THE CONNECTICUT VALLEY ELECTRIC TRANSMISSION RELIABILITY PROJECTS

APPLICATION TO THE

CONNECTICUT SITING COUNCIL

FOR CERTIFICATES OF ENVIRONMENTAL COMPATIBILITY AND PUBLIC NEED FOR

THE CONNECTICUT PORTION

OF THE GREATER SPRINGFIELD RELIABILITY PROJECT

AND FOR

THE MANCHESTER TO MEEKVILLE JUNCTION CIRCUIT SEPARATION PROJECT

BY

THE CONNECTICUT LIGHT & POWER COMPANY

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VOLUME 5: PLANNING

EX. 1: **ISO-NE Southern New England Transmission Reliability, "Report 1 – Need Analysis", January 2008, (Redacted)**

EX.2 **ISO-NE New England East-West Solutions (Formerly Southern New England Transmission Reliability), "Report 2 – Options Analysis", (Redacted) June 2008**

EX.3 **Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Greater Springfield Reliability Project, September 2008 (redacted to secure Critical Energy Infrastructure Information)**

EX.4 **Northeast Utilities "Solution Report for the Springfield Area The Greater Springfield Reliability Project Including The Springfield 115-kV Upgrades".** ***"GSRP Solution Report"*** **as of April 23, 2008.**

EX. 1: ISO-NE Southern New England Transmission Reliability, "Report 1 – Need Analysis", January 2008, (Redacted)

Southern New England Transmission Reliability Report 1 Needs Analysis

(Redacted)

January 2008

Southern New England Regional Working Group

ISO New England

National Grid

Northeast Utilities

The results of this study were first presented to ISO New England stakeholders in July 2006, with a draft report posted on the ISO's Web site the following month. Since then, the report has been modified to reflect clarifying comments that have been received. The working group has not intended to change any of the original results, assumptions, or conclusions.

Executive Summary

National Grid, Northeast Utilities, and ISO New England (ISO) formed a working group to conduct the studies necessary to develop a 10-year plan for transmission system improvements for the southern New England (SNE) region. The 10-year plan specifically addresses western and central Massachusetts (particularly the Springfield area), Rhode Island, and eastern and central Connecticut.

The objective of this plan is to ensure that the SNE region, as described in Section 1, complies with criteria and reliability standards established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the ISO.[1] These criteria and standards (summarized in Section 2) define regional transmission requirements and transmission-transfer capabilities with respect to stability, steady state, and fault-current simulations. They are in place to ensure, for the long term, that the regional transmission system serving New England is robust and flexible, reliably delivers power to customers under a wide range of projected future system conditions, and accounts for uncertainties and unforeseen events.

The first working group task was to assess the ability of the New England transmission system to satisfy these national and regional reliability standards, assuming an "as is" electric transmission system under future conditions. It also identified potential reliability violations (statements of need) for the southern New England transmission system and any likelihood of portions of this region not meeting the criteria and standards by 2009.[2] Section 3 presents the results of the coordinated needs-related studies.

The working group then developed solution options (groups of system upgrades) to address the deficiencies (needs) identified in this report and improve the transmission system in conjunction with the ISO's 10-year regional system planning process. A separate report, *New England East–West Solutions, Report 2—Options Analysis*, reviews the results of the working group's analysis of the solution options. It also explains how the solutions were developed to meet the identified needs, describes the main features of the solutions, and compares the solutions in terms of system performance characteristics.

The studies conducted were 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. When the identified weaknesses in southern New England are improved, the regional

[1] The ISO system must comply with NERC and NPCC criteria and standards and ISO planning and operating procedures. As certified by the Federal Energy Regulatory Commission in 2006, NERC is the "electric reliability organization" (ERO) whose mission is to improve the reliability and security of the bulk power system in North America. Information on NERC requirements is available online at http://www.nerc.com (Princeton, NJ: NERC, 2007). NPCC is the cross-border regional entity and criteria services corporation for northeastern North America. NPCC's mission is to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in the geographic area that includes New York State, the six New England states, and the Ontario, Québec, and the Maritime provinces. Additional information on NPCC is available online http://www.npcc-cbre.org/default.aspx (New York: NPCC Inc., 2007). Information about ISO New England Planning Procedure No. 3 (PP 3), *Reliability Standards for the New England Area Bulk Power Supply System*, is available online at http://www.iso-ne.com/rules_proceds/isone_plan/PP3_R3.doc (Holyoke, MA: ISO New England, 2006).

[2] Summaries of the ISO's projections for the southern New England transmission system have appeared in the *2005, 2006*, and *2007 Regional System Plans* (RSPs) as well as previous years' Regional Transmission Expansion Plans. These reports are available online at http://www.iso-ne.com/trans/rsp/index.html.

transmission system will be more reliable and generation will be less constrained, which should benefit all the New England states.

Method and Criteria

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 the New England Power Pool [NEPOOL]) is a member, was subsequently formed to develop regionally specific criteria based on NERC standards. ISO power system planning procedures are designed to meet these reliability standards, per ISO Planning Procedure No. 3 (PP 3), *Reliability Standards for the New England Bulk Power Supply System*, the specific standards that provide consistent system planning criteria throughout New England.

PP 3 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 determined to meet these standards. These tests take into account historical data and system occurrences and examine the following:

- **Area Transmission Requirements:** Is the area transmission system capable of delivering the necessary generation to the system load under anticipated facility outage events? (PP 3, Section 3)
- **Transmission Transfer Capability:** Is the interconnected transmission system designed with adequate capability to transfer power within the ISO New England Control Area and between ISO New England and neighboring control areas? (PP 3, Section 4)

Similar standards exist throughout North America.

When analyzing future system reliability needs, planners must consider possible system configurations (load and generation scenarios) and possible system contingencies (e.g., the sudden and unplanned outage of a generating unit or a transmission line). Given the geographic scope of the SNE region, a tremendous number of variables and interrelationships are involved in studying the possible system configurations and contingencies. Moreover, individual solutions in one area must be evaluated to ensure that they do not produce unintended consequences in another area. Specifically, the potential effects that system conditions in one area have on another part of the system must be understood. For instance, as illustrated in Figure 1, an outage on a 345 kV line supplying the Manchester area in north-central Connecticut could overload facilities in the western Massachusetts–Springfield area and the northeastern Connecticut–Rhode Island area when redistributing the power flow in trying to reach the load.

This graphic has been redacted
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Figure 1: Illustration of interrelationships in the southern New England region.

Statements of Need

Analyses performed for the 10-year period (from 2007 to 2016) showed that on the basis of ISO planning procedures, the SNE transmission system over the 10-year study period has five major reliability concerns and a number of system deficiencies in transmission security, specifically area transmission requirements and transfer capabilities. These deficiencies form the justification for the needed transmission system improvements.

Reliability Concerns

The reliability concerns are as follows and are depicted in Figure 2.

- **East–West New England Constraints:** Regional east–west power flows could be limited during summer peak periods across the SNE region as a result of thermal and voltage violations on area transmission facilities under contingency conditions.
- **Springfield Reliability:** The Springfield, Massachusetts, area could be exposed to significant thermal overloads and voltage problems under numerous contingencies at or near summer peak-load periods. The severity of these problems would increase as the transmission system attempts to move power into Connecticut from the rest of New England.

- **Interstate Transfer Capacity:** Transmission transfer capability into Connecticut and into Rhode Island during summer peak periods could be inadequate under existing generator availabilities for criteria contingency conditions.
- **East–West Connecticut Constraints:** East-to-west power flows in Connecticut could stress the existing system under “line-out,” or N-1-1, contingency conditions (i.e., conditions under which a transmission element is unavailable and a single power system element is lost) during system peaks.
- **Rhode Island Reliability**: The system depends heavily on limited transmission lines or autotransformers to serve its peak-load needs, which could result in thermal overloads and voltage problems during contingency conditions.

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Figure 2: Reliability concerns in the southern New England region.

Transmission Security Concerns

The analysis identified the following transmission security concerns related to meeting transfer capability and area transmission requirements:

Transfer Capability Concerns

- Power-transfer capabilities in the Connecticut area 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 conditions of generator unavailability and the loss of a single power system element (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 3,600 MW for N-1 conditions and 2,400 MW for N-1-1 conditions will be needed by 2016.
- Connecticut currently has internal elements that can limit transfers from neighboring New England states under certain system conditions. 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 overloads transmission facilities located within Connecticut that eventually tie into the new Middletown–Norwalk facilities.
- Under line-out (N-1-1) conditions and certain dispatch scenarios, the 345 kV transmission system in the southeastern Massachusetts and Rhode Island areas currently cannot support the requirements of southeast Massachusetts–Rhode Island, New England east–west, and the Connecticut power transfers following a contingency. These interfaces all have simultaneous and interrelated power-transfer limits.
- Rhode Island and Springfield have insufficient import capability to meet their load margins through 2016.
- 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 because of either an unplanned or a planned outage. As a result, numerous overloads occur in the 2009 simulations. These overloads are exacerbated when Connecticut transfers increase.

Concerns about Area Transmission Requirements

- In the Springfield area, local double-circuit tower (DCT) outages, stuck-breaker outages, and single-element outages currently can result in severe thermal overloads and low-voltage conditions.
- The severity, number, and location of the Springfield overloads and low-voltage conditions highly depend on the area's generation dispatch. Additional load growth and unit outages in the Springfield area would significantly aggravate these problems. As a result, network constraints in the Springfield area limit the system's present ability to serve local load under contingency conditions.
- Thermal and voltage violations can occur on the existing Rhode Island transmission system, dependent on unit availability and transmission outages (planned or unplanned). Relatively high load growth in the southwestern area and the coastal communities in recent years has increased the possible occurrence of criteria violations.
- The capabilities of the underlying Rhode Island 115 kV system currently are insufficient to handle the power requirements within the state following the loss of 345 kV transmission facilities, both lines and autotransformers, under certain system conditions. 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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Section 1
Introduction and Background Information

The analysis presented in this report is the culmination of several joint studies by ISO New England (ISO) transmission owners (TOs). The New England transmission system serving the southern New England (SNE) area was studied to evaluate projected future load and generation requirements to assess the performance of the transmission system and its ability 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, namely Massachusetts, Rhode Island, and Connecticut. As shown in this figure, a substantial number of significant load pockets exist—Boston and its suburbs, central Massachusetts, Springfield, Rhode Island, Hartford/central Connecticut, and Southwest Connecticut. The load pockets of Springfield, Rhode Island, Hartford/central Connecticut, and Connecticut as a whole are primary areas of concern in this study with respect to the ability of the existing transmission and generation systems to reliably serve projected load requirements in these areas.

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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 the region's supply resources with load centers. The major southern New England generation resources, as well as the supply provided via ties from northern New England, Hydro-Québec, 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 SNE area has experienced significant load growth, numerous resource changes, and changes in inter-area transfers.

The east–west transmission interface facilities divide New England roughly in half. Vermont, southwestern New Hampshire, western Massachusetts, and Connecticut are located to the west of this interface; while 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 transmission lines. A few underlying 115 kV facilities are also part of the interface; however, most run long distances, have relatively low thermal capacity, and do not add significantly to the transfer capability. In the early 1990s, this interface was important to monitor in day-to-day operations because of constraints in moving power from the significant generation in the west to Boston and its suburbs in the east. Following the influx of new generation in the east in the late 1990s, this interface now becomes constrained in the opposite direction, from east to west.

Supplying southern New England with electricity involves a number of complex and interrelated performance concerns. Connecticut's potential 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 strain the existing 345 kV network. These challenges are compounded further by transmission constraints in the Springfield and Rhode Island areas under contingency conditions. The following transmission transfer capabilities are all interrelated:

- 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 interface
- Connecticut import
- Connecticut East–West interface
- Southwest Connecticut (SWCT) import

Transfers through these paths can contribute to heavy loadings on the same key transmission facilities.

These relationships exist for both thermal and stability limits. Studies have identified the relationship 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 as a result of line reclosing also have become an issue in the SNE area. These behaviors illustrate the interdependent nature of the SNE 345 kV network. Recent analyses have quantified an additional interdependence between the ability to import power into Connecticut and the ability to supply load in the Springfield area. Springfield's reliability issues must be studied within the context of the overall southern New England analysis to not 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 existing transmission system does not allow for delivering 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. The Springfield and Rhode Island areas have additional transmission reliability concerns, both thermal limitations and voltage violations, which lead to a set of interrelated concerns with respect to the reliability of transmission service across southern New England (see Figure 1-2).

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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, which combine for approximately 2,000 MW. Around 55% (3,800 MW) of the internal generation is over 30 years old, 30% (2,100 MW) is over 40 years old, and 81 MW is 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). 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. A high-voltage direct-current (HVDC) interconnection with Long Island Power Authority in New York is rated at 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. The Rhode Island transmission system consists of two 345 kV connections to Massachusetts, one 345 kV connection to Connecticut, and an underlying 115 kV network. The two Rhode Island–Massachusetts 345 kV connections are (1) line 315 from Brayton Point in Somerset, Massachusetts, to West Farnum in North Smithfield, Rhode Island, and (2) line 3361 from ANP–Blackstone in Massachusetts to Sherman Road in Rhode Island. Line 347 is the 345 kV connection that runs from Sherman Road to Lake Road, Connecticut. 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. It is tied to Massachusetts via two 115 kV lines to Millbury substation and several 115 kV lines that ultimately terminate at Brayton Point and Somerset substations.

1.4 Western Massachusetts/Springfield

Western Massachusetts encompasses the four western counties of Massachusetts. Western Massachusetts Electric Company (WMECO)'s existing transmission circuits in Massachusetts consist 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. The WMECO transmission system is interconnected to other electric utilities, including Connecticut Light and Power Company (CL&P), National Grid, Holyoke Gas and Electric, Holyoke Water Power Company (HWP), Public Service of New Hampshire (PSNH), and the Massachusetts Municipal Wholesale Electric Company (MMWEC).

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 providers 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

The ISO develops a forecast of 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 on the basis of NEPOOL load data from various New England subareas. The results for each state are combined to produce the New England regional forecast. The analysis conducted to develop a New England forecast was based on the ISO's April 2005 published peak-load forecast. The most recent updated version of the ISO's peak-load forecast, published in March 2007, indicates that New England is expected to experience a slighter higher peak load than the April 2005 forecast used in the analysis in this report. This change is relatively small and would not change 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. While forecasts and load levels vary from year to year, they tend to be insignificant when studying a relatively large area for a number of years into the future.

Table 1-1 summarizes the ISO'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		CAGR (a)	50/50		90/10		CAGR (a)
	2005	2014	CAGR\ (a)	2005	2014	2005	2014		2005/06	2014/15	2005/06	2014/15	
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

(a) CAGR refers to the compound annual growth rate.

Section 2
Methodology for Analyzing System Reliability

One of the main activities of the ISO's transmission planning process is to analyze system reliability according to a number of planning standards and criteria, as described in this section. The results of these analyses show potential criteria violations that form the basis of this Needs Analysis.

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 (RSP). This systemwide 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 and identify system needs, which may be addressed by market responses, including both transmission and nontransmission alternatives. In addition, the reliability needs within geographic subareas of the system are investigated to ensure that the load requirement of each subarea is reliably served. Absent appropriate market solutions proposing either transmission or nontransmission alternatives, the ISO is authorized to engage in the development of transmission solutions.

The future performance of the system under projected operating conditions over a 10-year period is periodically reviewed. To perform these evaluations, analytical modeling software simulates the systemwide performance of the transmission system. 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

The ISO 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. The performance of the New England transmission system must adhere to reliability standards and criteria established by NERC, NPCC, and the ISO, which ensure 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.[3] NERC oversees a number of regional councils, one of which is the NPCC. The NPCC 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 also encompass the more general NERC standards. In turn, ISO New England has developed standards and criteria specific to New England that coordinate with the NPCC rules. Similar standards exist throughout the nation and other portions of North America.

Whether developed by NERC, NPCC, or the ISO, the standards and criteria applicable to the New England transmission system are applied in a deterministic fashion to assess the ability for 115 kV and 345 kV transmission systems to perform under 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 thermal overloads, voltages below limits, or loss of synchronism. 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 the ISO, these measurements are set forth in PP 3, which are used to plan the interconnected electrical network (generators and transmission circuits).

