Southern New England Transmission Reliability (SNETR)

Report 1 - Need Analysis

D R A F T

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Southern New England Regional Working Group
ISO-New England
National Grid
Northeast Utilities

EXECUTIVE SUMMARY

OBJECTIVE – ENSURE REGIONAL RELIABILITY

A working group of planners from National Grid, Northeast Utilities, ISO New England (ISO-NE), and several outside consultants, conducted a study to formulate a 10-year plan for coordinated transmission system improvements for the southern New England (SNE) region.

The portion of the SNE region evaluated in this analysis included the following interdependent areas:

- Western and Central Massachusetts (particularly the Springfield area),
- Rhode Island, and
- Eastern and Central Connecticut.

The objective of the plan is to ensure that the region complies with:

- North American Electric Reliability Council's (NERC) Reliability Standards for the Bulk Power Systems of North America,
- Northeast Power Coordinating Council's (NPCC) Basic Criteria for the Design and Operation of Interconnected Power Systems, and
- ISO-NE's Reliability Standards for the New England Area Bulk Power Supply System.

These criteria and standards are used to ensure that the regional transmission system serving New England can reliably deliver power to customers under a wide range of projected future system conditions.

METHOD AND CRITERIA

This report presents the results of coordinated studies conducted by the working group. The group's analysis is tied to the reliability standards listed above. The report assumes the "as is" electric transmission system under future conditions and identifies where the system is not likely to meet the national and regional standards and criteria. A follow-up report will identify preferred and alternative system upgrades to address the deficiencies that were identified.

ISO-NE power system planning procedures are designed to meet the reliability standards that are specifically defined in Planning Procedure No. 3 (PP3), "Reliability Standards for the New England Bulk Power Supply System," the published standard that provides consistent system planning criteria throughout New England. Following the northeast blackout of 1965, what is now known as NERC was formed to prevent future occurrences by establishing broad-based standards. NPCC, of which ISO New England (representing New England Power Pool (NEPOOL)) is a member, was subsequently formed to develop regionally specific criteria based on NERC standards.

PP3 defines the standards used to plan the interconnected generators and transmission circuits that comprise the region's electrical network. A number of "tests" must be "passed" before a system can be judged to meet these standards. These tests take into account historical data and system occurrences, and include an examination of the following:

- Section 3. Area Transmission Requirements: Is the area transmission system capable of delivering the generation to the load under anticipated facility outage events?

- Section 4. Transmission Transfer Capability: Is the interconnected transmission system designed with adequate inter-Area and intra-Area transfer capability?

Similar standards exist throughout North America.

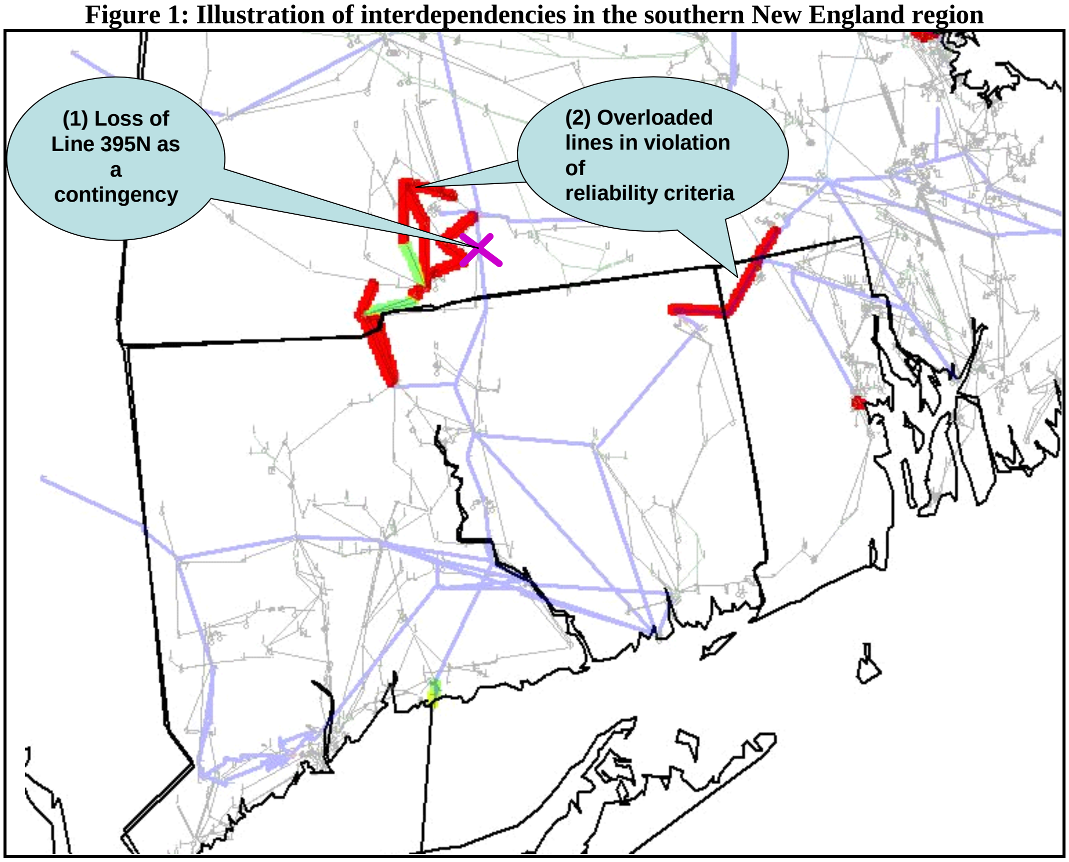
When analyzing future system reliability needs, planners have to consider possible:

- System Configurations (load and generation scenarios) and
- System Contingencies (e.g., sudden and unplanned outage of a generating unit or line).

Given the geographic scope of the SNE region, there are a tremendous number of variables and interdependencies involved in studying the possible system configurations and contingencies. Individual solutions in one area must be evaluated to ensure that they do not produce unintended consequences in another area.

Similarly, how potential system conditions in one area might impact another part of the system must be understood. For instance, as illustrated below in Figure 1, an outage on a 345-kV line supplying the Manchester area in north central Connecticut could result in overloaded facilities in the western Massachusetts – Springfield area and the northeastern Connecticut – Rhode Island area.

Figure 1: Illustration of interdependencies in the southern New England region



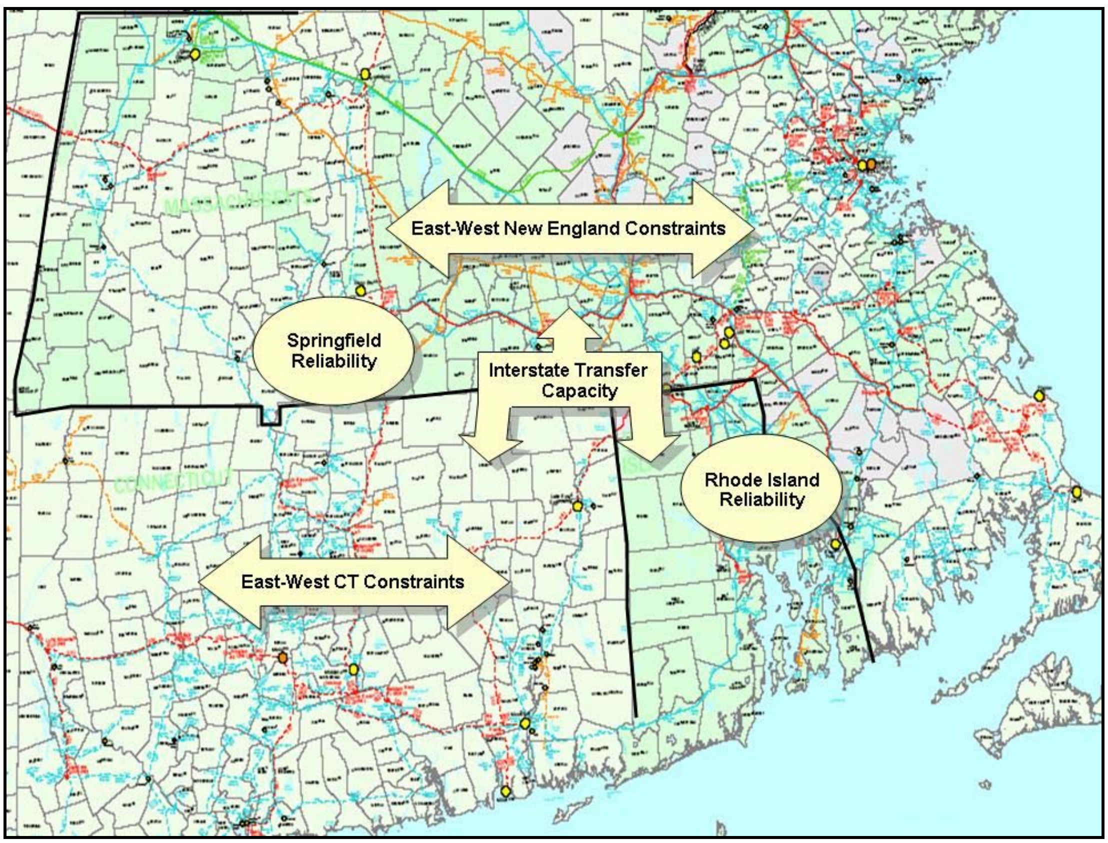
This example above is illustrative of just one contingency scenario that demonstrates the interdependencies that exist between the southeastern Massachusetts (SEMA), Western Massachusetts (WMA), Rhode Island (RI) and Eastern and Central CT areas of SNE.

STATEMENTS OF NEED

The analysis has shown that the southern New England transmission system has five major reliability concerns identified below and depicted in Figure 2 below:

- Regional East–West power flows are limited across southern New England due to potential thermal and voltage violations on area transmission facilities under contingency conditions.
- Massachusetts: The Springfield area experiences significant thermal overloads and voltage problems under numerous contingencies. The severity of these problems increases as the system tries to move power into Connecticut from the rest of New England.
- Connecticut: Power transfers into Connecticut are limited and will eventually result in the inability to serve load under many probable system conditions.
- Connecticut: East-to-West power flows in Connecticut stress the existing system resulting in future thermal overloads under contingency conditions.
- Rhode Island: The system is overly dependent on limited transmission lines or autotransformers to serve its needs resulting in thermal overloads and voltage problems for contingency conditions.

Figure 2: Reliability Concerns in the southern New England region



All of these concerns are related to the significant degree of load growth experienced in the SNE region and will ultimately lead to potential violations of reliability standards. Some of these violations could occur in today's system under specific conditions. For example, with a line out of service, the limitations of New England East-West transfer capability could result in overloads in today's system. Currently, operator actions are employed to address these events but such actions will no longer be viable as system loading increases and the resulting overload conditions worsen.

The studies conducted were a part of one of the most geographically comprehensive planning efforts to-date in New England, addressing five interrelated problems in three states and multiple service territories. The analysis was aimed at addressing the weaknesses in southern New England, which should benefit all of the New England states by addressing the issues of regional transmission system reliability and constrained generation.

Analyses performed for the 10-year period revealed a number of system deficiencies in transmission security, specifically area transmission requirements and transfer capabilities as outlined in PP3. These deficiencies form the justification for the needed transmission system improvements. These improvements will benefit all New England states by addressing limitations that have regional consequences. For example, addressing the transfer limitations associated with the New England East-West interface will also address limitations for delivering power from other New England areas to load centers all across southern New England. The following sections provide a detailed description of the problems identified in the SNE region.

TRANSMISSION SECURITY - TRANSFER CAPABILITY CONCERNS

- Connecticut area power transfer capabilities will not meet the area's import requirements as early as 2009. If improvements are not made by 2016, the import deficiency, (outlined using a 'Load Margin' approach in RSP06), for this area under generator unavailability and loss of a single power system element conditions (N-1 conditions) is expected to be greater than 1,500 MW assuming no new capacity is added.
- Based on planning assumptions concerning future generation additions and retirements within the Connecticut area an import level of 3600 MW for N-1 and 2400 MW for N-1-1 (i.e. conditions under which a transmission element is unavailable and loss of a single power system element) will be needed by 2016. (Details are included in Table 3.1 and Table 3.2.)
- Connecticut also has internal elements that limit transfers from neighboring New England states. These constraints limit the Connecticut East-West power transfers across the central part of Connecticut. The movement of power from east to west in conjunction with higher import levels to serve Connecticut results in overloads of transmission facilities located within Connecticut.
- Under "line-out" or N-1-1 conditions and certain dispatch scenarios, the 345-kV transmission system in the southeastern Massachusetts and Rhode Island areas cannot support the Southeast Massachusetts - Rhode Island, New England East–West, and the Connecticut power transfers following a contingency. These interfaces all have simultaneous and interdependent power transfer limits.
- Rhode Island and Springfield have insufficient import capability to meet their load margins through 2016.

