DOCKET DE 16-383 **EXH MDC-1**

Resume of Michael D. Cannata, Jr., P. E.

Areas of Specialization

Investigations of safety, reliability, and implementation of public policy in the electric and gas industries; facility siting, investigations of unit outage and system outage causes, electric utility operations and planning; bulk power system planning; interconnections; transmission system design.

Relevant Experience

Consulting

- Currently evaluating the need for major capital additions on the Unitil Energy and Liberty Utilities New Hampshire distribution systems for the New Hampshire Public Utilities Commission in major rate cases for each utility.
- Assisted the Staff of the New Hampshire Public Utilities Commission in the evaluation of the proposed divestiture of the Public Service Company of New Hampshire's generating fleet.
- Primary consultant providing transmission and engineering services to the New Hampshire Public Utilities Commission, including prudence reviews of the operation of Public Service Company of New Hampshire's generating fleet 2001 through 2014.
- Conducted a review of the maintenance, planning, construction, and operating practices and procedures of Unitil Energy System's NH distribution companies for the New Hampshire Public Utilities Commission.
- Lead investigator into the staffing requirements and project requirements to underground a variable portion of the Potomac Electric Power Company system to meet specified restoration target times for the Maryland Public Service Commission.
- Lead investigator into the reliability and equipment replacement requirements related to the Delmarva Power and Light's 2013 rate case for the Delaware Public Service Commission.
- Assisted the New Hampshire Public Utilities Commission in its investigation into the prolonged outages resulting from the October 2011 snowstorm.
- Managing consultant on an investigation into the prolonged outage resulting from the October 2011 snowstorm on the Western Massachusetts Electric Company system on behalf of the Massachusetts Attorney General's Office.
- Lead investigator and advisor to the Maryland Public Service Commission in its investigation into the causes for large prolonged outages occurring in 2010 on the Potomac Electric Power Company system.
- Technical consultant to the Maryland Public Service Commission in the merger of First Energy and Allegheny Energy.
- Lead consultant in a review of the transmission system of Nova Scotia Power after the collapse of multiple transmission lines in November 2004 on behalf of the Nova Scotia Utility and Review Board. The review included system maintenance, inspection, structural design, materials, system planning and design, operations, utility communications, call center operations, staffing, outage management system, staffing, and lessons learned, and related matters

- Lead investigator into the reliability and maintenance practices of the Nova Scotia Power T&D system for the Nova Scotia Utility and Review Board.
- Lead investigator in the management audit of Consolidated Edison Company of New York reviewing adequacy of multi-area transmission planning and resource adequacy within the multi-area system for the New York Public Service Commission, which also included a review of the electric and gas system designs.
- Lead investigator monitoring Commonwealth Edison's implementation of T&D system reliability improvement recommendations resulting from major system outages for the Illinois Commerce Commission.
- Lead investigator in the examination of the prolonged outage of Ameren T&D facilities following severe wind and ice events in 2006 for the Illinois Commerce Commission.
- Lead investigator monitoring Ameren's implementation of T&D system reliability improvement recommendations resulting from major system outages for the Illinois Commerce Commission.
- Lead investigator in the investigation of transmission grid security in Illinois after the August 2003 blackout for the Governor's blue ribbon committee.
- Lead investigator reviewing the adequacy of system interconnection requirements of a major renewable fuel resource for the Nova Scotia Utility and Review Board.
- Technical advisor to the Maine Public Utilities Commission, Vermont Public Service Board, Kentucky Public Service Commission, and the District of Columbia Public Service Commission regarding the public necessity and convenience for a multitude of 345 kV, 230 kV, 161 kV, 138 kV, 115 kV, and 69 kV facilities.
- Lead investigator reviewing the operation and outage of the fossil power plants of Arizona Public Service Company for the Arizona Public Service Commission.
- Lead investigator reviewing the operation and outage of the fossil power plants of Duke Energy-Ohio for the Ohio Public Utilities Commission.
- Lead investigator in the in-depth root cause analysis of a fire at a major Commonwealth Edison substation for the Illinois Commerce Commission.
- Lead investigator in the T&D system reliability reviews of four electric utilities in Maine.
- Investigator of the appropriateness of the proposed Storm Fund Adjustment Factor and the Inspection and Maintenance Program Basis Service Adjustment Mechanism for Power Option, a load aggregator in Massachusetts Electric Company's first delivery rate case in ten years.
- Technical advisor to the Maine Public Utilities Commission regarding the public convenience and necessity of the state-wide Maine Power Reliability Project consisting of 37 separate projects totaling more than 350 miles of 115 kV and 345 kV facilities and evaluation of those projects against non-transmission alternatives across the State of Maine.
- Technical advisor for Structural Bridge Corporation regarding electrical interconnection requirements for its plant expansion, making it the largest bridge manufacturer in North America.
- Lead investigator in the review of distribution and transmission practices at Alabama Power and Georgia Power Company.
- Advisor to the New Hampshire Public Utilities Commission in the merger of National Grid and Key Span and in the sale of Verizon's assets to Fair Point Communications.
- Lead investigator in prudence reviews of major fossil and nuclear plant outages and power purchases for the New Hampshire Public Utilities Commission.

- Principal technical and analytical member in the Seabrook nuclear unit sale team acting for the New Hampshire Public Utilities Commission.
- Investigator of the causes of overlapping unit outages at a major Reliant generation facility.

New Hampshire Public Utilities Commission - Chief Engineer

- Managed a professional staff of engineers and analysts engaged in investigations regarding safety, reliability, emergency planning, and the implementation of public policy in the electric, gas, telecommunications and water industries.
- Prime architect of the settlement between the State of New Hampshire and Public Service Company of New Hampshire (PSNH) that ended years of litigation and allowed state-wide competition in the electric industry to proceed.
- A lead investigator for the Commission in the proposed merger of Consolidated Edison and Public Service Company of New Hampshire.
- Investigated the operation and outages of the fossil and nuclear facilities of the Public Service Company of New Hampshire.
- Advisor to the Commission on utility system and operational issues including those of alternative energy generation.
- Decision-maker on the Site Evaluation Committee responsible for siting major electric and gas production and transmission facilities.
- Decision-maker at the New Hampshire Office of Emergency Management's Emergency Operations Center.
- Re-drafted the state's Bulk Power Siting Statute and facilitated resolution of widespread legislative tensions.
- Sat as designated member for the New Hampshire Public Utilities Commission Chairman on the State Emergency Response Commission.
- Instrumental in achieving quality of service levels among the highest in Verizon's service territory.

Public Service Company of New Hampshire (PSNH)

- As Director - Power Pool Operations and Planning, PSNH
    - Responsible for the operation and dispatch of PSNH transmission and generation facilities through the New Hampshire Electric System Control Center.
    - Core participant in the merger/acquisition team activities culminating in the corporate reorganization of PSNH. Recognized and developed a successful employee retention program used during the acquisition.
    - Core Task Force Member for the DC electrical interconnection between Hydro Quebec and the New England Power Pool.
    - Developed real time integrated transmission system loading capabilities for the New Hampshire Electric System Control Center.
    - Represented PSNH at all major relevant national and regional reliability organizations including:
        - New England Power Pool

        - System planning Committee
        - System Operations Committee
        - All technical planning and operations task forces conducting regional and inter-regional studies and analyses
    - Northeast Power Coordinating Council
    - Joint Coordinating Council
    - Edison Electric Institute System Planning Committee

- As Director - System Planning/Energy Management, PSNH
    - Coordinated the company's capital planning requirements for generation and transmission, and integrated its load forecasting and energy management activities.
    - A lead participant in the development and implementation of response strategies addressing the negative financial impacts associated with the proliferation of non-utility generation.
    - Ensured that the interconnections of non-utility generation met utility reliability requirements.
    - Re-designed the corporate budgeting system to allocate available resources by economic and need prioritization.
    - Driving force in re-directing corporate economic evaluations towards competitive business techniques.

- As Manager - Computer Department and System Planning, PSNH
    - Responsible for the Engineering Division's computer applications support and transmission system planning functions.
    - Principal in the development, design and implementation of the first-in-the-nation application of 345/34.5 kV distribution. Resolved daytime corporate-wide computer throughput logjam.
    - Integrated the Engineering Department's computer applications into the corporate computer organization.

Education

M.B.A., Northeastern University - 1975
M.S.E.E., Power System Major, Northeastern University - 1970
B.S.E.E., Power System Major, Northeastern University - 1969

Registration

Registered Professional Engineer - New Hampshire #5618

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 16-383
Distribution Service Rate Case

Staff Data Requests - Set 8

Date Request Received: 8/19/16
Request No. Staff 8-63

Date of Response: 9/2/16
Respondent: Christian Brouillard

REQUEST:

Reference Staff 4-3:

The request asked for a complete copy of the Liberty Planning criteria and a complete copy of the previous planning documents including that of National Grid showing all changes. The response included a summary document and a summary of changes. Please supply a complete copy of the document and changes as requested. If no other relevant documents exist, please state that in the response.

RESPONSE:

Please see Attachment Staff 8-63.1 for a copy of the National Grid Planning criteria at the time of the sale. Also see Attachment Staff 8-63.2 for a copy of the Liberty Planning criteria which was modeled from the National Grid Planning criteria. Please note that the Liberty planning criteria has been finalized on 8/30/16. Since late in 2014, Liberty was working off of a draft copy of the planning criteria.

nationalgrid

Distribution Planning Guide

Rev. 1

Approved by: ____________________ **Date:** 2/15/11

Patrick Hogan, Sr. VP
Distribution Asset Management
National Grid USA Service Company

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0	10/14/2009	Initial draft	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning	Patrick Hogan Sr. Vice President Distribution Asset Management
1	2/15/2011	Final approved document	Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	

Distribution Planning Criteria Strategy
Table of Contents

Strategy Statement

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

For normal loading conditions, all types of facilities are to remain within their normal ratings at all times. For N-1 contingency situations it is expected that load shall be returned to service within 24 hours via system reconfiguration through switching, the installation of temporary equipment such as mobile transformers or generators, or by the repair of a failed device. Where practical, switching flexibility should be integrated into the system design to minimize the duration of customer outages following an N-1 contingency to meet reliability objectives. The following shall guide contingency planning on the distribution system:

1.) For the loss of a power transformer or substation bus fault that disrupts distribution load, the following planning criterion applies:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Repairs or the installation of mobile equipment are expected to require 24 hour implementation.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.) For the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

3.) For the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

Application of these criteria will result in somewhat less load at risk than previous criteria in either New York or New England which generally limited load at risk to between 20 and 28 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 1:

Table 1 - Comparison of Capital Costs between Existing and New Criteria

Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in an increase in capital requirements up to $50M/year over the existing criteria for the 15-year period studied.

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities may be required over the next 15years.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long-term strategy and it is expected to take the full 15 year horizon to achieve compliance with existing facilities system-wide.

Performance targets for the adoption of the new planning criteria are:

- Quantification of equipment (sub-transmission lines, transformers, feeders) with load at risk forecast above the guidelines above.
- Identifying high load at risk areas and as part of annual summer preparedness and communicate monitoring plans for the Regional Control Centers.

- Developing project recommendations to eliminate or significantly reduce load at risk areas based on MWHr metrics, reliability performance and mitigation costs.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
0	10/14/2009	Initial draft	Curt J. Dahl Manager, T&D Planning LI John F. Duffy, Jr. Distribution Planning Max F. Huyck Network Asset Planning Jeffery H. Smith Distribution Asset Strategy	Patrick Hogan Sr. Vice President Distribution Asset Management
1	2/15/2011	Final approved document		

Strategy Justification

1.0 Purpose and Scope

This document describes the National Grid Electric Distribution Planning Criteria that will be applied by the Distribution Planning Department in future distribution studies. These criteria are applicable to the New England (NE) and upstate New York (UPNY) areas of National Grid.

A map showing National Grid electric service territory within New England and upstate New York is attached in Appendix A.

The electric distribution system on Long Island, NY shall continue to follow the LIPA Transmission and Distribution Planning Criteria.

This policy shall be reviewed and revised as often as needed to reflect any major standards or criteria changes. It is recommended that a 2-3 year review cycle be performed.

2.0 Strategy Description

2.1 Description of Distribution System

The distribution system of National Grid is comprised of all lines and equipment operated at a voltage below 69kV in New England and below 115kV in New York. The components of the distribution system are distribution substations, sub-transmission lines, and distribution circuits or feeders.

2.1.1 Distribution substations

The distribution substations within National Grid are a mixture of stations with one, two, and three or more transformers. The distribution substations step down voltage to a distribution or sub-transmission level. In Upstate New York approximately 70% of the substations have either a single source or a single transformer. In New England 40% of the substations have a single source and/or transformer.

A typical substation involves a 115/13 kV, 25-40 MVA rated transformer with either a load tap changer built into the transformer or individual voltage regulators applied to the feeders. In many locations, two or three transformers are within one substation and will interconnect via bus tie breakers. Many of the distribution substations supplied by the 115kV circuits also include one or more capacitor banks for reactive support.

National Grid maintains approximately 680 distribution substations containing approximately 1,530 power transformers. The total number of distribution substations, transformers, circuit miles of overhead and underground within NE and UPNY is listed in Distribution Line Overarching Strategy paper dated July 2008.

2.1.2 Sub-Transmission systems

The sub-transmission system within National Grid is designed to provide adequate capacity between transmission sources and load centers at reasonable cost and with minimal impact on the environment. The National Grid sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are neither bulk transmission nor distribution. The typical voltages for the sub-transmission system include 46, 34, and 23 kilovolts. In New York, the sub-transmission also includes the 69 kV.

Sub-transmission systems may be designed in a closed or open loop system originating from transmission substations, and generally providing a redundant supply for distribution substations. In other cases, a single radial sub-transmission supply line may serve load. The substations served from a sub-transmission line will serve approximately 10-40 MW of load depending on the voltage.

Generally, the sub-transmission system is presently designed with conductors ranging from 336.4 ACSR (UPNY) to 795 kcmil AAC (NE) overhead conductor and from 500 to 2000 kcmil copper underground conductor. However, most of the sub-transmission lines are older designs and built with smaller wire such as 2/0 AWG copper installed along right-of-ways or on public streets.

There are approximately 930 sub-transmission lines in New England and upstate New York within National Grid.

2.1.3 Distribution Feeders

Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductor. Feeders are designed in a radial configuration. The feeder mainline will typically have several normal open tie points to one or more adjacent feeders for backup. Protection for faults on the feeders consists of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits.

The National Grid Primary distribution system in New England and upstate New York is comprised of approximately 3,770 feeders.

2.1.4 Secondary Networks

Low voltage secondary networks have historically been employed in several urban areas to maximize the reliability for the customers in these areas. They typically have a 120/208V class secondary system that is connected as a grid with many downtown customers connected. Most of the secondary networks have from 4-10 supply feeders. The low voltage secondary network supply feeders will typically have 10-30 network transformers connecting into the secondary grid.

Spot secondary networks are used in areas to serve specific large loads in urban areas. Some of these are served at 120/208V, while others are served at 277/480V. Typically, 2-3 supply feeders are used to serve the spot networks.