Both NPCC and ISO 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:

- **Area Transmission Requirements:** Is the area transmission system capable of delivering the necessary generation to the system load under anticipated facility outage events? (PP 3, Section 3)
- **Transmission Transfer Capability:** Is the interconnected transmission system designed with adequate capability to transfer power within the ISO New England Control Area and between ISO New England and neighboring control areas? (PP 3, Section 4)

ISO Planning Procedure 3 states 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."[4]

The standards specifically define "reasonably foreseeable contingencies" that must be tested and the conditions under which these contingencies must be evaluated.[5] These circumstances generally

[3] *The Energy Policy Act of 2005* authorized the creation of a self-regulatory electric reliability organization (ERO) that spans North America, with Federal Energy Regulatory Commission (FERC) oversight in the United States. On July 20, 2006, FERC issued an order certifying NERC as the ERO for the United States.

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

[5] Ibid., Pg. 4

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 "contingencies," are planned or unplanned events wherein a transmission element, substation transformer, or autotransformer is out of service. The reliability criteria specify that system voltages and transmission line and equipment loadings should be within applicable normal and emergency limits under a set of predefined conditions.[6]

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 because of a lightning strike or a fallen tree, for example. 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 power flows on all other elements in the event of each contingency and to technically evaluate the system's capacity to meet normal and emergency operating requirements.

Events that include the outage of two transmission elements (N-1-1 contingency analyses) also are performed to evaluate the transmission system 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 also may provide added capacity in support of N-1-1 area supply issues.

[6] Ibid.

Section 3
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. Previous analysis revealed the interrelationships that exist between these areas. For example, 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 Section 3.1 and Section 3.2, each area has its own set of resource requirements and transfer limits, and as shown in the results section (Section 3.3), 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 (see list below) 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 ISO's most recently available system load forecast (90/10) at the time of the study. Planned transmission upgrades expected to occur prior to 2009 were included in the base case. (At the initiation of the study, all the southwest Connecticut system upgrades were scheduled to be in place before summer 2009.) Subsequent discussion details the load, generation, and transmission system transfer capabilities assessed for the base-case conditions.

Additionally, all the projects listed below were included in the base-case models used to assess system performance and were considered as being in service before 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

3.1 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 subareas 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 for Connecticut 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 at present and that all areas analyzed will experience substantial reliability concerns by 2016. Specifically, these tables assess the resource requirements and adequacy for each of the areas under study and include the following items:

- *Area loads*—The projected area peak loads are identified on the basis of the ISO's 2005 90/10 forecast. These forecast loads are the loads that are encompassed by the interfaces being studied and do not necessarily align with state or ISO 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*.[7]
- *Retirements*—The retirement values were determined based on an assumption that generation 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*—As stated above, new generation for Connecticut was assumed to be 500 MW based on the likelihood that either one large unit, such as the Kleen Project, or a number of smaller ones would be in service by 2016.
- *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 with 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.

[7] *2005– 2014 Forecast of Capacity, Energy, Loads, and Transmission*. Available on line at http://www.iso-ne.com/trans/celt/report/2005/2005_celt_report.pdf (Holyoke, MA: ISO New England, April 2005).

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) This analysis is based on the ISO's April 2005 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. Thus, transfer capability into the Springfield load pocket would be greatly reduced if these design contingencies were included.

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) This analysis is based on the ISO's April 2005 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. Thus, transfer capability into the Springfield load pocket would be greatly reduced if these design contingencies were included.

3.2 Interface Transfer Limits

The transmission system interfaces that define each of the study areas for this analysis are summarized below. The interfaces described may not be identical to interfaces that system operators currently use for the day-to-day management of system resources under varying system conditions. The Connecticut import interface is commonly used in daily system operations; however, the Rhode Island and Springfield interfaces were developed for this study and were based on the limiting transmission elements of their boundaries.

3.2.1 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				% of Interface Flow
	From Bus Name	kV	To Bus Name	kV	
395	Ludlow	345	Meekville Junction	345	30.0
330	Lake Rd.	345	Card	345	29.08
	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	North Bloomfield	115	2.4
1830	South Agawam	115	North Bloomfield	115	2.6
1821	South Agawam	115	North Bloomfield	115	2.6

The Connecticut import interface as defined in Table 3-3 is capable of reliably supporting import levels of 2,500 MW. As shown, 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 not be sufficient to support future import requirements.

3.2.2 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.

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 County	345	Kent County	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[a]
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

(a) The negative numbers indicate that flows on these elements are generally in the export direction.

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

3.2.3 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 #	**From Bus**	**kV**	**To Bus**	**kV**	
1421	Pleasant	115	Blandford	115	5.1
1768	North Bloomfield	115	Southwick	115	5.7
1481	Ludlow	115	East Springfield	115	15.8
1552	Ludlow	115	Orchard	115	13.2
1845	Ludlow	115	Shawinigan	115	36.0
1515	Ludlow	115	Scitico	115	6.2
1821	North Bloomfield	115	South Agawam	115	9.0
1836	North Bloomfield	115	South Agawam	115	9.0

(a) The percent flow values vary as a function of Connecticut import levels.

The import capability of the Springfield facilities is approximately 450 MW in 2009 and, as a result of load growth, is reduced to 200 MW in 2016. About 65% of the flows into the area are delivered through three 115 kV lines emanating from the Ludlow substation.

3.3 Results of Transmission Reliability Analysis

This section describes the results of the 2009 analysis concerning the reliability performance of the transmission systems in Connecticut, Springfield, and Rhode Island. 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. *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 also were analyzed, the results for which are not described herein.*

Also, “all-lines-in” refers to an N-1 (first-contingency) analysis, and “lines-out” refers to an N-1-1 (second-contingency) analysis. Both analyses are dictated by criteria.

3.3.1 Connecticut Power-Transfer Concerns

The 2009 resource requirements for the Connecticut area demonstrate the need for improvements to the area’s import capability, generating resources, or a combination of both. Some improvement in import capability can be obtained by mitigating the 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. 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 from the loss of a major 345 kV line under the simulated import conditions.

Table 3-6
Connecticut Transmission Line Overloads, 2009 Peak Load, All-Lines-In (N-1)

Worst Scenario		Overloaded Elements						
Generator Out of Service	**Contingency**	**Line/ Auto**	**From Bus**	**From kV**	**To Bus**	**To kV**	**Rating**	**Max Loading (%) Over Rating**
Largest generator unavailable **Average EFOR** **One unit retired**	This data has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.		ANP Blackstone	345	Sherman Road	345	1400	110.9
			Sherman Road	345	CT/RI	345	1618	109.6
			Carpenter Hill	345	Millbury	345	1405	102.2
			Ludlow	345	Barbour Hill autotrans.	345	1604	121.9
			Barbour Hill autotrans.	345	Meekville Junction	345	1604	103.1
			Bloomfield Junction	115	Northwest Hartford	115	228	114.7

Table 3-7
Connecticut Transmission Line Overloads, 2009 Peak Load, Line-Out (N-1-1)

Worst Scenario			Overloaded Element						
Generator Out of Service	**Line/Auto Out of Service**	**Contingency**	**Line/ Auto**	**From Bus**	**From kV**	**To Bus**	**To kV**	**Rating**	**Max Loading (%) Over Rating**
Average EFOR **One unit retired**	This data has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.		Ludlow autotrans.	Ludlow	345	Ludlow	115	705	124.0
			371	Montville	345	Millstone	345	1793	112.7
			364	Montville	345	Haddam Neck	345	1912	114.7
			348	Millstone	345	Haddam autotrans.	345	1912	112.5
			353	Manchester	345	Portland Junction	345	1446	108.9
			1207	Manchester	115	East Hartford	115	382	101.1
			1777	North Bloomfield	115	Bloomfield	115	228	106.0
			1751	Bloomfield Junction	115	Northwest Hartford	115	228	131.0

Consequently, significant improvement in Connecticut's power-transfer capability is essential for maintaining an adequate and reliable level of supply resource for the Connecticut area beginning in 2009 and beyond. The risk of system disruptions increases as the in-service date for such improvements is postponed beyond 2009.

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, which is the transfer level required per Table 3-1 to ensure system security. Transmission line overloads specific to the Springfield area are not included in Tables 3-6 and 3-7 but are addressed in Section 3.3.3. The line overload summary tables in this section show only the most severe overload contingency conditions and do not list all of the outage conditions that may overload the element shown. In many cases, numerous outage events may overload the elements shown. Additionally, more significant N-1-1 overloads are not shown here because of the special protection system (SPS) that backs down the Millstone plant output for certain contingency conditions

Figure 3-1 and Figure 3-2 are one-line 345 kV diagrams that display these overloads.

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and may be accessed by calling
ISO New England Customer Service
at (413) 540-4220.

Figure 3-1: 2009 Connecticut transmission line overloads, N-1.

This graphic has been redacted
and may be accessed by calling
ISO New England Customer Service
at (413) 540-4220.

Figure 3-2: 2009 Connecticut transmission line overloads, N-1-1.

3.3.2 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), generation unit availability, and transmission outages (planned or unplanned). Additionally, the Rhode Island 115 kV system is constrained when one of the Greater Rhode Island 345 kV lines 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.

The contingency testing for transmission system outages for the Rhode Island system, as summarized in Table 3-8 and Table 3-9, 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 (per Table 3-1), 3,050 MW (normal) and 1,850 MW (emergency), given projected load and generation conditions in Connecticut. For the N-1 analysis, the largest unit in the area 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. Table 3-8 and Table 3-9 show the most severe overload contingency conditions only and do not list all the outage conditions that may overload the element shown. In many cases, numerous outage events may overload the elements shown.

Table 3-8
Rhode Island Line Overloads, 2009 Peak Load,
All-Lines-In (N-1), One Generator Out of Service

	Overloaded Elements						
Worst Contingency	**Line/Auto**	**From Bus**	**From KV**	**To Bus**	**To kV**	**Rating (MVA)**	**Loading (%)**
This data has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.	Kent Co. 3 transformer	Kent Co.	345	Kent Co.	115	478	101.4
	E-105	Franklin Square	115	Hartford Ave.	115	240	145.7
	F-106	Franklin Square	115	Hartford Ave.	115	240	145.7
	T3	Somerset	115	Pawtucket	115	128	121.1
	G-185 N	Drumrock	115	Kent T1	115	286	116.3
	C-181 S	Brayton Point	115	Chartley Pond	115	268	115.2
	J-188	Drumrock	115	Kilvert T8	115	218	112.0
	Kent Co. 3 transformer	Kent Co.	345	Kent Co.	115	550	109.4
	E-183 E	Brayton Point	115	Warren 83	115	410	104.9
	I-187	Drumrock	115	Amtrak 187	115	218	102.0
	S-171 S	Johnston 171	115	Hartford Ave.	115	426	101.6

Table 3-9
Rhode Island Line Overloads, 2009 Peak Load,
Line-Out (N-1-1), No Generation Out of Service

		Overloaded Elements						
Line Out of Service	**Worst Contingency**	**Line/Auto**	**From Bus**	**From KV**	**To Bus**	**To kV**	**Rating (MVA)**	**Loading (%)**
This data has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.		S-171 S	Rise 171	115	West Cranston 71	115	449	229.3
		T-172 S	West Cranston 72	115	Rise 172	115	449	227.6
		S-171 S	Drumrock	115	West Cranston 71	115	449	216.4
		T-172-S	Drumrock	115	West Cranston 72	115	449	214.7
		F-106	Franklin Square	115	Hartford Ave.	115	240	182.5
		E-105	Franklin Square	115	Hartford Ave.	115	240	178.4
		S-171 S	Johnston 171	115	Hartford Ave.	115	426	151.1
		G-185 N	Drumrock	115	Kent T1	115	286	146.7
		P-142 S	Wyman Gordan TP42	115	Millbury	115	141	133.8
		T-172 S	Johnston 172	115	Rise 172	115	449	126.0
		S-171 S	Johnston 171	115	Rise 171	115	449	125.6
		Rise Tap	Rise 171	115	Rise	115	550	124.4
		Rise Tap	Rise 172	115	Rise	115	550	124.2
		T7	Somerset	115	Pawtucket	115	128	121.1
		1870-S	Wood River	115	CT/RI 1870	115	218	114.6
		J-188	Drumrock	115	Kilvert T8	115	218	111.3
		D-182 S	Brayton Point	115	Mansfield 82	115	283	107.5
		Brayton Point 3B Transformer	Brayton Point	345	Brayton Point	115	361	106.1
		K-189	Drumrock	115	Kent T7	115	359	104.4
		Kent Co. 3 Transformer	Kent Co.	345	Kent Co.	115	550	103.1
		F-184	Brayton Point	115	Warren 84	115	370	100.9
		W4	Somerset	115	Swansea	115	165	100.9
		Brayton Point T3	Brayton Point	115	Brayton Point T3 MID	99	561	100.8
		I-187	Drumrock	115	Amtrak 187	115	218	100.5

Each of these criteria violations are made worse by the unavailability of local area generation and transmission outages (line-out conditions). Figure 3-3 to Figure 3-5 depict a sampling of the Rhode Island reliability violations.

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Figure 3-3: 2009 Rhode Island reliability problems, N-1 thermal overloads.

This graphic has been redacted
and may be accessed by calling
ISO New England Customer Service
at (413) 540-4220.

Figure 3-4: 2009 Rhode Island low voltages for an area “design” contingency.

This graphic has been redacted
and may be accessed by calling
ISO New England Customer Service
at (413) 540-4220.

Figure 3-5: 2009 Rhode Island reliability problems, N-1-1 thermal overloads.

3.3.3 Springfield Area Transmission Reliability Concerns

The Springfield area faces a number of reliability concerns. Many local single outages, double-circuit tower outages and stuck breaker outages result in severe line overloads and low voltages in the Springfield area.

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 as a result of a forced or planned outage. For all years simulated, this leads to the appearance of numerous overloads 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-voltage conditions highly depend on the area's generation dispatch. These dependencies are illustrated in Figure 3-6 through Figure 3-9. The number of violations in the tables below indicates the number of transmission circuits that overload. Each transmission circuit may overload for multiple contingencies.

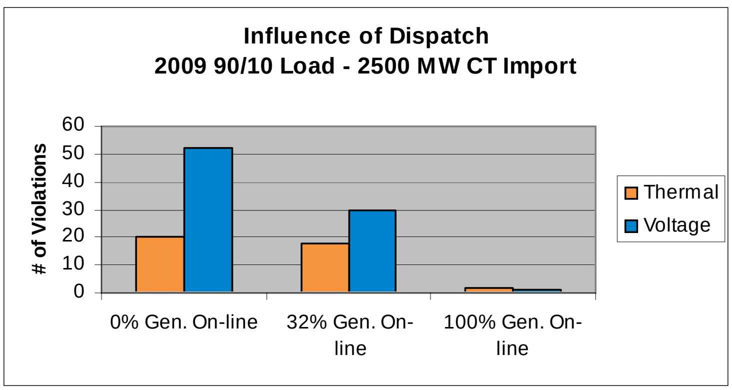

Figure 3-6: Influence of dispatch on Springfield violations—number of violations.

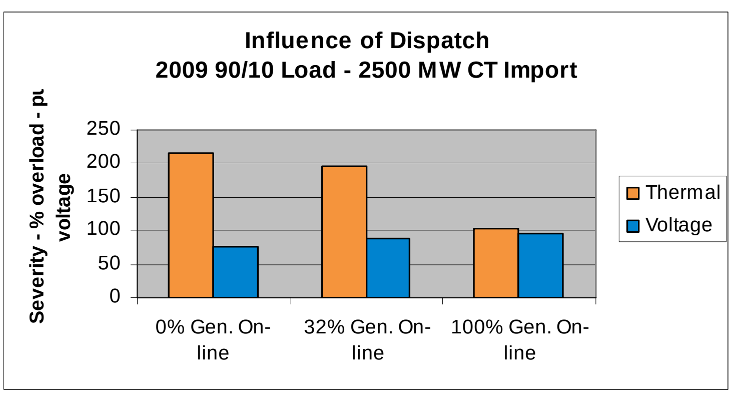

Figure 3-7: Influence of dispatch on Springfield violations—severity of violations.