TRANSMISSION SECURITY – AREA TRANSMISSION REQUIREMENTS CONCERNS

- In the Springfield area, local double-circuit tower outages (DCT), stuck breaker outages, and single element outages result in severe thermal overloads and low voltage conditions. These weaknesses are independent of the ability to handle power flows into Connecticut.

- The flow of power through the Springfield 115-kV system into Connecticut increases when the major 345-kV tie-line between western Massachusetts and Connecticut (the Ludlow–Manchester–North Bloomfield 345-kV line) is open due to either an unplanned or a planned outage. As a result, numerous overloads occur for all years simulated on the Springfield 115-kV system. These overloads are exacerbated when Connecticut transfers increase.
- The severity, number, and location of the Springfield overloads and low voltages are strongly dependent on the area's generation dispatch. Additional load growth and potential unit retirements would significantly aggravate these problems. As a result, network constraints in the Springfield area limit the ability to serve local load under contingency conditions and limit Connecticut transfer capability under certain area dispatch conditions.
- Thermal and voltage violations are observed on the transmission facilities in Rhode Island. Causal factors include: high load growth (especially in southwestern Rhode Island and the coastal communities), unit availability, and transmission outages (planned or unplanned).
- The Rhode Island 115-kV system is constrained when a 345-kV line is out of service. Outage of any one of a number of 345-kV transmission lines results in limits to power transfer capability into Rhode Island. For line-out conditions, the next critical contingency involving the loss of a 345/115-kV autotransformer or a second 345-kV line would result in numerous thermal and voltage violations.

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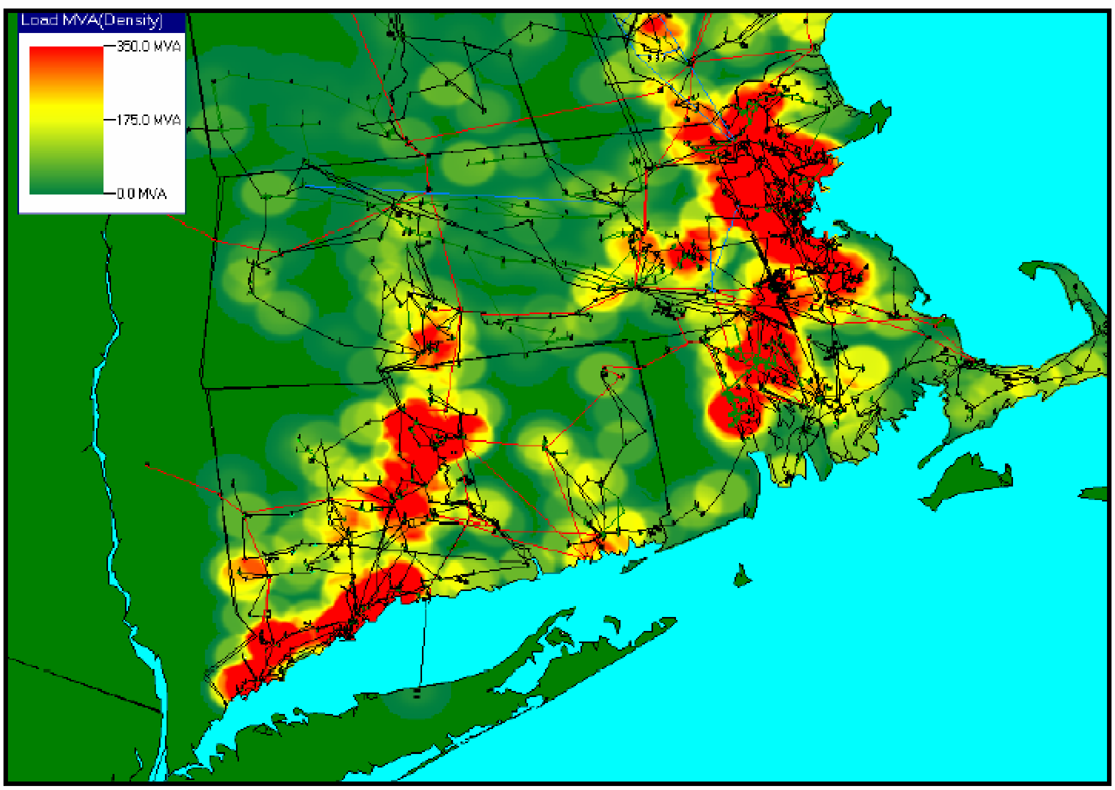
1 INTRODUCTION AND BACKGROUND INFORMATION

The analysis presented in this report is the culmination of several joint studies by Transmission Owners (TO's) and ISO New England. The New England transmission system serving the southern New England area was studied to evaluate projected future load and generation requirements to assess the performance of the future transmission system and its adequacy to meet existing reliability standards. This report identifies the likely deficiencies in the performance of the electric transmission system in the future.

1.1 SOUTHERN NEW ENGLAND

The map shown in Figure 1.1 depicts the load density for the geographic area of southern New England - Massachusetts, Rhode Island, and Connecticut. As shown in this figure, a number of significant load pockets exist: Boston and its suburbs; central Massachusetts, Springfield, Rhode Island, Hartford, and Southwest Connecticut. The load pockets of Springfield, Rhode Island, Hartford, and Connecticut are primary areas of concern in this study with respect to the ability of the existing transmission and generation systems to reliably serve the projected load requirements.

Figure 1.1: Southern New England Load Concentrations



Southern New England accounts for approximately 80% of the New England load. The 345-kV bulk transmission network is the key infrastructure that integrates area supply resources with load centers. The major southern New England resources, as well as the supply provided via ties from northern New England, Hydro-Quebec, and New York, primarily rely on the 345-kV transmission system for delivery of power to the area's load centers. This network provides significant bulk power supply to Massachusetts, Rhode Island, and Connecticut and is integral to the supply of the Vermont load in northwestern New England. The area has experienced significant load growth, resource changes, and changes in inter-area transfers.

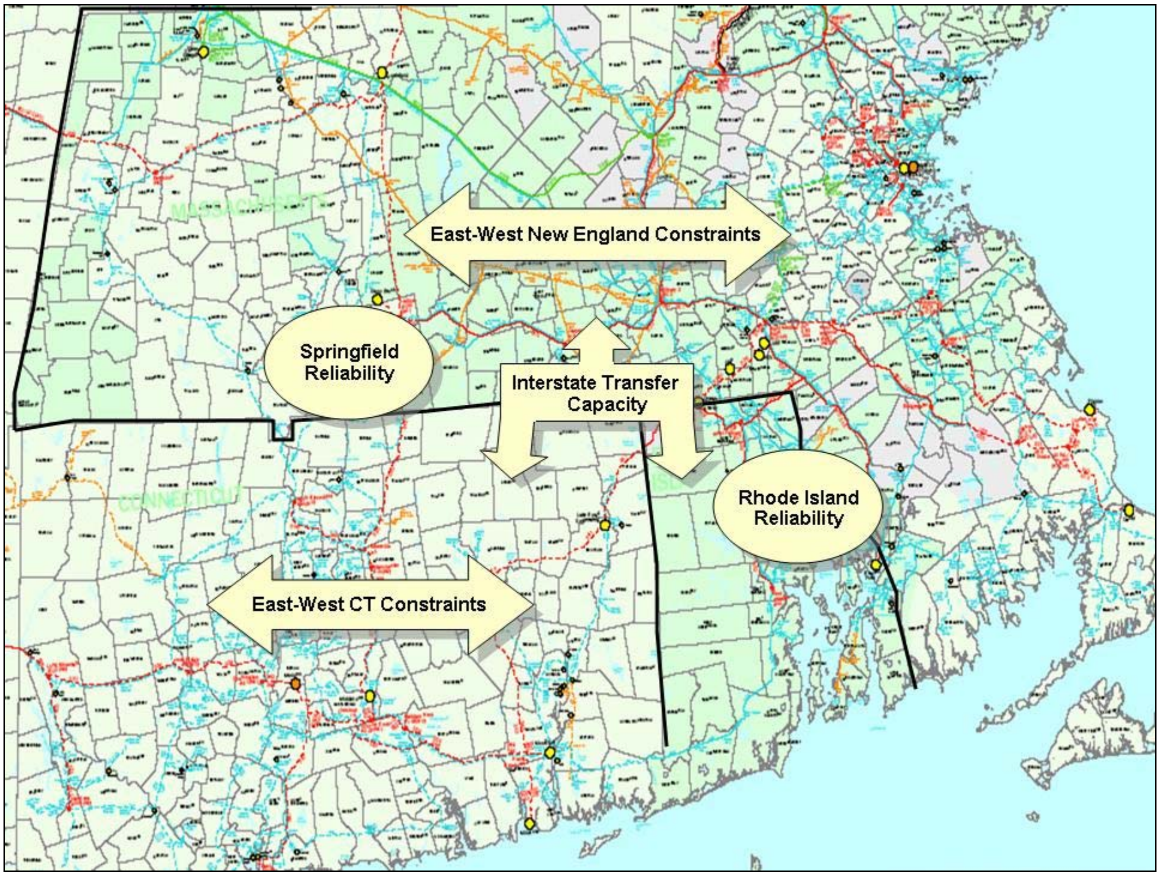
The East–West transmission interface divides New England roughly in half. Vermont, southwestern New Hampshire, western Massachusetts, and Connecticut are located to the west of this interface; Maine, eastern New Hampshire, eastern Massachusetts, and Rhode Island are to the east. The primary East–West transmission links are three 345-kV and two 230-kV lines. A few underlying 115-kV facilities are also part of the interface; however, most run long distances and have relatively low thermal capacity.

Supplying southern New England with electricity involves a number of complex and interrelated performance concerns. Looming Connecticut supply deficiencies, the addition of the Stoughton 345-kV station to serve the Boston area, and the demands of Rhode Island and western New England combine to significantly tax the existing 345-kV network. These are further compounded by transmission constraints in the Springfield and Rhode Island areas under contingency conditions. The transmission transfer capabilities are all interdependent among the Southeastern Massachusetts ("SEMA") export, Greater Rhode Island export (mostly generation located in Massachusetts bordering on Rhode Island), Boston import, Rhode Island import; New England East–West, Connecticut import, Connecticut East–West, and Southwest Connecticut ("SWCT") import interfaces. Transfers through these paths can contribute to heavy loadings on the same key transmission facilities.

These interdependent relationships can exist for both thermal and stability limits. Studies have identified the interdependence of stability limits among SEMA interface transfers, SEMA/RI exports, New England East–West transfers, New York–New England transfers, and the status of certain generators. Unacceptable torsional impacts on generators due to line reclosing have also become an issue in the Southern New England area. These behaviors illustrate the interdependent nature of the southern New England 345-kV network. Recent studies have also revealed an additional interdependency between the ability to import power into Connecticut and the ability to supply load in the Springfield area. Springfield's reliability issues, if not studied within the context of the overall southern New England analysis, could limit the benefits that improvements bring to the area and the ability to better integrate the supplies to the various load pockets in the region.

The eastern New England (ENE) area is currently surplus in generating capability, and that surplus is located in both northern New England and the southeastern Massachusetts/Rhode Island area (SEMA/RI). Given existing export limitations for these areas the surplus of generation in ENE is nearly 3,000 MW. The existing transmission system does not allow for delivery of this surplus capacity to all load centers in southern New England. Regional East-West transfer limits and Connecticut power transfer limitations do not allow this surplus capacity to be delivered to the load centers within Connecticut. Additional transmission reliability concerns exist for both the Springfield and the Rhode Island areas leading to a set of interrelated concerns with respect to the reliability of transmission service across southern New England (See Figure 1.2 below).

Figure 1.2: Southern New England Subareas and Constraints



1.2 CONNECTICUT

Approximately 70% of the Connecticut load is concentrated in the western part of the state and 30% of the Connecticut load is located in the eastern part of the state. Approximately 6,779 MW of internal generation supplies Connecticut. Fifty-five percent of this internal generation is located in the eastern part of the State. Connecticut has two of the larger generators in New England, Millstone Point 2 and Millstone Point 3. Around 55% (3,800 MW) of the internal generation is over 30 years old, 30% (2,100 MW) is over 40 years old with 81 MW over 60 years old.

Connecticut is integrated into the regional network primarily through three 345-kV lines, one 138-kV phase angle regulator-controlled line, four 115-kV lines and one 69-kV line. Connecticut is tied to Massachusetts through the Manchester–North Bloomfield–Ludlow (395) 345-kV tie and three 115-kV ties (Southwick–North Bloomfield–1768, South Agawam–North Bloomfield–1821, and South Agawam–North Bloomfield–1836).

