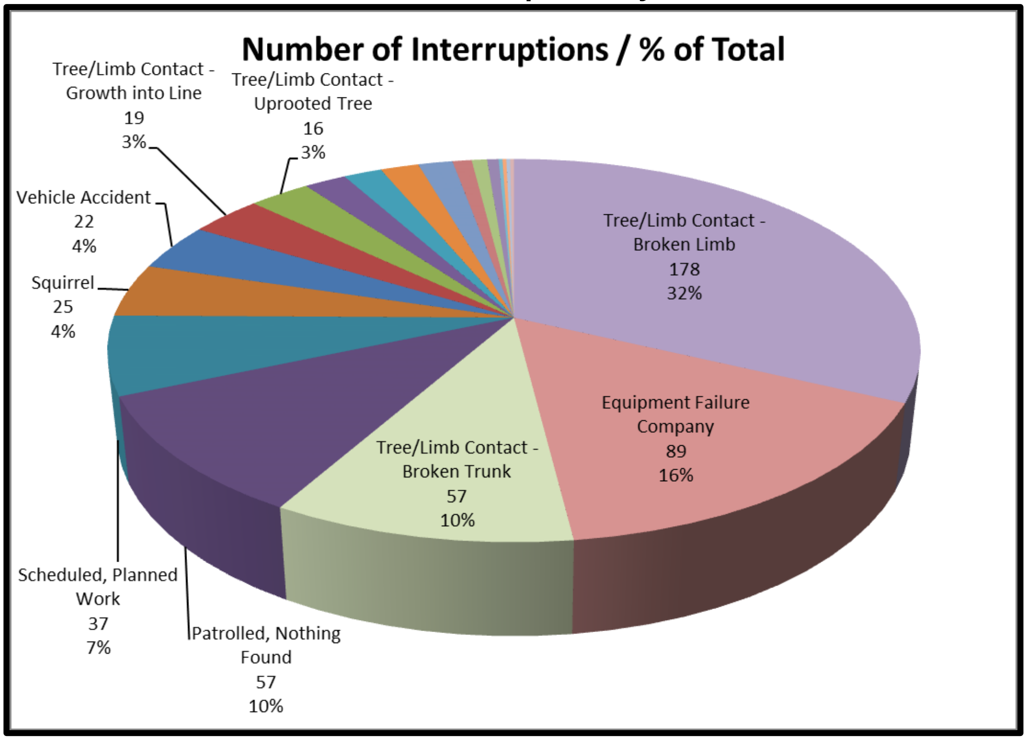


Chart 5
Number of Customer Interruptions by Cause

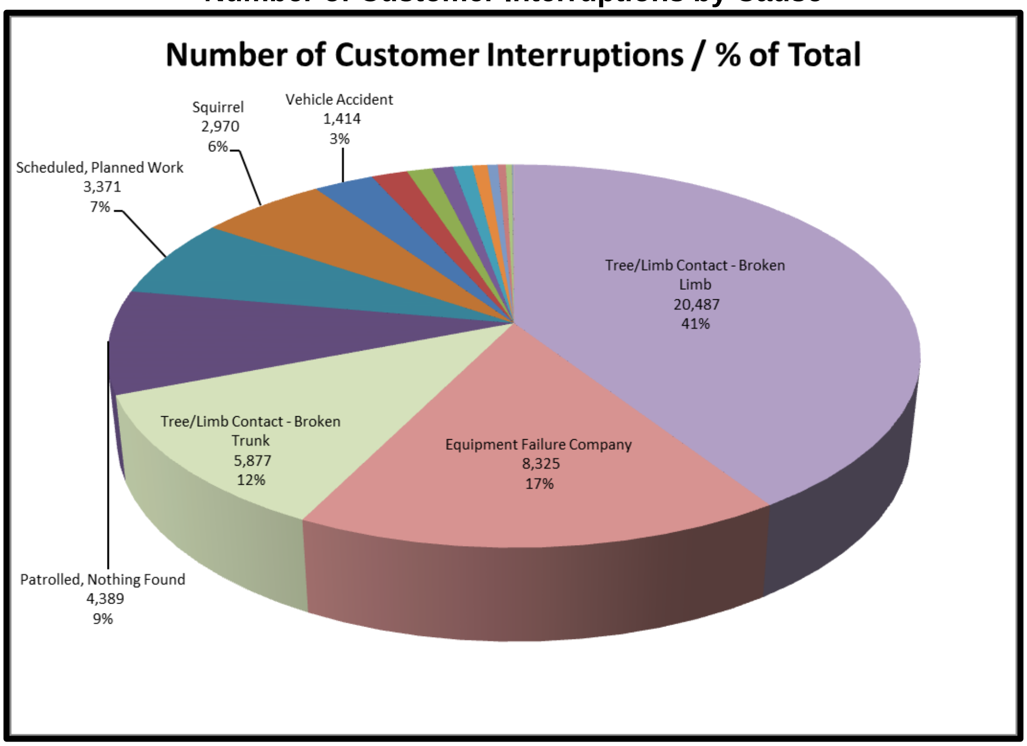


Chart 6
Percent of Customer-Minutes of Interruption by Cause

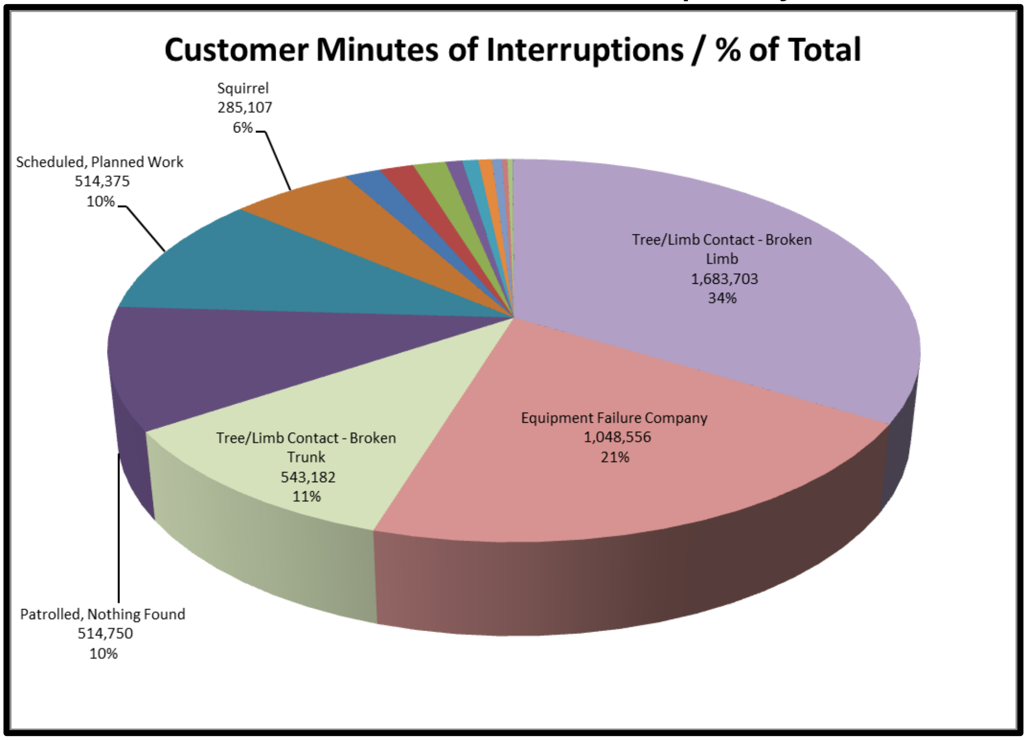


Table 1
Five-Year History of the Number of Interruptions for the Worst Three Trouble Causes

Year	Tree/Limb Contact - Broken Limb	Equipment Failure Company	Patrolled, Nothing Found
2018	178	89	57
2017	121	78	43
2016	147	79	46
2015	87	88	62
2014	131	70	63

4 10 Worst Distribution Outages

The ten worst distribution outages ranked by customer-minutes of interruption during the time period from January 1, 2018 through December 31, 2018 are summarized in Table 2 below.

Table 2
Worst Ten Distribution Outages

Circuit	Date/Cause	Customer Interruptions	Cust-Min of Interruption	SAIDI	SAIFI
E7W1	5/14/2018 Equipment Failure Company	1,226	231,891	4.90	0.026
E13W2	10/27/2018 Equipment Failure Company	1,629	199,227	4.21	0.034
E22X1	1/4/2018 Tree/Limb Contact - Broken Limb	1,159	196,898	4.16	0.024
E54X1	6/1/2018 Vehicle Accident	1,019	192,079	4.06	0.022
E58X1	3/13/2018 Equipment Failure Company	1,143	186,990	3.95	0.024
E54X2	1/23/20 Tree/Limb Contact - Broken Limb	1,020	186,660	3.94	0.022
E21W1	3/22/2018 Equipment Failure Company	1,366	178,445	3.77	0.029
E59X1	10/27/2018 Tree/Limb Contact - Broken Trunk	262	125,448	2.65	0.006
E58X1	7/31/2018 Tree/Limb Contact - Uprooted Tree	737	109,149	2.31	0.016
E7W1	12/20/2018 Vehicle Accident	1,250	107,965	2.28	0.026

5 Sub-transmission and Substation Outages

This section describes the contribution of sub-transmission line and substation outages on the UES-Seacoast system.