2.2 Distribution Planning Criteria

2.2.1 General Items impacting the Distribution Planning Criteria

2.2.1.1 Load Forecasting

The load forecast used by Distribution Planning for New England and New York will be based on a regional econometric regression model that considers historic loading, weather conditions, various economic indicators. The forecast is adjusted for known spot load additions and DSM forecasts. Presently, distribution planning is based on a forecast that considers loading during extreme weather conditions such that those weather conditions are expected to occur once in 20 years. Separate models are used for NE and UPNY.

2.2.1.2 Equipment Ratings

Distribution Planning maintains equipment ratings for New England and New York. The summer and winter normal and summer and winter long time emergency (LTE) ratings will be used. The major equipment ratings to be used by Distribution Planning relate to transformers, overhead lines, and underground cables. The normal and LTE rating limits for these items may be applied for the time associated with each rating. Generally, the durations for emergency loading are as listed below in Table 2. System operators must be aware of the limiting factor involved in any contingency:

Table 2 - Equipment Rating Durations

Equipment		Normal	LTE	STE
Transformer		Continuous	24 hour	15 Min
Overhead Line		Continuous	24 hour	N/A
Underground Cable		Continuous	24 hour	N/A

There is also a short time emergency rating which may be determined for substation transformers, in no instance should this rating exceed 200% of nameplate rating. In addition to the items in the above table, ratings are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers.

2.2.1.3 Planning Study Areas

A planning study area within National Grid is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. Some areas are totally independent, while others will have points of interconnection with other study areas. A listing of the planning study areas that exist in NE and UPNY to be used by Distribution Planning are presented in Appendix B.

2.2.1.4 Load Flows

Distribution planning studies will utilize the PSS/e load flow program for the study of the sub-transmission lines and networks. The distribution feeder load flow analyses will be done using the Cymedist feeder analysis software program.

2.2.1.5 Distribution Analysis Alternatives

When performing distribution system analyses, Distribution Planning shall consider both traditional capacity enhancements as well as alternatives for "Non-Wires" customer load management alternatives where appropriate. The factors below could impact capacity planning analysis

a. Distributed Generation
b. Controllable Load Curtailment
c. Energy Storage devices
d. Demand Side Management

e. Distribution Automation
f. Smart Grid solutions

2.2.2 Distribution Substation Transformer Planning Criteria

2.2.2.1 Normal transformer load planning criteria

A substation transformer will not be loaded above its Normal rating during non-contingency operating periods.

2.2.2.2 Contingency N-1 substation transformer planning criteria

For an N-1 contingency condition that would involve the loss of a power transformer or substation bus, the following planning criteria apply:

- The initial load increase at the remaining transformers within the area must not exceed either the summer or winter STE rating or 200% of nameplate.
- Load will need to be transferred or shed in a reasonable number of steps to reduce loading to the summer or winter LTE level within 15 minutes.
- Substations will be designed to allow the installation of a mobile transformer within a maximum of 24 hours for a failed transformer.
- Load on remaining transformers will be reduced to the summer or winter normal limit within 24 hours.
- Feeder ties within the area can be utilized to their emergency limits. Cascading of load between feeders and substations may be needed to reduce loading to normal limits within the time frames required.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 10MW.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.2.3 Automatic transfer of load

Many locations with two or more transformers at a substation utilize automatic bus transfers. In some stations, one bus tie breaker is used, while in other substations a breaker and half design is utilized and there may be several feeder bus tie breakers. Based on the loading limitations in Section 2.2.2.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during an N-1 contingency. Cases where automatic restoration are disabled will be documented and communicated with Regional Control Centers as part of an annual summer preparedness review. Recommendations to add capacity to the area will be evaluated and prioritized based load at risk, reliability and cost with other Load Relief alternatives.

When available, the use of the Energy Management System (EMS) control shall be implemented as needed to block automatic transfer. During an N-1 contingency, the System Operator will be required to maintain the loading on transformers as specified in Section 2.2.2.2.

2.2.2.4 Substation reactive support criteria

Reactive compensation shall be required for substations in the form of station capacitor banks or static VAR compensators. These should be sized to offset the reactive losses of the transformers at full load. Two or three stage capacitor banks may be needed for larger transformers to manage power factor and to limit voltage fluctuations.

2.2.2.5 Impact of planned maintenance

Capacity in all areas should allow the off loading of any distribution substation transformer for planned maintenance during the off peak months without exceeding the normal ratings of the other area equipment. However, in areas of the system with limited feeder ties, it may be more economical to allow the installation of a mobile transformer for maintenance.

2.2.3 Distribution Sub-transmission Planning Criteria

2.2.3.1 Normal sub-transmission load planning criteria

A sub-transmission supply line will not be loaded above its normal rating during non-contingency operating periods.

2.2.3.2 Contingency N-1 sub-transmission planning criteria

For an N-1 contingency condition that would involve the loss of a sub-transmission supply line, the following planning criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Load on the remaining sub-transmission line will need to be reduced to normal levels within 24 hours.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- Every effort must be made to return the failed sub-transmission line to service within 12 hours.
- The limit of load at risk for the loss of any sub-transmission line will be 20MW.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined, considering all substations served via the supply line.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 240MWHrs of load is at risk at peak load periods for a single line fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.3.3 Automatic line transfer systems

Auto transfer of load on the sub-transmission may be employed, but may not exceed the emergency (LTE) ratings of the remaining supply lines. When available, EMS control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed.

2.2.3.4 Sub-transmission reactive support criteria

Reactive compensation for sub-transmission lines shall be required in the form of station and distribution capacitor banks.

2.2.4 Distribution Feeder Planning Criteria

2.2.4.1 Normal feeder load planning criteria

A distribution feeder circuit will not be loaded above its normal rating during non-contingency operating periods.

2.2.4.2 Contingency N-1 feeder planning criteria

For an N-1 contingency condition that would involve the loss of a distribution feeder, the following planning criteria apply:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies.
- Following a contingency, all adjoining tie feeders can be loaded to their maximum thermal emergency or LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- Contingency risk shall be quantified via a MWHr metric calculated by determining the duration load is expected to be out of service at peak loading conditions considering a switch before fix restoration process.
- If more than 16MWHrs of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

2.2.4.3 Automatic transfers on feeders

In some cases, it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers.

2.2.4.4 Feeder reactive support criteria

Reactive compensation for feeders should be installed to provide additional capacity, improve voltage regulation and meet external power factor standards where applicable. A mixture of fixed and switched capacitor banks may be used as needed. All feeders in a planning area shall have proper reactive compensation prior to any requests for other load relief infrastructure improvements.

2.2.4.5 Feeder load balance criteria

Distribution Planning studies are based on three phase average loading. Load balance between the three phases on any feeder is assumed to be within a reasonable level.

Distribution feeder load balance shall require correction of the load imbalance for either of the following cases:

- Any feeder with the calculated neutral current exceeding 30% of the feeder ground relay pickup setting.

- Any feeder exceeding 100A between the high and low phase amps.

2.2.5 Network criteria

Secondary network criteria and loading limitations are defined in the National Grid distribution standards. The criteria are different for NE and UPNY based on the history of how various networks evolved.

2.2.6 Voltage criteria

2.2.6.1 Allowable Voltage Range at Service Point for Distribution Customers

The normal and emergency voltage to all customers shall be in line with limits specified by state regulators and within the limits of ANSI C84.1

These upper and lower voltage limits for each state in the service territory are listed in Table 3 below:

Table 3 - Voltage Requirements by State

State	Upper	Nominal	Lower
Massachusetts	126	120	114
New Hampshire	126	120	114
New York	123	120	114
Rhode Island	123	120	113

The values in Table 3 are in line with the National Grid Overhead Construction Standards.

Voltage on the sub-transmission and primary feeders is determined by many factors including:
- Primary mainline conductor sizes
- Distance of lines
- Reactive compensation

Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or padmounted line regulators. Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 3 above are maintained.

2.3 Residual risk and project prioritization

2.3.1 Residual risk after compliance with new criteria

The goal of the new planning criteria is to maintain the performance of the electric distribution system. Generally, after compliance with the new criteria, the residual risk for the worst case will be 10 MW of load out for 24 hours for a substation transformer failure or 20 MW out for 12 hours for an overhead supply line failure.

2.3.2 Methodology to prioritize capital projects

Prioritization of capital projects utilizes scoring system that considers the consequence of not completing the project and the probability that the consequences will be realized. A risk score between 1 and 49 is developed utilizing a 7x7 scoring matrix.

3.0 Risks/Benefits

The principal impacts of the planning criteria are reliability performance, customer service and efficiency. Due to the extended time frame for strategy compliance, the impact of the strategy will not be initially visible at the system level. These benefits will be most apparent in those areas where it has been implemented.

3.1 Safety & Environmental

Safety and environmental factors are not principal drivers of the planning strategy. However, the planning criteria will ensure equipment loading is maintained within accepted ratings reducing the risk of premature equipment failure that could result in environmental and public safety concerns.

3.2 Reliability

The planning criteria will provide operating flexibility to facilitate the restoration of customer outages following an N-1 contingency event. With an expected long implementation schedule, the impact will not be initially visible at the system level but will be significant in the areas where the criteria have been implemented. A long range reliability improvement of 11.4 minutes in SAIDI and 0.073 in SAIFI on a system basis is forecasted if the strategy is implemented over a 15 year planning horizon. Additionally, lower feeder loading will support future distribution automation to further improve reliability.

3.3 Customer/Regulatory/Reputation

The customer benefit associated with planning criteria is significant. Improved system reliability and lower equipment loading provide greater flexibility in serving both existing and new customers.

3.4 Efficiency

The planning strategy provides a consistent approach for feeder/substation and study area loading analysis across NE and UPNY. All studies being conducted under one criterion will create a consistent reference for ranking projects as part of the business planning process.

4.0 Estimated Costs

The estimated costs to adopt the new planning criteria are summarized as follows:

The capital cost associated with meeting the existing and proposed criteria for both normal and N-1 contingency conditions in New England and upstate New York are shown in Table 4:

Table 4 - Comparison of Capital Costs between Existing and New Criteria

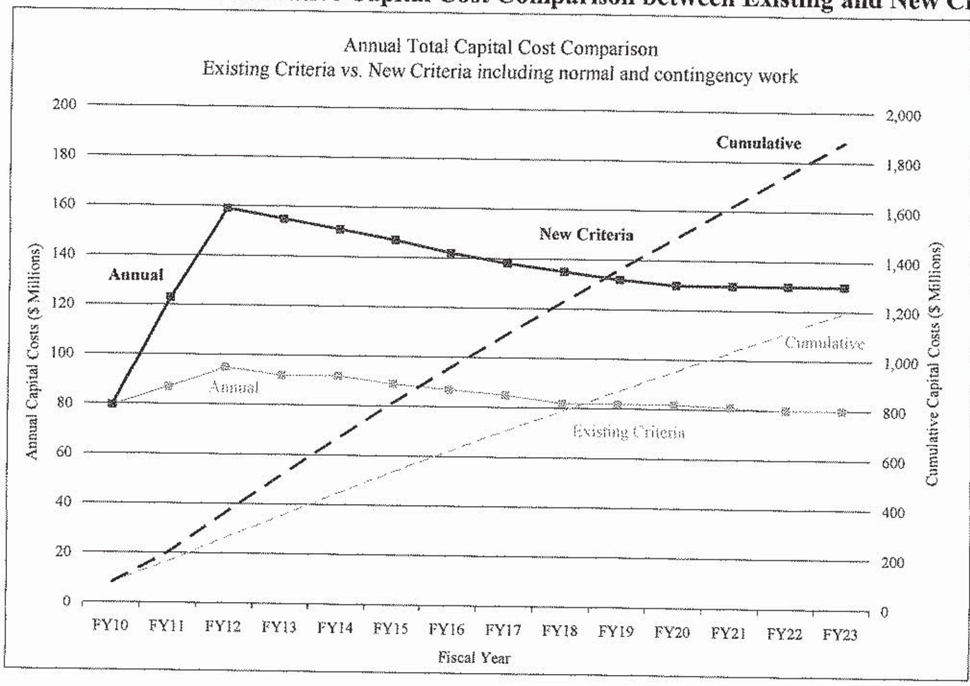
Criteria	Present Value ($ Millions)	15 Year Annualized ($ Millions)
Existing NE/NY Criteria	$800	$80
New Criteria	$1,250	$130

The new criteria may result in increased in capital costs of $50M/year in the Load Relief budget category compared to previous criteria for the 15-year period studied.

Based on an analysis of normal loading issues, it is projected that capital work associated with normal loading will remain at present levels or slightly higher for several years and then ramp down as contingency projects will tend to drive the load relief spending.

These combined normal and contingency capital costs are shown in Figure 1 below:

Figure 1 - Annual and Cumulative Capital Cost Comparison between Existing and New Criteria



5.0 Implementation

Based on the results of the sample areas (expanded to the overall system) the following approximate quantities of additional facilities are forecasted to be required over the next 15 years in NE and UPNY.

Transformers (at existing or new substations)	180
Sub-Transmission Lines	46
Distribution Feeders	319

The new criteria will be applied to new installations and/or significant rebuilds initially. This is a long term strategy and it is expected to take many years to implement system-wide.