Connecticut is tied to Rhode Island through a 345-kV line between Lake Road and Sherman (347) and a 115-kV line between Mystic and Wood River (1870). The 115-kV connection to Rhode Island provides very limited power transfer capability benefit to the present system. This is because the tie will automatically open via a Special Protection System (SPS) action (1870 SPS) following the critical transmission contingencies of the Card–Lake Road (330) or Lake Road–Sherman (347) 345-kV ties during times of heavy Connecticut imports. Upgrades are planned that will allow the removal of the

1870 SPS (Wood River to Shunock 1870S line), thereby providing reliability benefits to Connecticut. Furthermore, the 1870 (Wood River to Kenyon) and 1870N (Kenyon to West Kingston) lines are slated for reconductoring in 2007.

Connecticut is tied to the neighboring New York area through the Long Mountain–Pleasant Valley (398) 345-kV tie and through the Norwalk–Northport (1385) 138-kV tie. Flow on the 1385 is controlled by coordination between New York ISO and ISO New England to maintain system reliability and is normally maintained at zero MW. The remaining High Voltage direct current (HVdc) interconnection with Long Island Power Authority in New York is installed and functioning as a fully commercial facility. Under normal operating conditions, it is mostly used during peak hours to provide relief to Long Island, with exports ranging from 50 MW to 330 MW.

Transmission import capability into Connecticut is influenced by several simultaneous transfers. Conditions that can affect the ability to import power into Connecticut include New York–New England imports and exports, New England East–West transfers, SEMA/RI exports, East–West transfers within Connecticut, and Springfield/Western Massachusetts generation dispatches.

1.3 GREATER RHODE ISLAND

The Greater Rhode Island (GRI) area includes the transmission system in the state of Rhode Island and surrounding 345-kV transmission in Massachusetts and Connecticut. Greater Rhode Island is at the end of two interstate gas pipelines (Tennessee and Algonquin). This has spurred construction of a significant amount of gas-fired generation in the GRI area. A total of 2,500 MW of this relatively new gas-fired generation has been interconnected to the GRI 345-kV transmission system since 1990.

The Rhode Island transmission system consists of 345-kV connections to Massachusetts and Connecticut, and an underlying 115-kV network. The 345-kV system is connected to Brayton Point in Somerset, Massachusetts, via Line 315 from West Farnum in North Smithfield, Rhode Island, to ANP–Blackstone via Line 3361 from Sherman Road, and to Lake Road via Line 347 from Sherman Road. The Ocean State Power Plant is connected to Sherman Road via a 345-kV radial line (Line 333). Three 345/115-kV substations supply the underlying 115-kV system in Rhode Island—Brayton Point, West Farnum, and Kent County. The system is tied to the southeastern Connecticut system by a 115-kV interconnection from Kent County to Mystic, and to Massachusetts via two 115-kV lines to Millbury Substation and several 115-kV lines that ultimately terminate at Brayton Point and Somerset stations.

1.4 WESTERN MASSACHUSETTS / SPRINGFIELD

Western Massachusetts encompasses the four western counties of Massachusetts. Western Massachusetts Electric Company (WMECO) serves the major portion of the load in this area. At the end of 2005, WMECO’s existing transmission circuits in service in Massachusetts were comprised of 104.5 circuit miles of 345-kV, 346.0 circuit miles of 115-kV (which includes 9.4 miles of underground cables and an abundance of double-circuit towers), and 5.5 circuit miles of 69-kV lines. These transmission lines supply power to 36 substations in the WMECO service territory. The WMECO transmission system is interconnected to other electric utilities, including The Connecticut Light and Power Company (CL&P), National Grid, Holyoke Gas and Electric, Holyoke Water Power Company (HWP), and the Chicopee Electric Light Department. Various municipal utilities are also interconnected to the WMECO transmission system at the distribution level.

The WMECO service territory is divided into two areas, Pittsfield/Greenfield and Springfield. The Springfield area is of concern for this analysis. The Springfield area includes the City of Springfield and extends west to Blandford, south to the Connecticut border, north to Amherst, and east to Ludlow.

WMECO is the primary service provider for this area. Other municipals/utilities that serve load in this area are Holyoke Gas and Electric, Holyoke Water Power Company, Chicopee Electric Light, Westfield Gas and Electric, South Hadley, and National Grid.

1.5 NEW ENGLAND REGIONAL LOAD FORECAST PROJECTIONS

ISO-NE forecasts the regional peak load for New England on an annual basis. The New England regional forecast is derived by modeling load for each of the New England states, based on NEPOOL load data from various New England subareas. The results for each state are summed to produce the New England regional forecast. The NEPOOL Load Forecast Committee, the NEPOOL Reliability Committee, and the Planning Advisory Committee review the forecast on an annual basis. The analysis conducted to develop a New England forecast was based on the April 2005 ISO-NE published peak load forecast. The most recent version of the ISO-NE peak load forecast was published in March 2006 and comparison of the updated forecast with the April 2005 forecast used in the analysis indicates that New England is expected to experience a slightly higher peak load. This change is relatively small and would not lead to any changes in the results of the analysis performed for any of the areas studied. Consequently, the need and timing for system upgrades would not be affected as a result of the slight change in system load forecast. Appendix A includes a full description of the process ISO-NE uses to develop the peak load projections for each of the New England areas.

The following Table 1.1 summarizes the ISO-NE's 2005 Regional System Plan (RSP05) subarea peak and energy forecast.

Table 1.1: Energy and Peak-Load Forecast Summary for the ISO New England Control Area and States,

Area	Net Energy for Load (GWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50		90/10			50/50		90/10		
	2005	2014	CAGR	2005	2014	2005	2014	CAGR	2005/06	2014/15	2005/06	2014/15	CAGR
NE Control Area	**134,085**	**152,505**	**1.4**	**26,355**	**30,180**	**27,985**	**32,050**	**1.5**	**22,830**	**26,005**	**23,740**	**27,030**	**1.5**
BHE	2,135	2,215	0.4	360	380	380	400	0.6	355	370	365	380	0.5
ME	6,500	7,520	1.6	1,045	1,225	1,090	1,280	1.8	1,065	1,235	1,090	1,260	1.7
SME	3,630	4,135	1.5	595	685	620	715	1.6	575	655	590	670	1.5
NH	9,665	11,540	2.0	1,860	2,250	2,010	2,440	2.1	1,675	1,990	1,745	2,070	1.9
VT	7,190	7,940	1.1	1,220	1,360	1,295	1,440	1.2	1,175	1,315	1,210	1,350	1.3
BOSTON	26,770	29,720	1.2	5,360	5,940	5,685	6,295	1.1	4,515	5,070	4,700	5,275	1.3
CMA/NEMA	8,520	9,635	1.4	1,705	1,965	1,815	2,085	1.6	1,470	1,645	1,540	1,720	1.3
WMA	10,775	11,735	1.0	2,015	2,200	2,140	2,335	1.0	1,865	2,035	1,940	2,115	1.0
SEMA	13,420	15,405	1.5	2,750	3,210	2,915	3,405	1.7	2,270	2,585	2,370	2,695	1.5
RI	11,285	12,985	1.6	2,390	2,755	2,540	2,925	1.6	1,905	2,200	1,975	2,280	1.6
CT	17,065	19,980	1.8	3,515	4,165	3,740	4,430	1.9	2,990	3,490	3,120	3,645	1.7
SWCT	11,275	12,950	1.6	2,290	2,645	2,440	2,815	1.6	1,980	2,260	2,065	2,360	1.5
NOR	5,880	6,760	1.6	1,250	1,415	1,330	1,505	1.4	1,000	1,170	1,045	1,220	1.8

2 METHODOLOGY FOR ANALYZING SYSTEM RELIABILITY

2.1 TRANSMISSION PLANNING PROCESS

Transmission planning for the New England electric power system is a dynamic, ongoing activity that is summarized annually in a regional system plan. This system wide summary is the result of numerous assessments that evaluate the capacity and reliability of the transmission facilities that make up the New England bulk power transmission system. In addition, the reliability needs within geographic subareas of the system are investigated to ensure that the load requirement of each sub-area is reliably served.

Periodic review evaluates the future performance of the system under projected operating conditions over a 10-year period. To perform these evaluations, analytical modeling software simulates system wide transmission system performance. These models are designed to simulate load-flow patterns and loading characteristics across the system.

The simulation software makes it possible to run a series of “what if” scenarios to analyze the impact of a contingency event on the transmission system and to test various operational adjustments that could be implemented to address any inadequacies discovered as a result of the contingency analysis. These adjustments typically include system reconfigurations, phase-angle regulator adjustments, fast-response unit dispatch, and load transfers between substations or transmission circuits. If the model shows that the transmission system would experience violations even with those adjustments in place, a reliability issue must be addressed through a more significant effort (i.e., the addition or upgrade of transmission facilities). Models were developed to test various alternatives for mitigating the reliability concern.

Because a relatively long lead-time is involved in identifying, planning, and implementing transmission line additions and upgrades, the 10-year planning-process horizon is designed to provide sufficient time to identify and plan for needed large-scale system changes, additions, or upgrades. However, the 10-year horizon also involves a significant amount of uncertainty as to the impact of future events, load-growth trends, and local area load growth on the system.

2.2 PLANNING STANDARDS AND CRITERIA

ISO-NE is responsible for dispatching generation and conducting the day-to-day operation of the integrated transmission system. It operates the various transmission systems owned by electric utilities in New England as a single transmission system. As noted previously, the performance of the New England transmission system must adhere to reliability standards and criteria established by NERC, NPCC, and ISO-NE, which ensure that the electric power systems serving New England are appropriately designed to provide an adequate and reliable electric power delivery system.

These standards are under the purview of NERC, which has national authority to ensure the reliability of transmission systems across the United States. NERC oversees a number of regional councils, one of which is the NPCC, which covers New York, New England, and Canada. Under this framework, NERC has established a general set of rules and criteria applicable to all geographic areas. NPCC has established a set of rules and criteria particular to the Northeast, although they encompass the more general NERC standards. In turn, ISO-NE has developed standards and criteria specific to New England that also coordinate with the NPCC rules. Similar standards exist throughout the nation and other portions of North America.

Whether developed by NERC, NPCC, or ISO-NE, the standards and criteria applicable to the New England transmission system are applied in a deterministic fashion in order to assess the ability for 115-kV and 345-kV transmission systems to perform under a series of defined contingency situations.

Specifically, these standards and criteria dictate a set of operating circumstances or contingencies under which the New England transmission system must perform without experiencing overloads. For NPCC, these performance measurements are set forth in "Basic Criteria for the Design and Operation of Interconnected Power Systems" (revised May 2004) (NPCC Standards). For ISO-NE, these measurements are set forth in Planning Procedure No. 3, "Reliability Standards for The New England Area Bulk Power Supply System" amended February 1, 2005), which are used to plan the interconnected electrical network (generators and transmission circuits).

Both NPCC and ISO-NE standards establish that the electric transmission system must pass specific tests to comply with the established criteria. These tests take into account historical data and occurrences and include an examination of the following:

- Section 3. Area transmission requirements: Is the area transmission system capable of delivering the generation to the load under anticipated facility outage events?
- Section 4. Transmission Transfer Capability: Is the interconnected transmission system designed with adequate inter-Area and intra-Area transfer capability?

The standards state that:

> "The bulk power system should be designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, should not result from any reasonably foreseeable contingencies. . . . Analyses of simulations of these contingencies should include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse."[1]

The standards documents specifically define "reasonably foreseeable contingencies"[2] that must be tested and the conditions under which these contingencies must be evaluated. These circumstances generally consider the loss of transmission system elements and the availability (or unavailability) of generating resources.

The New England transmission system is operated with sufficient capacity to serve area loads under normal operating conditions, as well as facility outage conditions. These outages, referred to as "single-contingency" outages, are planned or unplanned events wherein a single transmission element, substation transformer, or autotransformer is out of service. The reliability criteria specify that system voltages, line loadings, and equipment loadings should be within normal limits for normal conditions and within applicable emergency limits for single-contingency outages.[3]

To determine whether the system complies with the applicable criteria, analytical models are built to represent the existing system configuration and capabilities. These models then undergo contingency testing (i.e., the loss of one or more elements). Specifically, the criteria require a simulation of system performance in the event of an N-1 (single) contingency, which is the base system minus one element. For example, an N-1 contingency would occur when a transmission line is forced out of service due to a lightning strike or fallen tree. To perform this analysis, an exhaustive list of the transmission elements on the system is compiled. The elements include transmission lines, transformers, and breakers. A series of simulations are run to test the system with each of these individual elements taken out of service (contingencies). The simulations are used to monitor the loads and flows on all other elements in the

[1] ISO-NE Planning Procedure No. 3 Reliability Standards for the New England Area Bulk Power Supply System, February 1, 2005, Pg. 2
[2] Ibid., Pg. 4
[3] Ibid.

event of each contingency and to technically evaluate the system's capacity to meet normal and emergency operating requirements.