All substation and sub-transmission outages ranked by customer-minutes of interruption during the time period from January 1, 2018 through December 31, 2018 are summarized in Table 3 below.

Table 4 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 11% of the total customer-minutes of interruption for UES-Seacoast.

Table 3
Sub-transmission and Substation Outages

Line / Substation	Date/Cause	Customer Interruptions	Cust-Min of Interruption	SAIDI	SAIFI	Number of Outages in Prior Four Years
3348/3350 Line	9/10/2018 Equipment Failure Company	1,112	120,096	2.54	0.023	0

Table 4
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
7W1	3348/50	53,460	8%	43.68	1
7X2	3348/50	66,636	27%	37.27	1

6 Worst Performing Circuits

This section compares the reliability of the worst performing circuits using various performance measures.

6.1 Worst Performing Circuits in Past Year (1/1/18 – 12/31/18)

A summary of the worst performing circuits during the time period between January 1, 2018 and December 31, 2018 is included in the tables below.

Table 5 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 6 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 during 2018.

Circuits having one outage contributing more than 80% of the Customer-Minutes of interruption were excluded from this analysis.

Table 5
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
E7W1	7,545	17%	584,159	40%	477.25	6.164	77.42
E21W1	3,411	40%	390,105	4%	285.58	2.519	113.37
E58X1	2,597	44%	375,007	50%	167.86	1.162	144.40
E54X2	1,991	51%	322,312	58%	315.37	1.948	161.88
E13W2	2,896	56%	319,857	62%	196.23	1.777	110.45
E54X1	5,003	77%	309,716	62%	304.24	4.915	61.91
E22X1	1,974	59%	284,263	69%	209.94	1.458	144.00
E19X3	2,155	22%	236,890	23%	68.88	0.627	109.93
E21W2	3,118	34%	197,626	34%	130.10	2.053	63.38
E51X1	1,522	26%	169,504	32%	88.51	0.795	111.37

Note: all percentages and indices are calculated on a circuit basis

Table 6
Circuit Interruption Analysis by Cause

Circuit	Customer-Minutes of Interruption / # of Outages					
	Tree/Limb Contact - Broken Limb	Tree/Limb Contact - Broken Trunk	Equipment Failure Company	Squirrel	Patrolled, Nothing Found	Loose/Failed Connection
E7W1	0 / 0	233,688 / 3	0 / 0	185,495 / 4	107,965 / 1	0 / 0
E21W1	100,535 / 7	180,654 / 2	20,651 / 4	3,593 / 2	8,019 / 3	0 / 0
E58X1	32,709 / 9	191,126 / 7	27,806 / 2	7102 / 3	1,300 / 2	110,518 / 3
E54X2	221,962 / 8	1,247 / 2	67,816 / 2	23,431 / 3	0 / 0	2,720 / 1
E13W2	73,169 / 9	20,133 / 5	4,340 / 2	30,374 / 5	5,247 / 1	0 / 0
E54X1	113,046 / 3	1,774 / 3	78 / 1	764 / 1	192,079 / 1	0 / 0
E22X1	223,665 / 11	8,014 / 3	15,035 / 2	9,399 / 2	3,444 / 1	0 / 0
E19X3	13,940 / 7	8,700 / 9	9,443 / 2	61,514 / 3	38,417 / 2	67,817 / 2
E21W2	153,214 / 15	0 / 0	29,825 / 1	4,612 / 4	0 / 0	0 / 0
E7X2	697 / 1	7,216 / 2	7,101 / 2	228 / 1	99,161 / 1	0 / 0
E51X1	99,216 / 16	9,235 / 6	3,073 / 3	17,417 / 3	9,539 / 1	0 / 0

6.2 Worst Performing Circuits of the Past Five Years (2014 – 2018)

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 7 lists the ten worst performing circuits ranked by SAIDI and Table 7 lists the ten worst performing circuits ranked by SAIFI. Table 8 lists the ten worst overall performing circuits ranked by average SAIDI and SAIFI over the past five years. Table 9 lists the ten worst circuits in terms of SAIFI and SAIDI for the past five years.

The data used in this analysis includes all system outages except those outages that occurred during Snowstorm Cato in 2014 and IEEE MEDs in 2015 through 2018.