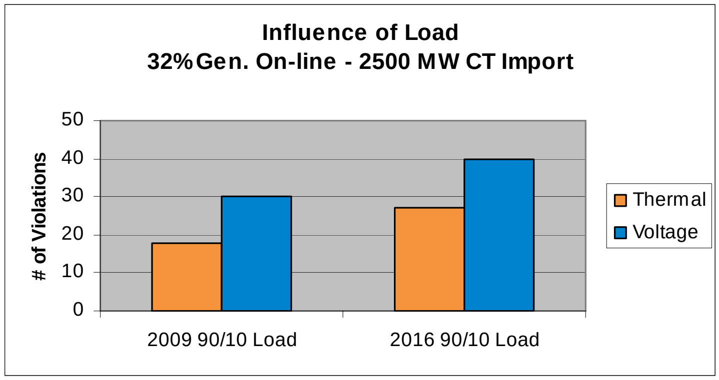

Figure 3-8: Influence of load on Springfield violations—number of violations.

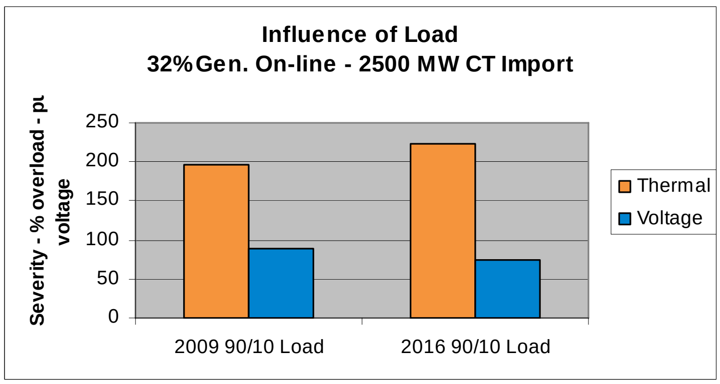

Figure 3-9: Influence of load on Springfield violations—severity of violations.

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

The specific overload and voltage violation conditions are summarized in Table 3-10 through Table 3-12. 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, numerous outage events may overload the elements shown.

Table 3-10
Springfield Line Overloads, 2009 Peak Load, All-Lines-In (N-1)

Worst Scenario		Overload Elements						
Generator Out of Service	**Contingency**	**Line/Auto**	**From Bus**	**From kV**	**To Bus**	**To kV**	**Rating**	**Max Loading (%) Over Rating**
This data has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.		1254	East Springfield Junction 1254	115	Chicopee	115	265	111.6
		1254	East Springfield Junction 1254	115	Freemont South	115	282	101.9
		1254	East Springfield Junction 1254	115	Shawinigan	115	382	152.3
		1512	Southwick	115	Granville Junction	115	191	101.8
		1768	Southwick	115	North Bloomfield	115	165	100.3
		1433	West Springfield	115	Breckwood	115	140	249.9
		1314	Agawam	115	Chicopee	115	228	105.7
		1322	Breckwood	115	East Springfield	115	141	295.3
		1481	East Springfield	115	Ludlow	115	289	117.4
		1552	Orchard	115	Ludlow	115	305	101.0
		1845	Ludlow	115	Shawinigan	115	311	107.7
		1723	Piper Rd.	115	East Springfield Junction 1723	115	164	113.3

Table 3-11
Springfield Voltage Violations, 2009 Peak Load, All-Lines-In (N-1)

Worst Scenario		Bus Terminals		
Generator Out of Service	**Contingency**	**Bus**	**Bus kV**	**Low Voltage (per unit)**
This data has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.		Five Corners 13	115	0.8477
		Five Corners 34	115	0.8463
		Agawam	115	0.9215
		Amherst	115	0.8368
		Breckwood	115	0.9357
		Chicopee	115	0.9033
		Clinton	115	0.924
		Franconia	115	0.9214
		Freemont North	115	0.8485
		Freemont South	115	0.8514
		Gunn	115	0.8588
		Midway	115	0.8534
		Mt. Tom	115	0.8537
		Orchard	115	0.9488
		Piper Rd.	115	0.9131
		Pochassic	115	0.8859
		South Agawam	115	0.948
		South Agawam	115	0.948
		Scitico	115	0.8988
		Silver 81	115	0.9252
		Silver 82	115	0.9252
		South Agawam	115	0.9269
		Southampton	115	0.8666
		West Springfield	115	0.9245

Table 3-12
Springfield Line Overloads, 2009 Peak Load, Line-Out (N-1-1)

Worst Scenario			Overloaded Elements						
Generator Out of Service	Line/Auto Out of Service	Contingency	Line/ Auto	From Bus	From kV	To Bus	To kV	Rating	Max Loading (%) Over Rating
This data has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.			1512	Blandford	115	Granville Junction	115	147	118.3
			1421	Blandford	115	Pleasant	115	167	112.7
			1322	Breckwood	115	East Springfield	115	141	252.3
			1481	East Springfield	115	Ludlow	115	289	131.6
			1426	East Springfield	115	Orchard	115	311	102.8
			1007	Elm	115	Agawam	115	239	100.9
			1254	East Springfield Junction 1254	115	Freemont South	115	282	108.8
			1254	East Springfield Junction 1254	115	Shawinigan	115	382	137.2
			1525	Holyoke	115	Frreemont South	115	192	107.9
			Auto 1X	Ludlow	345	Ludlow	115	705	110.4
			1552	Orchard	115	Ludlow	115	305	119.9
			1723	Piper Rd.	115	East Springfield Junction 1723	115	164	104.1
			1781	South Agawam	115	Silver 81	115	228	108.6
			1782	South Agawam	115	Silver 82	115	228	108.2
			1512	Southwck	115	Granville Junction	115	191	138.0
			1412	West Springfield	115	Agawam	115	143	144.0
			1311	West Springfield	116	Agawam	116	143	144.0
			1433	West Springfield	115	Breckwood	115	140	210.4
			1371	Woodland	115	Pleasant	115	228	109.3

Figure 3-10 to Figure 3-12 of Springfield area transmission display the overloads and low voltages shown above.

This graphic has been redacted
and may be accessed by calling
ISO New England Customer Service
at (413) 540-4220.

Figure 3-10: 2009 Springfield overloads, N-1.

This graphic has been redacted
and may be accessed by calling
ISO New England Customer Service
at (413) 540-4220.

Figure 3-11: 2009 Springfield N-1 low voltages for an area “design” contingency.

This graphic has been redacted
and may be accessed by calling
ISO New England Customer Service
at (413) 540-4220.

Figure 3-12: 2009 Springfield overloads, N-1-1.

3.4 Needs Analysis Conclusions

In summary, this analysis demonstrates that in 2009 area transmission capabilities will be inadequate to meet NERC, NPCC, and ISO New England reliability standards and criteria for the projected load and generation conditions in the Connecticut, Springfield, and Rhode Island areas. These problems, some of which may already exist, become increasingly more severe as peak load continues to grow. The problems enumerated in this report demonstrate a need to construct new transmission facilities to significantly improve the reliability of the transmission grid serving Connecticut, Rhode Island, and western Massachusetts. Given the lead times necessary for permitting and other preconstruction activities, as well as the time required for construction itself, these problems constitute needs that should be addressed now.

Connecticut Light & Power
The Northeast Utilities System

NEW ENGLAND EAST–WEST SOLUTION

EX.2 ISO-NE New England East-West Solutions (Formerly Southern New England Transmission Reliability), “Report 2 – Options Analysis", (Redacted) June 2008

New England East–West Solutions
(Formerly Southern New England Transmission Reliability)
Report 2
Options Analysis

(Redacted)

June 2008

Southern New England Regional Working Group

ISO New England

National Grid

Northeast Utilities

Executive Summary

National Grid, Northeast Utilities, and ISO New England (ISO) formed a working group to conduct the studies necessary to develop a 10-year plan for transmission system improvements for the southern New England (SNE) region. The 10-year plan specifically addresses western and central Massachusetts (particularly the Springfield area), Rhode Island, and eastern and central Connecticut.

The objective of this 10-year plan is to ensure that the SNE region continues to comply with criteria and reliability standards established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the ISO.[1] These criteria and standards define regional transmission requirements and transmission-transfer capabilities with respect to stability, steady state, and fault-current conditions. They are in place to ensure, for the long term, that the regional transmission system serving New England is robust and flexible, reliably delivers power to customers under a wide range of projected future system conditions, and is able to address reasonably foreseeable contingencies.

The working group developed the transmission system improvements described in this analysis in conjunction with the ISO's 10-year regional system planning process, which showed the likelihood of portions of the SNE region not meeting the criteria and standards by 2009.[2] A full explanation and review of the criteria, the results of the analysis, and the statement of need for the SNE transmission system are contained in the January, 2008, report, *Southern New England Transmission Reliability (SNETR) Report 1—Need Analysis* (Needs Analysis).[3]

This report, *Report 2—Options Analysis*, describes the results of the working group's analysis of the options that address the needs identified in the Needs Analysis. The Options Analysis explains how the options were developed to meet the identified needs, describes the main features of the solutions, and compares the solutions in terms of system performance characteristics. As shown in this report, a number of the potential solutions would ensure reliable system performance for the SNE region for the time periods under study.

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[1]The ISO system must comply with NERC and NPCC criteria and standards and ISO planning and operating procedures. As certified by the Federal Energy Regulatory Commission in 2006, NERC is the "electric reliability organization" (ERO) whose mission is to improve the reliability and security of the bulk power system in North America. Information on NERC requirements is available online at http://www.nerc.com (Princeton, NJ: NERC, 2007). NPCC is the cross-border regional entity and criteria services corporation for northeastern North America. NPCC's mission is to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in the geographic area that includes New York State, the six New England states, and the Ontario, Québec, and the Maritime provinces of Canada. Additional information on NPCC is available online at http://www.npcc-cbre.org/default.aspx (New York: NPCC Inc., 2007). Information about ISO New England Planning Procedure No. 3 (PP 3), *Reliability Standards for the New England Area Bulk Power Supply System*, is available online at http://www.iso-ne.com/rules_proceds/isone_plan/PP3_R3.doc (Holyoke, MA: ISO New England, 2006).

[2] Summaries of the ISO's projections for the southern New England transmission system have appeared in the 2005, 2006, and 2007 Regional System Plans (RSPs) as well as previous years' Regional Transmission Expansion Plans. These reports are available online at http://www.iso-ne.com/trans/rsp/index.html.

[3] The *Southern New England Transmission Reliability (SNETR) Report 1—Needs Analysis* can be obtained by contacting ISO Customer Service at 413-540-4220 or custserv@iso-ne.com.

Development and Assessment of Plan Components and Options

The first step for this study was to establish the design objectives for the future southern New England transmission system based on the reliability deficiencies identified in the Needs Analysis. Using these design objectives, the working group developed and evaluated a combination of complementary options for upgrading the system to meet the identified performance objectives during the long-term planning horizon.

In formulating each option, the working group considered more than just the performance of the option under specific conditions. It also considered the relationship that each option could have with other components of the comprehensive solution for the SNE region, with other elements of the transmission system, and with the regional transmission system as a whole. Consideration of these relationships ensured that the development of a "solution" was comprehensive and did not have an adverse impact on other parts of the bulk transmission system. These relationships led the working group to develop an approach to solving the SNE region's needs with these four components:

- **Interstate Component**—This component provides an additional link between Massachusetts, Rhode Island and Connecticut or, in one case, just between Rhode Island and Connecticut, and improves regional transfer capabilities. Initial brainstorming sessions among working group members resulted in 17 options for the Interstate component, of which five viable options remain.
- **Rhode Island Component**—This component increases Rhode Island's access to New England's 345 kV bulk transmission system and eliminates both thermal overloads and voltage violations. Three options (two Interstate options plus one independent option) were developed to better connect Rhode Island to the rest of the system, three options were developed to extend these new facilities farther into the major load center in southwest Rhode Island, and two options were developed to bring an additional source into the 115 kV load center from the east.
- **Connecticut East–West Component**—This component provides an additional link between western and eastern Connecticut and improves system transfer capabilities between these areas. Initially, four options were developed for this component. One option was eliminated as a result of poor performance, which left three options for further study.
- **Springfield Component**—This component eliminates both thermal and voltage violations in the Springfield area while increasing the area's access to the 345 kV bulk transmission system. The number of 345 kV options for the Springfield component was limited; however, 35 options were initially developed because a number of possible 115 kV solutions would work well with any of the 345 kV options, which created a multiplicative effect. Three 345 kV options remain, each having four 115 kV variations, for a total of 12 potential solutions.

Developing the options for each of these four components has been an iterative process for the working group. Options that appeared to be capable of mitigating reliability concerns were formulated and then analyzed for compliance with design criteria and objectives. Additional modifications were formulated as necessary and then the option was reevaluated. This step was repeated until either the option was clearly workable or was determined to be not viable or not practical because it would require too many modifications.

Component Options that Exhibited Superior Performance

In each of the four components, most of the options that were found to meet or exceed the system criteria and objectives involve adding new 345 kV transmission lines, although all the upgrades associated with the four components also include 115 kV facilities and autotransformers.

Interstate Component Options

The Interstate component serves to strengthen the ties between the southern New England states and increase the ability to move power between eastern New England and western New England. For the five Interstate options that exhibited superior performance in meeting system criteria and objectives, the new 345 kV lines that would act as the 'backbone' for the options are listed below.

- **Interstate Option A**—a new 345 kV line from the Millbury, MA, substation to the West Farnum, RI, substation and then to the Lake Road, CT, substation and terminate at the Card, CT, substation
- **Interstate Option B**—a new 345 kV line from the West Farnum substation to the Kent County, RI, substation and then to the Montville, CT, substation. (The line from the West Farnum substation to the Kent County substation is part of the Rhode Island component.)
- **Interstate Option C**—a new 345 kV line from the Millbury substation to the Carpenter Hill, MA, substation and terminate at the Manchester, CT, substation
- **Interstate Option D**—a new 345 kV line from the Millbury substation to the Carpenter Hill substation to the Ludlow, MA, substation to the Agawam, MA, substation to the North Bloomfield, CT, substation. (The line from the Ludlow substation to the Agawam substation to the North Bloomfield substation is part of the Springfield component.)
- **Interstate Option E**—a new 1,200 MW high-voltage direct-current (HVDC) tie between the Millbury substation and the Southington, CT, substation

Rhode Island Component Options

The Rhode Island component upgrades would serve three basic functions: (1) bring an additional source (in the form of a new transmission line) into Rhode Island, (2) extend a second source (transmission line) to the southwest area of Rhode Island, and (3) add a new source (345/115 kV autotransformer) from the east into the 115 kV load center.

Bringing an additional source into Rhode Island is handled as part of Interstate Options A and B or by installing a second Sherman Road, RI–West Farnum 345 kV line as part of Interstate Options C, D, and E.

The addition of a second West Farnum–Kent County 345 kV line proved to be the most cost-effective option for extending a second source to the southwest area. Adding 115 kV lines and upgrades proved unable to support the loss of the existing West Farnum–Kent County 345 kV line.

Similarly, adding a new 345/115 kV substation into the 115 kV system from the east side proved to be the most effective option for eliminating the 115 kV voltage concerns that had been identified and forecast. This new substation would be looped into the existing 345 kV line (the 303 line) that extends from Brayton Point to ANP–Bellingham. The 115 kV lines that currently tie the South Wrentham substation to the Brayton Point substation (the 181 and 182 lines) also would be looped into this new substation under this option.

Connecticut East–West Component Options

The Connecticut East–West component increases the ability to move power between eastern and western Connecticut. It can be thought of as an extension to the Interstate component by helping to move power from eastern to western New England, and vice versa, depending on the dispatch of existing generation and on the location of future generators. The three options for the Connecticut East–West component that exhibited superior performance are as follows:

- **Option A**—a new 345 kV line from Manchester to Southington
- **Option B**—a new 345 kV line from Manchester to Scovill Rock and from Berlin to Hans Brook Junction
- **Option C**—a new 345 kV line from North Bloomfield to Frost Bridge

Springfield Component Options

The Springfield component reduces Springfield's dependence on internal generation by increasing the area's access to the 345 kV bulk transmission system and eliminates the thermal and voltage criteria violations of the area. The three options for the Springfield component that exhibited superior performance in meeting these objectives are as follows:

- **Option A**—a new 345 kV line from Ludlow to Agawam to North Bloomfield
- **Option B**—a new 345 kV line from Ludlow to North Bloomfield
- **Option C**—a new 345 kV line from Ludlow to Manchester

Relationships among Components and Options

The relationships among the four components and options are as follows:

- **Interstate Component**—The preferred Interstate option can be selected without respect to other component selections; however, this selection will dictate some of the Rhode Island component selections. Interstate Option E, which adds a HVDC line from the Millbury substation to the Southington substation, obviates the need for a separate 345 kV line to mitigate Connecticut East–West constraints.
- **Rhode Island Component**—As stated, some of the system improvements that make up the Rhode Island options depend on which Interstate option is selected (as shown in Appendix A, Table A-2). Therefore, the Interstate option selected will directly affect which Rhode Island option is selected. Some of the improvements of the Rhode Island component options are independent of the selections for any of the other components of the plan.
- **Connecticut East–West Component**—The improvements for the Connecticut East–West component options are independent of the selections for any of the other component options. However, as stated, the selection of Interstate Option E would obviate the need for a Connecticut East–West 345 kV option, since it would satisfy the reliability need for both the Interstate and the Connecticut East–West components.
- **Springfield Component**—The improvements for the Springfield component are independent of the preferred Interstate option unless Option D is selected. In this case, additional Springfield area upgrade(s) would be required. This component is independent of the Rhode Island and Connecticut East–West Component options.