N-1-1 contingency analyses are also performed to evaluate the transmission system supply capabilities in each area. These analyses assess the performance of the system assuming the base-case condition minus two major resources, such as a loss of one transmission system element followed by the loss of a second transmission system element (assuming available resources are adjusted between outages). To the extent that the analysis determines an area's resources to be inadequate under contingency conditions, it also identifies the increase in transmission capacity or level of area resources needed in these conditions to avoid being short of supply. Area resources can be added either by adding new supply-side resources or new transmission capacity. The addition of transmission capacity improvements to address the traditional reliability concerns associated with N-1 contingencies may also provide added capacity in support of N-1-1 area supply issues.

3 NEEDS ANALYSIS

3.1 ASSESSMENT OF PROJECTED SOUTHERN NEW ENGLAND SYSTEM PERFORMANCE

The study included the entire state of Connecticut and the state of Rhode Island as well as the Springfield area system. Analysis has revealed the interdependencies that exist between these areas. The power transfer capability for the state of Connecticut is directly affected by the requirements and constraints of the Rhode Island and Springfield area supply systems. As indicated in the tables below, each area has its own set of resource requirements and, as shown in the results section, their own set of reliability concerns. The analyses discussed in this section are based on tests of the projected system performance for the three study areas assuming the system would have no major transmission system upgrades beyond those currently planned or extensive generation additions beyond those already installed.

The load levels tested include the 2009 and the 2016 peak-load conditions for summer based on the most recently available ISO-NE system load forecast at the time of the study. The 90/10 load forecast was used as described in Appendix A. Planned transmission upgrades expected to occur prior to 2009 were included in the base case including all of the Southwest Connecticut system upgrades. Subsequent discussion details the load, generation, and transmission system transfer capabilities assessed for the base-case conditions.

Additionally, all of the projects listed below were included in the base-case models used to assess system performance and were considered as being in service prior to the implementation of the upgrades proposed in this analysis.

- Southwest Connecticut Phase I and II Projects
- Boston 345-kV Transmission Reliability Project
- Northeast Reliability Interconnection Project
- Northwest Vermont Reliability Projects
- Central Massachusetts Reliability Projects
- Southwest Rhode Island Reliability Projects
- Barbour Hill Reliability Project
- Killingly Reliability Project

3.2 AREA TRANSMISSION AND PROJECTED TRANSFER-CAPABILITY REQUIREMENTS

Table 3.1 and Table 3.2 summarize the load, generation, resource assumptions, transfer requirements, and transfer capabilities for the study areas. The interfaces used for Rhode Island and Springfield were defined for the purpose of conducting the reliability assessments and are not interfaces used for operational purposes. Similarly, the loads defined for these areas were based on the loads encompassed by the study interfaces and do not necessarily match any currently defined sub-areas of the system.

The resource assumptions consider likely generation additions, generation retirements based on a 60-year age limit, and equivalent forced outage rates (EFOR) based on typical EFOR statistical performance for each of the areas of concern. The new generation additions were based on the assumption that 500 MW of additional generation is fully operational by 2016. The Connecticut power transfer capabilities are based on an assumption that the Springfield transmission system constraints are not limiting as they apply to Connecticut import capabilities.

The data in Table 3.1 and Table 3.2 suggest that certain areas in the southern New England system are of concern.

Table 3.1 and Table 3.2 assess the resource requirements and adequacy for each of the areas under study. The tables include the following items:

Area Loads

Identification of the projected area peak loads based on the ISO-NE 2005 90/10 forecast. These loads are the loads that are encompassed by the interfaces being studied and do not necessarily align with state or ISO-NE zone boundaries.

Existing Capacity

The existing generation capacity values are based on the summer claimed capability values in the 2005 Capacity, Energy, Load and Transmission (CELT) report.

Retirements

The retirement values were determined based on an assumption that units greater than 60 years old would no longer be available.

EFOR

The EFOR values are based on calculated values for the equivalent forced outage rate for units in the specified areas.

Unavailable Generation

The unavailable generation values are derived from the values of the largest unit in the area. Under emergency import conditions the largest unit is assumed to be available and import capability is based on loss of two transmission elements.

New Generation

The new generation values were based on units that have I.3.9 approval, are not yet under construction and are likely to proceed to completion.

Total Resource

Total resource values are based on the net sum of existing capacity plus new generation less retirements, EFOR and unavailable generation.

Transfer Required

Comparing the total area resource value to projected peak loads provides the transfer levels that would be needed to serve area peak loads.

Existing Transfer Capability

Existing transfer capabilities are based on today’s values as derived through the studies.

Load Margin/ (Deficiency)

The load margin is the amount of additional load that can be supplied reliably. Conversely, the load deficiency is the amount of load that cannot be supplied reliably.

Table 3.1: Summary of 2009 Area Requirements

	CT Normal	CT Emergency	RI Normal	RI Emergency	Springfld Normal	Springfld Emergency
2009 Area Load 90/10 [a]	8,065	8,065	1,883	1,883	1,015	1,015
Existing Capacity	6,797	6,797	1,016	1016	874	874
Retirements >60 yrs old	-81	-81	0	0	-31	-31
EFOR	-501	-501	-23	-43	-60	-70
Unavailable Generation	-1,200	0	-515	0	-231	0
New Generation	0	0	0	0	0	0
Total Resource	5,015	6,215	478	993	552	773
Transfer Required	3,050	1,850	1,405	910	463	242
Existing Transfer Capability	2,500	1,220	1420	900	446 [b]	326 [b]
Load Margin/(Deficiency)	(550)	(630)	15	(10)	(17)	84

[a] As noted in earlier sections, this analysis is based on the April 2005 ISO-NE published peak load forecast.

[b] The import values exclude constraints associated with 115 kV double circuit tower contingencies that are not normally used in daily operation of the system.

Table 3.2: Summary of 2016 Area Requirements

	CT Normal	CT Emergency	RI Normal	RI Emergency	Springfld Normal	Springfld Emergency
2016 Area Load 90/10 [a]	8,970	8,970	2,085	2,085	1,135	1,135
Existing Capacity	6,797	6,797	1,016	1,016	874	874
Retirements >60 yrs old	-204	-204	0/0	0/0	-31	-31
EFOR	-501	-501	-30	-50	-60	-70
Unavailable Generation	-1,200	0	-515	0	-231	0
New Generation	500	500	0	0	0	0
Total Resource	5,392	6,592	471	966	552	773
Transfer Required	3,578	2,378	1,614	1,119	583	362
Existing Transfer Capability	2,500	1,220	1370	865	205 [b]	274 [b]
Load Margin/(Deficiency)	(1078)	(1158)	(244)	(254)	(378)	(88)

[a] As noted in earlier sections, this analysis is based on the April 2005 ISO-NE published peak load forecast.

[b] The import values exclude constraints associated with 115 kV double circuit tower contingencies that are not normally used in daily operation of the system.

3.3 MAJOR INTERFACE TRANSFER LIMITS

The transmission system interfaces that define each of the study areas are summarized below. The interfaces described were used for study purposes only and may not conform to interfaces system operators use for the day-to-day management of system resources. These interfaces were determined based on observing the transmission elements that became limiting at the boundary of the area being studied.

3.3.1 Connecticut Power Transfer limits

For these studies, the set of transmission system elements shown in Table 3.3 define the Connecticut import area.

Table 3.3: Connecticut Import Interface Definition

Line #	Transmission Element				% Flow
	From Bus Name	kV	To Bus Name	kV	
395	LUDLOW	345	MEEKVILLE JCT	345	30.0%
330	LAKE ROAD	345	CARD	345	29.08%
XFMR	KILLINGLY	345	KILLINGLY	115	5.5%
398	PLEASANT VALLEY	345	CT-NY BORDER	345	23.7%
1870	WOOD RIVER	115	CT-RI BORDER	115	4.1%
1768	SOUTHWICK	115	N.BLMFLD	115	2.4%
1830	SO.AGAWAM	115	N.BLMFLD	115	2.6%
1821	SO.AGAWAM	115	N.BLMFLD	115	2.6%

The Connecticut power interface as defined in Table 3.3 is capable of reliably supporting import levels of 2,500 MW. As seen above the 395 and 330 lines carry approximately 60% of the Connecticut import flows under typical dispatch conditions. The projected Connecticut resource requirements indicate that the existing transmission infrastructure will be insufficient to support future import requirements and that a number of system reconfigurations will be necessary to increase the import capability.

3.3.2 Rhode Island Power Transfer limits

For these studies, the set of transmission system elements shown in Table 3.4 define the Rhode Island import area.

The N-1 import capability of these facilities is approximately 1,420 MW in 2009 and, as a result of load growth is reduced to 1,370 MW in 2016. As seen above about 65% of the flows into the area are delivered through three 345-kV to 115-kV autotransformers and another 30-35% is delivered via the Brayton Point 115-kV station.

Table 3.4: Rhode Island Import Interface Definition

Line #	From Bus	From-kV	To Bus	To-kV	Ckt ID	% of Interface Flow
175X	West Farnum	345	West Farnum	115	1	13.5
174X	West Farnum	345	West Farnum	115	2	19.5
3X	Kent Co.	345	Kent Co.	115	1	32.8
W4	Somerset	115	Swansea	115	1	4.4
T7	Somerset	115	Pawtucket	115	1	3.5
X3	Somerset	115	Phillipsdale	115	1	3.9
1870	CT/RI Border	115	Wood River	115	1	-2.8
Q143	Millbury	115	Whitins Pond	115	1	-3.2
R144	Millbury	115	Woonsocket	115	1	-6.1
E183	Brayton Point	115	Warren 83	115	1	13.3
F184	Brayton Point	115	Warren 84	115	1	21.0

3.3.3 Springfield Power Transfer Limits

For these studies, the set of transmission system elements shown in Table 3.5 define the Springfield import area..

Table 3.5: Springfield Import Interface Definition

	Transmission Element				% of Interface Flow [a]
Line #	Fr Bus Name	kV	To Bus Name	kV	
1421	PLEASANT	115	BLANDFRD	115	5.1%
1768	N.BLMFLD	115	SOUTHWCK	115	5.7%
1481	LUDLOW	115	E.SPGFLD	115	15.8%
1552	LUDLOW	115	ORCHARD	115	13.2%
1845	LUDLOW	115	SHAWINGN	115	36.0%
1515	LUDLOW	115	SCITICO	115	6.2%
1821	N.BLMFLD	115	SAGAR	115	9.0%
1836	N.BLMFLD	115	SAGBR	115	9.0%

[a] The percent flow values vary as a function of Connecticut import levels.

3.4 RESULTS OF TRANSMISSION RELIABILITY ANALYSIS

The results of the 2009 analysis concerning the reliability performance of the transmission systems in Connecticut, Springfield and Rhode Island are described below. These results are based on assessments of the transmission system under projected load and generation conditions as established for these areas at the time of the study. *It is important to note that not all of the reliability violations found are being included in the descriptions, tables and diagrams that follow. Results noted in subsequent sections are obtained using only sample, representative system conditions. A wide variety of other probable system conditions were also analyzed, the results for which are not described here.*

Also,' N-1' refers to 'an all-lines-in' or '1st contingency' analysis and 'N-1-1' refers to a 'line-out' or '2nd contingency' analysis. Both analyses are dictated by criteria.

3.4.1 Connecticut Power Transfer Concerns

The Connecticut area resource requirements in 2009 demonstrate the need for improvement in the area's import capability and generating resources. Some improvement in import capability can be obtained through mitigation of limitations associated with the Springfield area. However these improvements are still insufficient to meet the projected supply resource requirements for the 2009 Connecticut peak load conditions. Limitations of the Connecticut import capabilities are a result of insufficient available 345-kV transmission capacity. This can be seen through simulation of 345-kV contingencies associated with the Connecticut interface. Loss of major 345-kV transmission lines on the interface results in overloads of the underlying 115-kV transmission near the outaged 345-kV facility. This problem is most prevalent in the Springfield area and, as shown in Table 3.6 and Table 3.7, a number of Springfield area 115-kV transmission facilities would overload for loss of a major 345-kV line under the import conditions expected to exist in 2009.

Consequently, significant improvement in the Connecticut power transfer capability is essential for maintaining an adequate and reliable level of supply resource for the Connecticut area beginning in 2009 and beyond.

Table 3.6 shows that elements of the Connecticut area transmission system overload for the 2009 system at a power transfer level of 3,050 MW. It should be noted that transmission line overloads specific to the Springfield area are not included in the tables below but are included in Section 3.3.3. The line overload summary tables in this section only show the most severe overload contingency conditions and do not list all of the outage conditions that may overload the element shown. In many cases there are numerous outage events that may overload the elements shown.

Additionally, there are more significant N-1-1 overloads that are not shown here because of the Special Protection System (SPS) that backs down the Millstone plant output for certain contingency conditions.