Table 7
Circuit SAIDI

Circuit Ranking (1=worst)	2018		2017		2016		2015		2014	
	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI	Circuit	SAIDI
1	E7W1	520.93	E54X2	275.94	E3H2	463.53	E6W1	429.2	E6W1	392.13
2	E54X2	338.4	E6W1	269.71	E7W1	375.29	E58X1	371.96	E19X3	358.77
3	E21W1	285.58	E19H1	254.56	E3H3	255.03	E47X1	362.03	E54X1	304.14
4	E54X1	221.9	E22X1	238.1	E54X2	249.35	E6W2	306.7	E20H1	271.23
5	E22X1	209.94	E5H1	200.6	E6W1	241.11	E51X1	201.87	E18X1	258.98
6	E6W1	205.87	E15X1	192.52	E43X1	226.55	E22X1	168.43	E43X1	183.86
7	E13W2	196.23	E51X1	158.75	E21W2	214.57	E56X2	138.86	E51X1	180.9
8	E2H1	192.59	E58X1	134.36	E17W2	210.69	E17W2	136.96	E21W1	170.41
9	E23X1	176.73	E59X1	125.01	E58X1	203.82	E27X1	126.5	E1H3	158.85
10	E58X1	167.86	E22X2	117.33	E54X1	196.61	E3W4	97.95	E1H4	158.03

Table 8
Circuit SAIFI

Circuit Ranking (1=worst)	2018		2017		2016		2015		2014	
	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI	Circuit	SAIFI
1	E7W1	6.569	E6W1	4.096	E43X1	2.945	E47X1	3.824	E20H1	4.287
2	E6W1	3.257	E22X1	2.606	E3H2	2.867	E6W1	2.871	E51X1	3.558
3	E54X2	2.949	E15X1	2.536	E21W2	2.641	E51X1	2.511	E6W2	3.288
4	E21W1	2.519	E54X2	2.271	E17W2	2.309	E58X1	2.354	E19X3	3.09
5	E6W2	2.334	E19H1	2.012	E21W1	2.198	E2X3	2.176	E6W1	2.73
6	E54X1	2.115	E23X1	1.527	E58X1	2.107	E22X1	1.922	E11X1	2.451
7	E21W2	2.053	E59X1	1.496	E22X1	1.922	E17W2	1.86	E21W1	2.315
8	E13W2	1.777	E43X1	1.481	E27X1	1.917	E13X3	1.466	E43X1	2.133
9	E43X1	1.465	E18X1	1.414	E54X1	1.892	E13W1	1.444	E22X1	2.12
10	E22X1	1.458	E19X2	1.387	E6W1	1.772	E21W2	1.425	E18X1	1.84

Table 9
Worst Performing Circuits in Past Five Years

SAIDI			SAIFI		
Circuit Ranking (1=worst)	Circuit	# of Times in Worst 10	Circuit Ranking (1=worst)	Circuit	# of Times in Worst 10
1	E6W1	5	**1**	E6W1	5
2	E7W1	2	**2**	E22X1	5
3	E58X1	4	**3**	E21W1	3
4	E54X2	3	**4**	E7W1	1
5	E22X1	3	**5**	E6W2	2
6	E21W1	2	**6**	E43X1	3
7	E54X1	3	**7**	E51X1	2
8	E6W2	1	**8**	E21W2	3
9	E51X1	3	**9**	E54X2	2
10	E43X1	2	**10**	E47X1	1

6.3 System Reliability Improvements (2018 and 2019)

Vegetation management projects completed in 2018 or planned for 2019 that are expected to improve the reliability of the 2018 worst performing circuits are included in Table 10 below. Table 11 below details electric system upgrades that are scheduled to be completed in 2019 or were completed in 2018 that were performed to improve system reliability.

Table 10
Vegetation Management Projects Worst Performing Circuits

Circuit(s)	Year of Completion	Project Description
E6W1	2018	Hazard Tree Mitigation Storm Resiliency Pruning
E58X1	2018	Cycle Pruning Hazard Tree Mitigation
E22X1	2018	Mid-Cycle Pruning
E21W1	2019	Cycle Pruning Hazard Tree Mitigation
E21W2	2019	Cycle Pruning Hazard Tree Mitigation
E54X1	2019	Hazard Tree Mitigation
E6W2	2018	Storm Resiliency Pruning
E51X1	2019	Hazard Tree Mitigation Mid-Cycle Pruning
E43X1	2019	Hazard Tree Mitigation Mid-Cycle Pruning

Circuit(s)	Year of Completion	Project Description
E47X1	2019	Cycle Pruning
E13W2	2018	Cycle Pruning Hazard Tree Mitigation
E19X3	2019	Hazard Tree Mitigation Mid-Cycle Pruning