Next Steps

The next part of the process is for the participating transmission owners to analyze the environmental impacts, cost, constructability, and routing for each option of each component. Once this information is gathered and analyzed, preferred options for each of the four plan components can be identified.

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Section 1
Introduction

National Grid, Northeast Utilities, and ISO New England (ISO) formed a working group to conduct the studies necessary to develop a 10-year plan for transmission system improvements for the southern New England (SNE) region. The plan specifically addresses western and central Massachusetts (particularly the Springfield area), Rhode Island, and eastern and central Connecticut (see Figure 1-1).

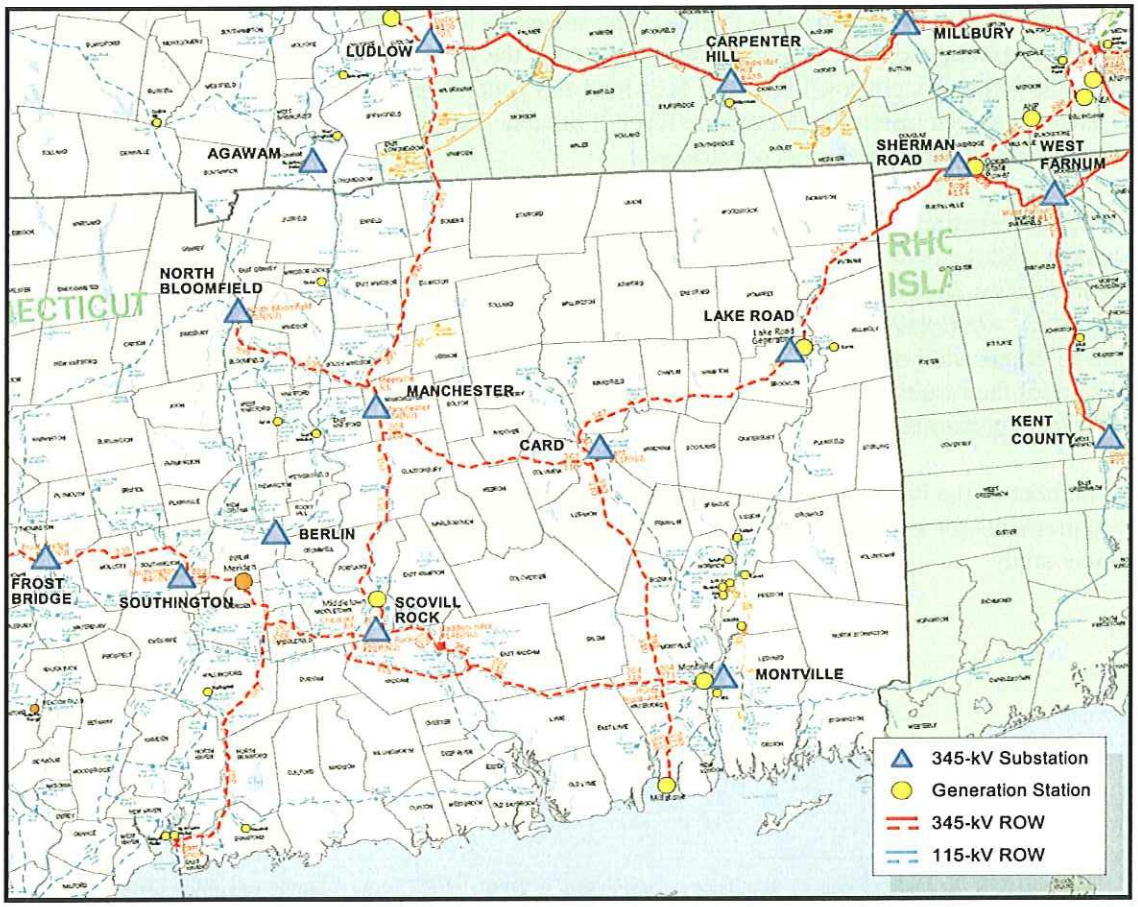

Figure 1-1: Key substations in southern New England.

The objective of the 10-year integrated SNE transmission enhancement plan is to ensure that the region complies with a number of design, operation, and reliability criteria and standards, as follows, to improve the long-term reliability and performance of the southern New England transmission system:

- North American Electric Reliability Corporation's (NERC) Reliability Standards for the Bulk Power Systems of North America[4]
- Northeast Power Coordinating Council's (NPCC) Basic Criteria for the Design and Operation of Interconnected Power Systems[5]
- The ISO's Planning Procedure No. 3 (PP 3), Reliability Standards for the New England Area Bulk Power Supply System[6]

These criteria and standards are in place to ensure that the regional transmission system serving New England can reliably deliver power to customers under a wide range of system conditions, such as anticipated facility outage events and system contingencies (i.e., the sudden and unplanned outage of a generating unit or transmission facility). The standards and criteria also ensure the adequate transfer of power among the New England Control Area and the surrounding control areas and account for possible future system configurations (i.e., load and generation scenarios). To comply with PP 3, the system meets the minimum acceptable level of reliable service if it passes the test conditions under simulation, as specified in this procedure.

A full explanation and review of the criteria, the statement of need for the SNE regional transmission system, and the results of an analysis of the needs are contained in *Southern New England Transmission Reliability (SNETR) Report 1—Needs Analysis* (Needs Analysis).[7] This report, *Report 2—Options Analysis*, summarizes the needs identified in the first report and describes each of the solutions and how they were developed for addressing the identified needs. This report also discusses the results of the analysis for developing options for solutions and compares them in terms of system performance characteristics.

A number of the transmission upgrades that were developed were found to meet the stated requirements for ensuring reliable and adequate system performance for the areas and time periods under study.

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[4] As certified by the Federal Energy Regulatory Commission in 2006, NERC is the "electric reliability organization" (ERO) whose mission is to improve the reliability and security of the bulk power system in North America. Information on NERC requirements is available online at http://www.nerc.com (Princeton, NJ: NERC, 2007).

[5] NPCC is the cross-border regional entity and criteria services corporation for northeastern North America. NPCC's mission is to promote and enhance the reliable and efficient operation of the international, interconnected bulk power system in the geographic area that includes New York State, the six New England states, and the Ontario, Québec, and the Maritime provinces of Canada. Additional information on NPCC is available online at http://www.npcc-cbre.org/default.aspx (New York: NPCC Inc., 2007).

[6] ISO New England Planning Procedure No. 3, *Reliability Standards for the New England Area Bulk Power Supply System*, is available online at http://www.iso-ne.com/rules_proceds/isone_plan/PP3_R3.doc (Holyoke, MA: ISO New England, 2006).

[7] The *Southern New England Transmission Reliability (SNETR) Report 1—Needs Analysis* (August 7, 2006) can be obtained by contacting ISO Customer Service at 413-540-4220 or custserv@iso-ne.com.

Section 2
Overview of Transmission System Problems and Needs

Through its analyses of the 10-year planning period, the working group identified a number of deficiencies in transmission system security that could lead to violations of the planning criteria and standards the system must meet. These deficiencies—many of which are a result of the significant degree of load growth in the SNE region—form the justification for the needed transmission system improvements. Although discussed in detail in the Needs Analysis, the specific reliability needs are summarized as follows for quick reference:

- The amount of power that can be delivered between eastern New England and western New England must be increased. The east–west power flows across southern New England could be limited because of potential thermal and voltage violations of area transmission facilities under contingency conditions.
- The amount of power that can be moved between Connecticut, Massachusetts, and Rhode Island must be increased to eliminate transmission security criteria violations.
- The reliability of the transmission supply to the Springfield, Massachusetts, area must be improved by eliminating thermal overloads and voltage problems under numerous contingencies. The severity of these problems increases as the system attempts to move power into Connecticut from the rest of New England. In the Springfield area, local double-circuit tower outages (DCT), stuck-breaker outages, and single-element outages all can result in severe thermal overloads and low-voltage conditions. **This sentence has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.**
- The ability to move power into and out of Connecticut must be enhanced. In the past, the limited ability to export power from Connecticut to the rest of New England was the more serious problem; however, this has reversed in recent years. The ability to import power presently is limited and could eventually result in the inability to serve load under many probable system conditions. Power-transfer capabilities in the Connecticut area are forecast to be insufficient for meeting the area's requirements as early as 2009.[8] If improvements are not made by 2016, the deficiency for this area under "generator unavailability conditions" (i.e., when the largest unit plus a historical average amount of other generation is out-of-service) and when a single power system element is lost (N-1 conditions) is expected to be greater than 1,500 MW, assuming a transfer limit of 2,500 MW and no new capacity additions. On the basis of planning assumptions of future generation additions of 500 MW and retirements of 204 MW within the Connecticut area, by 2016 a deficiency of approximately 1,100 MW will occur for N-1 conditions, and 1,200 MW for N-1-1 conditions (i.e., conditions under which a transmission element is unavailable and a single power system element is lost).
- The amount of power that can be delivered from eastern Connecticut to western Connecticut must be increased by eliminating transmission security criteria violations. These violations, which can cause thermal constraints, limit the Connecticut east–west power transfers across the central part of Connecticut. The movement of power from east to west, in conjunction

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[8] RSP06, Table 9-3

with higher import levels to serve Connecticut, overloads transmission facilities within Connecticut.

- The reliability of the transmission supply to the Rhode Island area must be improved by eliminating thermal overloads and voltage problems. Rhode Island now is overly dependent on a limited number of transmission lines or autotransformers to serve its needs, which could result in thermal overloads and voltage problems during contingency conditions. Causal factors for these conditions include high load growth (especially in southern Rhode Island and the coastal communities), unit availability, and planned and unplanned transmission outages. 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 limits the amount of power that can be transferred 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 results in numerous thermal and voltage violations.

Section 3
Development and Assessment of Options

Developing and assessing the options for addressing the identified reliability needs has been a highly complex effort. The first part of the process was to establish the objectives for the future performance of the SNE transmission system based upon the reliability deficiencies shown in the Regional System Plans (RSPs) and as discussed in the Needs Analysis report. Using these performance objectives, the working group developed and evaluated a combination of complementary options for transmission system upgrades for the long-term planning horizon. This section describes the design objectives for the options as well as the ability of each set of options to meet these objectives.

3.1 Developing the Four-Component Approach

In formulating each option, the working group considered not only the performance of the option but also the relationship that each option could have with other components of the comprehensive solution, with other elements of the transmission system, and with the regional transmission system as a whole. Consideration of these relationships ensured that the development of one "solution" was comprehensive and did not have an adverse impact on other parts of the system. These relationships led the working group to develop an approach to solving the SNE region's needs with these four components:

- **Interstate Component**—This component either provides an additional link between Massachusetts, Rhode Island, and Connecticut or, in one case, just between Rhode Island and Connecticut, and improves regional transfer capabilities. Initial brainstorming sessions identified 17 options for the Interstate component, of which five viable options remain.
- **Rhode Island Component**—This component increases Rhode Island's access to New England's 345 kV bulk transmission system and eliminates both thermal overloads and voltage violations. Three options (two Interstate options plus one independent option) were developed to better connect Rhode Island to the rest of the system, three options were developed to extend these new facilities farther into the major load center in southwest Rhode Island, and two options were developed to bring an additional source into the 115 kV load center from the east.
- **Connecticut East–West Component**—This component provides an additional link between western and eastern Connecticut and improves system transfer capabilities. Four options were initially developed for this component; one was eliminated as a result of poor performance, which left three options for further study.
- **Springfield Component**—This component eliminates both thermal and voltage violations in the Springfield area while increasing the area's access to the 345 kV bulk transmission system. The number of 345 kV options for the Springfield component was limited; however, 35 options were initially developed because a number of possible 115 kV solutions would work well with any of the 345 kV options. Three 345 kV options remain, each having four 115 kV variations, for a total of 12 potential solutions.

As shown in Figure 3-1, a number of factors were considered in formulating and evaluating the options within each component of the plan. These factors ranged from considering the impacts of an option on the New York–New England transfer capabilities to assessing the impact of adding a specific generating unit.

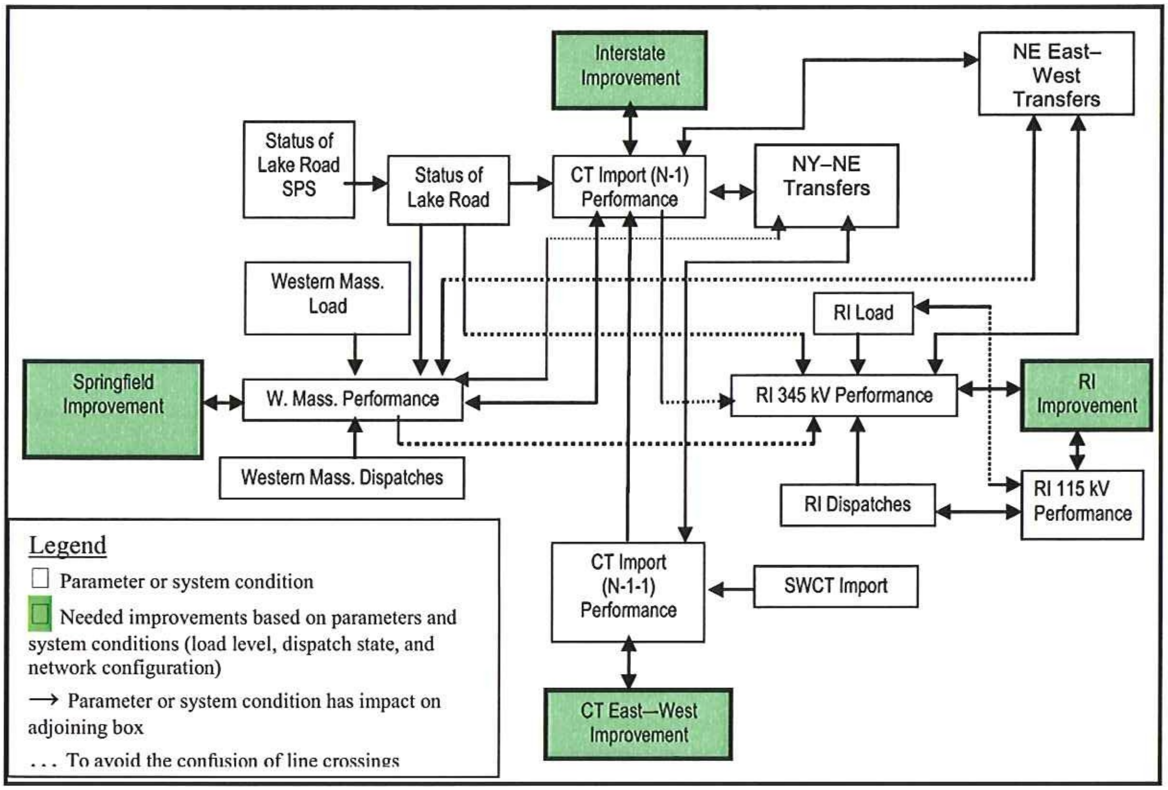

Figure 3-1: Diagram of relationships among southern New England components.