Table 3.6: Connecticut Transmission Line Overloads (N-1) - 2009

	Worst Scenario			Line / Auto Terminals							
Load Level	Gen. Out of Service	Line / Auto Out of Service	Contingency	Line / Auto	From Bus	From-kV	To Bus	To-kV	Ckt ID	Rating	Max Loading (%) Over Rating
2009_Pk	LargestGen. & Av.EFOR & Ret.	None	395N	3361	ANP 336	345	SHERMAN	345	1	1400	110.9
2009_Pk	LargestGen. & Av.EFOR & Ret.	None	395N	347	SHERMAN	345	CTRI	345	1	1618	109.6
2009_Pk	LargestGen. & Av.EFOR & Ret.	None	347LINE	302	CARP HL	345	MILLBURY	345	1	1405	102.2
2009_Pk	LargestGen. & Av.EFOR & Ret.	None	347LINE	395N	LUDLOW	345	BHAUTO	345	1	1604	121.9
2009_Pk	LargestGen. & Av.EFOR & Ret.	None	347LINE	395S	BHAUTO	345	MEEKVL J	345	1	1604	103.1
2009_Pk	LargestGen. & Av.EFOR & Ret.	None	1207-1775DCT	1751	BLM JCT	115	NW.HTFD	115	1	228	114.7

Table 3.7: Connecticut Transmission Line Overloads (N-1-1) - 2009

	Worst Scenario			Line / Auto Terminals							
Load Level	Gen. Out of Service	Line / Auto Out of Service	Contingency	Line / Auto	From Bus	From-kV	To Bus	To-kV	Ckt ID	Rating	Max Loading (%) Over Rating
2009_Pk	Av.EFOR & Ret.	395N	301-302LNS	Ludlow Auto	LUDLOW	345	LUDLOW	115	2	705	124.0
2009_Pk	Av.EFOR & Ret.	348	310-368DCT	371	MONTVILE	345	MILLSTNE	345	1	1793	112.7
2009_Pk	Av.EFOR & Ret.	348	310-368DCT	364	MONTVILE	345	HADDM NK	345	1	1912	114.7
2009_Pk	Av.EFOR & Ret.	364	310-368DCT	348	MILLSTNE	345	HADAUTO	345	1	1912	112.5
2009_Pk	Av.EFOR & Ret.	348	MONTV1TSTB	353	MANCHSTR	345	PORT JCT	345	1	1446	108.9
2009_Pk	Av.EFOR & Ret.	348	1775LINE	1207	MANCHSTR	115	E.HTFD	115	1	382	101.1
2009_Pk	Av.EFOR & Ret.	348	1207-1775DCT	1777	N.BLMFLD	115	BLOOMFLD	115	1	228	106.0
2009_Pk	Av.EFOR & Ret.	348	1207-1775DCT	1751	BLM JCT	115	NW.HTFD	115	1	228	131.0

The following diagrams show these overloads on 345-kV diagrams.

Figure 3.1: 2009 Connecticut Transmission Line Overloads – N-1

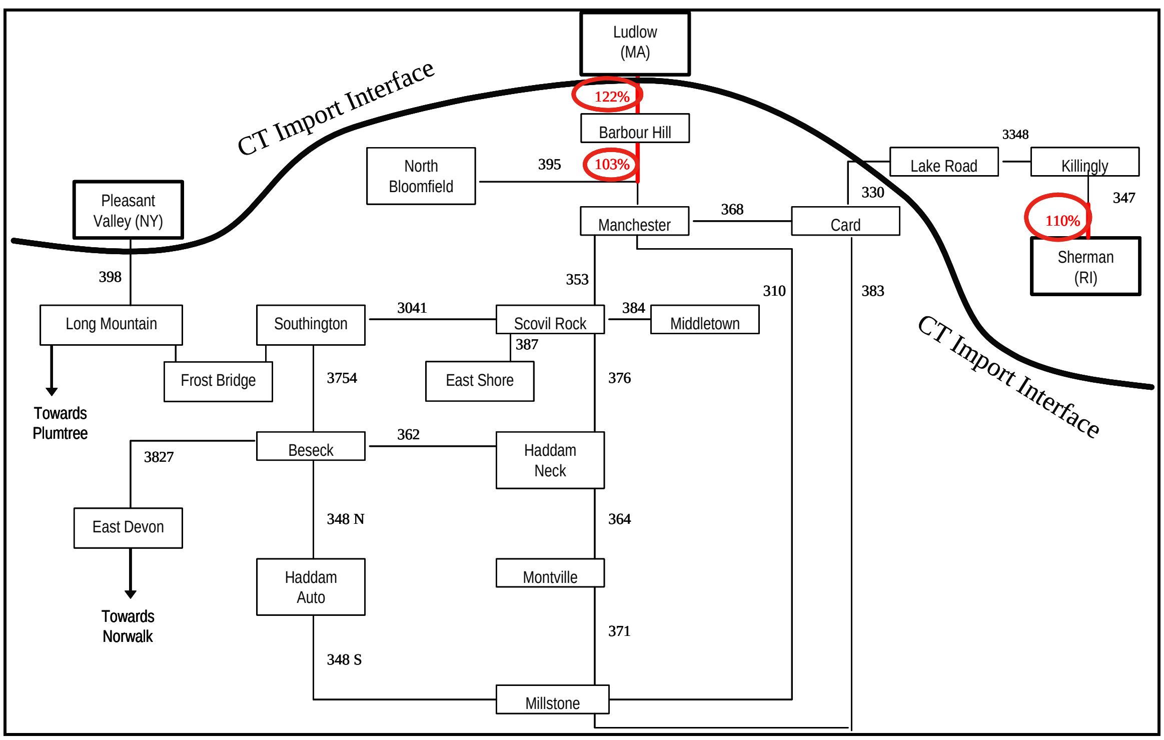
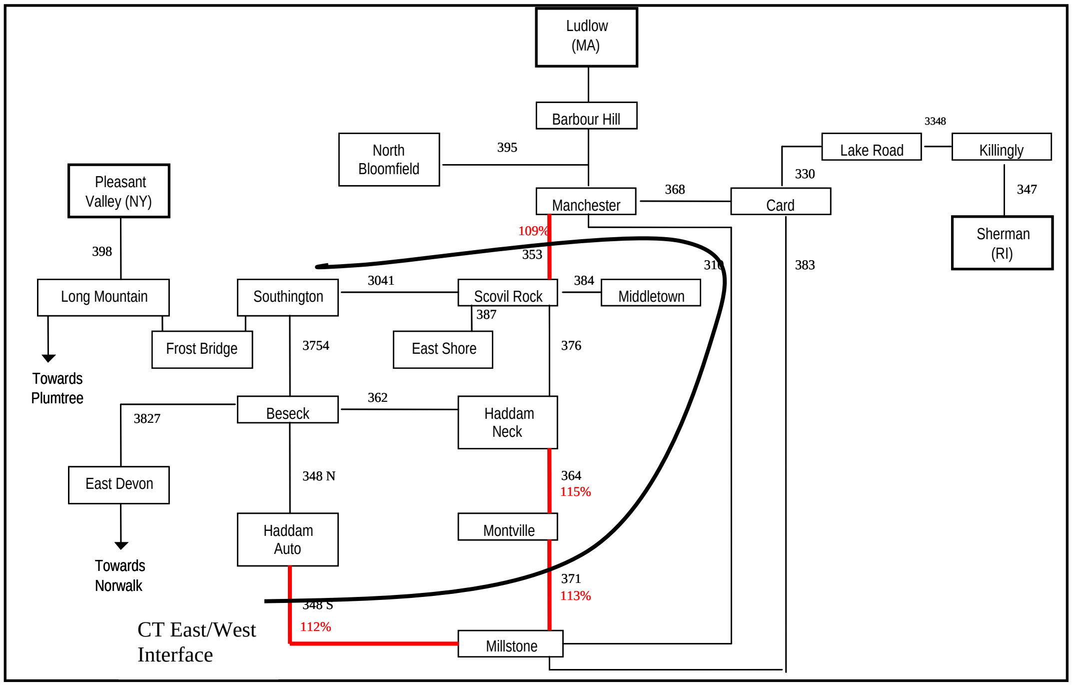


Figure 3.2: 2009 Connecticut Transmission Line Overloads – N-1-1



3.4.2 Springfield Area Transmission Reliability Concerns

The area resource analysis presented above indicates that the Springfield area is not an import-constrained area and is not expected to suffer significant resource deficiencies to serve area loads until later in the study period. However, the Springfield area faces a number of reliability concerns.

Many local single outages, double-circuit tower outages (DCT) and stuck breaker outages result in severe line overloads and low voltages in the Springfield area, independently of the transfer conditions with its neighboring areas.

Additionally, the Springfield 115-kV transmission system is one of the paths for transporting power into Connecticut. The flow of power through the Springfield 115-kV system increases when the major 345-kV tie line between western Massachusetts and Connecticut (the Ludlow–Manchester–North Bloomfield 345-kV line) is open due to a forced or planned outage. As a result, for all years simulated, numerous overloads appear on the Springfield 115-kV system and increased Connecticut imports aggravate the thermal loadings in Springfield.

Overall, the severity, number, and location of the Springfield overloads or low voltages are highly dependent on the area's generation dispatch and would be significantly aggravated by additional load growth and potential unit retirements. These dependencies are illustrated in Table 3.8 through Table 3.11. The number of violations in the tables below indicates the number of transmission circuits that overload. Each transmission circuit may overload for multiple contingencies.

Table 3.8: Influence of Dispatch on Springfield Violations – Number of Violations

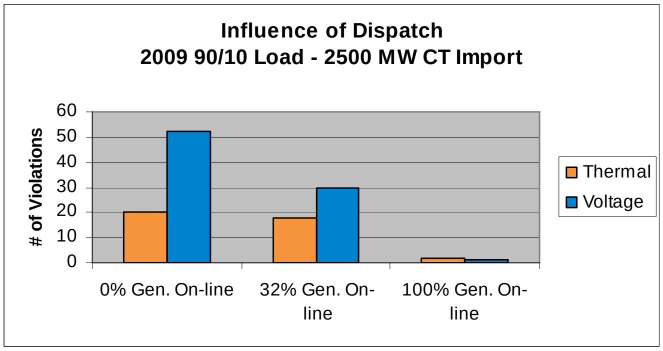


Table 3.9: Influence of Dispatch on Springfield Violations – Severity of Violations

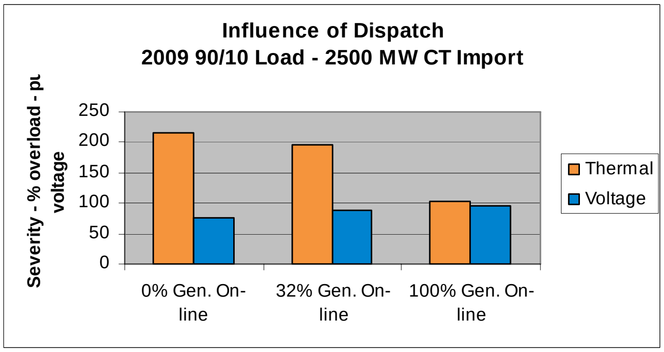


Table 3.10: Influence of Load on Springfield Violations – Number of Violations

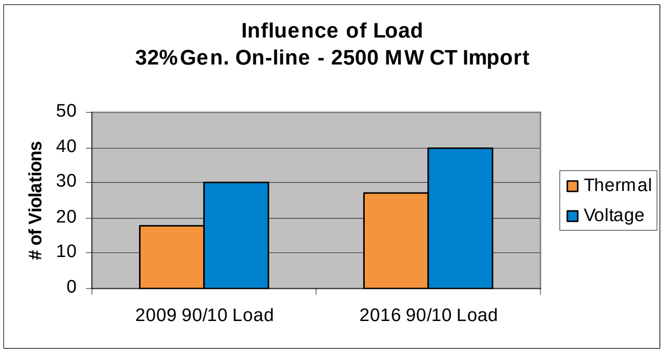
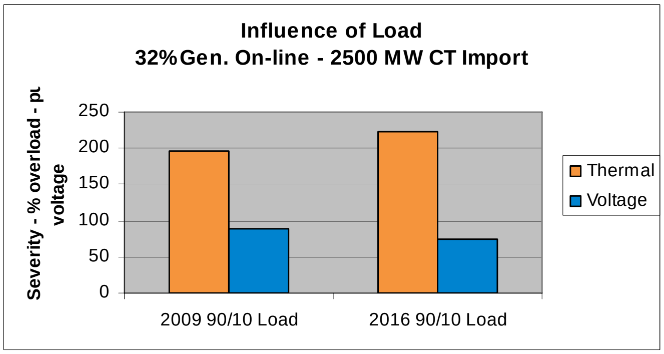


Table 3.11: Influence of Load on Springfield Violations – Severity of Violations



The above analysis indicates that network constraints in the Springfield area limit the ability to serve load under contingency conditions and limit the Connecticut import capability under certain area dispatch conditions

The specific overload and voltage violation conditions are summarized in Table 3.12 through Table 3.14. The line overload summary tables in this section only show the most severe overload contingency conditions and do not list all of the outage conditions that may overload the element shown. In many cases there are numerous outage events that may overload the elements shown.