Table 11
Electric System Improvements Performed to Improve Reliability

Circuit(s)	Year of Completion	Project Description
E43X1	2018	Replace Willow Road tap recloser and install distribution recloser on Exeter Road
E43X1	2018	Install Electronically Controlled Recloser – Exeter Road
Guinea Sw/S	2018	Installation of additional animal protection, replacement aging insulators and arresters that have been prone to failure.
Various	2018/2019	Various protection changes identified through the distribution planning process and the review of outage reports.
	2019	Porcelain Cutout Replacements
E5X3/E58X1	2019	Establish Distribution Circuit Tie
3346 Line	2019	Install Reclosers and Implement an Automatic Transfer Scheme
E17W1	2019	Install Hydraulic Reclosers – North Shore Road
E17W2	2019	Install Electronically Controlled Recloser – Little River Road
E3W1, E3W4, E17W1	2019	Conversion of Hampton Beach area included the creation of distribution circuit ties between circuits 3W1/3W4 and 3W1/17W1 and the installation of two electronically controlled reclosers.

7 Tree Related Outages in Past Year

This section summarizes the worst performing circuits by tree related outage during the time period between January 1, 2018 and December 31, 2018.

Table 12 shows the ten worst circuits ranked by the total number of Customer-Minutes of interruption. The number of customer-interruptions and number of outages are also listed in this table.

All streets on the UES-Seacoast system with three or more tree related outages are shown in Table 13 below. The table is sorted by number of interruptions and customer-minutes of interruption.

Table 12
Worst Performing Circuits – Tree Related Outages

Circuit	Customer Minutes of Interruption	Number of Customers Interrupted	No. of Interruptions
E54X2	292,498	1,778	11
E22X1	263,032	1,779	14
E21W2	183,712	2,944	17
E58X1	172,018	1,265	16
E59X1	146,825	506	6
E6W1	139,972	1,805	14
E21W1	122,266	1,760	13
E43X1	119,412	2,530	16
E19X3	115,900	836	14
E54X1	114,399	3,947	5

Table 13
Multiple Tree Related Outages by Street

Circuit(s)	Street, Town	# Outages	Customer-Minutes of Interruption	Number of Customer Interruptions
E21W2	Maple Ave, Atkinson	4	772	5
E22X1	Sandown Rd, Danville	4	5,420	79
E51X1	Squamscott Rd, Stratham	4	14,058	195
E6W1	Haverhill Rd, East Kingston	4	18,794	245
E13W1	North Main St, Plaistow	3	1,260	10
E13W1	Old County Rd, Plaistow	3	10,043	138
E13W2	Main St, Newton	3	5,506	76
E13W2	Thornell Rd, Newton	3	67,902	492
E21W1	Meditation Ln, Atkinson	3	48,341	256
E27X2	North Rd, East Kingston	3	12,717	155
E51X1	High St, Stratham	3	4,111	66
E51X1	Jack Rabbit Lane, Stratham	3	2,978	30
E54X2	Ball Rd, Kingston	3	211,072	1407
E6W1	South Rd, East Kingston	3	91,209	1100
E6W2	Main St, Kingston	3	52,207	1001

8 Failed Equipment

This section is intended to clearly show all equipment failures throughout the study period from January 1, 2018 through December 31, 2018. Chart 7 shows all equipment failures throughout the study period. Chart 8 shows each equipment failure as a percentage of the total failures within this same study period. The number of equipment failures in each of the top three categories of failed equipment for the past five years are shown below in Chart 9.