The lines interconnecting the boxes in Figure 3-1 show how the components can have an impact on one another. For example, the performance of the Rhode Island 345 kV system depends, to some extent, on all the following:

- RI Load (Rhode Island load levels)
- NE East-West Transfers (transfer level from eastern to western New England)
- CT Import (N-1) Performance (transfer level into Connecticut)
- RI Dispatches (generation dispatch in Rhode Island)
- Status of Lake Road (generation dispatch on the borders)
- W. Mass. Performance (performance of western Massachusetts system [i.e., Ludlow to Manchester loading])

To ensure the resiliency of the solutions, the design of the system upgrades accounted for the premature loss of generation concurrent with the ability of the system to maintain an acceptable level of performance under line-out-of-service conditions. This is an important planning consideration because implementing a transmission system upgrade to ensure system reliability in response to an unforeseen event can require from three to five years. To create solutions that are sufficient to meet minimum reliability requirements for both the foreseeable and the unforeseen circumstances, the following assumptions have been included as planning considerations:

- Connecticut generation—the unavailability of the following generation, alone or in combination, plus no new major generation additions:
    - Millstone #3 (1,260 MW)
    - Other major area generation (Equivalent demand forced-outage rates are calculated at over 500 MW.[9])
- Rhode Island generation—the unavailability of any of the following units or stations, alone or in combination, plus no new major generation additions:
    - Rhode Island State Energy combined-cycle unit (448 MW)
    - Manchester Street station (357 MW)
    - Brayton Point 115 kV generation (479 MW)
    - Milford Power and Tiverton generation (433 MW)
- Springfield generation—the unavailability of any of the following plants, alone or in combination:
    - Berkshire Power (280 MW)
    - Mount Tom (147 MW)
    - West Springfield station (194 MW)

All these assumptions enable the design of a system that would be responsive to potential events or conditions that limit the resources available to a supply area. The development and selection of options that contemplate such conditions allow for a more robust and flexible system and, ultimately, system upgrades with greater longevity.

Developing these options has been an iterative process. Options that seemed capable of mitigating reliability concerns were formulated and analyzed for compliance with the design criteria and objectives. Additional modifications were formulated as necessary and the options reevaluated. This step was repeated until either a workable option was identified or it became clear that the option was not viable because it would require too many system modifications.

3.2 Assessing the Options

All the system upgrades associated with the four plan components were designed to resolve the reliability concerns for the southern New England transmission system over the projected planning horizon, as identified in the Needs Analysis. The options for the four plan components were evaluated for their potential to improve the reliability and performance of the transmission system, including the following factors:

- Improving the capability to transfer power into and within the load centers in southern New England
- Improving east-to-west and west-to-east transfer capability across New England and within Connecticut
- Eliminating projected line overloads under contingency conditions

[9] An *equivalent demand forced-outage rate* is the portion of time a unit is in demand but is unavailable because of a forced outage.

- Improving system voltages under contingency conditions
- Decreasing system losses
- Improving system expandability and flexibility

The options also were compared on the basis of the thermal transfer limits across key New England interfaces that would be affected by these improvements. These included the New England–New York interface, the New England East–West interface, the Connecticut Import interface, and the Connecticut East–West interface. Thermal transfer limits are a function of a number of variables, as follows:

- Load levels
- Load distribution
- Generation availability assumptions
- Generation source and sink combinations[10]
- Transmission facility outage assumptions
- Transmission facility equipment ratings
- Phase-angle regulator settings
- Solution techniques

Varying any of these factors produces a range of values for any interface transfer limit. System conditions could exist that restrict transfers below the limits stated. Conversely, system conditions also could allow for even higher transfers. For comparing the transfer-capability improvements resulting from the various options of each component, all thermal transfer limit variables were held constant in this analysis.

The study evaluated the number of times an element is highly loaded (above 90%) under various contingency and dispatch conditions for each of the options within the Interstate component. Similarly, the study compared contingency voltage levels. These performance measures convey the relative strength of each option. The likelihood of each option reducing system losses, which provides both economic and efficiency improvements, also was evaluated.

Limiting the increase in short-circuit duty for areas of the transmission system that may experience future short-circuit constraints is important for developing future generation. Areas that presently contain existing equipment that is close to the short-circuit limit are less likely to attract new generation because of the potential cost for system upgrades that would be required for the generation to interconnect. Therefore, comparing options on the basis of their impact on the short-circuit duty of an area's existing equipment is useful. This analysis did not consider the number of locations where increases may occur but rather only the highest increase at any single location observed on the system.

[10] A *source* point is a point on the transmission system where electric energy is injected, such as an increase in generation. A *sink* point is a point on the transmission system where electric energy is withdrawn, such as a decrease in generation or an increase in load.

The working group also evaluated each option's potential for enhancing system expandability and flexibility. This is a key consideration given that transmission assets typically have lifetimes that exceed 40 years.

Section 4
Interstate Component Options

System studies have extensively examined the existing key transmission paths that interconnect Connecticut, Massachusetts, and Rhode Island. These studies have determined that reinforcing or otherwise modifying existing facilities alone will not bring the system into compliance with applicable reliability criteria and planning standards for the future. The most practical options to meet reliability criteria and simultaneously improve interstate transfer capability and load-serving ability were determined to be adding new 345 kV lines coupled with other reinforcements, as described elsewhere in this report.

Accordingly, all five options for the Interstate component include the addition of new 345 kV lines, together with additional modifications and reinforcements. In general, each of the proposed Interstate options, coupled with the solutions of the three other components, will improve the ability of the SNE bulk transmission system to move power between eastern New England and western New England and enhance transmission security in Connecticut. They also will mitigate area transmission supply concerns for the Springfield and the Rhode Island supply areas and relieve transmission constraints for the transfer of power between eastern Connecticut and western Connecticut.

Each option has been designed such that its general performance meets the design criteria established for the reliability of the SNE system. However, some salient characteristics related to such areas of concern as transfer capabilities, line loadings, voltage levels, and expandability are unique to each solution.

This section summarizes the five options of the Interstate component and each option's potential to improve system performance and reliability. The factors used in evaluating each option are discussed and their individual characteristics compared in terms of their impact on other system characteristics. Detailed listings of the upgrades associated with each option are included in Appendix A.

4.1 Process to Develop and Eliminate Interstate Options

During an initial study session, 17 Interstate options were developed for discussion. The options identified as impractical, infeasible, or likely poor performers were eliminated over time, and new options were added to the mix. One of three original HVDC options was modified and reconsidered. Fourteen options were retained for further testing, which eventually were reduced to the five remaining options. The review process is depicted in Table 4-1, which also summarizes the 14 options and the reasoning used to either eliminate or retain them.

Table 4-1
The Process to Develop and Eliminate the Interstate Options

Original 345 kV Interstate Options	Disposition	Final Top 5 Options
1 Card–Lake Road 2 Card–Lake Road–Sherman Road	This option was eliminated because it proved to be only a partial solution without adequate increases in interstate transfer capability.	
3 Card–Lake Road–Sherman Road–Millbury	This option was eliminated because of performance issues compared with option 4.	
4 Card–Lake Road–West Farnum–Millbury		4. Card–Lake Road–West Farnum–Millbury (designated Option A)
5 Card–Lake Road–Sherman Road–West Farnum–Millbury	This option was eliminated because of performance issues compared with option 4.	
6 Millbury–Sherman Road–West Farnum–Kent County–Montville		6. Millbury–Sherman Road–West Farnum–Kent County–Montville (designated Option B)
7 Card–Lake Road–Carpenter Hill	This option was eliminated because it proved to be only a partial solution without adequate increases in interstate transfer capability.	
8 Montville–Brayton Point	This option was eliminated because of performance issues. (Constructability issues also were raised.)	
9 Manchester–Carpenter Hill	This option was eliminated because it proved to be only a partial solution without adequate increases in interstate transfer capability.	
10 Manchester–Carpenter Hill–Millbury		10. Manchester–Carpenter Hill–Millbury (designated Option C)
12 North Bloomfield–Agawam–Ludlow–Carpenter Hill–Millbury 12a North Bloomfield–Agawam–Ludlow–Carpenter Hill–Millbury, plus separation of existing 395 line (Ludlow–Manchester–North Bloomfield)	Options 12 and 12a were combined into one option: option 12.	12 Ludlow–Carpenter Hill–Millbury, plus separation of existing 395 line (designated Option D)
13 Montville–Kent County–Manchester–Brayton Point	This option was eliminated because of performance issues. (Constructability issues also were raised.)	
14 Ludlow–Agawam–North Bloomfield	This option became part of the Springfield Component analysis.	
	DC–Millbury–Southington (added)	DC–Millbury–Southington (designated Option E)

The five final Interstate options are as follows:

- **Interstate Option A**—a new 345 kV line from the Millbury, MA, substation to the West Farnum, RI, substation and then to the Lake Road, CT, substation, terminating at the Card, CT, substation
- **Interstate Option B**—a new 345 kV line from the West Farnum substation to the Kent County, RI, substation and then to the Montville, CT, substation. (The line from the West Farnum substation to the Kent County substation is part of the Rhode Island component.)
- **Interstate Option C**—a new 345 kV line from the Millbury substation to the Carpenter Hill, MA, substation, terminating at the Manchester, CT, substation
- **Interstate Option D**—a new 345 kV line from the Millbury substation to the Carpenter Hill substation to the Ludlow, MA, substation to the Agawam, MA, substation to the North Bloomfield, CT, substation. (The line from the Ludlow substation to the Agawam substation to the North Bloomfield substation is part of the Springfield component.)
- **Interstate Option E**—a new 1,200 MW high-voltage direct-current (HVDC) tie between the Millbury substation and the Southington, CT, substation

4.2 Description and Performance of the 345 kV Interstate Options

This section describes each of the interstate options in further detail. One-line diagrams of the 345 kV transmission upgrades for each option are included. These figures do not show associated 115 kV system improvements; however, Appendix A contains a detailed description of all the upgrades included in each option. For simplicity, these figures also do not show some intermediate 345 kV substations, such as Barbour Hill and Killingly.

Each section also contains a table summarizing how the option performed with respect to the assessment process as described in Section 3.2.

4.2.1 Interstate Option A—Millbury to West Farnum to Lake Road to Card 345 kV Major Upgrades

This option adds a new 345 kV line that connects Millbury to West Farnum and then continues on to connect West Farnum to Card, with an intermediate connection at Lake Road. The reconductoring of the portion of the Sherman Road to Lake Road 345 kV line that physically is in Rhode Island also is part of this option.

Figure 4-1 depicts the major upgrades that comprise Interstate Option A. Table 4-2 summarizes the assessment results for this option.

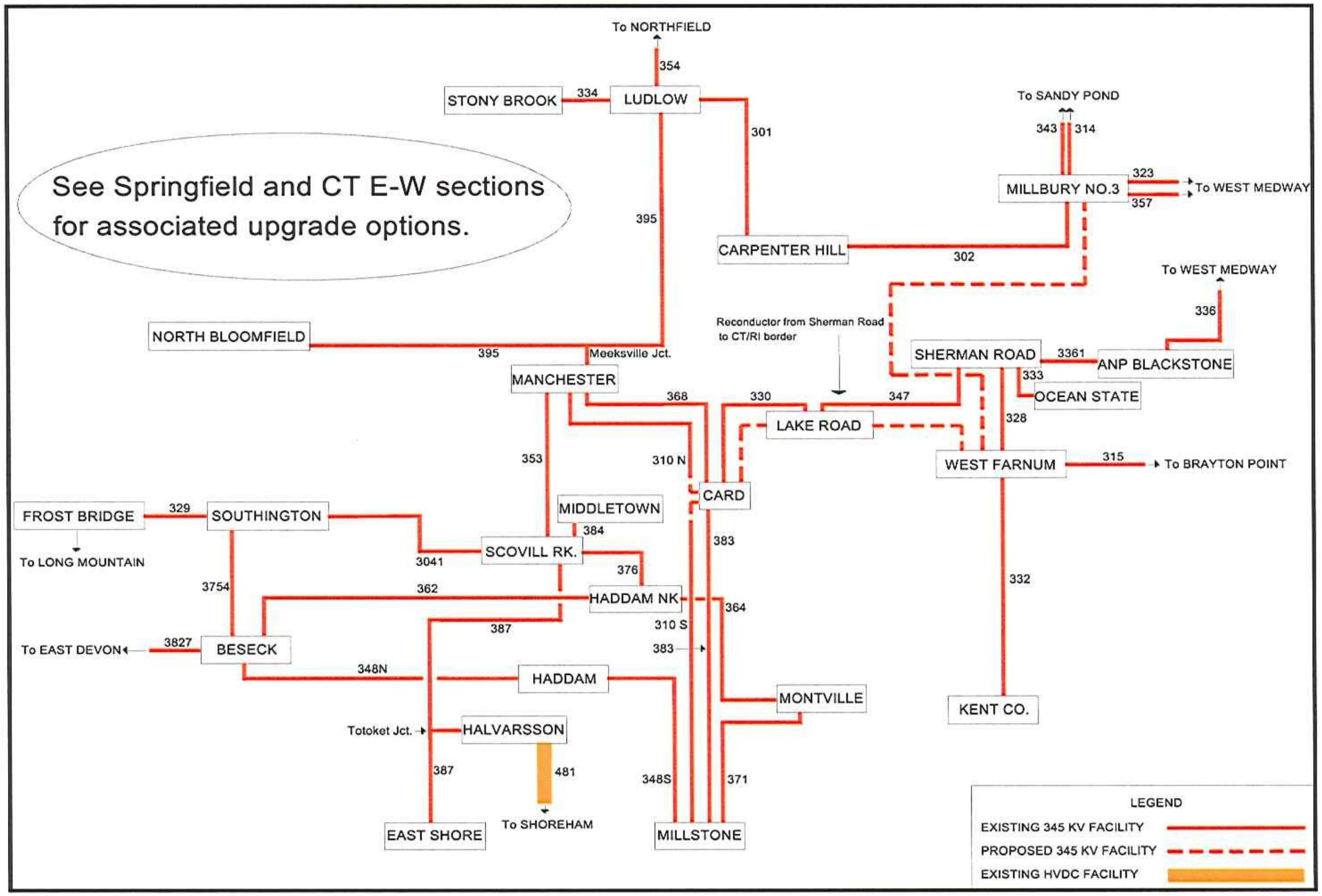

Figure 4-1: Interstate Option A—Millbury to West Farnum to Lake Road to Card 345 kV major upgrades.

Table 4-2
System Performance Factors of Interstate Option A

System Performance Factors	Results	Comments[(a)]
Effect on transfer capability between New York and New England	Positive effect	See Section 4.3.8 for details.
Improving New England east–west transfer capability	Increases capability by 1,376 MW (to 4,174 MW total)	Ranked third
Improving Connecticut's import capability	N-1 import capability increases by 1,766 MW (to 4,443 total); N-1-1 import capability increases by 1,591 MW (to 2,783 MW)	N-1 limit tied for third among the options; N-1-1 ranked second
Eliminating high line loadings under contingencies (2016)	46 high line loadings total; 3 high all-lines-in loading; 43 high line-out loadings	Ranked first—lowest number of high loadings
Improving system voltages during contingencies (2016)	6 borderline voltage cases following N-1 contingencies	Ranked first—lowest number of borderline voltage issues
Decreasing system losses	56 MW reduction in system losses compared with pre-project system	Ranked fourth
Decreasing short-circuit duty	8.9% increase on worst location	Ranked fourth
Improving system expandability	Yes	AC lines can readily be tapped for future substations and generator interconnections.

(a) The performance rankings range from one to five, one being the best and five being the worst.

4.2.2 Interstate Option B—West Farnum to Kent County to Montville 345 kV Major Upgrades

Interstate Option B extends the existing 345 kV line from the West Farnum station to the Kent County station into Connecticut to Montville station, providing a common supply path for both Rhode Island and Connecticut. This option also includes the reconductoring of the 345 kV line from Millbury through Carpenter Hill to Ludlow and the 345 kV line from ANP Blackstone (MA) to Sherman Road.

Figure 4-2 depicts the major upgrades that comprise Interstate Option B. Table 4-3 summarizes the assessment results for this option.