Table 3.12: Springfield Area Transmission Line Overloads (N-1) – 2009

	Worst Scenario			Line / Auto Terminals							
Load Level	**Gen. Out of Service**	**Line / Auto Out of Service**	**Contingency**	**Line / Auto**	**From Bus**	**From-kV**	**To Bus**	**To-kV**	**Ckt ID**	**Rating**	**Max Loading (%) Over Rating**
2009_Pk	W.Spg & Berk.[1]	None	1254LG2	1254	ESPJ1254	115	CHICOPEE	115	1	265	111.6
2009_Pk	W.Spg & Berk.	None	1481/1552LNS	1254	ESPJ1254	115	FRMNT SO	115	1	282	101.9
2009_Pk	W.Spg & Berk.	None	1481/1552LNS	1254	ESPJ1254	115	SHAWINGN	115	1	382	152.3
2009_Pk	None	None	395N	1512	SOUTHWCK	115	GRANVL J	115	1	191	101.8
2009_Pk	None	None	395N	1768	SOUTHWCK	115	N.BLMFLD	115	1	165	100.3
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	1433	W.SPRING	115	BRECKWD	115	1	140	249.9
2009_Pk	W.Spg & Berk.	None	1254LG2	1314	AGAWM PF	115	CHICOPEE	115	1	228	105.7
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	1322	BRECKWD	115	E.SPGFLD	115	1	141	295.3
2009_Pk	W.Spg & Berk.	None	1254&XFMR	1481	E.SPGFLD	115	LUDLOW	115	1	289	117.4
2009_Pk	W.Spg & Berk.	None	1481	1552	ORCHARD	115	LUDLOW	115	1	305	101
2009_Pk	W.Spg & Berk.	None	1481/1552LNS	1845	LUDLOW	115	SHAWINGN	115	1	311	107.7
2009_Pk	W.Spg & Berk.	None	1322&XFMR	1723	PIPER RD	115	ESPJ1723	115	1	164	113.3

[1]W.Spg & Berk. Implies that West Springfield plant and Berkshire Power plant are offline.

Table 3.13: Springfield Area Transmission Voltage Violations – 2009

	Worst Scenario			Bus Terminals		
Load Level	Gen. Out of Service	Line / Auto Out of Service	Contingency	Bus	Bus-kV	Low Voltage (pu)
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	5CRNR13	115	0.8477
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	5CRNR34	115	0.8463
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	AGAWM PF	115	0.9215
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	AMHRST S	115	0.8368
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	BRECKWD	115	0.9357
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	CHICOPEE	115	0.9033
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	CLINTON	115	0.924
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	FRANCONA	115	0.9214
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	FRMNT NO	115	0.8485
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	FRMNT SO	115	0.8514
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	GUNN	115	0.8588
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	MIDWAY	115	0.8534
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	MT TOM	115	0.8537
2009_Pk	W.Spg & Berk.	None	1481/1552LNS	OCHARD	115	0.9488
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	PIPER RD	115	0.9131
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	POCHASSC	115	0.8859
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	SAGAR	115	0.948
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	SAGBR	115	0.948
2009_Pk	W.Spg & Berk.	None	1515&XFMR	SCITICO	115	0.8988
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	SILVER81	115	0.9252
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	SILVER82	115	0.9252
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	SO.AGAWM	115	0.9269
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	SOUTHMPT	115	0.8666
2009_Pk	W.Spg & Berk.	None	1254/1723LNS	W.SPRING	115	0.9245

Table 3.14: Springfield Area Transmission Line Overloads (N-1-1) – 2009

	Worst Scenario			Line / Auto Terminals							
Load Level	Gen. Out of Service	Line / Auto Out of Service	Contingency	Line / Auto	From Bus	From-kV	To Bus	To-kV	Ckt ID	Rating	Max Loading (%) Over Rating
2009_Pk	W.Spg & Berk.	330	354-5T	1512	BLANDFRD	115	GRANVL J	115	1	147	118.3
2009_Pk	W.Spg & Berk.	330	354-5T	1421	BLANDFRD	115	PLEASANT	115	1	167	112.7
2009_Pk	W.Spg & Berk.	395N	1254/1723LNS	1322	BRECKWD	115	E.SPGFLD	115	1	141	252.3
2009_Pk	W.Spg & Berk.	1254X	1552	1481	E.SPGFLD	115	LUDLOW	115	1	289	131.6
2009_Pk	W.Spg & Berk.	1254X	1481	1426	E.SPGFLD	115	ORCHARD	115	1	311	102.8
2009_Pk	None	1161XS	395N	1007	ELM	115	AGAWM PF	115	1	239	100.9
2009_Pk	W.Spg & Berk.	1314	1481/1552LNS	1254	ESPJ1254	115	FRMNT SO	115	1	282	108.8
2009_Pk	W.Spg & Berk.	395N	1481/1552LNS	1254	ESPJ1254	115	SHAWINGN	115	1	382	137.2
2009_Pk	W.Spg & Berk.	1039	1314/1723LNS	1525	HOLYOKE	115	FRMNT SO	115	1	192	107.9
2009_Pk	W.Spg & Berk.	330	395N-3T	Auto 1X	LUDLOW	345	LUDLOW	115	1	705	110.4
2009_Pk	W.Spg & Berk.	1254X	1481	1552	ORCHARD	115	LUDLOW	115	1	305	119.9
2009_Pk	W.Spg & Berk.	1322C	1254&XFMR	1723	PIPER RD	115	ESPJ1723	115	1	164	104.1
2009_Pk	W.Spg & Berk.	1254X	1426/1481LNS	1781	SO.AGAWM	115	SILVER81	115	1	228	108.6
2009_Pk	W.Spg & Berk.	1254X	1426/1481LNS	1782	SO.AGAWM	115	SILVER82	115	1	228	108.2
2009_Pk	None	1161XS	1007/1302LNS	1512	SOUTHWCK	115	GRANVL J	115	1	191	138.0
2009_Pk	None	1311X	1254/1723LNS	1412	W.SPRING	115	AGAWM PF	115	2	143	144.0
2009_Pk	None	1412	1254/1723LNS	1311	W.SPRING	116	AGAWM PF	116	1	143	144.0
2009_Pk	W.Spg & Berk.	395N	1254/1723LNS	1433	W.SPRING	115	BRECKWD	115	1	140	210.4
2009_Pk	W.Spg & Berk.	330	354-5T	1371	WOODLAND	115	PLEASANT	115	1	228	109.3

The following diagrams depict the overloads & low voltages shown above on a Springfield area transmission diagram.

Figure 3.3: 2009 Springfield N-1 Overloads

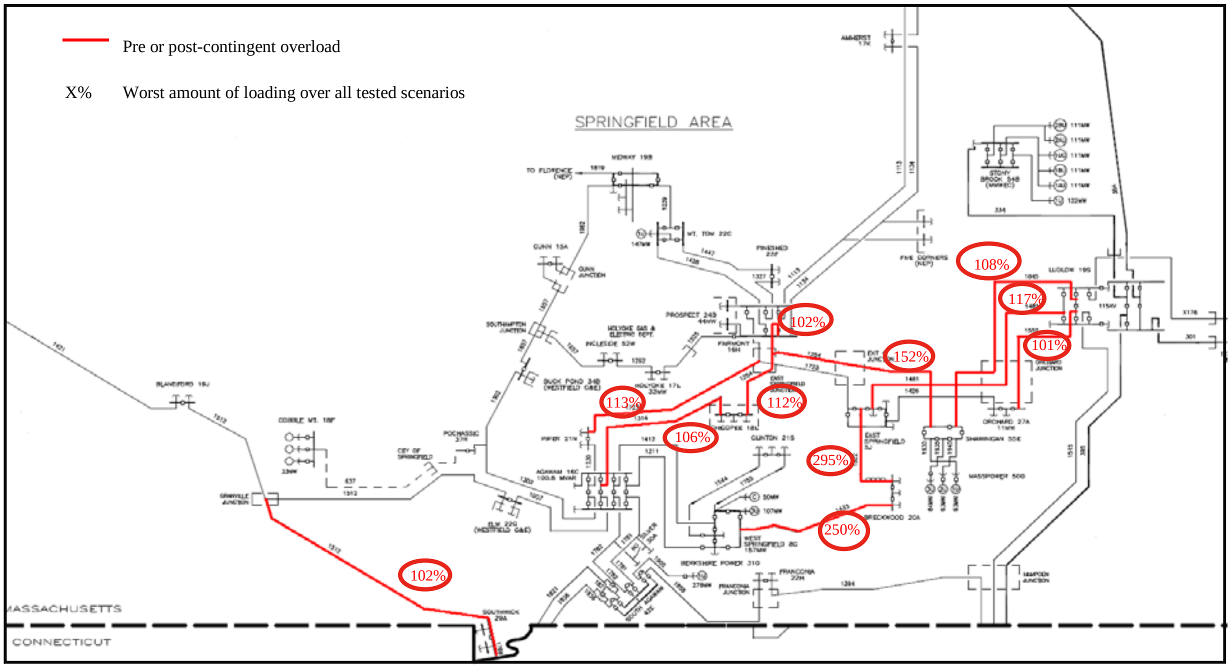


Figure 3.4: 2009 Springfield N-1 Low Voltages for an area 'design' contingency

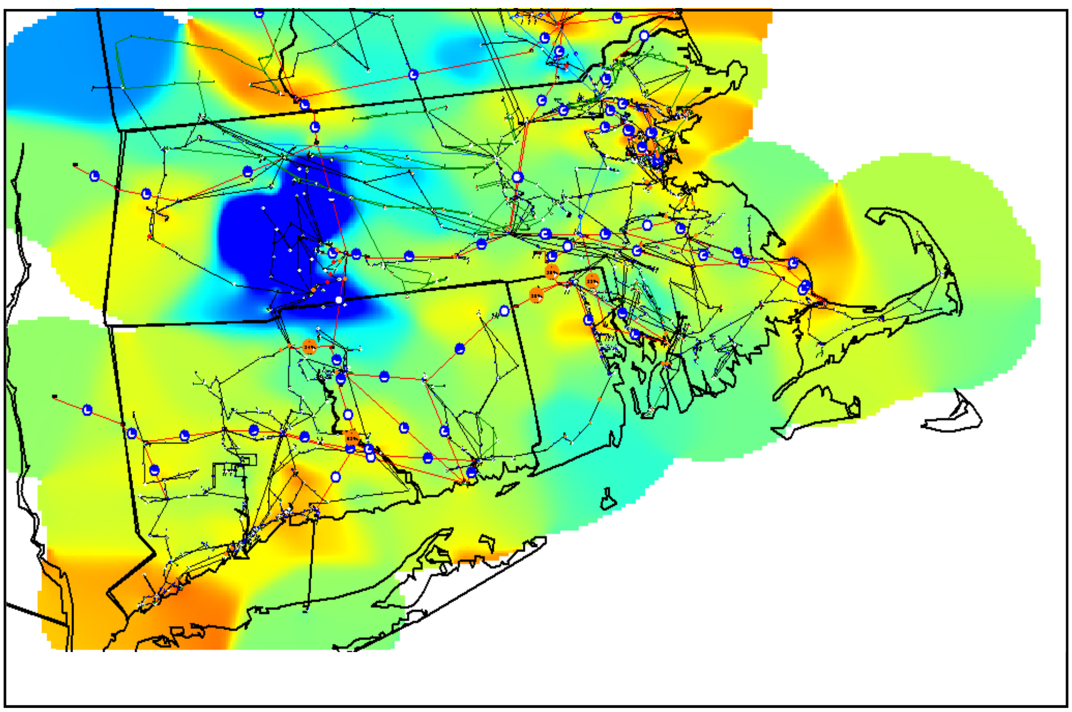
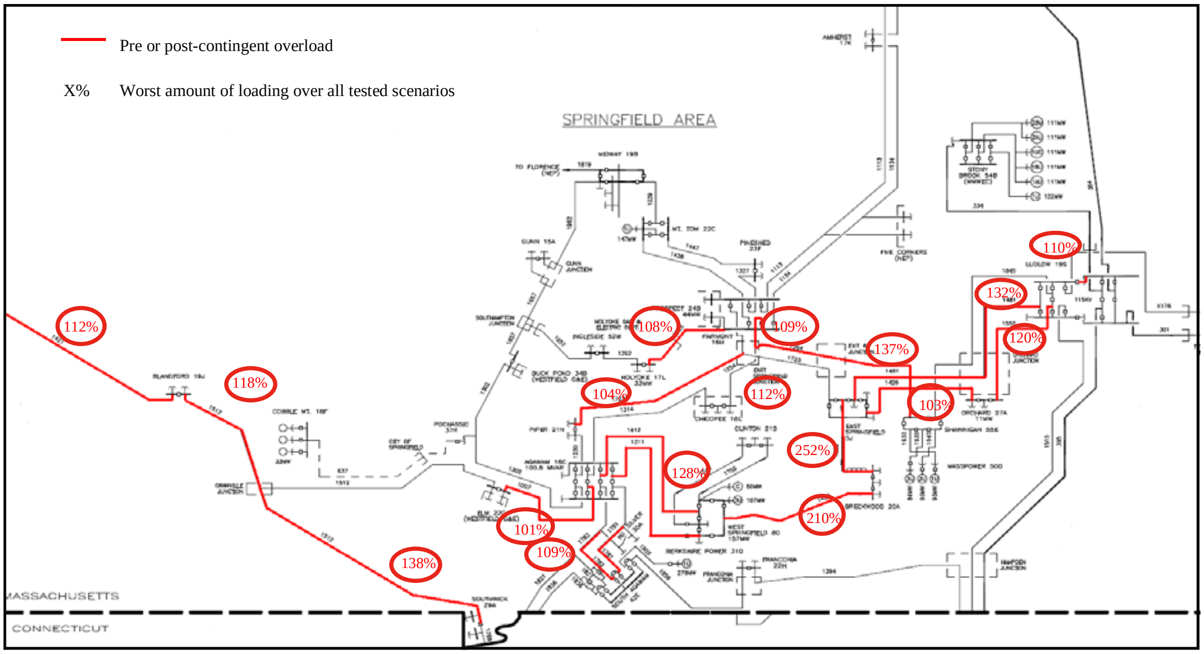


Figure 3.5: 2009 Springfield N-1-1 Overloads



3.4.3 Rhode Island Area Transmission Reliability Concerns

Transmission system reliability and dependence on local generation are the major concerns for the Greater Rhode Island area. A number of steady-state thermal and voltage violations have been observed on the transmission facilities while analyzing the conditions for the 2009 system.