Chart 7
Equipment Failure Analysis by Cause

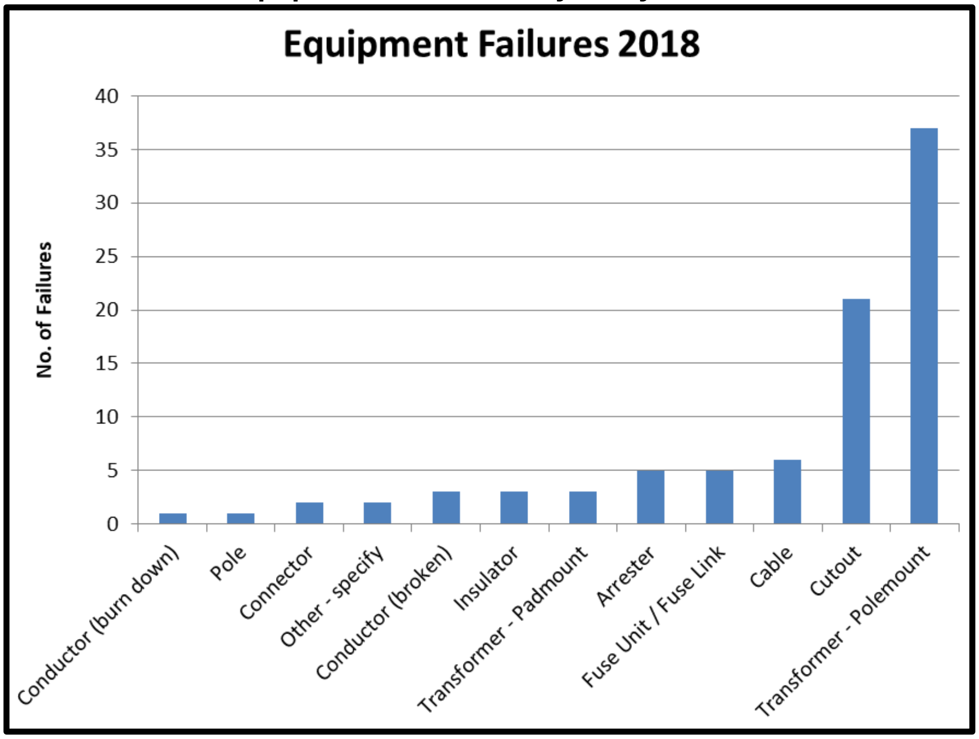


Chart 8
Equipment Failure Analysis by Percentage of Total Failures

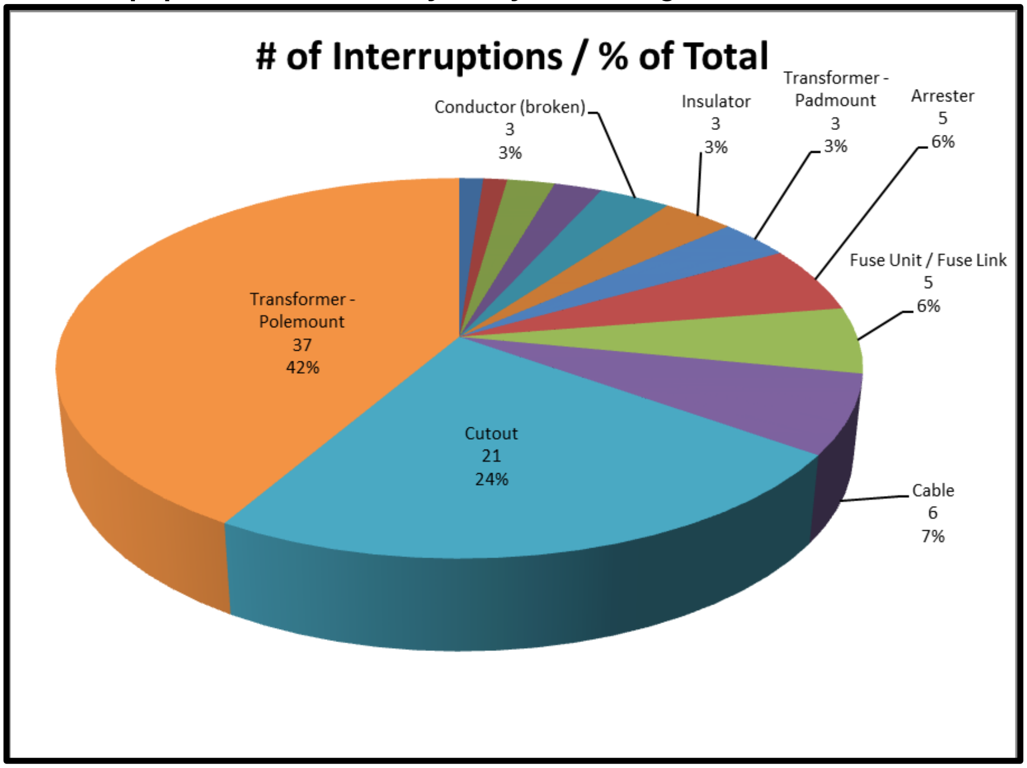
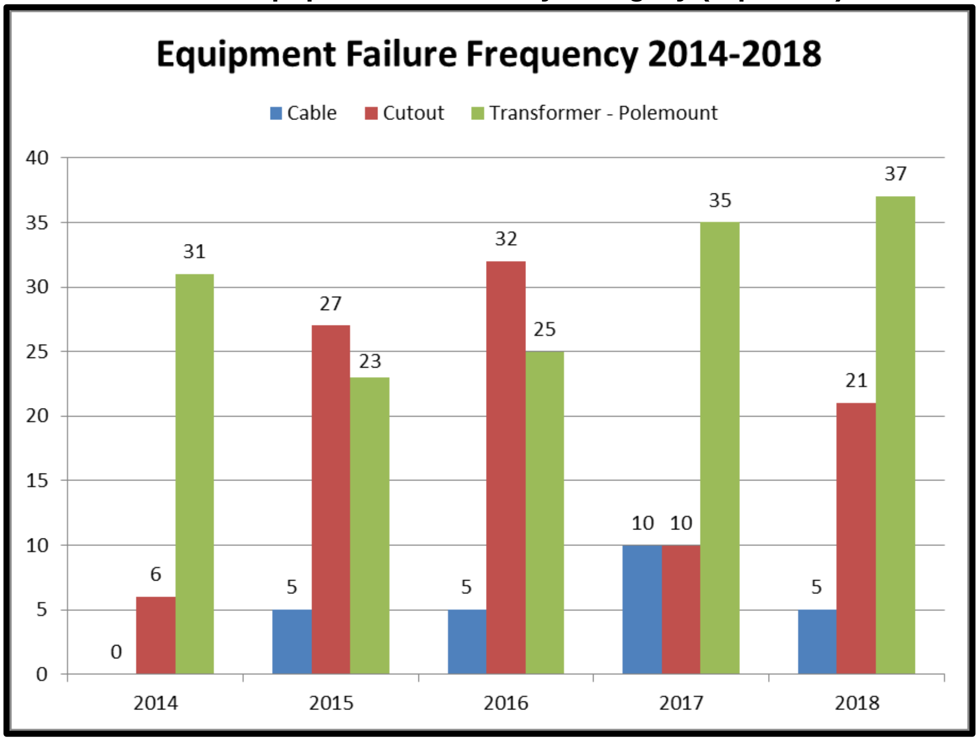