6.0 Data Requirements

The data sources required for the proper execution of the planning strategy include:

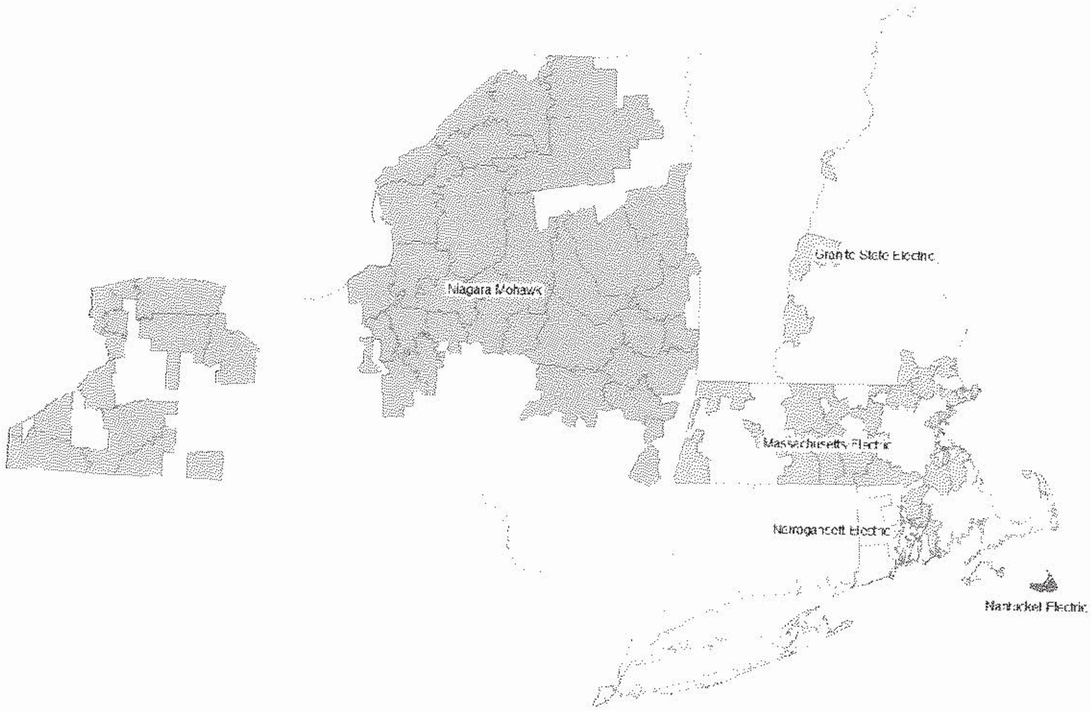
6.1 Planning Tools:

Cymedist (Cyme) – for radial feeder load flow and voltage analysis
Smallworld GIS – to support Cyme analysis
PSS/e – for network load flow analysis
FeedPro - for equipment loading and ratings
EMS and PI or ERS access in NE and UPNY

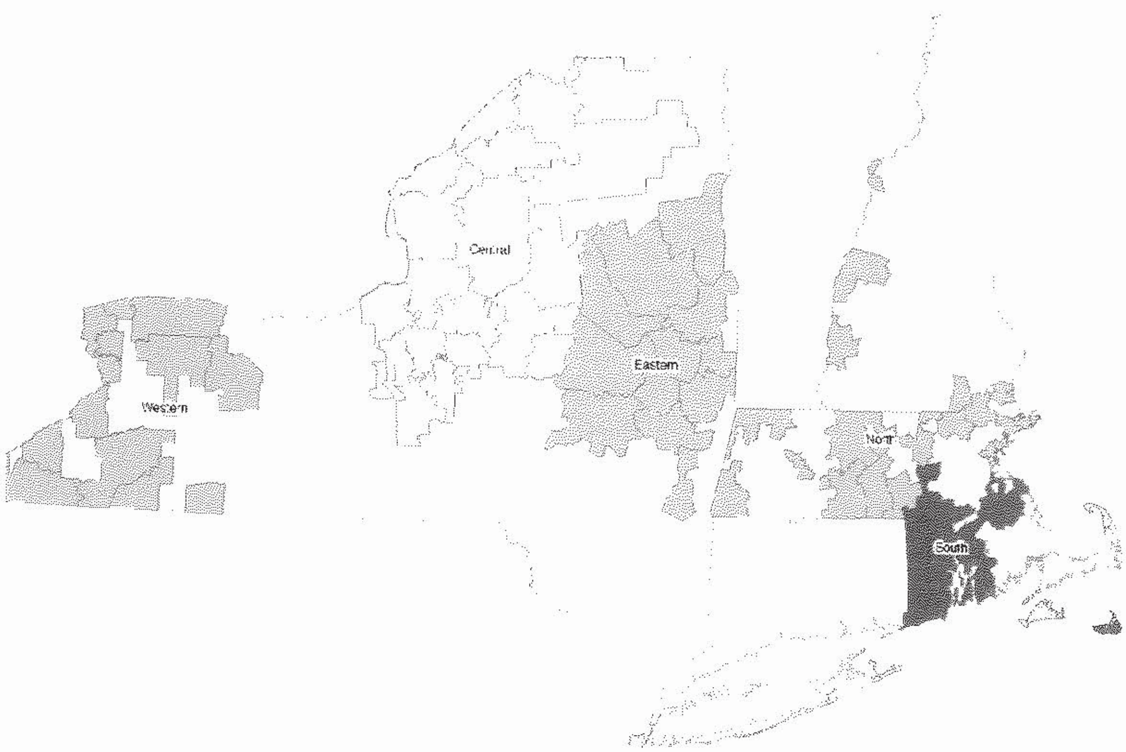
Appendix A – Service Territory Maps

Maps of Electric Distribution Service Territories for five companies and five divisions:

Companies

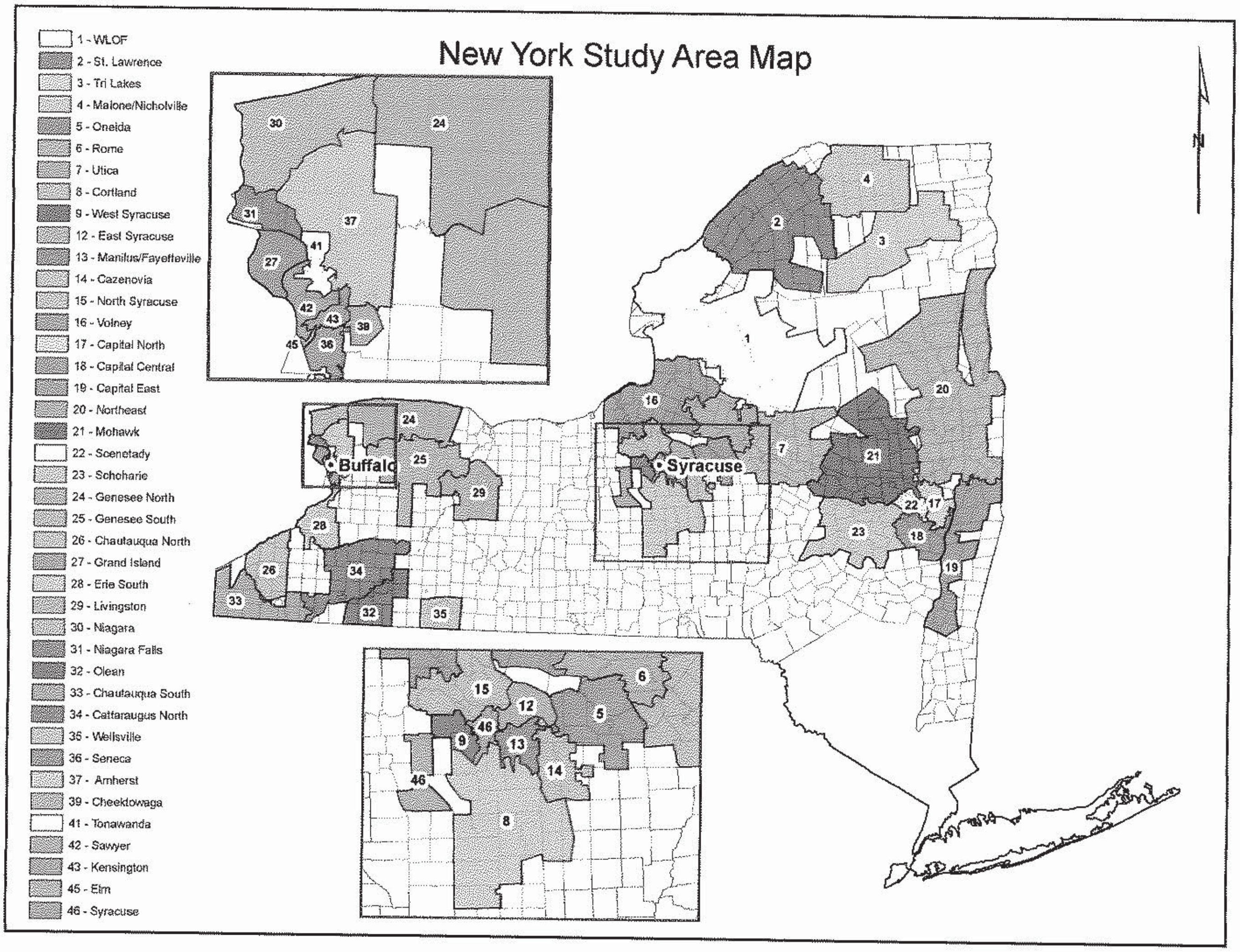


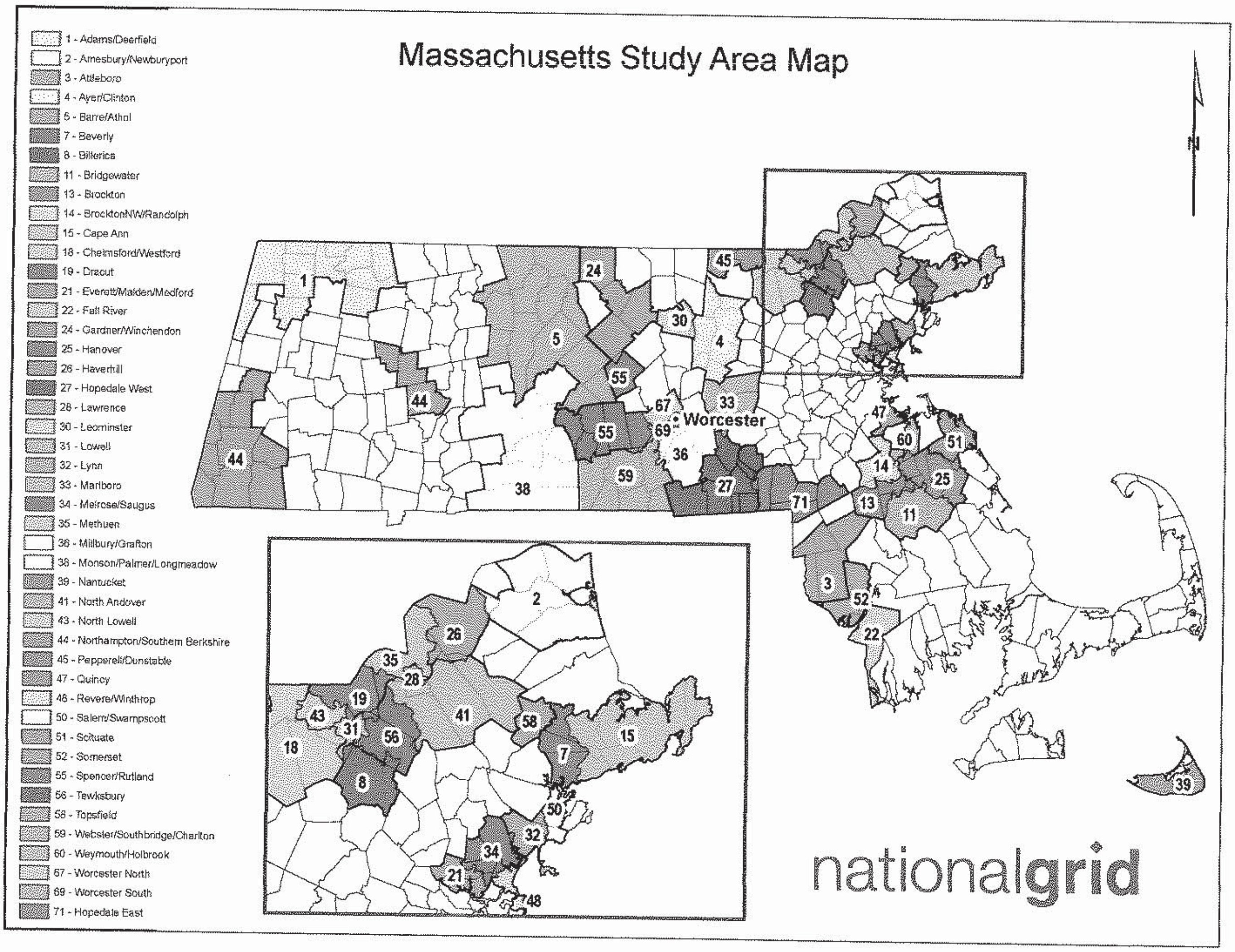
Divisions

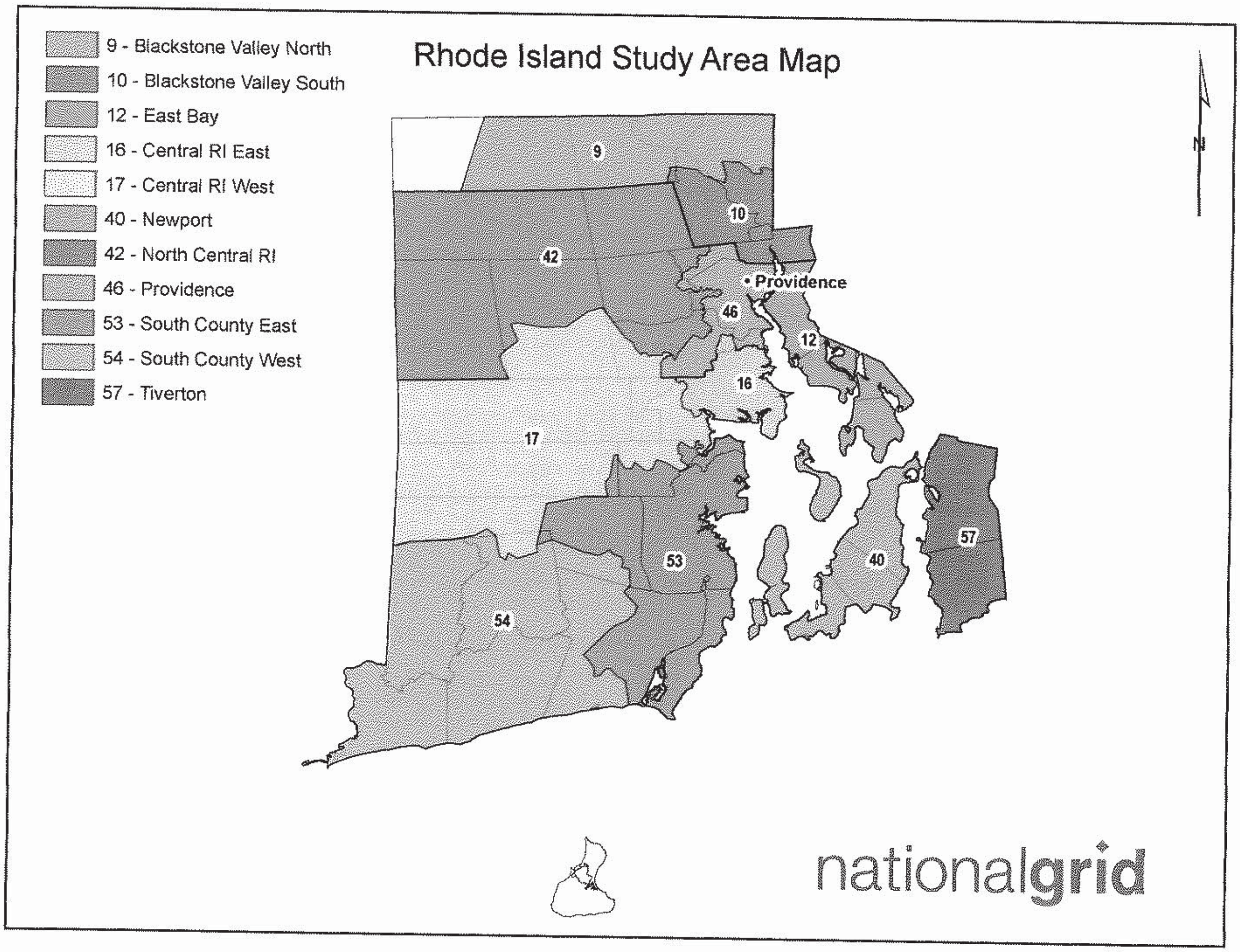


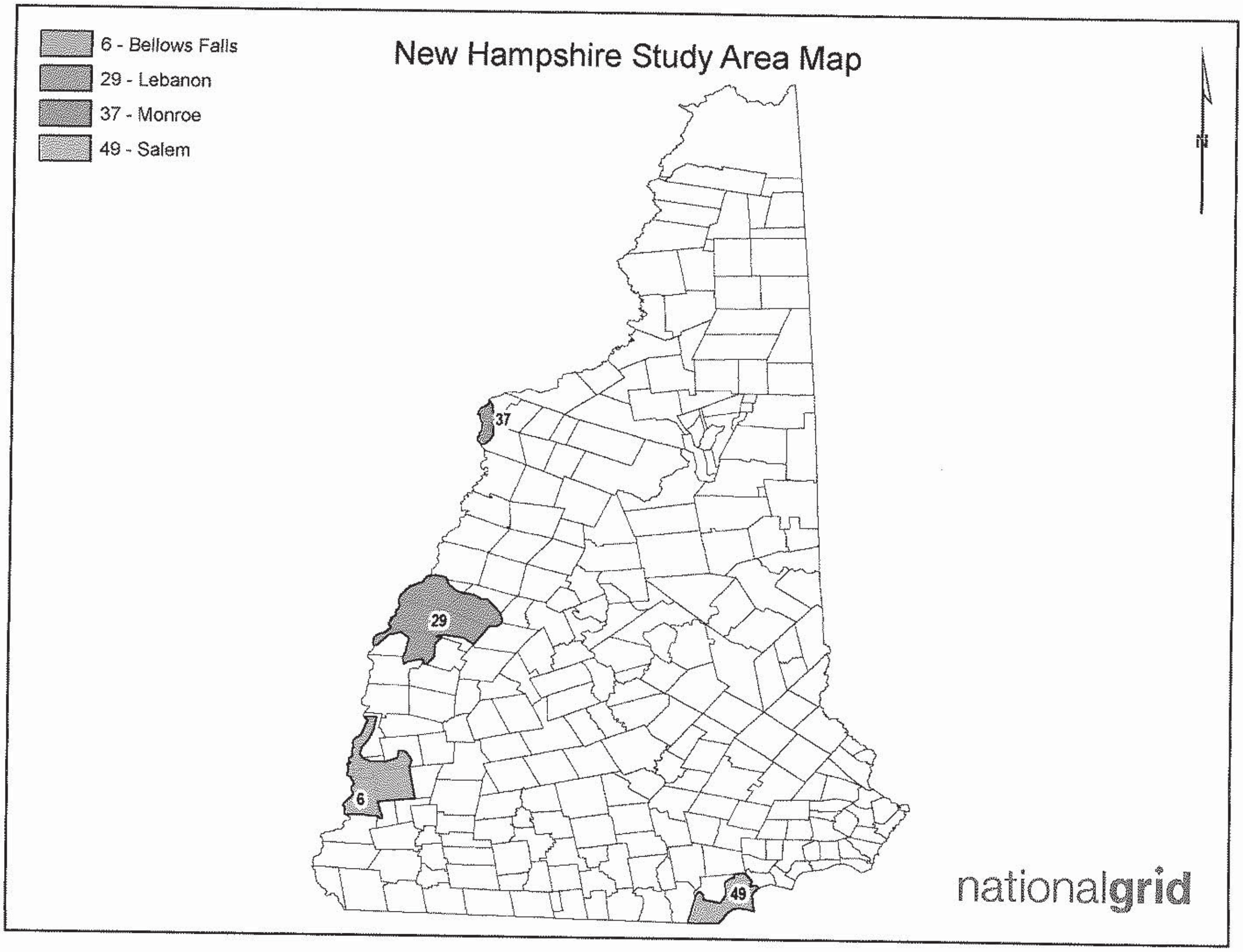
Appendix B - Distribution Planning Study Areas

To foster the annual capacity planning assessment, the distribution system across UNY and NE has been segmented into Planning Study Areas as shown in the following figures.




Massachusetts Study Area Map
1 - Adams/Deerfield
2 - Amesbury/Newburyport
3 - Attleboro
4 - Ayer/Clinton
5 - Barre/Athol
7 - Beverly
8 - Billerica
11 - Bridgewater
13 - Brockton
14 - BrocktonNW/Randolph
15 - Cape Ann
18 - Chelmsford/Westford
19 - Dracut
21 - Everett/Malden/Medford
22 - Fall River
24 - Gardner/Winchendon
25 - Hanover
26 - Haverhill
27 - Hopedale West
28 - Lawrence
30 - Leominster
31 - Lowell
32 - Lynn
33 - Marlboro
34 - Melrose/Saugus
35 - Methuen
36 - Millbury/Grafton
38 - Monson/Palmer/Longmeadow
39 - Nantucket
41 - North Andover
43 - North Lowell
44 - Northampton/Southern Berkshire
45 - Pepperell/Dunstable
47 - Quincy
48 - Revere/Winthrop
50 - Salem/Swampscott
51 - Scituate
52 - Somerset
55 - Spencer/Rutland
56 - Tewksbury
58 - Topsfield
59 - Webster/Southbridge/Charlton
60 - Weymouth/Holbrook
67 - Worcester North
69 - Worcester South
71 - Hopedale East
Worcester
N
nationalgrid


Rhode Island Study Area Map
9 - Blackstone Valley North
10 - Blackstone Valley South
12 - East Bay
16 - Central RI East
17 - Central RI West
40 - Newport
42 - North Central RI
46 - Providence
53 - South County East
54 - South County West
57 - Tiverton
N
Providence
9
10
42
46
12
16
17
53
40
57
54
nationalgrid


6 - Bellows Falls
29 - Lebanon
37 - Monroe
49 - Salem
New Hampshire Study Area Map
N
37
29
6
49
nationalgrid

Liberty Utilities WATER GAS ELECTRIC		Liberty Utilities 15 Buttrick Rd Londonderry, NH 03053		
Description:	**Electric Distribution Planning Criteria**	Revision #:	2.0	Page 1 of 24

Contents

1.0 INTRODUCTION

This document describes the Distribution Planning Criteria and Strategy that will be used by the Liberty Utilities Engineering Department to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA"). A PSA is a group of distribution facilities, including substations, feeders, transformers, and sub-transmission lines, within a specific geographic area that are interconnected and are studied as a group. There are four PSAs in Liberty's service territory: Salem, Lebanon, Bellows Falls and Monroe. See Attachment A for Liberty Utilities Planning Study Area Map. The review and evaluation of each PSA is to be documented in a report ("Distribution PSA Study") that describes the assumptions, procedures, economic comparison, conclusions, and recommendations for the PSA. Liberty will conduct a PSA Study periodically, or when conditions within the PSA change, such as: changes in overall PSA demand forecast; changes in how load is distributed within the PSA; significant load additions; and/or other changes in conditions that warrant a PSA Study.

When preparing a PSA Study, Liberty will consider wires and non-wires alternatives to address system needs, such as those listed in Table 1 below.

Table 1. Distribution System Planning Alternatives

Wires Alternatives	Non-Wires Alternatives
• Load Balancing • Power Factor Improvement • Reconductoring/Recabling • Circuit and Substation Equipment Upgrades • Voltage Conversions (e.g. 4kV to 13.2kV) • Feeder reconfigurations	• Distributed Generation • Controllable Load Curtailment • Energy Efficiency • Energy Storage Devices • Demand Side Management • Distribution Automation • Smart Grid Solutions (Ex: Dynamic Ratings, Real Time Load Transfers and Capacitor Activation, etc.)

1.1 Objective

The goal of these planning criteria is to provide adequate capacity for safe, reliable and economic service to customers with minimal impact on the environment. To achieve that goal, the distribution system is planned, measured, and operated with the objective of providing electric service to customers under system intact conditions (i.e., "normal") and first contingency conditions ("N-1").

1.2 New Planning Criteria

Since the purchase of the New Hampshire electric assets from National Grid in 2012, Liberty Utilities has refined the distribution planning criteria to better fit Liberty's strategy and scale of facilities.[1] These refinements, such as reducing the normal operating ratings limit from 100% to 75% on feeders and transformers and from 100% to 90% on supply lines, reflect Liberty's strategy of having sufficient capacity available to meet changes in demand, including new customer demand, to improve operations during emergency conditions, and to allow more time for the planning, analysis and construction, as needed, of new facilities. In addition the refinements reflect the operating parameters of Liberty's smaller distribution footprint and resource base.

Table 2 shows an estimate of additional facilities that may be required as a result of new planning criteria for the entire system over the next 15 years, based on the results of a sample of areas.

Table 2. Additional Facilities as a Result of New Criteria

Asset	Additional Quantity Required
Transformers (at existing or new substations)	0
Sub-Transmission Lines	0
Distribution Feeders	7

The new criteria will be scaled in over a 15-year period, and initially, will be applied to new installations and/or significant rebuilds initially. The criteria shall be reviewed and refined further, as needed, to reflect any major changes in standards or operating criteria.

2.0 PLANNING CRITERIA SUMMARY

The planning criteria are used to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA"). The planning criteria are a critical input to identifying system deficiencies in Liberty's distribution planning process. See Figure 1 for the planning process. The planning criteria described in this document provides the framework to identify normal and emergency conditions, the acceptable equipment ratings under these conditions, and the corrective action required when the criteria is exceeded.

[1] Attachment B provides a summary of the changes to Liberty's new criteria from the previous criteria under National Grid.

For normal loading conditions, the planning criteria are based on feeders and transformers to remain within 75% of normal ratings at all times and supply lines to remain within 90% of normal ratings at all times.

For N-1 contingency situations, the planning criteria is based on interrupted load returning to service via system reconfiguration through switching, installation of temporary equipment, such as mobile transformers or generators, and/or by repair of a failed device. Where practical, at least three feeder ties are planned for each feeder for switching flexibility and are integrated into the system design to minimize the duration of customer outages to meet reliability objectives.

The following criteria summarized in Table 3 shall guide planning on the distribution system:

Table 3. Distribution System Design Criteria Summary

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	• Loading to remain within 90% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced. • Each feeder should have at least three feeder ties to adjacent feeders.
N-1 Contingency, which results in facilities operating above their Long Term Emergency (LTE) rating but below their Short Term Emergency (STE) rating.	• Load must be transferred to other supply lines in the area to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 36 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby transformers to within their LTE rating. • Repairs or installation of Mobile Transformer expected to take place within 24 hours. • Evaluate alternatives if more than 60 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby feeders to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 16 MWhr of load at risk results following post-contingency switching.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables	• Loads must be reduced within 15 minutes to operate within their LTE rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables

3.0 DESCRIPTION OF THE DISTRIBUTION SYSTEM

Liberty's distribution system consists of lines and equipment operated at a voltage at or below 23 kilovolts ("kV"). The components of the distribution system include: distribution substations, sub-transmission lines, and distribution circuits or feeders.

3.1 Distribution Substations

The distribution substations within Liberty Utilities are a mixture of stations with one, two or three or more transformers. A typical substation consists of 23/13 kV, 5-10 MVA rated transformers with individual voltage regulators applied to the feeders. Some distribution substations are supplied by the 115 kV circuits and are jointly owned by Liberty Utilities and National Grid. Liberty Utilities and National Grid maintain approximately 16 distribution substations containing approximately 26 power transformers in the Liberty Utilities' service territory. Liberty Utilities anticipates that the distribution planning criteria will, in general, be applied to both Liberty and New England Power assets serving Liberty customers, however all 115kV transformers serving Liberty customers are owned and maintained by National Grid. System Non-Wires and Wires solution alternatives will be developed along the lines of these criteria recognizing, however, the unique nature of transmission supply contingencies on the distribution system.

3.2 Sub-Transmission System

The sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are considered neither bulk transmission nor distribution. The voltages for Liberty's sub transmission system include 23 and 13.8 kV. The voltages for National Grid sub transmission system include 46 kV. The sub-transmission system is designed in an open loop or "radial" system and generally provides a redundant supply for distribution substations. The sub-transmission system is presently designed with conductors ranging from 336.4 ACSR to 1113 thousand circular mils ("kcmil") overhead conductors and from 500 to parallel 1000 kcmil copper underground conductor. There are eight sub-transmission lines that are maintained by Liberty Utilities.

3.3 Distribution Feeders

The distribution feeders from each substation are in a "radial" configuration with provisions for manual or automatic transfer of load between feeders, including feeders from adjacent substations. Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductors. Protections for faults on the feeders consist of relays at the circuit breaker, automatic circuit reclosers at points on the mainline and fuses and trip savers on the branch circuits. The Liberty Utilities distribution system is comprised of approximately 41 feeders ranging from 2.4kV to 13.2kV.

4.0 EQUIPMENT RATINGS

Thermal limits are recognized for all system elements in conducting planning studies. Current in equipment and lines are limited so that voltage drops are held to reasonable values; so that conductors will not be severely annealed or damaged; so that switches, connectors, etc. will not be overloaded and that clearances are not exceeded. Several factors are taken into account, including: 1) ambient temperatures, 2) load cycles, 3) wind velocities, and 4) potential loss of life of equipment.

Liberty's Distribution Planning Department maintains equipment ratings for all major equipment, including transformers, overhead lines, and underground cables. Overcurrent protection system settings are also taken into account where applicable.

4.1 Overhead Conductors

The current carrying capacity (also known as, "ampacity") of an overhead conductor may be limited either by conductor clearances or maximum allowable operating temperature under a predefined set of reasonably severe summer or winter ambient conditions. The Company's Overhead Construction Standards book lists maximum ratings not to be exceeded for each conductor for normal and emergency operation.

As part of system operation, standard conductor sizes for overhead distribution construction of #2 AAAC, 1/0 AAAC and 477 AAAC or equivalent tree wire have been selected by Liberty Utilities.

The following general guidelines were developed for 13.2 kV overhead distribution lines:

- New single-phase overhead distribution lines should be constructed with #1/0 AAAC and new single-phase underground distribution lines should be constructed with #1/0 AL for loads less than 500kW.
- The single-phase lines should be reconductored to three-phase wherever needed based on operating conditions, phase imbalance and voltage drop.
- New three-phase overhead distribution lines and/or future distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:
    - For loads less than 3,000 kW: 1/0 AAAC
    - For loads greater than 3,000 kW: 477 AAAC
- The single-phase and three phase lines should be reconductored with covered tree conductor or spacer cable wherever needed based on operating conditions in tree prone areas.

The maximum ampacity of an overhead conductor is estimated for Normal (continuous) and Long-Time Emergency (LTE) operations for summer and winter conditions.

4.1.1 Normal Capability

The Normal rating shall be interpreted as the maximum value for normal peak loads on all new and rebuilt feeders. This is done to accommodate emergency conditions where ampacity may be increased for a period of time no greater than 24 hours. The temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, and covered conductors.

4.1.2 Long-Time Emergency Capabilities (24 hours)

The LTE rating shall be interpreted as the absolute maximum ampacity allowed for a given conductor. This ampacity should not be exceeded at any time unless an appropriate engineering review has been conducted. The temperature limit for LTE for 100% ampacity for operating conductor at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, and covered conductors.

4.1.3 Short-Time Emergency Capability (As needed)

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. These are typically less than 15 minutes in duration.