The reliability problems on the Rhode Island 115 kV system are caused by a number of contributing factors (both independently and in combination), including: high load growth (especially in southwestern Rhode Island and the coastal communities), unit availability, and transmission outages (planned or unplanned).

Additionally, the Rhode Island 115-kV system is constrained when a Greater Rhode Island 345-kV line is out of service. The 345-kV transmission lines critical for serving load in the Rhode Island 115-kV system are as follows:

- Line 328 (Sherman Rd–West Farnum)
- Line 332 (West Farnum–Kent County)
- Line 315 (West Farnum–Brayton Point)
- Line 303 (ANP Bellingham–Brayton Point)

Outage of any of these transmission lines result in limits to power transfer into Rhode Island. For line-out conditions, the next critical contingency would involve a loss of a 345/115-kV autotransformer or the loss of a second 345-kV tie.

A summary of the results of contingency testing for transmission system outages for the Rhode Island system are included in Table 3.15 and Table 3.16. These tests were run for the 2009 system and represented the extreme summer forecast (90/10) peak-load levels. They were run with the Connecticut import operating at its required level given projected load and generation conditions. For the N-1 analysis, the largest unit in the area (FPL Rise) was considered unavailable, as was the equivalent forced outage of other area generation. For the N-1-1 analysis, only the equivalent forced outage generation was considered unavailable.

The line overload summary tables in this section only show the most severe overload contingency conditions and do not list all of the outage conditions that may overload the element shown. In many cases there are numerous outage events that may overload the elements shown.

Table 3.15: Rhode Island Area Transmission Line Overloads (N-1) – 2009

				Overload Elements									
Load level	Gen Out-of Service	Line Out-Of Service	Worst Contingency	Line / Auto	From Bus No.	From Bus Name	From kV	To Bus No.	To Bus Name	To kV	Ckt ID	Rating (MVA)	Loading (%)
pk	**FPL Rise**	**None**	**BASE CASE**	**Kent Cty T3**	**71811**	**KENT CO.**	**345**	**72565**	**KENT CO**	**115**	**1**	**478**	**101.4**
pk	FPL Rise	None	HARTAVE F106	E-105	72569	FRSQ	115	72584	HARTAVE	115	1	240	145.7
pk	FPL Rise	None	HARTAVE E105	F-106	72569	FRSQ	115	72584	HARTAVE	115	2	240	145.7
pk	FPL Rise	None	P11+X3 DCT	T3	71377	SOMERSET	115	71405	PAWTUCKT	115	1	128	121.1
pk	FPL Rise	None	KC 8910 BF	G-185 N	72560	DRUMROCK	115	72585	KENT T1	115	1	286	116.3
pk	FPL Rise	None	S WREN 8229	C-181 S	72252	BRAYTN P	115	72253	CHARTLEY	115	1	268	115.2
pk	FPL Rise	None	DRUMRCK 8587	J-188	72560	DRUMROCK	115	72655	KILVERT8	115	1	218	112
pk	FPL Rise	None	WFARNUM 170	Kent Cty T3	71811	KENT CO.	345	72565	KENT CO	115	1	550	109.4
pk	FPL Rise	None	WFARNUM 171	E-183 E	72252	BRAYTN P	115	72573	WARRN 83	115	1	410	104.9
pk	FPL Rise	None	DRUMRCK 8588	I-187	72560	DRUMROCK	115	72591	AMTRK187	115	1	218	102
pk	FPL Rise	None	KC 8910 BF	S-171 S	72563	JOHNS171	115	72584	HARTAVE	115	1	426	101.6

Table 3.16: Rhode Island Area Transmission Line Overloads (N-1-1) – 2009

				Overload Elements									
Load level	Gen Out-of Service	Line Out-Of Service	Worst Contingency	Line / Auto	From Bus No.	From Bus Name	From kV	To Bus No.	To Bus Name	To kV	Ckt ID	Rating (MVA)	Loading (%)
pk	None	332 OOS	HARTAVE 7205	S-171 S	72567	RISE 171	115	72575	WCRAN 71	115	1	449	229.3
pk	None	332 OOS	HARTAVE 7106	T-172 S	72576	WCRAN 72	115	72593	RISE 172	115	1	449	227.6
pk	None	332 OOS	HARTAVE 7205	S-171 S	72560	DRUMROCK	115	72575	WCRAN 71	115	1	449	216.4
pk	None	332 OOS	HARTAVE 7106	T-172 S	72560	DRUMROCK	115	72576	WCRAN 72	115	1	449	214.7
pk	None	332 OOS	HARTAVE 7205	F-106	72569	FRSQ	115	72584	HARTAVE	115	2	240	182.5
pk	None	332 OOS	HARTAVE 7106	E-105	72569	FRSQ	115	72584	HARTAVE	115	1	240	178.4
pk	None	332 OOS	DRUMRCK 7289	S-171 S	72563	JOHNS171	115	72584	HARTAVE	115	1	426	151.1
pk	None	332 OOS	DRUMRCK 7189	G-185 N	72560	DRUMROCK	115	72585	KENT T1	115	1	286	146.7
pk	None	328 OOS	BP-15-300T	P-142 S	72078	WG TP42	115	72096	MILLBURY	115	1	141	133.8
pk	None	332 OOS	DRUMRCK 7189	T-172 S	72564	JOHNS172	115	72593	RISE 172	115	1	449	126
pk	None	332 OOS	DRUMRCK 7289	S-171 S	72563	JOHNS171	115	72567	RISE 171	115	1	449	125.6
pk	None	332 OOS	HARTAVE 7205	Rise Tap	72567	RISE 171	115	72608	RISE	115	1	550	124.4
pk	None	332 OOS	HARTAVE 7106	Rise Tap	72593	RISE 172	115	72608	RISE	115	1	550	124.2
pk	None	315 OOS	P11+X3 DCT	T7	71377	SOMERSET	115	71405	PAWTUCKT	115	1	128	121.1
pk	None	332 OOS	HARTAVE 7106	1870-S	72581	WOOD RIV	115	73285	CTRI1870	115	1	218	114.6
pk	None	332 OOS	DRUMRCK 8587	J-188	72560	DRUMROCK	115	72655	KILVERT8	115	1	218	111.3
pk	None	315 OOS	BP 8183 BF	D-182 S	72252	BRAYTN P	115	72262	MNSFLD82	115	1	283	107.5
pk	None	BP3T OOS	BP 1+2+3 GN	BP T3	71801	BRAYTN P	345	72252	BRAYTN P	115	2	361	106.1
pk	None	332 OOS	DRUMRCK 8588	K-189	72560	DRUMROCK	115	72999	KENT T7	115	2	359	104.4
pk	None	WF T174 OOS	FPLE PP-71	Kent Cty T3	71811	KENT CO.	345	72565	KENT CO	115	1	550	103.1
pk	None	315 OOS	BP 8183 BF	F-184	72252	BRAYTN P	115	72574	WARRN 84	115	1	370	100.9
pk	None	328 OOS	BP-15-300T	W4	71377	SOMERSET	115	71379	SWANSEA	115	1	165	100.9
pk	None	315 OOS	SHERMAN 142	BP T3	72252	BRAYTN P	115	72307	BPT3 MID	99	1	561	100.8
pk	None	332 OOS	DRUMRCK 8588	I-187	72560	DRUMROCK	115	72591	AMTRK187	115	1	218	100.5

Each of these criteria violations are made worse by the unavailability of local area generation and transmission outages (line-out conditions). The following diagrams depict a sampling of the Rhode Island reliability violations.