Chart 9
Annual Equipment Failures by Category (top three)



9 Multiple Device Operations and Streets with Highest Number of Outages

A summary of the devices that have operated three or more times from January 1, 2018 to December 31, 2018 is included in Table 14 below. Refer to section 11.6 for recommendations to address some of the areas identified that have experienced recurring outages in 2018.

A summary of the streets on the UES-Seacoast system that had customers with 7 or more non-exclusionary outages in 2018 is included in Table 15 below. The table is sorted by circuit and then the maximum number of outages seen by a single customer on that street.

Table 14
Multiple Device Operations

Circuit	Number of Operations	Device	Customer Minutes	Customer Interruptions	# of Times on List in Previous 4 Years
E7W1	6[1]	7W1 Recloser, Seabrook S/S	566,353	7,354	0
E13W2	4	Fuse, Pole 29/33 Thornell Rd, Newton	78,984	596	0
E51X1	4	Fuse, Pole 47/1, Jack Rabbit Lane, Stratham	3,483	40	0

Table 15
Streets with the Highest Number of Outages

Circuit	Street	Max Number of Outages Seen by a Single Customer	Number of Times on List in Previous 4 Years
7W1	Various, Seabrook	9	0
21W1	Sawyer Ave, Atkinson	8	0
13W2	Wentworth Drive, Newton	7	0

[1] Four of these outages were a result of patrolled nothing found and occurred within a period in which the 7W1 reclosing functionality was not functioning and has since been repaired.

10 Other Concerns

This section is intended to identify other reliability concerns that would not necessarily be identified from the analysis above.

10.1 Subtransmission Lines across Salt Marsh

The 3348 and 3350 lines are constructed through salt marsh, making them very difficult to access and repair. There are significant condition related concerns associated with their aging infrastructure

Over the last five years these lines have experienced damage on multiple occasions resulting in outage to circuits 7W1 and 7X2. In addition, damage to these lines results in the lines being out of service months at time while repairs are permitted, scheduled and executed.

In 2019 a detailed assessment of the present condition of these lines was completed. Following the completion of the assessment options for repairs, replacement, or relocation of these lines will be evaluated to mitigate the identified concerns.

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 2019 capital budget. All project costs are shown without general construction overheads.

11.1 Miscellaneous Circuit Improvements to Reduce Recurring Outages

11.1.1 Forestry Review

Table 13 of this report; Multiple Tree Related Outages by Street indicates that there were fifteen streets that experienced three or more tree related outages in 2018.

It is recommended that a forestry review of the areas identified in Table 13 be performed in 2019 in order to identify and address any growth or hazard tree problems.

11.2 Circuit 6W1 – Re-conductor Portion of South Road with Spacer Cable

11.2.1 Identified Concerns

6W1 has been on the worst performing SAIDI and SAIFI list for the last five consecutive years. The owner of a section of property along South has repeatedly refused to allow effective pruning and hazard tree mitigation. This section of South Road has experienced five interruptions due to tree contacts, totaling 1,557 customer interruptions and 696,479 customer minutes of interruption since January 1st, 2017.

11.2.2 Recommendation

Re-conductor South Road from pole 28 to pole 49 with spacer cable.