4.2 Underground Cables

Underground distribution line ratings were derived from the October 1957 AIEE paper entitled "The Calculation of the Temperature Rise and Load Capability of Cable System" by J.H. Neher and M.H. McGrath. These calculations integrate all aspects of the cable system design such as conductor material, conductor size, insulation, properties, insulation thickness, cable type, shield connections, load characteristics, installation conditions and environment. Cable ampacities are based on normal and emergency operating conditions. Normal cable ampacities are based on a 90° insulation operating temperature while emergency cable ampacities are based on 130° insulation operating temperature. The Company's underground construction standards book provides estimates of cable ampacity for common sizes and configuration of main line cables. Given the many different aspects of a cable system, specific cable ratings are typically derived using computer software such as Synergee Electric or PC Amp.

New three-phase underground distribution lines or future three-phase underground distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:

- For loads less than 1000 kW: #1/0 AL
- For loads greater than 1000 kW: 500 MCM CU
- For feeder cable getaways: 1000 MCM CU

Ampacities are defined for underground cables as follows:

4.2.1 Normal Ampacity (Continuous)

This is the maximum loading on the cable that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle.

4.2.2 100-300 Hour Ampacity (LTE)

This is the maximum emergency loading on the cable that does not cause the conductor temperature to exceed its applicable emergency value over a period of several consecutive 24-hour load cycles. At the end of the emergency time period, the load on the cable must be reduced to a value within its normal ampacity.

4.2.3 One-Hour to 24-Hour Emergency Ampacities (STE)

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. These are the maximum emergency loadings on the cable that do not cause the conductor temperature to exceed its allowable emergency value at any time during the period. At the end of the emergency time period, the load on the cable must be reduced so that the peak load in the next load cycle does not exceed the LTE ampacity (defined above).

4.3 Transformers

Distribution substation transformers are rated for loading according to the American National Standards Institute ("ANSI") standards for maximum internal hot spot and top oil temperatures. This is detailed in the Institute of Electrical and Electronics Engineers ("IEEE") Guide for Loading Mineral-Oil-Immersed Power Transformers up to and including 100 MVA with 55°C, or 65°C, winding temperature rise (ANSI/IEEE C57.91 latest version). The manufacturer's factory test data and the experienced 24-hour loading curve data are used in an iterative computer program that calculates allowable loading levels.

The transformer's "ratings" for the Normal ("N"), Long Term Emergency ("LTE"), and Short Term Emergency ("STE") load levels are identified based upon maximum internal temperatures and selected values for the loss of the transformer's life caused by its operation at the criteria temperatures for a specified duration, and on a defined load curve. Three categories of transformer capabilities are defined below:

4.3.1 Normal Capability

Winter normal and summer normal capabilities are based on a normal daily load cycle and on the maximum 24-hour average ambient temperature for the period involved. The maximum load for Normal operation of the transformer is determined and set when the operation of the transformer at that level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or the Top Oil Temperature exceeds 110 °C, or the Hot Spot Copper temperature exceeds 180 °C. Conditions above any of these limitations will result in a shortening of the transformer service life beyond prescribed design levels and/or physical damage to the equipment.

4.3.2 Long-Time Emergency Capabilities (1 hour to 300 hours)

These capabilities are based on a normal daily load cycle, with the emergency load increment added. The maximum 24-hour average ambient temperature is used for the appropriate season. The LTE rating of a substation transformer is determined and set when the 24 hour operation of the transformer, with that additional load in each of the hours in the 24 hour load cycle curve, causes a cumulative (24 hour) 3.0% loss of transformer life or the Top Oil temperature to exceed 130 °C, or the hot spot copper temperature to exceed 180 °C.

4.3.3 Short-Time Emergency Capability (15 minutes or less)

The STE rating of a transformer is determined and set when the one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (i.e., 24 hour) 3.0% Loss of Transformer Life or a hot spot copper temperature exceeding 180°C. However, the maximum STE rating is limited to a value equal to twice the transformer's "nameplate" rating (i.e., 200%).

4.4 Other Equipment

Docket No. DE 16-383
Attachment Staff 8-63.2
Page 10 of 24

In addition to the items above, normal and emergency capabilities are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers. Emergency capabilities usually involve elevated temperatures with some potential loss of equipment life. However, any circuit rating may be limited by other circuit equipment such as circuit breakers, disconnects, regulators, et cetera. These ratings are generally based on the allowable maximum temperature of the equipment. The facility (feeder, sub transmission line, and/or transformer) rating is determined by identifying the "limiting device" and applying the rating criteria for that device or equipment.

4.4.1 Distribution Step-Down Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
110%	130%	130%	160%

4.4.2 Circuit Breakers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
107%	123%	115%	130%

4.4.3 Voltage Regulators

The following generic regulator ratings in % of nameplate for 10% regulation are used:

55ºC INSULATION SYSTEM				65ºC INSULATION SYSTEM			
NORMAL		EMERGENCY		NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
125%	148%	125%	148%	141%	160%	141%	160%

4.4.4 Disconnect Switches

The following generic air switches ratings in % of nameplate:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
113%	134%	139%	147%

4.5 Equipment Rating Criteria Summary

The major equipment ratings to be used by planning engineers relate to transformers, overhead lines and underground cables. The normal and LTE rating limits for feeders, sub transmission lines and transformers may be applied for the time associated with each rating. Table 4 summarizes the durations for emergency loading that system operators must be aware of including the limiting factor involved in any contingency. There is also a short time emergency (STE) rating that is mainly used for transformers and must not exceed 200% of nameplate rating. Table 5 summarizes the Equipment Rating criteria, as described in more detail above.

Table 4. Facility Rating Durations

Equipment	Normal	LTE	STE
Feeders	Continuous	24 Hours	As Needed
Sub Transmission lines	Continuous	24 Hours	As Needed
Transformer	Continuous	1 - 300 Hours	15 Minutes

Table 5. Equipment Rating Criteria Summary

	Overhead Conductors		Underground Cables		Transformers	
Condition	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**
Normal	Continuous	• The maximum value for normal peak loads on all new and rebuilt feeders • Temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, & covered conductors	Continuous	• Maximum loading that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle • Normal cable ampacities are based on a 90° insulation operating temperature.	Continuous	• Level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or • The Top Oil Temperature exceeds 110 °C, or • The Hot Spot Copper temperature exceeds 180 °C
LTE	24 Hours	• The absolute maximum ampacity allowed for a given conductor and should not be exceeded at any time. • Temperature limit for 100% ampacity for operating at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, & covered conductors	100 - 300 Hours	• Maximum loading that does not cause the conductor temperature to exceed its design value over several consecutive 24-hour load cycles. • Emergency cable ampacities are based on 130° insulation operating temperature.	1 - 300 Hours	• Level for the peak hour with the emergency load added in the 24-hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer life, or • the Top Oil Temperature exceeds 130 °C, or • the Hot Spot Copper temperature exceeds 180 °C
STE	As Needed	• Estimated conservatively using seasonal ambient data along with circuit specific information by the Engineering Department	1 - 24 Hours	• Maximum loading that does not cause the conductor temperature to exceed its allowable emergency value at any time during a 24-hour load cycle. • Emergency cable ampacities are based on 130° insulation operating temperature.	15 minutes	• The one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer Life, or • a hot spot copper temperature exceeding 180°C. • Maximum STE rating is limited to twice the transformer's "nameplate" rating (200%).

5.0 DISTRIBUTION SUBSTATION TRANSFORMER LOADING CRITERIA

The ratings of transformers are calculated from their thermal heat transfer characteristics and the expected electric loading experience over a 24-hour cycle. All distribution substation transformer bank ratings are evaluated seasonally for their summer and winter values.

5.1 Normal Operation Design Criteria

Normal operation is the condition under which all-electric infrastructure equipment is fully functional. A substation transformer will not be loaded above 75% of its Normal rating during non-contingency operating periods.

5.2 First Contingency Emergency Design Criteria

First contingency operation is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service. For first contingency emergency conditions involving the loss of one distribution substation transformer in an existing two-bank or more configuration, the following system design criteria applies:

- In cases where a first contingency situation causes the LTE rating of the remaining transformer to be exceeded, all load above the LTE rating of the remaining transformers must be transferred to neighboring facilities or shed 15 minutes without exceeding the LTE rating of the substation transformers or distribution circuits receiving the load.
- In cases where a first contingency situation will cause the STE rating of a remaining transformer to be exceeded, load must be immediately reduced (dropped/shed) to a level within the STE. All load between the LTE and STE ratings, and any load that was initially shed to get the remaining transformer below its STE rating, must be transferred to peripheral facilities without exceeding the LTE rating of the substation transformers or the distribution circuits receiving the load.
- Repairs or the installation of mobile equipment are expected to require at least a 24 hour implementation.
- For a typical Liberty owned substation consisting of 9.375 MVA transformers, the quantity of load at risk of being out of service following post contingency switching should be limited to 2.5 MW. If more than 60MWhrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts and the cost to mitigate.

5.3 Automatic Transfer of Load

Locations with two or more transformers at a substation utilize automatic bus transfers. Based on the loading limitations on Section 5.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during a first contingency. Cases where automatic restoration is disabled will be communicated with Electric Control as part of an annual summer preparedness review. Disabling of automatic bus transfer schemes will not be considered as a permanent solution to a criteria violation.

6.0 DISTRIBUTION CIRCUIT LOADING CRITERIA

6.1 Normal Operation Design Criteria

A feeder circuit should be loaded to no more than 75% of capacity during normal conditions. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions and/or provides capacity to serve new business or commercial applications in a timely manner.

After 75% loading is reached, unacceptable voltage levels are often experienced on tap lines and at the end of the feeder.

6.2 First Contingency Emergency Design Criteria

For first contingency emergency conditions on a distribution circuit, the worst of which is the loss of the circuit's getaway cable or circuit breaker. For the loss of a distribution feeder, the following criterion applies:

- Feeders shall tie to neighboring feeders as much as practical as the flexibility to reconfigure feeders has a positive reliability impact for a wide range of possible contingencies. In general, and whenever practical, each feeder should have three feeder ties to neighboring feeders.
- Distribution feeders should be limited to 2,500 customers and sectionalized such that the number of customers does not exceed 500 or 2,000kVA of load between disconnecting devices.
- After transfers, all resultant components must be below the emergency ratings as defined by the appropriate loading guides. All adjoining tie feeders can be loaded to their maximum LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- If more than 16 MWh of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.
- For a typical Liberty owned 10 MW feeder, approximately 8 MW would need to be restored via switching within one hour. The remaining 2 MW would be restored after repairs within 4 hours. Where longer repair times are needed such as for a cable getaway fault, the load out of service should be reduced to 1 MW.

6.3 Automatic transfer on feeders

In some cases it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers or due to automatic reclosing loop schemes in the distribution lines.

6.4 Primary Circuit Voltage Criteria

The normal and emergency voltage to all customers shall be in line with limits specified by the state of NH and within the limits of ANSI C84.1-2006.

These upper and lower voltage ANSI limits, as measured at the customer's meter, are listed below in Table 6:

Table 6. Voltage Requirements for LU

For 120 V – 600 V Systems				
Nominal Voltage (V)	Service Voltage (V)			
	Range A		Range B	
	Max	Min	Max	Min
120	126	114	127	110
240	252	228	254	220
480	504	456	508	440

Source: ANSI

Voltage at the customer meter will be maintained within 5% of nominal voltage (120V). Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or pad mounted line regulators.

Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 7 above are maintained. The ultimate goal is to keep all customers' service voltages within accepted limits. From a supply point of view, the acceptability of voltage regulation is determined at the distribution substation buses. At substations with feeder or bus regulating equipment, the regulation (the extreme range of voltages expressed as a percentage of normal peak load voltage) should be no greater than 10 percent for normal and 15 percent for emergency conditions on the source side of the regulating equipment. Most substation regulating equipment has a range of 20 percent. Under normal conditions, therefore, half the regulator range can compensate for variations in supply voltage, leaving the other half available for voltage drops on the distribution feeders. The substation transformer taps are chosen to allow this control.

6.5 Distribution Circuit Phase Imbalance Criteria

Adding new customer loads to the distribution circuit must be done in the manner to minimize phase imbalance on the distribution system. This criterion is established to limit the load imbalance among the three phases of a primary distribution circuit. Such an imbalance gives rise to return current through the neutral conductor which contributes towards additional losses and voltage drop. Heavily loaded phases overstress the conductors reducing their life and can also lead to their eventual burn down or connector overheating, even at low loadings of the circuit. A high imbalance could also lead to the ground relay operating on the feeder breaker. These criteria call for the correction of phase imbalances of existing and new distribution circuits. Phase imbalance is defined on the basis of connected KVA (CKVA) load for that circuit as:

$$\%imbalance = \frac{(phase\ load - average\ phase\ load)}{average\ phase\ load} X\ 100$$

Two criteria should be met for the circuit to be considered for corrective action:

1. The calculated neutral current should not exceed 30% of the feeder ground relay pickup setting.
2. The loading between the low and high phase should not exceed 100A

Any circuit violating these criteria will be monitored to get actual loading data, and will be corrected if the imbalance is verified. Any new load addition to a circuit should adhere to these criteria.

For all new single phase load additions, the new installation is connected to the phase with the least connected KVA, if it is available, to maintain a balanced circuit.

7.0 SUB-TRANSMISSION LINE LOADING CRITERIA

7.1 Normal Operation Design Criteria

A sub transmission line should be loaded to no more than 90% of capacity during normal conditions. This loading level provides reserve capacity that can be used to carry the load of adjacent supply lines during first contingency N-1 conditions.

7.2 First Contingency Emergency Design Criteria

For first contingency emergency conditions on a supply circuit, the worst of which is the loss of the circuit's getaway cable or circuit breaker. After transfers, all resultant components must be below the emergency ratings as defined by the appropriate loading guides. For the loss of a supply line, the following criterion applies:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 24 hours.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- For a typical LU owned sub-transmission supply line consisting of either 13.8 kV or 23 kV, the quantity of load at risk of being out of service following post contingency switching should be limited to 1.5 MW. If more than 36MWh of load is at risk at peak load periods

for a single fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts and the cost to mitigate.

7.3 Automatic Transfer of Load

Auto transfer of load on the sub-transmission may be employed, but may not exceed the LTE ratings of the remaining supply lines. When available, EMS control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed.