Figure 3.6: 2009 Rhode Island Reliability Problems – N-1 Thermal Overloads

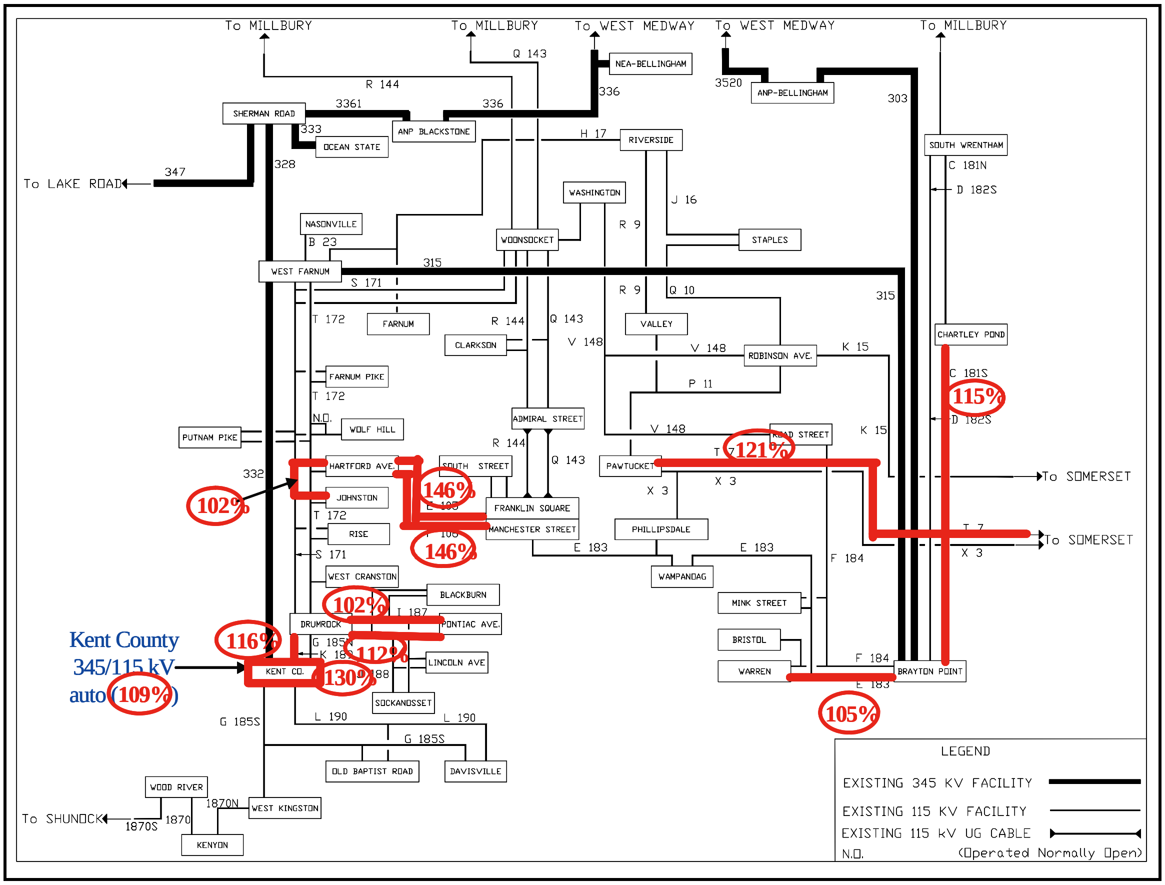


Figure 3.7: 2009 Rhode Island Low Voltages for an area 'design' contingency

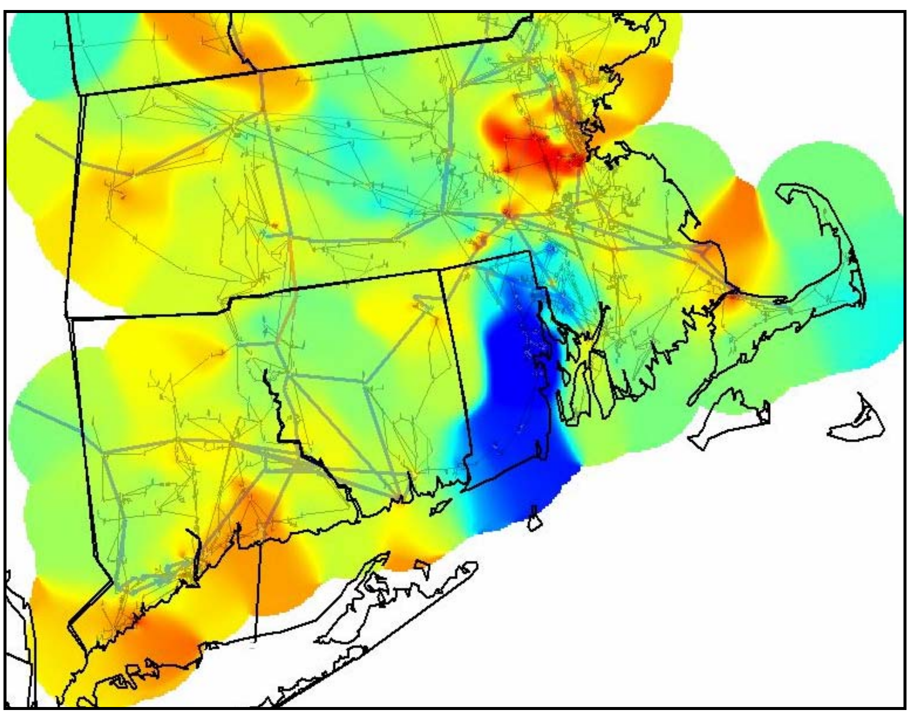
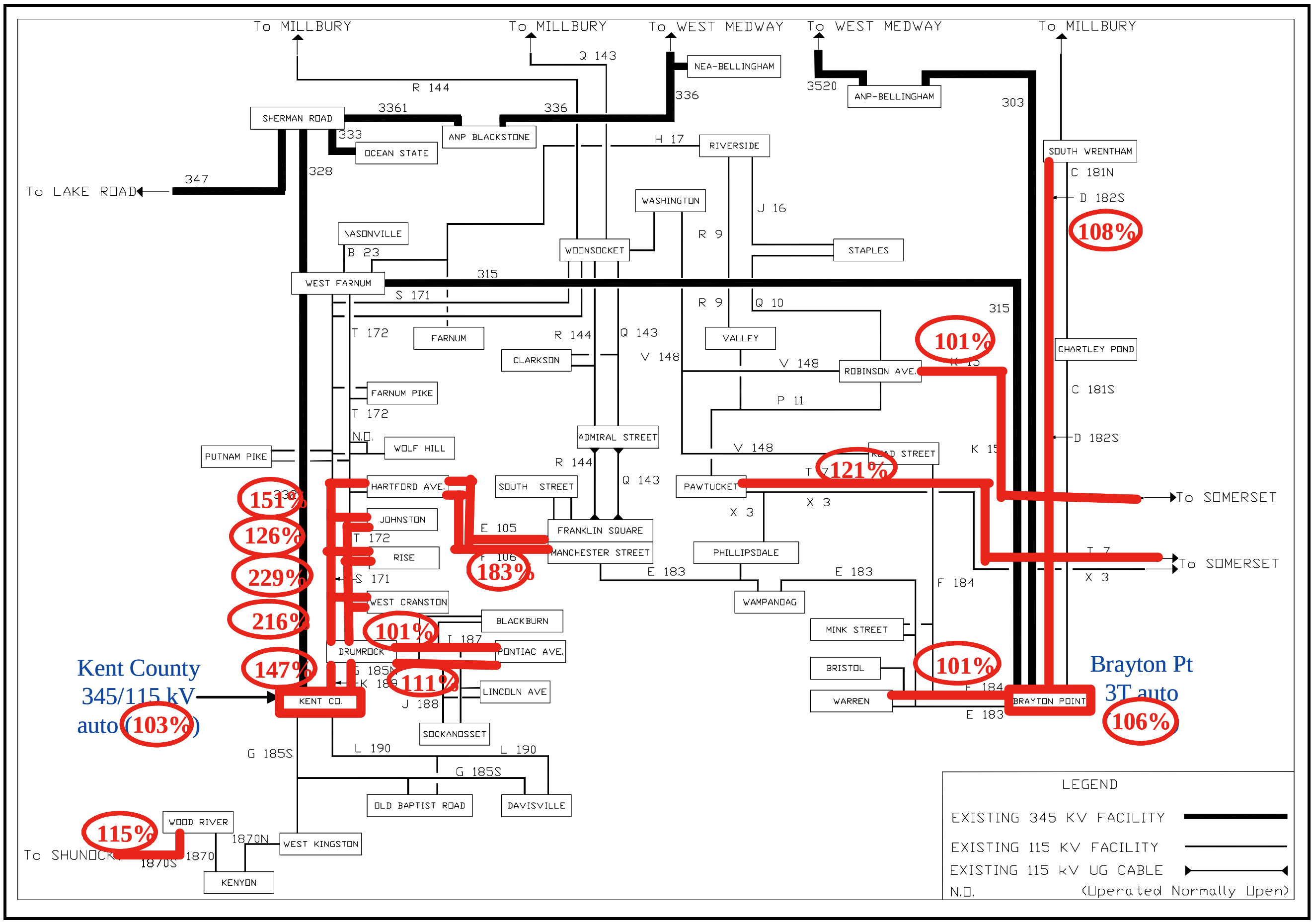


Figure 3.8: 2009 Rhode Island Reliability Problems – N-1-1 Thermal Overloads



3.5 CONCLUSIONS ON NEEDS ANALYSIS

In summary, the analysis presented above demonstrates that in 2009 area transmission capabilities are inadequate to meet NERC, NPCC and ISO-NE reliability standards and criteria for the projected load and generation conditions in the Connecticut, Springfield and Rhode Island areas. These problems become increasingly more severe as peak load continues to grow and, even with reasonable assumptions for generation additions, problems are anticipated to continue into the future. The problems enumerated above demonstrate a need to construct new transmission facilities for significantly improving the reliability, performance, and resource adequacies for the studied areas.

APPENDIX A - ISO LOAD FORECAST

To develop the peak-load forecast, ISO-NE first develops long-term energy forecasts for each state. ISO-NE's long-term energy forecasts are econometric and project electricity use based upon regression models relating energy per household (1980–2002) to four variables: (1) real income per household; (2) real price in cents/kWh; (3) annual heating and cooling-degree days, and (4) an auto-regressive moving average (ARMA) model for the residual process. The ARMA model is a proxy for variables that are not individually quantified as explaining changes in electricity use.

Once the long-term energy forecasts are developed, ISO-NE then develops a peak-load forecast by applying load factors to the energy forecasts. The load factors are short term and are derived by relating the ISO-NE daily peaks to weather conditions, which are a combination of temperature and humidity. Based on this calculation, ISO-NE develops a load factor for one year, which it then applies to the energy load forecasts for each state to arrive at a peak forecast for the New England region.

The peak-load forecasts include forecasts based on both normal and "design" weather conditions. ISO-NE's normal weather peak-load forecast is based on a 50/50 probability of occurrence, which means that there is a 50/50 probability that the actual peak load will be equal to or higher than the forecast level (and a 50% chance that the actual peak load will be less than the forecast level). Under ISO-NE's design weather scenario, the peak-load forecast is modeled assuming that there is a 10% probability that peak load will be higher than forecast (and a 90% chance that the actual peak load will be less than the forecast level). ISO-NE and NEPOOL employ the 'design" weather probability level for planning purposes to ensure the reliable operation of the grid under weather conditions that may be infrequent but reasonably foreseeable in terms of their potential to occur. This approach is consistent with having a highly reliable electric system and the overarching requirement that the system be designed with sufficient capacity to meet heat-wave conditions consistent with historical experience. Moreover, the risk and consequences of having shortfalls and a constrained electric system are far more significant than having an electric system that has the flexibility to respond to both normal and reasonably foreseeable peak demands.

The specific steps and procedures ISO-NE uses to develop a New England load forecast begin with the data that are submitted to FERC on an annual basis. Each spring, all New England transmission companies submit FERC Form No. 715, an *Annual Transmission Planning and Evaluation Report*. These reports include base-case power flow data, with a summer- and winter-peak forecast by bus, for a near-term (2005) and midterm (2009) year. The busloads within each operating company are reported on a consistent (additive) basis, but the loads between companies are not. This is because some are based on "normal" weather and others on "extreme" weather.

ISO-NE develops operating company growth rates by summing the busses within an operating company for both years and calculating the annualized growth rates (Columns B–D). By using the FERC 715 annualized growth rates (see Column D) and the 2004 weather normal seasonal peaks (Column F), the initial long-term operating company forecasts are developed (Columns G–I). These forecasts are now all based on consistent weather conditions and therefore are additive. The forecasts for operating companies within a state are summed and then calculated as percents of their total (Columns K, L). Final operating company forecasts are calculated by applying the operating company percent of state total to the ISO New England state seasonal and monthly peak and energy forecasts (Columns N–P).

The FERC 715 detailed busload data are used to allocate the operating company seasonal and monthly peak-load forecasts back to the busses within that operating company. RSP subarea forecasts are developed by summing the busses that fall within each of the subareas.

Using FERC 715 Operating Company Summer Peak Load Growth to Calculate ISO-NE Operating Company Forecasts
AAPC is the annual average percent change. ISO-NE peaks are the 50/50 Reference Case.

	B	C	D	F	G	H	I	K	L	N	O	P
	FERC 715 OpCo Loads			ISO-NE Historical	Initial ISO-NE Loads			Percent of State Total		Final IOSO-NE Loads		
	2005	2009	AAPC	2004	2005	2014	AAPC	2005	2014	2005	2014	AAPC
State of CT	6941	7374	1.6	6985	7092	8144	1.6			7125	8305	1.8
CMEEC	374	401	1.8	420	427	500	1.9	0.060	0.061	429	510	2.1
UI	1394	1420	0.5	1325	1331	1387	0.5	0.188	0.170	1337	1414	0.6
CLP	5173	5554	1.8	5240	5334	6257	1.9	0.752	0.768	5358	6381	2.1
State of ME	2195	2309	1.3	1930	1954	2187	1.3			1975	2255	1.6
BHE	307	309	0.2	295	296	302	0.2	0.151	0.138	299	311	0.4
CMP	1889	2000	1.5	1635	1659	1886	1.5	0.849	0.862	1676	1944	1.8
State of MA	12159	13079	1.9	11840	12063	14219	2.0			12110	13660	1.4
BECO	3378	3600	1.6	3339	3394	3918	1.7	0.281	0.276	3407	3764	1.2
COMEL	1337	1464	2.4	1269	1299	1592	2.5	0.108	0.112	1304	1530	1.9
MA-NGRID	4823	5223	2.1	4778	4876	5834	2.2	0.404	0.410	4895	5604	1.6
WMECO	818	853	1.1	800	809	890	1.1	0.067	0.063	812	855	0.6
MUNI:BOST	533	563	1.4	455	461	522	1.5	0.038	0.037	463	501	0.9
MUNI:CNEMA	310	341	2.5	285	292	360	2.6	0.024	0.025	293	346	2.0
MUNI:W-MA	388	404	1.0	380	384	420	1.0	0.032	0.030	385	404	0.5
MUNI:SEMA	459	510	2.8	430	441	558	2.9	0.037	0.039	443	536	2.3
MUNI:RI	112	120	1.8	105	107	125	1.9	0.009	0.009	107	120	1.4
State of NH	2562	3078	5.0	2230	2334	3522	5.7			2300	2720	2.0
PSNH	2045	2478	5.3	1750	1836	2829	6.0	0.787	0.803	1810	2185	2.3
GSE	204	221	2.1	205	209	250	2.2	0.090	0.071	206	193	-0.7
UNTIL	313	379	5.3	275	288	443	6.0	0.124	0.126	284	342	2.3
State of RI	1838	1988	2.0	1765	1800	2149	2.2			1805	2075	1.7
RI-NGRID	1838	1988	2.0	1765	1800	2149	2.2	1.000	1.000	1805	2075	1.7
State of VT	1025	1121	2.3	1020	1043	1276	2.5			1045	1175	1.4
VELCO	1025	1121	2.3	1020	1043	1276	2.5	1.000	1.000	1045	1175	1.4