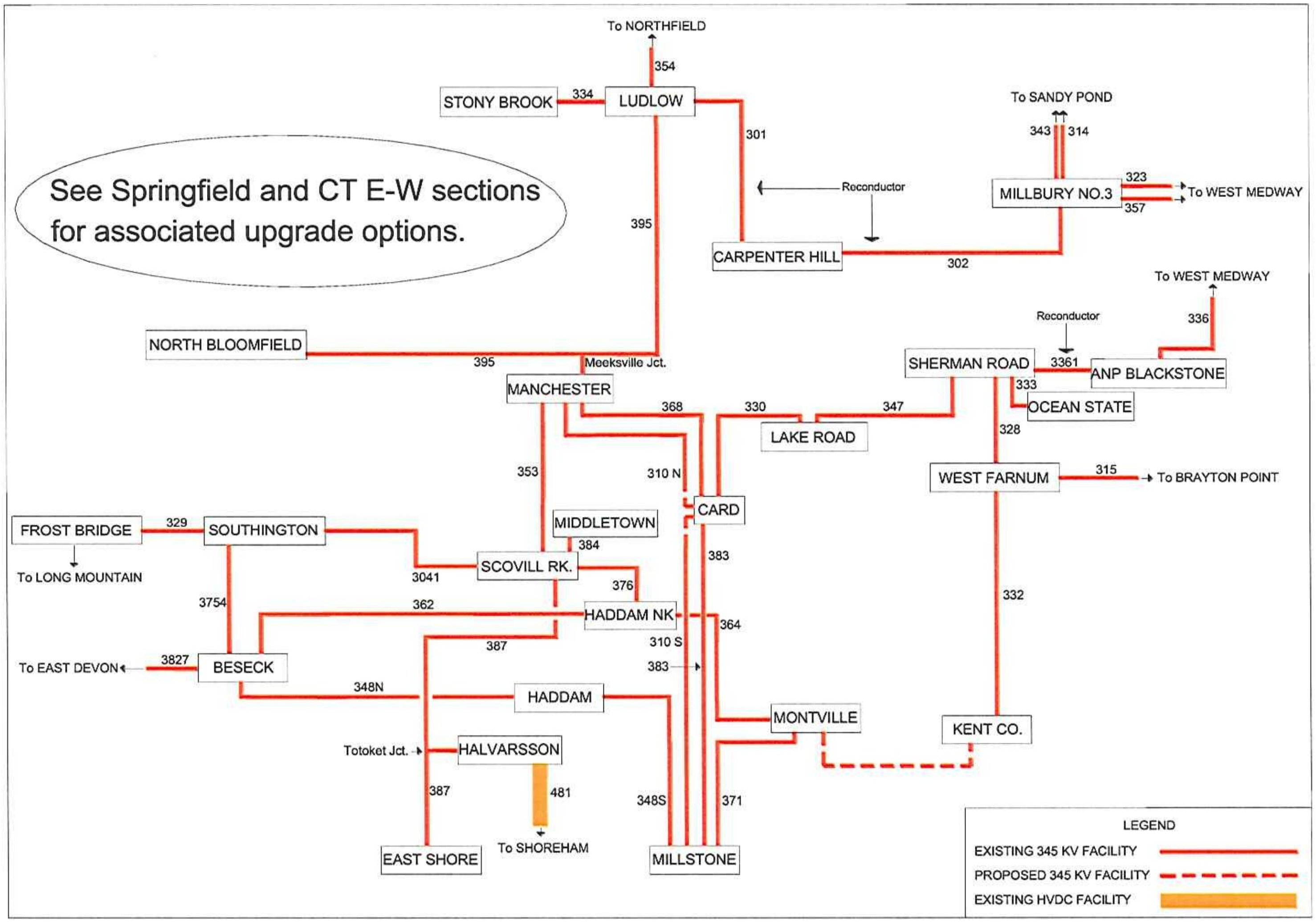

Figure 4-2: Interstate Option B—West Farnum to Kent County to Montville 345 kV major upgrades.

Table 4-3
System Performance Factors of Interstate Option B

System Performance Factors	Results	Comments[a]
Effect on transfer capability between New York and New England	Positive effect	See Section 4.3.8 for details
Improving New England east–west transfer capability	Increases capability by 1,198 MW (to 3,996 MW total)	Ranked fifth
Improving Connecticut's import capability	N-1 import capability increases by 1,298 MW (to 3,975 total); N-1-1 import capability increases by 1,347 MW (to 2,539 MW)	N-1 limit ranked fifth among the options; N-1-1 ranked fourth
Eliminating high line loadings under contingencies (2016)	118 high line loadings total; 21 high all-lines-in loading; 97 high line-out loadings	Ranked fifth—highest number of high loadings
Improving system voltages during contingencies (2016)	29 borderline voltage cases following N-1 contingencies	Ranked fifth—highest number of borderline voltage issues
Decreasing system losses	55 MW reduction in system losses compared with pre-project system	Ranked fifth
Decreasing short-circuit duty	5.3% increase on worst location	Ranked second
Improving system expandability	Yes	AC lines can readily be tapped for future substations and generator interconnections.

(a) The performance rankings range from one to five, one being the best and five being the worst.

4.2.3 Interstate Option C—Millbury to Carpenter Hill to Manchester 345 kV Major Upgrades

Interstate Option C provides a new 345 kV line from Millbury through Carpenter Hill to Manchester. In addition, a new 345 kV line from Sherman Road to West Farnum is required.

Figure 4-3 depicts the major upgrades that comprise Interstate Option C. Table 4-4 summarizes the assessment results for this option.

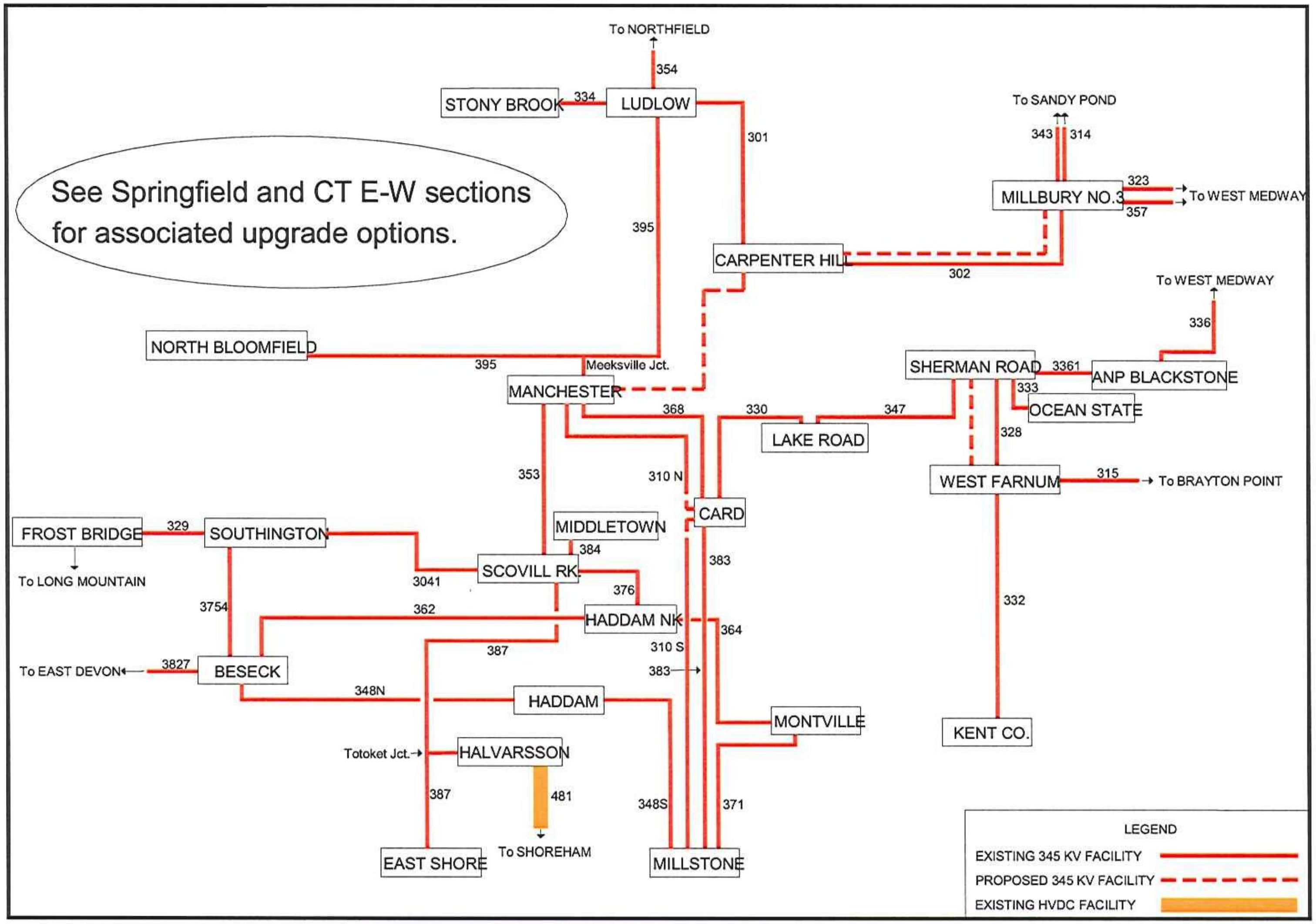

Figure 4-3: Interstate Option C—Millbury to Carpenter Hill to Manchester major 345 kV upgrades.

Table 4-4
System Performance Factors of Interstate Option C

System Performance Factors	Results	Comments[a]
Effect on transfer capability between New York and New England	Positive effect	See Section 4.3.8 for details
Improving New England east–west transfer capability	Increases capability by 1,293 MW (to 4,091 MW total)	Ranked fourth
Improving Connecticut's import capability	N-1 import capability increases by 1,766 MW (to 4,443 total); N-1-1 import capability increases by 1,535 MW (to 2,727 MW)	N-1 limit tied for third among the options; N-1-1 ranked third
Eliminating high line loadings under contingencies (2016)	73 high line loadings total; 6 high all-lines-in loading; 67 high line-out loadings	Ranked second
Improving system voltages during contingencies (2016)	8 borderline voltage cases following N-1 contingencies	Ranked second
Decreasing system losses	69 MW reduction in system losses compared with pre-project system	Ranked first
Decreasing short-circuit duty	9.3% increase on worst location	Ranked fifth
Improving system expandability	Yes	AC lines can readily be tapped for future substations and generator interconnections.

(a) The performance rankings range from one to five, one being the best and five being the worst.

4.2.4 Interstate Option D—Millbury to Carpenter Hill to Ludlow 345 kV Major Upgrades

Interstate Option D builds a new 345 kV line from Millbury to Carpenter Hill to Ludlow and takes advantage of the proposed Springfield area improvements to complete the interstate connection. It also requires uprating of the 345 kV lines from Ludlow to Manchester and from Sherman Road to the state border. A new line from Sherman Road to West Farnum also is required.

Figure 4-4 depicts the major upgrades that comprise Interstate Option D. Table 4-5 summarizes the assessment results for this option.

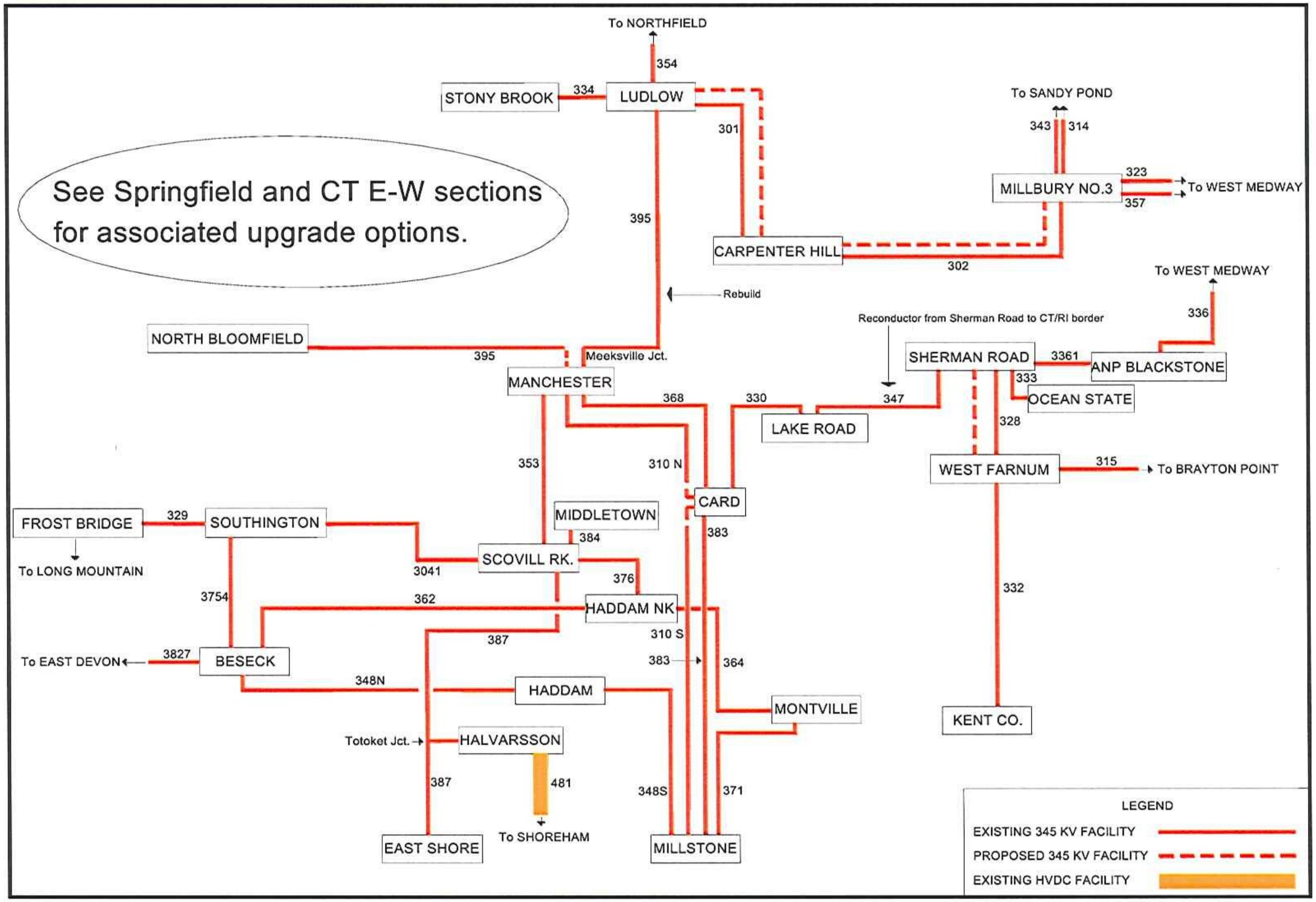

Figure 4-4: Interstate Option D—Millbury to Carpenter Hill to Ludlow major 345 kV upgrades.

Table 4-5
System Performance Factors of Interstate Option D

System Performance Factors	Results	Comments[a]
Effect on transfer capability between New York and New England	Positive effect	See Section 4.3.8 for details
Improving New England east–west transfer capability	Increases capability by 1,853 MW (to 4,651 MW total)	Ranked first
Improving Connecticut's import capability	N-1 import capability increases by 1,903 MW (to 4,580 total); N-1-1 import capability increases by 1,262 MW (to 2,454 MW)	N-1 limit tied for second among the options; N-1-1 ranked fifth
Eliminating high line loadings under contingencies (2016)	76 high line loadings total; 5 high all-lines-in loading; 71 high line-out loadings	Ranked third
Improving system voltages during contingencies (2016)	9 borderline voltage cases following N-1 contingencies	Ranked third
Decreasing system losses	57 MW reduction in system losses compared with pre-project system	Ranked third
Decreasing short-circuit duty	7.5% increase on worst location	Ranked second
Improving system expandability	Yes	AC lines can readily be tapped for future substations and generator interconnections.

(a) The performance rankings range from one to five, one being the best and five being the worst.

4.2.5 Interstate Option E—Millbury to Southington High Voltage DC Major Upgrades

Interstate Option E involves the installation of HVDC facilities and provides an independent, controllable supply path through the addition of a bipole HVDC line from Millbury to Southington. A new 345 kV line from Sherman Road to West Farnum also is required in connection with Interstate Option E.

Figure 4-5 depicts the major upgrades that comprise Interstate Option E. Table 4-6 summarizes the assessment results for this option.