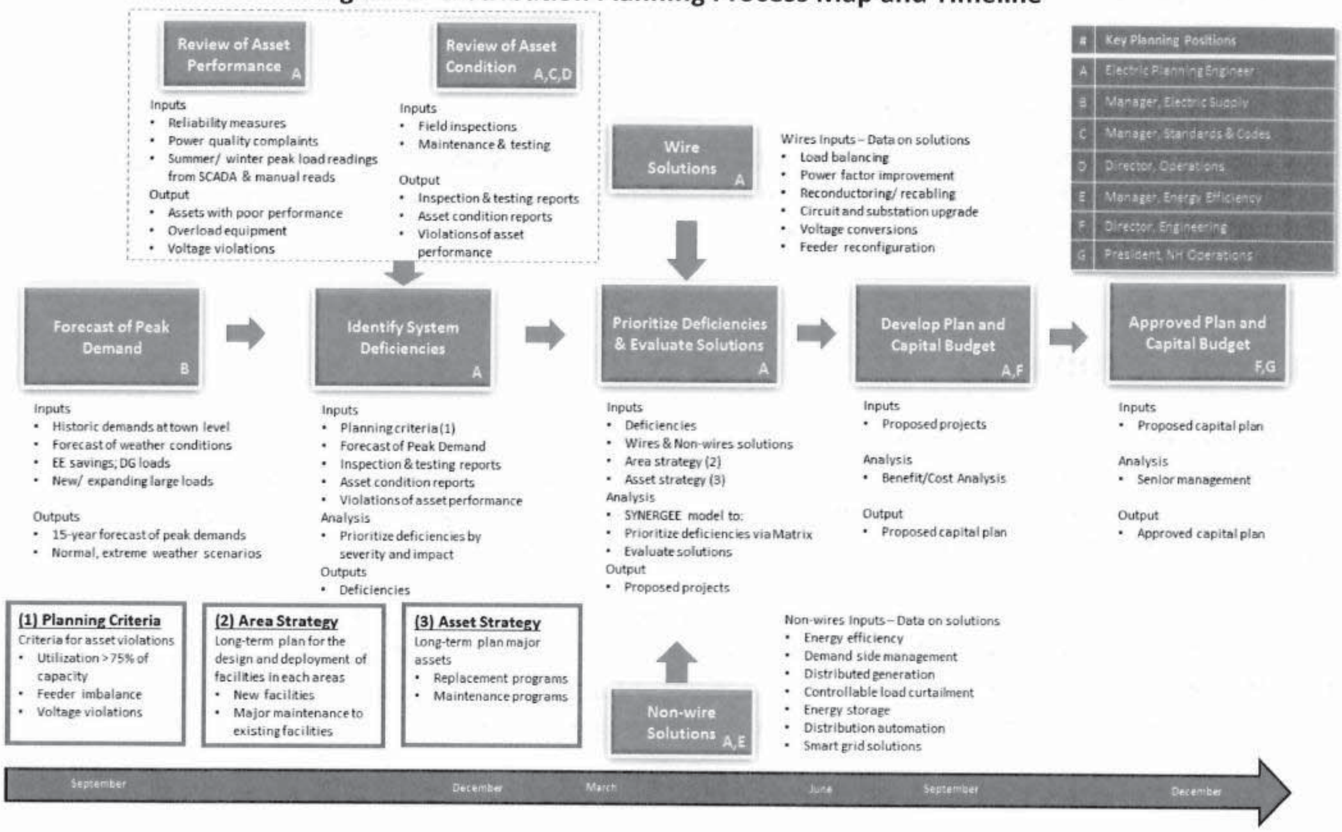
8.0 PLANNING STUDIES

A planning study area ("PSA") within Liberty Utilities is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. PSA's in Liberty's service territory are totally independent from each other. A listing of the planning study areas that exist in the LU service territory are presented in Attachment A.

Liberty conducts an annual capacity planning process covering a 5 year period with inputs from various stakeholders that is intended to meet future customer demands, identify thermal capacity constraints, ensure adequate delivery voltage, and assess the capability of the system to respond to contingencies that might occur. The distribution planning process is illustrated in Figure 1 below:

Liberty Utilities WATER GAS ELECTRIC		Liberty Utilities 15 Buttrick Rd Londonderry, NH 03053		
Description:	Electric Distribution Planning Criteria	Revision #:	2.0	Page 18 of 24

Figure 1. Distribution Planning Process Map and Timeline



8.1 Electric System Planning Criteria and Methodology

8.1.1 Modeling Guidelines

As shown in Figure 1 above, the planning process for designing the Distribution System begins with the load forecast. The PSA load forecast is updated annually. The load forecast at the system level is based on econometric models, and is developed on both a weather-normalized and weather-probabilistic basis. Currently, the Liberty distribution system is modeled for a "peak hour" load level that has a 5% probability of occurrence such that those weather conditions are expected to occur once in 20 years. Specific major known or planned load additions are factored into the load forecast. Historical DSM and DG along with specific DSM/DG installations are also factored into the forecast. The resultant load forecasts are utilized in two types of planning studies which assess the ability of the distribution system to meet future customer load requirements. These studies include (1) Area Studies, and (2) Interconnection Studies, and are described below.

Load flow analyses are used to determine expected circuit overloads and to evaluate alternatives for system reinforcements. Liberty Utilities utilizes the Synergee computer application to model load flows in the distribution system.

Substation circuit breakers are modeled using their rated interrupting capability in the ASPEN™ short circuit analysis computer program. Any breaker that meets or exceeds its rated interrupting capability is targeted for replacement.

Area studies

Are generally 15-year forecast time frames and address specific load areas, including the area supply system, substations, and distribution feeders.

Interconnection studies

System interconnection studies are designed to determine the interconnection facilities and system reinforcements required for specific generation and distribution growth projects to enable them to be effective over the life of the project.

9.0 SYSTEM RELIABILITY

The supply and distribution system in the Liberty Utilities system are designed to limit the interruption of energy delivery for a loss of any single element.

The indices of service reliability are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). The SAIDI measures the total duration of an interruption for the average customer during a given time period. The SAIFI measures the average number of times that a customer experiences an outage during a given time period.

The supply and distribution systems shall be designed so that the annual SAIDI and SAIFI do not exceed the five-year rolling averages, excluding severe weather related events and support a nominal improving five-year reliability trend. When an exceedance does occur, efforts shall be made in the subsequent year(s) to further improve reliability performance to an improving trend level.

10.0 OTHER CONSIDERATIONS

The planning engineer must consider the effect of each plan on all aspects of system design. These include:

- Protection: Protection or Coordination studies are performed when it is needed to adjust relay settings at substations to increase rating of the facility. Settings are carefully selected to avoid miss-coordination and trips due to load imbalance.
- Operation and Maintenance ("O&M"): O&M is taken into account when ranking different project alternatives.
- System Power Factor: Liberty will strive to maintain a 95% power factor at the substations to provide quality power to its customers and limit system losses via the addition of new capacitor banks. In addition, annual Surveys for system power factor will allow Liberty Utilities to properly manage reactive support by adjusting settings from capacitor bank controls.
- Short Circuit Duty: Substation circuit breakers are modeled using their rated interrupting capability in the ASPEN™ short circuit analysis computer program. Any breaker that meets or exceeds its rated interrupting capability is targeted for replacement.

11.0 BENEFITS OF PLANNING CRITERIA STRATEGY

The principal benefits to the planning criteria are improved reliability performance, customer service and efficiency.

11.1 Safety and Environmental

In the long term, the planning criteria will result in overall lower equipment loading. This will translate into improved safety and environmental performance for equipment overload related problems.

11.2 Reliability

The planning criteria will increase operating flexibility and reduce equipment loading. Both of these items support improved reliability performance due to smaller customer interruptions, faster service restoration times and fewer load related interruptions. Additionally, lower feeder loading will support future distribution automation to further improve reliability. The increased operating flexibility will allow for better response to weather related events and major storms.

11.3 Customer and Regulatory

The customer benefit associated with planning criteria is significant. Improved system reliability and lower equipment loading provide greater flexibility in serving both existing and new customers. This increased flexibility creates an opportunity to better meet our obligations to both customers and regulators. Additionally, this planning strategy provides a documented approach to managing our system. This will better support the investment plans needed to implement the loading guidelines outlined in the strategy.

11.4 Efficiency

The planning strategy provides a consistent approach for feeder/substation/supply line and PSA loading analysis across Liberty. All studies being conducted under one new criterion will make way for a consistent

Docket No. DE 16-383
Attachment Staff 8-63.2
Page 21 of 24

reference for ranking studies as part of the budgeting process. Both of these improvements will result in a more efficient organization and a streamlined flow of information from the planning study results into the budgeting process.

12.0 COST ESTIMATES

Application of these criteria will result in somewhat less load at risk than previous criteria which generally limited load at risk to between 4 and 20 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the new criteria for both normal and N-1 contingency conditions are shown in Table 7:

Table 7. Estimated Capital Costs of New Criteria

	($ Millions)	15 Year Annualized ($Millions)[1]
Total Substation Scope	$6.5	$0.98
Other Distribution Line Scope	$7.5	$1.13
Total Cost over 15 Years	$14.0	$2.10

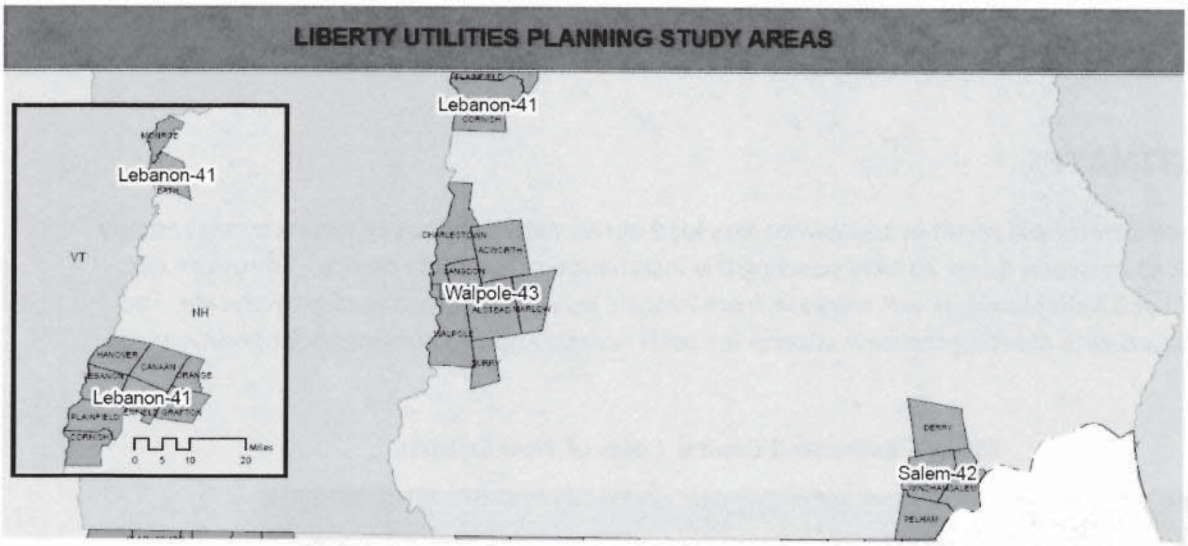
[1.] Assumes 15% carrying cost

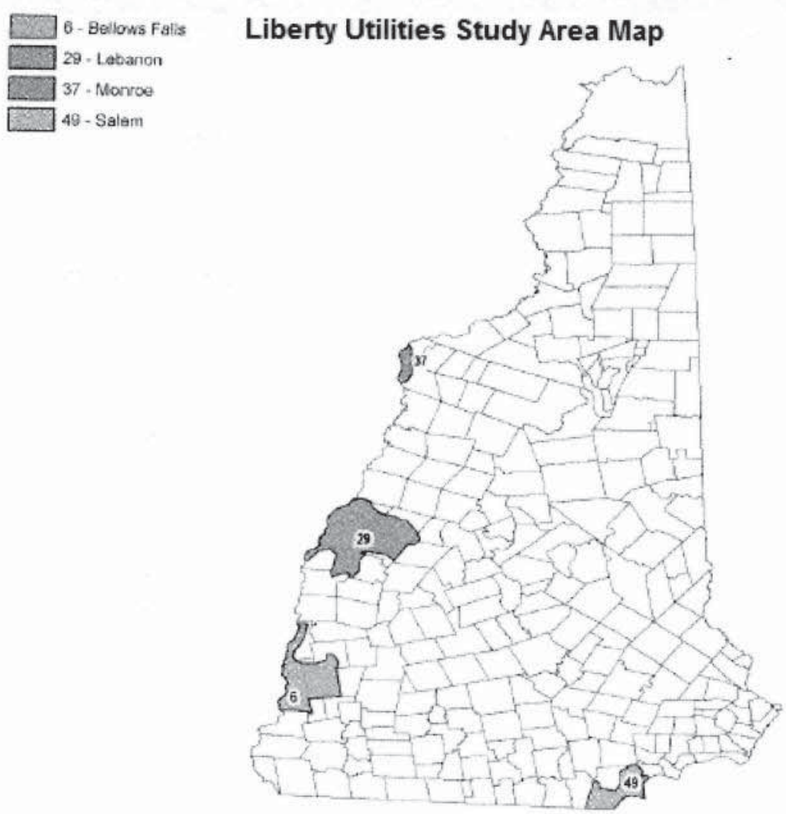
The new criteria may result in an increase in capital requirements up to $2.10 million per year over the existing criteria for the 15-year period studied.

Docket No. DE 16-383
Attachment Staff 8-63.2
Page 22 of 24

Liberty Utilities WATER | GAS | ELECTRIC		Liberty Utilities 15 Buttrick Rd Londonderry, NH 03053		
Description:	**Electric Distribution Planning Criteria**	Revision #:	2.0	Page 22 of 24

Attachment A – Liberty Utilities Planning Study Area Map





Liberty Utilities WATER GAS ELECTRIC		Liberty Utilities 15 Buttrick Rd Londonderry, NH 03053		
Description:	**Electric Distribution Planning Criteria**	Revision #:	2.0	Page 23 of 24

Attachment B – Summary of Planning Criteria Changes

New Criteria	Previous Criteria	Reason for Change
During normal operation, all distribution feeders to remain within 75% of normal ratings.	During normal operation, all distribution feeders to remain within 100% of normal ratings.	Allows for adequate capacity on adjacent lines to restore load post-contingency and reflects Liberty's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all sub-transmission lines to remain within 90% of normal ratings.	During normal operation, all sub-transmission lines to remain within 100% of normal ratings.	Allows for adequate capacity on adjacent lines to restore load post-contingency and reflects Liberty's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all transformers to remain within 75% of normal ratings.	During normal operation, all transformers to remain within 100% of normal ratings.	Reflects Liberty's strategy to proactively plan for sufficient capacity to meet changes in demand.
For the loss of a distribution feeder, if more than 16MWhrs of load at risk results for a single feeder fault evaluate alternatives to mitigate.	No Change.	Existing targets are adequate given size of a typical Liberty distribution feeder.
For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 1.5MW combined. If more than 36MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	Reflects Liberty's strategy and scale of facilities.
For the loss of a transformer, the quantity of load at risk of being out of service following post contingency switching should be limited to 2.5MW combined. If more than 60MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	For the loss of a transformer, the quantity of load at risk of being out of service following post contingency switching should be limited to 10MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	Reflects Liberty's strategy and scale of facilities.

Liberty Utilities WATER GAS ELECTRIC		Liberty Utilities 15 Buttrick Rd Londonderry, NH 03053		
Description:	**Electric Distribution Planning Criteria**	Revision #:	2.0	Page 24 of 24

Every effort must be made to return the failed sub-transmission line to service within 12 hours.	Every effort must be made to return the failed sub-transmission line to service within 24 hours.	Establishes a new limit for repairing feeder faults on Liberty's distribution feeders.
N/A	Every effort must be made to return the failed distribution feeder to service within 24 hours.	Establishes a new limit for repairing feeder faults on Liberty's distribution feeders.
In general, and whenever practical, each feeder should have three feeder ties to neighboring feeders.	N/A	Reflects Liberty's strategy to increase operating flexibility and support improved reliability performance due to faster service restoration times and future implementation of distribution automation.
Distribution feeders should be limited to 2,500 customers and sectionalized such that the number of customers does not exceed 500 or 2,000kVA of load between disconnecting devices.	N/A	Reflects Liberty's strategy to increase operating flexibility and support improved reliability performance due to faster service restoration times and future implementation of distribution automation.