Customer Exposure = 367 customers

The projected average annual savings for this project is 230,000 customer minutes of interruptions and 500 customer interruptions.

Estimated Project Cost: $250,000

Forestry and operations are currently reviewing this project to determine if the appropriate pruning can be performed to increase pole height to accommodate spacer cable construction.

11.3 Circuit 43X1 – Install Reclosers and Implement Distribution Automation

11.3.1 Identified Concerns

Circuit 43X1 is typically one of the worst performing circuits on the UES-Seacoast system. It is on both the Worst Performing Circuits in the Past Five Years SAIDI and SAIFI lists.

11.3.2 Recommendation

This project will consist of installing four electronically controlled reclosers along circuit 43X1 and 19X3.

Two of the reclosers will be installed along the mainline of circuit 43X1 between 43X1R1 and 19X3J43X1 tie. The 43X1J19X3 tie switch will be replaced with a recloser.

In order to increase the load carrying capability of the 19X3J43X1 tie the cutout mounted sectionalizers along Pine Street will be replaced with a recloser and the solid blades on Court Street will be replaced with a switch. Additionally, circuits 43X1 and 19X3 will be balanced to reduce loading on phase B.

Once installed a distribution automation scheme will be implemented between the new reclosers and the existing 43X1R1 recloser. The intent of the scheme is to have 43X1 and 19X3 automatically reconfigure for permanent faults on the mainline of circuit 43X1.

- Fault between 43X1 and 43X1R1 – 43X1 and 43X1R1 lockout and 19X3J43X1 closes.
- Fault between 43X1R1 and 43X1R2 – 43X1R1 and 43X1R2 lockout and 19X3J43X1 closes.
- Fault between 43X1R2 and 43X1R3 – 43X1R2 and 43X1R3 lockout and 19X3J43X1 closes.

- Fault between 43X1R3 and 19X3J43X1 – 43X1R3 lockout and 19X3J43X1 remains open.

Customer Exposure = 1,200 customers

The projected average annual savings for this project is 125,000 customer minutes of interruptions and 1,650 customer interruptions.

Estimated Project Cost: $350,000 (4 reclosers @ $75,000 per location plus switch replacement)

11.4 3343 and 3354 Lines – Install Reclosers

11.4.1 Identified Concerns

The 3343 and 3354 lines have historically experienced one interruption per year and are routinely damaged during major storms.

11.4.2 Recommendation

This project will consist of installing electronically controlled reclosers, one on the 3354 line and one on the 3343 line between East Kingston substation and Willow Road tap.

These reclosers will be programmed to coordinate with Kingston and operate for downline faults. Additionally, these reclosers will be remotely opened in the event of a lockout of the 03343 or 03354 at Kingston allowing load on the Guinea side of the reclosers to be restored remotely without patrolling.

In order to obtain the desired benefit East Kingston substation will be transferred to the 3343 line and Willow Road Tap will be transferred to the 3354 line.

Customer Exposure = 7,150 customers

The projected average annual savings for this project is 290,000 customer minutes of interruptions and 1,250 customer interruptions.

Estimated Project Cost: $150,000 (2 reclosers @ $75,000 per location plus)

11.5 58X1 – Install Reclosing Devices Wentworth Ave

11.5.1 Identified Concerns

The Wentworth Avenue Plaistow and Atkinson area has experienced eleven patrolled nothing found outages since January 1, 2017. Additionally, circuit 58X1 is typically one of the worst performing circuits on the UES-Seacoast system. It is currently on the Worst Performing Circuits in the Past Five Years SAIDI list.

11.5.2 Recommendation

This project will consist of installing an electronically controlled recloser between pole 6 and 7 on Wentworth Ave.

In addition to the recloser installation the 200QA's at pole 20 Atkinson Depot Road will be replaced with solid blades. The 125QAs at poles 28 and 29 and the 75QAs at pole 75/1 Sawyer Avenue will be replaced with S&C TripSavers.

Customer Exposure = 315 customers

The projected average annual savings for this project is 17,800 customer minutes of interruptions and 140 customer interruptions.

Estimated Project Cost: $120,000

12 Conclusion

The annual electric service reliability of the UES-Seacoast system over the last few years has been some of the best years on record after discounting MEDs. The improvement in reliability can be largely attributed to an aggressive vegetation management program. Still, the most significant risk to reliability of the electric system continues to be vegetation.

The recommendations in this report focus on addressing equipment concerns as well as increasing the flexibility of the system to facilitate quicker restoration of customers that can be isolated from a faulted section of the system. This includes upgrading equipment and adding additional circuit sectionalizing points and protection where it will be most effective. 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.