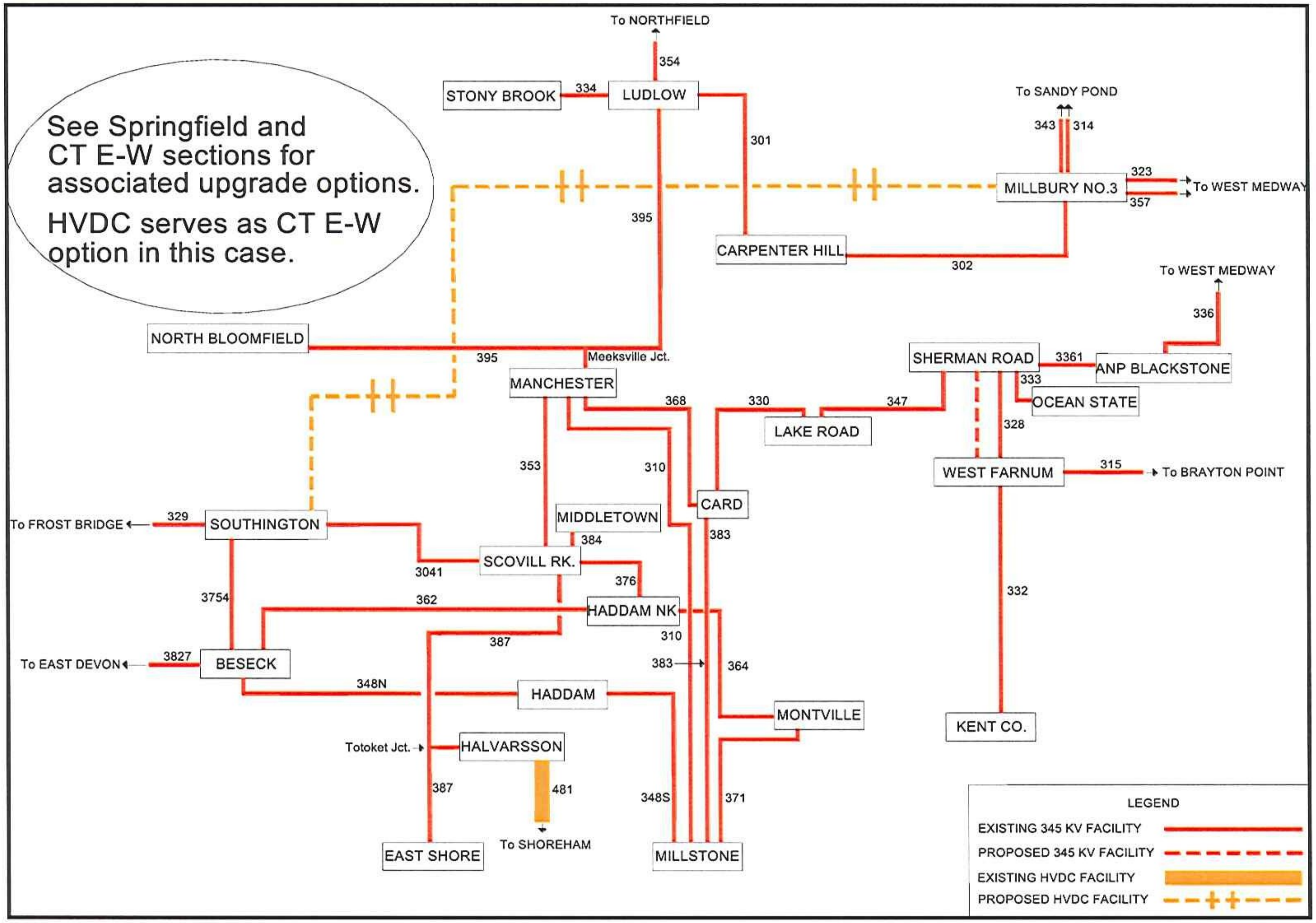

Figure 4-5: Interstate Option E—Millbury to Southington HVDC line.

Table 4-6
System Performance Factors of Interstate Option E

System Performance Factors	Results	Comments[a]
Effect on transfer capability between New York and New England	This option was originally more limiting on NY to NE. However, the 2010 western MA improvements eliminate that limiting condition.	See Section 4.3.8 for details
Improving New England east–west transfer capability	Increases capability by 1,580 MW (to 4,378 MW total)	Ranked second
Improving Connecticut's import capability	N-1 import capability increases by 1,974 MW (to 4,651 total); N-1-1 import capability increases by 1,621 MW (to 2,813 MW)	N-1 limit ranked first among the options; N-1-1 ranked first
Eliminating high line loadings under contingencies (2016)	100 high line loadings total; 18 high all-lines-in loading; 82 high line-out loadings	Ranked fourth
Improving system voltages during contingencies (2016)	23 borderline voltage cases following N-1 contingencies	Ranked fourth
Decreasing system losses	68/33 MW (conventional DC/DC light) reduction in system losses compared with pre-project system	Ranked second/fifth
Decreasing short-circuit duty	7.5% increase on worst location	Ranked first
Improving system expandability	No	DC system not easily expandable; an additional converter station would be needed for adding a generator or substation

(a) The performance rankings range from one to five, one being the best and five being the worst.

4.3 Comparison of Interstate Options

Each of the five options of the Interstate component fully addresses all the reliability concerns for the SNE bulk transmission system over the projected planning horizon, although each has its own set of characteristics with respect to system performance improvements. This section compares the improvements that each option could contribute to system performance for the reliability-based characteristics important for the southern New England system and includes comparison tables for several of the electrical performance factors.

Target values shown in these tables are based on either the project design objectives or the minimum requirements needed to satisfy the reliability requirements for the system.

Table 4-7 is a master comparison table that includes all the factors. Each factor is discussed in detail.

Table 4-7
Comparison of Interstate Options

Interstate Options and Needs	Pre-Project System	Option A	Option B	Option C	Option D	Option E
New England east–west transfer capability (MW)	2,798	4,174	3,996	4,091	4,651	4,378
CT import: N-1 (MW)	2,677	4,443	3,975	4,443	4,580	4,651
CT import: N-1-1 (MW)	1,192	2,783	2,539	2,727	2,454	2,813
Number of 'high' 'all-lines-in' loadings in 2016	NA	3	21	6	5	18
Number of 'high' 'line-out' loadings in 2016	NA	43	97	67	71	82
Total high loadings	NA	46	118	73	76	100
Number of borderline voltage cases	NA	6	29	8	9	23
Decrease in New England system losses (MW)	NA	56	55	69	57	68 (conv)/ 33 (light)
Short-circuit impact (percent increase)	NA	8.9	5.3	9.3	7.5	3.8

4.3.1 New England East–West Transfer Capability

The improvement in New England east–west transfer capability ranged from a low of about 1,200 MW for Interstate Option B to a high of about 1,900 MW for Option D. Table 4-8 shows the incremental improvement for each of the options for N-1 conditions.

Table 4-8
New England East–West 2012 N-1 Transfer Capability Improvement

Interstate Option	New England East–West Transfer Capability (MW)	Incremental Increase in New England East–West Transfer Capability (MW)
Base	2,798	
A	4,174	1,376
B	3,996	1,198
C	4,091	1,293
D	4,651	1,853
E	4,378	1,580

4.3.2 Connecticut Import Improvement

The results for improving the import capability into the Connecticut area show that each option more than satisfies the year 2012 planning horizon requirements for area supply, although each option differs in the amount of improvement it could provide to the system.

Table 4-9 and Table 4-10 show the target improvement level, the import level, and the incremental improvement for each of the options for both N-1 and N-1-1 conditions, respectively.

Table 4-9
Connecticut 2012 N-1 Import Comparison

Interstate Option	CT Import: N-1 (MW)	Incremental Improvement in CT Import: N-1 (MW)
Base	2,677	
Target[(a)]	3,574	923
A	4,443	1,766
B	3,975	1,298
C	4,443	1,766
D	4,580	1,903
E	4,651	1,974

(a) The target of 3,574 MW is the result of adding the year 2012 N-1 shortage of 1,074 MW (from Table 9-3 in RSP06) to the existing N-1 limit of 2,500 MW.

Table 4-10
Connecticut 2012 N-1-1 Import Comparison

Interstate Option	CT Import: N-1-1 (MW)	Incremental Improvement in CT Import: N-1-1 (MW)
Base	1,192	
Target[(a)]	2,374	1,308
A	2,783	1,591
B	2,539	1,347
C	2,727	1,535
D	2,454	1,262
E	2,813	1,621

(a) The target of 2,374 MW is the result of adding the year 2012 N-1-1 shortage of 1,154 MW (from table 9-3 in RSP06) to the existing N-1-1 limit of 1,220 MW.

The target is a 923 MW increase for N-1 and a 1,308 MW increase for N-1-1 Connecticut-import capability.

Interstate Option A provides an improvement of almost 1,800 MW over the existing N-1 Connecticut-import capability. The N-1-1 improvement under this option for the Connecticut-import capability is about 1,600 MW, one of the highest.

Interstate Option B provides the least improvement in Connecticut-import capability, increasing N-1 imports by about 1,300 MW, which is almost 700 MW less than the option with the greatest improvement. The N-1-1 import capability improvement for this option also is about 1,300 MW, one of the lowest.

Interstate Option C provides an improvement in N-1 and N-1-1 import capability similar to Option A.

Interstate Option D provides an improvement of N-1 import capability at about 1,900 MW, one of the highest. However, the N-1-1 import capability improvement for Option D of less than 1,300 MW is the lowest of all options.

Interstate Option E (HVDC) provides the greatest level of N-1 import improvement of all options studied at about 2,000 MW. The N-1-1 import capability improvement for this option is about 1,600 MW, also the highest among all options.

4.3.3 Line Loading during Contingencies

All five Interstate options eliminate transmission element overloads that occur for N-1 or N-1-1 contingency conditions. A comparison of the number of line loadings above 90%-of-rating following such events suggests the amount of additional transmission capacity margin each option could provide. Alternatives with fewer high loadings indicate more robust plans.

These results are displayed in Table 4-11. In total, Interstate Options A, C, and D performed somewhat better than the other two options.

Table 4-11
Comparison of Line Loadings in 2016

Interstate Option	Number of High "All-Lines-In" Loadings	Number of High "Line-Out" Loadings	Total Number of Line Loadings
A	3	43	46
B	21	97	118
C	6	67	73
D	5	71	76
E	18	82	100

4.3.4 System Voltages during Contingencies

Similar to the number of contingency high line loadings, the lower the number of borderline contingency voltage cases that occur in an option might also suggest that it is a more robust option. In general, Interstate Options A, C, and D performed somewhat better than the other options. The voltage results appear in Table 4-12 and reflect the number of cases of low or high equipment voltages during contingency events for each of the Interstate options.

Table 4-12
Comparison of Voltages during Disturbances in 2016

Interstate Option	Number of Borderline Voltage Cases
A	6
B	29
C	8
D	9
E	23

4.3.5 System Losses

The Interstate options varied in their ability to reduce system losses from about 55 MW to as high as 69 MW, as shown in Table 4-13.

Table 4-13
Comparison of System Loss Reductions

Interstate Option	Decrease in New England System Losses (MW)
A	56
B	55
C (assuming the Route I-84 path)	69
D	57
E	68 (conventional DC) 33 (DC light)

4.3.6 Stability Screening Analysis

A stability screening analysis was performed to determine if any options exhibited undesirable transient behavior following a fault condition. Generally, all the options improved system performance; however, some findings are worth noting.

If the West Medway South bus were out of service, only Option A would be able to mitigate system instability for a three-phase fault on West Medway bus B (stuck breaker 104). Similarly, only Option A would prevent a Lake Road trip if the 330 line (Lake Road–Card 345 kV) were out of service and the 347 line (Sherman Road–Killingly 345 kV) had a fault. This also would hold true if the fault were on the 330 line and the 347 line were out of service. Also under Option A, Lake Road would not trip if the 347 line were out of service and the 383 line (Millstone-Card 345 kV) at Card had a three-phase fault that resulted in a 3T stuck-breaker condition (the 383 line, the 330 line, and the autotransformer).

Option B is the only option that does not mitigate a Lake Road and Ocean States Power trip for the condition where the 330 line is out of service and Sherman Road has a subsequent stuck breaker (stuck breaker 142, which takes the 3361 line from Sherman Road to ANP Blackstone and the 328 line from Sherman Road to West Farnum out of service). This indicates the need to add a second Card–Lake Road 345 kV line or a second West Farnum–Sherman Road 345 kV line or to eliminate the possible stuck-breaker condition.

4.3.7 Short-Circuit Duty Impacts

Based on a high-level approximation of the percent increase in short-circuit duty at constrained locations, Interstate Option E showed the lowest increase in fault duty compared with the other options, and Option C showed the greatest increase. The differences in these results, which are displayed in Table 4-14, do not appear to be significant and may not be a material factor for selecting a preferred alternative. However, the testing did serve as an effective screening tool for determining whether any options were fatally flawed. Once the preferred selection is made and the associated short-circuit studies are completed, more clearly determining any significant impacts will be possible.

Table 4-14
Comparison of Short-Circuit Impacts

Interstate Option	Short Circuit Impact (percent increase)
A	8.9
B	5.3
C	9.3
D	7.5
E	3.8

4.3.8 System Expandability and Flexibility

In terms of future system expandability and system flexibility, all four AC options offer much more expandability than the DC option. DC systems historically have been used for relatively long, point-to-point type delivery and have not been integrated into the center of AC systems.

The only action required to increase the capacity of an AC line might be a simple reconductoring; increasing the capacity of a DC system would require, at a minimum, either major converter additions or converter change-outs at each end of the line. Adding a new generator midpoint to a DC line would most likely require a new converter station, possibly with two new converters. Similarly, the need to connect to a lower voltage system, either to provide voltage support or eliminate thermal overloads, would be equally difficult.

4.3.9 Impact of Improved Connecticut Transfer Capability on the New York–New England Interface

This section presents the results of a parallel transfer analysis conducted by the working group that evaluated the impact of each SNE transmission reinforcement upgrade option on the ability of the New England bulk transmission system to export to and import from New York. The intent was to determine whether any option particularly enhances or has an adverse impact on this capability.

In the simulation analysis performed by the working group, generation in New York was chosen to aggravate, as much as possible, a potential clockwise loop flow through New England. In this analysis, generation was scaled up at Gilboa (NY) (near the Berkshire–Alps 345 kV tie with New England) and scaled down at Bowline (NY) (south of Long Mountain to the Pleasant Valley 345 kV tie with New England). As most New York generation was on line in the base case, Roseton (NY) generation had to be scaled up to provide coverage for New York exports, despite its beneficial impact on countering any clockwise loop flow.

Generation in eastern New England was chosen to represent a homogeneous source or sink point across all three eastern regions: Maine, Boston, and Southeast Massachusetts. Because most existing generation was on line in the base case, some older retired units had to be scaled up to provide coverage for eastern New England exports.

The main transfer analysis was first performed as described in the preceding paragraph. The following sensitivity analyses were then performed:

- Replacing output from Millennium with Seabrook
- Replacing output from Mystic with West Springfield and Berkshire Power
- Changing the New York source and sink subsystems to represent a "best-case loop-flow scenario." Generation was scaled up at Bowline and scaled down at Bethlehem (Albany area) and Athens.

The results of the analysis show the following:

- Except for Option E, the HVDC option, all options either maintain the transfer capability with New York or improve it.
- Except for the Option E, the HVDC option, all options perform similarly.
- The HVDC option marginally limits imports from New York. However, the transfer-response factor on the limiting element is low (5.9%), and the limiting element (Bear Swamp autotransformer) is a known issue, which will be fixed as part of the central and western Massachusetts upgrades.
- In all instances, exports to New York are limited by the overload of the E131 line from Bear Swamp to the E131 tap. This limiting element also is a known issue, which will also be fixed as part of the central and western Massachusetts upgrades.
- None of the sensitivity runs identified any significant difference in performance among Options A, B, C, or D.

4.3.10 Input from Operations Personnel

The working group presented the details of the Interstate options to Operations personnel from ISO New England, CONVEX, and REMVEC at a joint Planning-Operations meeting. The operators, who were not presented with any information concerning cost, environmental, or routing impacts, preferred Option A for the following reasons:

- It best alleviates the angular difference between Rhode Island and Connecticut, thus removing all the operating complexities related to taking lines out of service in the area.
- Alleviating the angular differences will eliminate the need for the SPS that takes the Lake Road units out of service for certain contingencies to avoid possible shaft damage.
- The new Killingly substation serving eastern Connecticut can receive support from the rest of New England even with the 347 line out of service.

4.4 Interstate Component Conclusion

The comparison of the Interstate options indicates that all options meet the design objectives for satisfying the reliability criteria for the projected New England transmission system. Each option offers different advantages and disadvantages compared with the other options in terms of system performance. These differences will be combined with cost, siting, and construction-related factors to determine the optimal solution for the identified needs.