Approved by: CPBrouillard

Digitally signed by CPBrouillard
DN: cn=CPBrouillard, o=Liberty Utilities, ou=Engineering, email=chris.brouillard@libertyutilities.com, c=US
Date: 2016.08.30 14:14:06 -04'00'

Date: 8/30/2016

Christian Brouillard
Director of Engineering
Liberty Utilities

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 16-383
Distribution Service Rate Case

Staff Data Requests - Set 8

Date Request Received: 8/19/16
Request No. Staff 8-64

Date of Response: 9/2/16
Respondent: Christian Brouillard

REQUEST:

Reference Staff 4-3:

Please supply a list of all the companies that Liberty benchmarked or reviewed when changing the Liberty planning criteria and please provide a copy of the planning criteria for those companies.

RESPONSE:

The Company reviewed the existing planning criteria that were developed by National Grid during its ownership of Granite State Electric Company. A summary of the previous (National Grid) criteria is provided below. Please see Attachment Staff 8-63.1 for a copy of the National Grid planning criteria.

New Criteria	Previous Criteria	Reason for Change
During normal operation, all distribution feeders to remain within 75% of normal ratings.	During normal operation, all distribution feeders to remain within 100% of normal ratings.	Reflects Liberty's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all sub-transmission lines to remain within 90% of normal ratings.	During normal operation, all sub-transmission lines to remain within 100% of normal ratings.	Reflects Liberty's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all transformers to remain within 75% of normal ratings.	During normal operation, all transformers to remain within 100% of normal ratings.	Reflects Liberty's strategy to proactively plan for sufficient capacity to meet changes in demand.
For the loss of a distribution feeder, if more than 16MWhrs of load at risk results for a single feeder fault evaluate alternatives to mitigate.	No Change.	Existing targets are adequate given size of a typical Liberty distribution feeder.

For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 1.5MW combined. If more than 36MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	Reflects Liberty's strategy and scale of facilities.
For the loss of a transformer, the quantity of load at risk of being out of service following post contingency switching should be limited to 2.5MW combined. If more than 60MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	For the loss of a transformer, the quantity of load at risk of being out of service following post contingency switching should be limited to 10MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	Reflects Liberty's strategy and scale of facilities.
Every effort must be made to return the failed sub-transmission line to service within 12 hours.	Every effort must be made to return the failed sub-transmission line to service within 24 hours.	Reducing normal loading to 90% for sub-transmission lines allows for adequate capacity on adjacent lines to restore load post-contingency.
N/A	Every effort must be made to return the failed distribution feeder to service within 24 hours.	Establishes a new limit for repairing feeder faults on Liberty's distribution feeders.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 16-383
Distribution Service Rate Case

Staff Data Requests - Set 11

Date Request Received: 10/19/16
Request No. Staff 11-32

Date of Response: 11/2/16
Respondent: Christian Brouillard

REQUEST:

Please show any feeder and transformer planning violations that require the additional work at the Golden Rock Substation. Please also supply any work papers related to any violations as part of your response.

RESPONSE:

The Golden Rock project addresses load at risk at the Spicket River Substation as mentioned in the responses to Staff 11-30 and Staff 11-31, and retirement of the Baron Ave Substation due to asset concerns. The following criteria violation is being addressed with the Golden Rock project (Phase 1 of the Salem Area Study):

- Baron Ave 10L1 and 10L4 feeders contain less than three feeder ties. As part of the Baron Ave Substation retirement, consideration will be given to reconfigure the feeders and mitigate this criteria violation. Additional capital costs are not expected.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 16-383
Distribution Service Rate Case

Staff Data Requests - Set 8

Date Request Received: 8/19/16
Request No. Staff 8-75

Date of Response: 9/2/16
Respondent: Christian Brouillard

REQUEST:

Reference Staff 4-34:

Regarding response parts (b), (d) and (f), please provide the underlying calculations for the values provided.

RESPONSE:

The expected improvement in duration and frequency reliability indices from the installation of the tree wire/spacer cable is estimated as follows:

From 2011 – 2015 the average customers interrupted from tree interruptions in the areas where bare wire was replaced is 6,859 per year. During this same time period the average customer minutes interrupted from tree interruptions was 441,965 per year.

The average cost to replace 2 miles of bare wire is $930,000. This equates to a $/dCI of $135.58 and a $/dCMI of $2.10 per year.

Please note that these estimates are different from those provided under Staff 4-34. The estimates provided under Staff 4-34 were based on a sample of outages between 2011 and 2012 for only three bare wire replacement projects that were part of the REP program. The estimates provided above include outages between 2011 and 2015 for all bare wire replacements including REP and other capital budget projects.

The expected improvements in duration and frequency reliability indices from the installation of single phase reclosers were estimated based on the following assumptions:

- Each single phase recloser will save on average 250 interruptions per year.
- Each single phase recloser will save on average 30,000 customer minutes interrupted per year.

The average cost to install a single phase recloser is $83,000. This equates to a $/dCI of $332 and a $/dCMI of $2.77 per single phase recloser.

The expected improvements in duration and frequency reliability indices from the installation of trip savers were estimated based on the following assumptions:

- Each trip saver will save on average 50 interruptions per year.
- Each trip saver will save on average 6,000 customer minutes interrupted per year.

The average cost to install a trip saver is $4,500. This equates to a $/dCI of $90 and a $/dCMI of $0.75 per trip saver.

1.0 INTRODUCTION

This document summarizes the Distribution Planning Criteria and Strategy that will be used by the Liberty Utilities East ("LUE") Engineering Department to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA").

2.0 EQUIPMENT RATINGS

Thermal limits are recognized for all system elements in conducting planning studies. Current in equipment and lines are limited so that voltage drops are held to reasonable values; so that conductors will not be severely annealed or damaged; so that switches, connectors, etc. will not be overloaded and that clearances are not exceeded. Several factors are taken into account, including: 1) ambient temperatures, 2) load cycles, 3) wind velocities, and 4) potential loss of life of equipment.

LUE's Distribution Planning Department maintains equipment ratings for all major equipment, including transformers, overhead lines, and underground cables. Overcurrent protection system settings are also taken into account where applicable.

Tables 1 summarizes the Equipment Rating criteria:

Table 1. Equipment Rating Criteria Summary

	Overhead Conductors		Underground Cables		Transformers	
Condition	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**
Normal	Continuous	• The maximum value for normal peak loads on all new and rebuilt feeders • Temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, & covered conductors	Continuous	• Maximum loading that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle • Normal cable ampacities are based on a 90° insulation operating temperature.	Continuous	• Level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or • The Top Oil Temperature exceeds 110 °C, or • The Hot Spot Copper temperature exceeds 180 °C
LTE	24 Hours	• The absolute maximum ampacity allowed for a given conductor and should not be exceeded at any time. • Temperature limit for 100% ampacity for operating at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, & covered conductors	100 - 300 Hours	• Maximum loading that does not cause the conductor temperature to exceed its design value over several consecutive 24-hour load cycles. • Emergency cable ampacities are based on 130° insulation operating temperature.	1 - 300 Hours	• Level for the peak hour with the emergency load added in the 24-hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer life, or • the Top Oil Temperature exceeds 130 °C, or • the Hot Spot Copper temperature exceeds 180 °C
STE	As Needed	• Estimated conservatively using seasonal ambient data along with circuit specific information by the Engineering Department	1 - 24 Hours	• Maximum loading that does not cause the conductor temperature to exceed its allowable emergency value at any time during a 24-hour load cycle. • Emergency cable ampacities are based on 130° insulation operating temperature.	15 minutes	• The one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer Life, or • a hot spot copper temperature exceeding 180°C. • Maximum STE rating is limited to twice the transformer's "nameplate" rating (200%).

2.0 PLANNING CRITERIA

For normal loading conditions on distribution feeders and transformers, the planning criteria is based on facilities to remain within 75% of normal ratings at all times. For subtransmission lines, facilities are to remain within 90% of normal ratings.

For N-1 contingency situations, the planning criteria is based on interrupted load returning to service within a reasonable time via system reconfiguration through switching, installation of temporary equipment, such as mobile transformers or generators, and/or by repair of a failed device. Where practical, switching flexibility is integrated into the system design to minimize the duration of customer outages to meet reliability objectives.

The following criteria summarized in Table 2 shall guide loading and contingency planning on the distribution system:

Table 2. Distribution System Planning Criteria Summary

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	• Loading to remain within 90% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced. • Each feeder should have at least three feeder ties to adjacent feeders.
N-1 Contingency, which results in facilities operating above their Long Term Emergency (LTE) rating but below their Short Term Emergency (STE) rating.	• Load must be transferred to other supply lines in the area to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 36 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby transformers to within their LTE rating. • Repairs or installation of Mobile Transformer expected to take place within 24 hours. • Evaluate alternatives if more than 60 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby feeders to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 16 MWhr of load at risk results following post-contingency switching.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables	• Loads must be reduced within 15 minutes to operate within their LTE rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables

Application of these criteria will result in somewhat less load at risk than previous criteria which generally limited load at risk to between 4 and 20 MW pending the installation of a mobile device. Therefore it is expected that the Load Relief budgets will increase from historic levels for a given load growth rate. The capital cost associated with meeting the new criteria for both normal and N-1 contingency conditions are shown in Table 4:

Table 4. Estimated Capital Costs of New Criteria

	($ Millions)	15 Year Annualized ($Millions)[1]
Total Substation Scope	$16.5	$1.1

Other Distribution Line Scope	$3	$0.2
Total Cost over 15 Years	$19.5	$1.3

1. Assumes 15% carrying cost

The new criteria may result in an increase in capital requirements up to $1.3M/year over the existing criteria for the 15-year period studied.

Liberty Utilities has refined the distribution planning criteria to better fit LUE's strategy and scale of facilities. The table below provides a summary of the changes to LUE's new criteria from the previous criteria under National Grid.

Table 5 – Summary of Planning Criteria Changes

New Criteria	Previous Criteria	Reason for Change
During normal operation, all distribution feeders to remain within 75% of normal ratings.	During normal operation, all distribution feeders to remain within 100% of normal ratings.	Reflects LUE's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all sub-transmission lines to remain within 90% of normal ratings.	During normal operation, all sub-transmission lines to remain within 100% of normal ratings.	Reflects LUE's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all transformers to remain within 75% of normal ratings.	During normal operation, all transformers to remain within 100% of normal ratings.	Reflects LUE's strategy to proactively plan for sufficient capacity to meet changes in demand.
For the loss of a distribution feeder, if more than 16MWhrs of load at risk results for a single feeder fault evaluate alternatives to mitigate.	No Change.	Existing targets are adequate given size of a typical Liberty distribution feeder.
For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 1.5MW combined. If more than 36MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	Reflects Liberty's strategy and scale of facilities.
For the loss of a transformer, the quantity of load at risk of being out of service following post contingency switching should be limited to 10MW combined. If more than 240MWhrs of load at risk results for a single line fault	For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 2.5MW combined. If more than 60MWhrs of load at risk results for a single line	Reflects Liberty's strategy and scale of facilities.

evaluate alternatives to mitigate.	fault evaluate alternatives to mitigate.	
Every effort must be made to return the failed sub-transmission line to service within 12 hours.	Every effort must be made to return the failed sub-transmission line to service within 24 hours.	Reducing normal loading to 90% for sub-transmission lines allows for adequate capacity on adjacent lines to restore load post-contingency.
N/A	Every effort must be made to return the failed distribution feeder to service within 24 hours.	Establishes a new limit for repairing feeder faults on Liberty's distribution feeders.

3.0 PRIMARY CIRCUIT VOLTAGE CRITERIA

The normal and emergency voltage to all customers shall be in line with limits specified by the state of NH and within the limits of ANSI C84.1-2006.

These upper and lower voltage ANSI limits, as measured at the customer's meter, are listed below in Table 6:

Table 6. Voltage Requirements for LU

For 120 V – 600 V Systems				
Nominal Voltage (V)	Service Voltage (V)			
	Range A		Range B	
	Max	Min	Max	Min
120	126	114	127	110
240	252	228	254	220
480	504	456	508	440

Source: ANSI

Voltage at the customer meter will be maintained within 5% of nominal voltage (120V). Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or pad mounted line regulators.

4.0 DISTRIBUTION CIRCUIT PHASE IMBALANCE CRITERIA

This criterion is established to limit the load imbalance among the three phases of a primary distribution circuit. These criteria call for the correction of phase imbalances of existing and new distribution circuits. Phase imbalance is defined on the basis of connected KVA (CKVA) load for that circuit as:

$$\%imbalance = \frac{(phase\ load - average\ phase\ load)}{average\ phase\ load} X\ 100$$

Two criteria should be met for the circuit to be considered for corrective action:

1. The calculated neutral current should not exceed 30% of the feeder ground relay pickup setting.
2. The loading between the low and high phase should not exceed 100A

Estimated Capital Costs of New Planning Criteria

Liberty Utilities (Granite State Electric) Corp. d/b/a/ Liberty Utilities

PROJECT	2017 Capital Budget	2018 Capital Budget	2019 Capital Budget	2020 Capital Budget	2021 Capital Budget	2022 Capital Budget	2023 Capital Budget	Total Capital Budget
NEW MICHAEL AVE 40L3 PROJECT DLINE PHASE 2		$1,415,000						$1,415,000
NEW SLAYTON HILL 39L4 PROJECT DLINE		$25,000	$290,000					$315,000
NEW SLAYTON HILL 39L4 PROJECT DSUB		$50,000	$300,000					$350,000
NEW 1L2 - 1L3 FEEDER TIE PROJECT		$25,000	$340,000					$365,000
SALEM AREA STUDY PHASE 1 DSUB - GOLDEN ROCK		$50,000	$300,000					$350,000
SALEM AREA STUDY PHASE 1 DLINE - GOLDEN ROCK				$2,120,000	$242,000			$2,362,000
SALEM AREA STUDY PHASE 2 DLINE - ROCKINGHAM					$214,000	$200,000	$200,000	$614,000
SALEM AREA STUDY PHASE 2 DSUB - ROCKINGHAM					$350,000	$350,000		$700,000
NEW PELHAM DSUB PROJECT	$350,000							$350,000
NEW PELHAM DLINE PROJECT	$200,000	$225,000						$425,000
TOTAL SUB SCOPE								$1,750,000
TOTAL DLINE SCOPE								$5,496,000
TOTAL SUBT SCOPE								$0
TOTAL 15 YR PLAN								$7,246,000

Expected Reliability Improvements of New Planning Criteria

Liberty Utilities (Granite State Electric) Corp. d/b/a/ Liberty Utilities

	A	B	C	D	E	F	G	H	I
	PROJECT	Total Capital Budget	Annual System SAIDI Improvement	Annual System SAIFI Improvement	Annual System CMI Improvement	Annual System CI Improvement	Annual $/dCMI	Annual $/dCI	Load at Risk (MW)
1	NEW MICHAEL AVE 40L3 PROJECT DLINE PHASE 2	$1,415,000	3.55	0.03	147,498	1,396	9.59	1,014	4.8
2	NEW SLAYTON HILL 39L4 PROJECT	$665,000	0.60	0.01	25,249	357	26.34	1,863	0.0
3	NEW 1L2 - 1L3 FEEDER TIE PROJECT	$365,000	6.60	0.07	275,638	3,057	1.32	119	0.0
4	SALEM AREA STUDY PHASE 1 - GOLDEN ROCK	$2,712,000	4.08	0.05	170,217	2,133	15.93	1,271	8.9
5	SALEM AREA STUDY PHASE 2 - ROCKINGHAM	$1,314,000	5.22	0.04	216,880	1,636	6.06	803	11.6
6	NEW PELHAM PROJECT	$775,000	4.04	0.04	169,131	1,613	4.58	480	8.0

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 16-383
Distribution Service Rate Case

Staff Data Requests - Set 11

Date Request Received: 10/19/16 | Date of Response: 11/2/16
Request No. Staff 11-34 | Respondent: Christian Brouillard

REQUEST:

Please supply the plus/minus estimate accuracy percentages used by National Grid in its project evaluations and Liberty Utilities when planning grade estimates are made for a construction project.

RESPONSE:

Liberty cannot attest to the accuracy percentages used by National Grid in its project evaluations. In the past, when Granite State Electric was part of National Grid, National Grid typically utilized investment grade estimates for budgeting purposes, conceptual or planning grade estimates to secure approvals and procure long lead items, and project grade estimates for final sanctioning.

Liberty Utilities utilizes the following percentages in its project evaluations:

- Investment grade estimate +100% / -50%
- Conceptual (Planning) grade estimate +/- 25%
- Project grade estimate +/- 10%
- Construction grade estimate +/- 5%

Salem Area Study Report – Executive Summary DRAFT – July 16, 2016

Executive Summary

ControlPoint Technologies has completed the Salem, NH area distribution Study for Liberty Utilities. The Liberty Utilities Distribution Planning Criteria was used to determine any Electric Supply System upgrades required to meet existing and future capacity requirements.

The Distribution System under study included:

- Four (4) 23kV supply circuits.
- Four (4) 23kV/13.2kV substations, Baron Ave No.10, Olde Trolley No.18, Salem Depot No. 9 and Spicket River No 13.
- Thirteen (13), 13.2kV distribution circuits.

Explanation

The study, focused on current and future capacity needs of the substations and distribution system supplying the area along with the asset conditions of the existing electrical infrastructure. Evaluations identified a number of existing and predicted system Circuit, Supply Line, and Transformer capacity concerns that did not meet the requirements of the Liberty Distribution Planning Criteria. Criteria violations were identified by year for both the Normal Loading and the Contingency Loading cases and include the following:

1. Conductor Thermal overloads in excess of 100% Summer Normal ratings on the Salem Depot 9L3, Olde Trolley 18L3, and 18L4 circuits.

2. During Contingency (N-1) cases, the Olde Trolley 18L1 Circuit violates the 16 MWH rule with 6.3 MVA of Load at risk.

3. During Contingency (N-1) cases the Spicket River Loss of 23kV Supply violates the 16 MWH rule with 8.9 MVA load at risk.

In addition to the existing distribution evaluation the study also focused on the distribution requirements needed to supply the hypothetical 15 MW “Casino” spot load located at the Jockey Club in Rockingham Park. The existing deficiencies identified above do not reflect the Casino’s load increase due to the fact that the existing system cannot support this load increase.

Existing and predicted loading concerns amplify with the addition of the proposed “Casino” and other known spot loads. Existing transformer capacity in the Salem area will be exceeded, presenting many challenges to the existing 23kV/13.2kV substation transformer based distribution system.

Recommended Plan

Several plans were evaluated to address the existing and future system needs of the area. The study took into consideration existing distribution asset concerns while determining possible recommendations. These asset concerns include the following:

1. Barron Ave No. 10 Substation is supplied by the 2393 supply line, which originates from Golden Rock Station, and the National Grid 2353 supply line, which originates from the Methuen No 5 Station. Liberty Utilities has experienced multiple issues with customer concern based on the poor location of the substation.

2. Salem Depot No. 9 Substation is supplied by the 2393 supply line and the 2352 supply line, which originate from Golden Rock Station. The existing 9L1 and 9L2 Breaker Positions and bus are constructed on Wood Pole Structures with limited clearance. This causes reliability and maintenance concerns at the station.

The recommended plan for consideration accomplishes all system capacity and asset replacement requirements. The plan will be achieved in two (2) phases. It addresses the existing concerns and the future concerns in the most complete way while moving the system from the legacy 23 kV supplied system to a more reliable and sustainable 115 kV supplied system.

Phase One (New 115/13.2 kV Transformer at Golden Rock Station with Baron Ave Station Elimination & Spicket River Mitigation)

Phase One of the recommended plan consists of a second 115 kV transmission line into Golden Rock Station supplying a second 115kV/13.2 kV substation transformer with four (4) new 13.2 kV circuit positions. The 13.2 kV circuits would be constructed to provide contingency support to Spicket River Station and to eliminate the Baron Ave Station.

This phase would also include the replacement of existing conductor, in excess of 100% of Summer Normal ratings, on the Salem Depot 9L3, Olde Trolley 18L3, and 18L4 circuits. All conductor upgrades would be accomplished using 477 Al spacer to the first protective device, then 477 Al open wire or 477 Al spacer depending upon field conditions.

Phase Two (New 115/13.2 KV Transformers at New Rockingham Station with Salem Depot Station Elimination)

Phase Two of the recommended plan consists of an extension of the 115 kV transmission system from Golden Rock Station to a proposed new double ended 115kV/13.2kV station in the Rockingham area.

Each new 115 kV/ 13.2 kV supply transformer, T1 and T2, would have four (4) circuits, eight (8) total, with secondary breakers and a bus tie breaker. An automatic bus transfer system would be utilized to improve reliability and simplify maintenance.

Three (3) of the T1 supply transformer circuits would be used to supply a reconfigured 13.2 kV distribution system, which will bring the system into compliance with Liberty's Distribution Planning Criteria. The configuration would be targeted to improve reliability and better balance loading on all circuits.

Three (3) of the T2 supply transformer circuits would be used eliminate the Salem Depot Station. The fourth circuits on both the T1 and T2 supply transformers would serve the proposed "Casino" load.

Reasons for Recommendation

The recommended plan addresses present and predicted normal and contingency operational, capacity, and asset challenges associated with the existing 23kV/13.2kV based distribution system. In addition, the plan addresses, capacity loading concerns developed with the addition of the proposed "Casino" and other known spot loads.

Additionally, Spicket River Station is presently supplied by one 23kV circuit fed from National Grid. With the loss of this supply, the existing 13.2 kV circuit ties do not have sufficient capacity to pick up all the station load on peak. The added capacity and 13.2 kV circuits would be constructed from Golden Rock to provide contingency support to Spicket River Station.

The opportunity to move the system from a 23kV/13.2kV to an 115kV/13.2kV substation transformer based system is presented. The 115kV/13.2kV transformers will allow larger capacity transformers to be utilized in supplying system demand. By utilizing the additional capacity available from the larger capacity transformers; Liberty Utilities could develop a multi-phased plan to eliminate existing 23 kV facilities, such as Baron Ave and Salem Depot station, with their legacy maintenance and operational concerns. Also, the recommended plan will decrease the reliance on the 23 kV supply line system and its continued dependence on National Grid to allocate 23 kV capacity for Liberty Utilities.

Recommended Onelines

Refer to section 3.3 Recommended Plan Onelines, for Station and Distribution

Systems
Recommendation Estimates

The following tables provide estimated costs, by phase, for the Recommended Plan.

Recommended Plan Phase One Estimate	
Required Construction	**Cost - $k**
Baron Ave Station Elimination & Spicket River Mitigation Distribution Circuit Estimate	**$5,885**
New 115/13.2 kV Transformer at Golden Rock Station Estimate	**$3,000**
Phase One Project Total	**$8,885**

Recommended Plan Phase Two Estimate	
Required Construction	**Cost - $k**
Salem Depot Station Elimination Distribution Circuit Estimate	**$2,075**
Design Criteria Compliance	**$1,500**
New 115/13.2 KV Transformer, T1, at New Rockingham Station Estimate	**$2,800**
New 115/13.2 KV Transformer, T2, at New Rockingham Station Estimate	**$3,000**
Phase Two Project Total	**$9,375**

If the implementation of a new Rockingham Station is significantly delayed, Salem Depot Station upgrades should be pursued.

Recommended Plan Phase Two Delay Estimate	
Required Construction	**Cost - $k**
Salem Depot Station Upgrades Station Estimate	**$1,550**
Phase Two Project Total (Delay)	**$1,550**

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 16-383
Distribution Service Rate Case

Staff Data Requests - Set 3

Date Request Received: 7/8/16
Request No. Staff 3-63

Date of Response: 7/22/16
Respondent: Christian Brouillard

REQUEST:

Reference Brouillard and Hall testimony, Bates 369, and line 14. Please supply all project documentation for the proposed Golden Rock Substation Upgrade project.

RESPONSE:

The Company is finalizing the Salem area study. We expect to have the study finalized by August or September. The Company is providing a DRAFT of the executive summary section of the report at this time. Given that the study and its contents are still under active review by the Company and its consultant, the Company emphasizes that elements of the study recommendations of scope, schedule, and costs may change before the study is finalized. Attachment Staff 3-63 is a DRAFT of the executive summary of the Salem Area Study Report.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 16-383
Distribution Service Rate Case

Staff Data Requests - Set 4

Date Request Received: 7/15/16
Request No. Staff 4-3

Date of Response: 8/5/16
Respondent: Christian Brouillard

REQUEST:

Reference page 1 (Bates 0181), lines 7 through 10:

Please supply a complete copy of the system planning criteria/guideline used by Liberty to determine the timing of new capital investments. If the criteria has changed since 2013, please supply all revisions, their dates, and the reasoning thereof.

RESPONSE:

Liberty Utilities Planning Criteria

Liberty Utilities' planning criteria is the collection of principles and guidelines that provide engineers, planners, and operators with the capability to plan system improvements and operate the system in a manner that meets the delivery system reliability requirements in a cost effective manner. A distribution system that has adequate capacity is one in which, in the event of an outage, all customers can be restored in a timely manner through system reconfiguration by means of electrical switching or automatic reclosing schemes. Adequate contingency capacity on power transformers, sub-transmission lines, and feeders are key design and operation objectives. The Company considers these criteria when identifying deficiencies with the existing distribution system and identifying improvements to address the identified deficiencies. These criteria are described in the Company's Distribution Planning Criteria, summarized in Figure 1 below. These planning criteria reflect Liberty's philosophy to strategically plan well ahead of when system upgrades are needed. Additionally, these criteria better reflect Liberty's smaller equipment and resource base as well as its commitment to increased customer focus.

Figure 1 - Summary of Liberty Utilities Distribution Planning Criteria

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	• Loading to remain within 90% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced. • Each feeder should have at least three feeder ties to adjacent feeders.
N-1 Contingency, which results in facilities operating above their Long Term Emergency (LTE) rating but below their Short Term Emergency (STE) rating.	• Load must be transferred to other supply lines in the area to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 36 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby transformers to within their LTE rating. • Repairs or installation of Mobile Transformer expected to take place within 24 hours. • Evaluate alternatives if more than 60 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby feeders to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 16 MWhr of load at risk results following post-contingency switching.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables	• Loads must be reduced within 15 minutes to operate within their LTE rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables

For normal loading conditions on distribution feeders and transformers, the planning criteria are based on facilities remaining within 75% of normal ratings at all times. For sub-transmission lines, facilities are to remain within 90% of normal ratings. For N-1 contingency situations, the planning criteria are based on interrupted load returning to service within a reasonable time via system reconfiguration through switching, installation of temporary equipment such as mobile transformers or generators, and/or by repair of a failed device. Wherever practical, switching flexibility is integrated into the system design to minimize the duration of customer outages in order to meet reliability objectives.

Changes to the planning criteria began to be applied to projects and studies in mid-2015. Those changes were formally issued in January 2016 with the filing of the Least Cost Integrated Resource Plan. Please see Figure 2 below for a listing of the changes to the planning criteria and the reason for each change.

Figure 2 - Summary of Planning Criteria Changes

New Criteria	Previous Criteria	Reason for Change
During normal operation, all distribution feeders to remain within 75% of normal ratings.	During normal operation, all distribution feeders to remain within 100% of normal ratings.	Reflects LUE's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all sub-transmission lines to remain within 90% of normal ratings.	During normal operation, all sub-transmission lines to remain within 100% of normal ratings.	Reflects LUE's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all transformers to remain within 75% of normal ratings.	During normal operation, all transformers to remain within 100% of normal ratings.	Reflects LUE's strategy to proactively plan for sufficient capacity to meet changes in demand.
For the loss of a distribution feeder, if more than 16MWhrs of load at risk results for a single feeder fault evaluate alternatives to mitigate.	No Change.	Existing targets are adequate given size of a typical Liberty distribution feeder.
For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 1.5MW combined. If more than 36MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	Reflects Liberty's strategy and scale of facilities.
For the loss of a transformer, the quantity of load at risk of being out of service following post contingency switching should be limited to 10MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 2.5MW combined. If more than 60MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	Reflects Liberty's strategy and scale of facilities.
Every effort must be made to return the failed sub-transmission line to service within 12 hours.	Every effort must be made to return the failed sub-transmission line to service within 24 hours.	Reducing normal loading to 90% for sub-transmission lines allows for adequate capacity on adjacent lines to restore load post-contingency.
N/A	Every effort must be made to return the failed distribution feeder to service within 24 hours.	Establishes a new limit for repairing feeder faults on Liberty's distribution feeders.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities

DE 16-383
Distribution Service Rate Case

Staff Data Requests - Set 4

Date Request Received: 7/15/16
Request No. Staff 4-11

Date of Response: 8/5/16
Respondent: Christian Brouillard

REQUEST:

Reference page 3 (Bates 0183), lines 14 through 18:

Please supply all plans and development showing how they reflect Liberty's resourcing and outage response capabilities to weather and outage events. If any plans or development have changed since 2013, please supply a copy of each revision showing clearly the changes were made and the reasoning thereof.

RESPONSE:

Please refer to the Company's response to Staff 4-3. The planning criteria was revised in 2014 to reflect the Company's goal to provide locally managed, high quality service and value to its customers. The criteria allow us to better plan for system normal operating conditions and contingencies, and to be in a better position to respond to them, rather than simply reacting to those events. The revised criteria provide for additional capacity to both limit the exposure to events and to better respond to them should they occur. In planning for and responding to weather and other outage events, we can lessen the frequency, duration and impact of weather events by planning and building a system that is more resilient to such events. This further allows for a lesser dependency on outside resources, pre-staging, support resources, internal labor overtime, and stocking of material. Also, the Company schedules its capital projects around the traditional weather event periods, allowing for more improved access to outside contractors during such periods. In 2013, the Company joined NAMAG to further our ability, as a smaller utility, to access a broader contractor resource pool for storm response. Lastly, a robust and consistent vegetation management program provides for a virtual year round presence of tree crews in the Salem and Lebanon areas, further enhancing our response to weather events.