Section 5
Rhode Island Component Options

As discussed in Section 2, Rhode Island now is overly dependent on limited transmission lines or autotransformers to serve its needs, which could result in thermal overloads and voltage problems during contingency conditions. Causal factors include high load growth (especially in southern Rhode Island and the coastal communities), unit availability, and planned and unplanned transmission outages. The Rhode Island 115 kV system is constrained when a 345 kV line is out of service; an 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.

To address the identified reliability issues, three new 345 kV facilities were found to be necessary to support the Greater Rhode Island area and to better integrate it with the rest of the New England system. Generally, these improvements would bring a third source into Rhode Island. **This sentence has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.** The improvements also would extend a second source into the load center in southern Rhode Island and add a new source into a 115 kV load center located just east of the Rhode Island border. Several options were evaluated for each of these facilities, which are described in the following sections.

5.1 Rhode Island Recommendations

Figure 5-1 displays the recommended improvements for Rhode Island to increase the ability to move power into West Farnum, creating a stronger tie to the rest of New England; extend another 345 kV path to the southern part of the state; and add a new 345 kV injection point into the load center from the east.

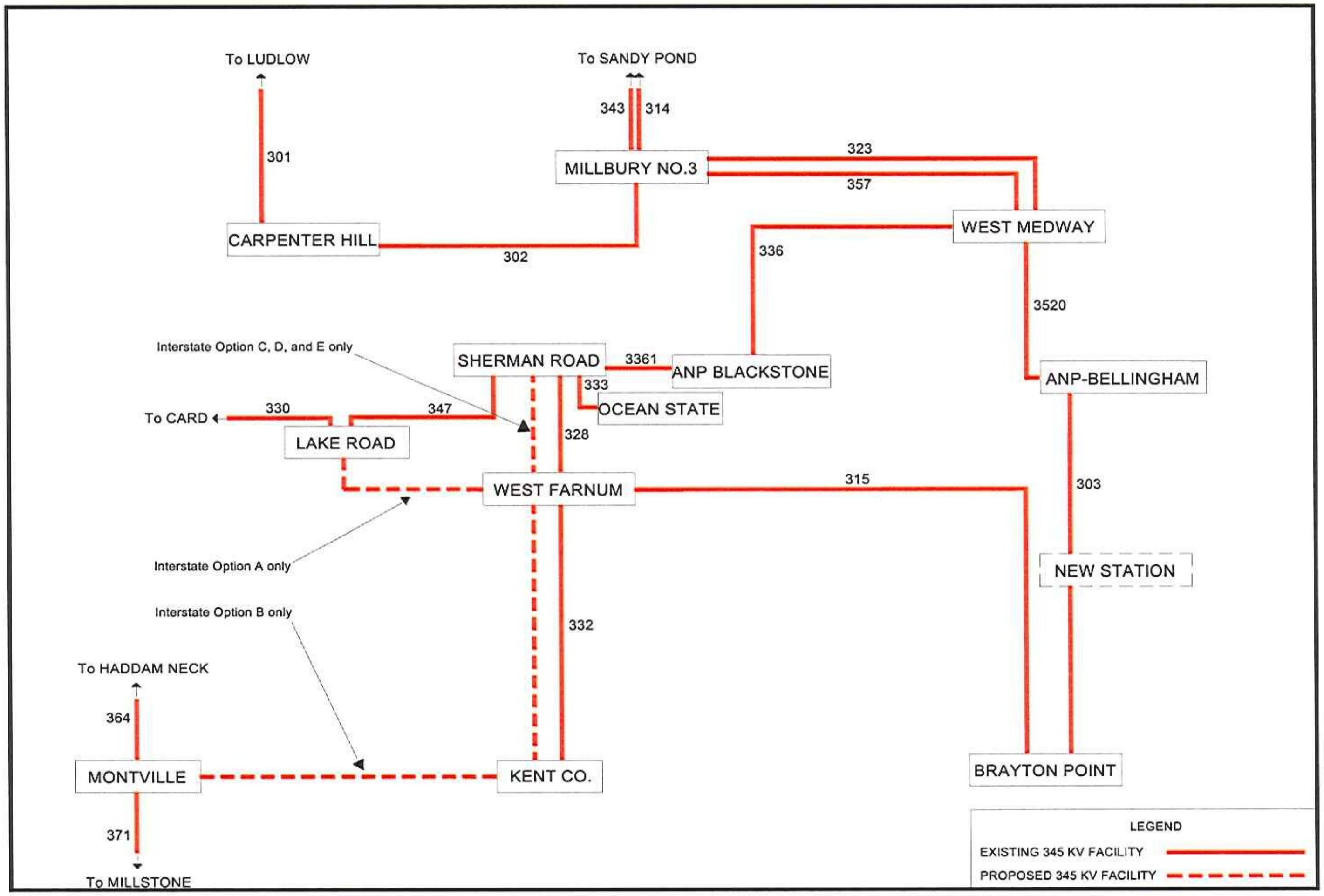

Figure 5-1: Rhode Island upgrades.

5.2 Overview of Rhode Island Options

This section further describes the three areas of Rhode Island needing improvement and the options that were considered for each. The solutions to these three problems are as follows:

- A new 345 kV line from West Farnum to Kent County (recommended with all Interstate options over two other options)
- A new 345 kV line from Sherman Road to West Farnum (recommended with Interstate Options C, D, and E but not needed for Interstate Option A and which brings new lines in from Lake Road, CT, and Millbury, MA) or Interstate Option B (which brings a new line in from Montville, CT)
- A new 345/115 kV substation and transformer (recommended with all Interstate options over one other option)

5.2.1 New 345 kV Line from West Farnum to Kent County (Recommended with All Interstate Options)

A new 345 kV line from West Farnum to Kent County is needed to support the southwestern Rhode Island area if the existing 345 kV line (line 332) is lost, especially if either the FPLE Rise or Manchester Street generation plant is out of service. This recommended line would be critical when line 332 is out of service and an additional key southwestern Rhode Island element is lost (an N-1-1 contingency condition).

Several alternatives to this recommendation were developed, analyzed, and subsequently eliminated. One option was to add a new 345 kV line from Brayton Point to Franklin Square to Kent County. This option was a part of an original Interstate option that the working group is no longer pursuing; the full 345 kV portion of this option was Montville–Kent County–Hartford Ave.–Franklin Square–Brayton Point. This option attempted to resolve some of the transmission bottlenecks by interconnecting the three Greater Rhode Island stations of Brayton Point, Hartford Avenue, and Kent County with a new 345 kV line. Other modifications associated with this option follow:

- Convert the E105 and F106 115 kV cables from Hartford Ave. to Franklin Square to a single 345 kV cable
- Remove the 115 kV W4/K15 and X3 lines and move the Swansea substation to the E-183E line (to make space available for the new 345kV line)
- Feed all of Phillipsdale from E183W (also to make space for the new 345 kV line)

The analysis showed that this option tended to push too much power from Brayton Point to West Farnum and Kent County and thus heavily overloaded transmission system elements in Rhode Island. For certain contingencies under some dispatch scenarios, very low voltages were observed on the Rhode Island 115 kV system that would be difficult to mitigate. Additional 345 kV lines and 345/115 kV transformers (along with significant 115 kV upgrades) would be required for second-contingency conditions. As a result, the working group concluded that these improvements do not provide a viable option compared with the recommended second 345 kV line between West Farnum and Kent County.

Another option developed and analyzed for the Rhode Island component was to add two new 115 kV cables from Franklin Square to Sockanosset. Although these cables strengthen the 115 kV transmission system that connects the Providence area to southwestern Rhode Island, this option does not perform as well under N-1-1 (line-out) system conditions. When the existing 345 kV line from West Farnum to Kent County (line 332) is out of service, various second contingencies cause significant 345/115 kV transformer and 115 kV line overloads, along with very low 115 kV voltages. The working group concluded that these two 115 kV cables do not provide a viable option compared with the second 345 kV line between West Farnum and Kent County.

5.2.2 New 345 kV Line from Sherman Road to West Farnum (Recommended with Interstate Options C, D, E)

A new 345 kV line into Rhode Island is needed to respond to the contingency condition when both line 328 (from West Farnum to Sherman Road) and line 315 (from Brayton Point to West Farnum) are out of service. In the case of Interstate Options C, D, and E, this second-contingency condition would leave all of Rhode Island without a 345 kV connection and could result in very low voltages or voltage collapse for certain dispatch scenarios.

For Interstate Option A (Lake Road to West Farnum and Millbury to West Farnum) and Interstate Option B (Montville to Kent County), this new 345 kV line segment from Sherman Road to West Farnum is not needed because Rhode Island second-contingency support is afforded by the Interstate options themselves.

5.2.3 New 345/115 kV Substation and Transformer (Recommended with All Interstate Options)

The working group also recommends that a new 345/115 kV substation and transformer be located about 1.5 miles south of the existing South Wrentham substation. This new substation will interconnect the 345 kV 303 line and the 115 kV C-181 and D-182 lines and provide transformation from 345 kV to 115 kV. This substation will off-load the existing Brayton Point 3A/3B transformer pair and also eliminate 115 kV contingency low-voltage conditions in the surrounding area of this new substation.

One option developed for this aspect of the Rhode Island component was to add a new 345/115 kV transformer at Brayton Point substation. This transformer would off-load the existing Brayton Point 3A/3B transformer pair, but it would not eliminate the 115 kV contingency low-voltage conditions in the area surrounding South Wrentham substation. The working group also found that the addition of a 345/115 kV transformer at Brayton Point would increase the 115 kV fault current to a value above the 63 kA rating of the existing Brayton Point 115 kV breakers. (The combination of the additional 345/115 kV transformer at Brayton Point and a proposed 115 kV line from Brayton Point substation to Somerset substation—proposed as a part of a separate study of the Somerset Area—would raise the 115 kV fault current above 63 kA.)

Appendix A contains a full list of all the recommended Greater Rhode Island area upgrades.

5.3 Rhode Island Component Conclusion

The recommended items for the Rhode Island component (along with the additional Rhode Island area upgrades listed in Appendix A) will fully address the Rhode Island area reliability issues and coordinate with the three other component upgrades.

Section 6
Connecticut East–West Component Options

This section presents the three final options for the Connecticut East–West component, as follows, and compares the transfer improvements for each option relative to each of the Interstate options:

- **Connecticut East–West Option A**—a 345 kV line from Manchester to Southington
- **Connecticut East–West Option B**—a 345 kV line from Manchester to Scovill Rock with a tap to the New Berlin 345 kV substation
- **Connecticut East–West Option C**—a 345 kV line from North Bloomfield to Frost Bridge

As discussed in Section 2, the ability to move power into Connecticut currently is limited and could eventually result in the bulk transmission system's inability to serve load under many probable system conditions. Connecticut-area power-transfer capabilities will not meet the area's requirements as early as 2009. If improvements are not made by 2016, the deficiency for this area under "generator unavailability conditions" (i.e., when the largest unit plus a historical average amount of other generation is out-of-service) and under N-1 conditions is expected to be greater than 1,500 MW, assuming a transfer limit of 2,500 MW and no new capacity additions. On the basis of planning assumptions that added 500 MW of generation and retired 204 MW within the Connecticut area, a deficiency of approximately 1,100 MW will occur by 2016 for N-1 conditions, and 1,200 MW for N- 1-1 conditions.

The amount of power that can be delivered from eastern Connecticut to western Connecticut is limited by transmission security criteria violations. These violations, which can cause thermal 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.

The most practical solutions to eliminate the second-contingency transmission security violation when trying to move power from eastern to western Connecticut were found to be new 345 kV line additions. Of the four solutions initially selected, only one failed to be a viable option—a possible 345 kV line from Montville to Haddam Neck, which was eliminated because of poor system performance that could not easily be corrected. Accordingly, the three options previously described were retained for further consideration and analysis.

6.1 Description of Connecticut East–West Options

Figure 6-1 to Figure 6-3 are 345 kV one-line diagrams depicting each option of the final three Connecticut East-West components.

Figure 6-1 depicts Connecticut East–West Option A, adding a 345 kV line from Manchester to Southington. This option creates a link from the Manchester substation (which has ties to Massachusetts, to Rhode Island, and to the Millstone Plant) to the Southington substation, which serves as a source into the southwestern Connecticut load pocket.

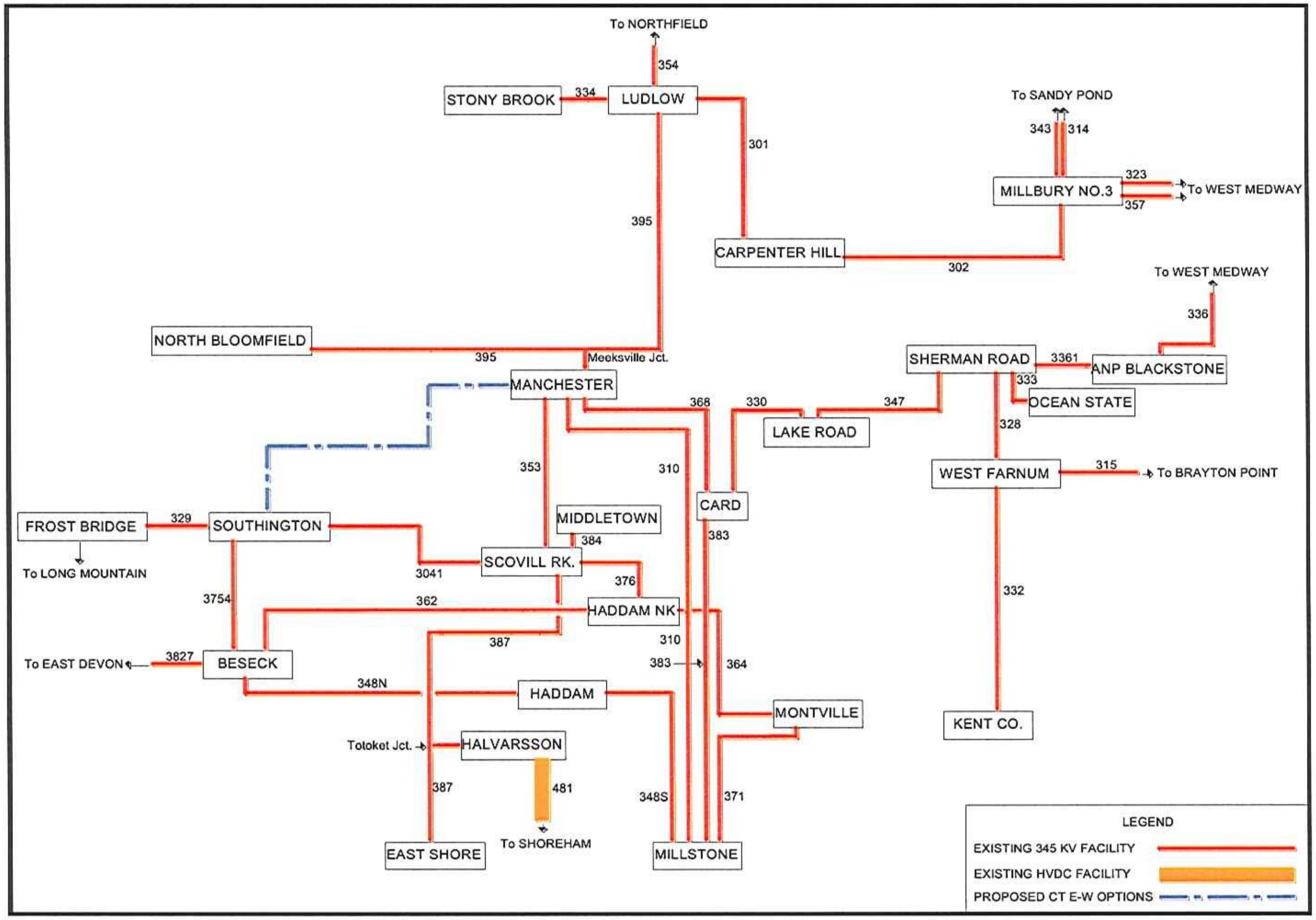

Figure 6-1: Connecticut East–West Option A—345 kV line from Manchester to Southington.

Figure 6-2 depicts Connecticut East–West Option B, adding a 345 kV line from Manchester to Scovill Rock with a tap to a new 345 kV substation in Berlin. This option also taps the Manchester substation but ties it into the Scovill Rock substation as opposed to the Southington substation. Because this line does not extend sufficiently far in a westerly direction, additional stress is placed on the 115 kV system through Hartford, and accordingly, the Berlin 345/115kV autotransformer must provide support to the area's 115 kV system.

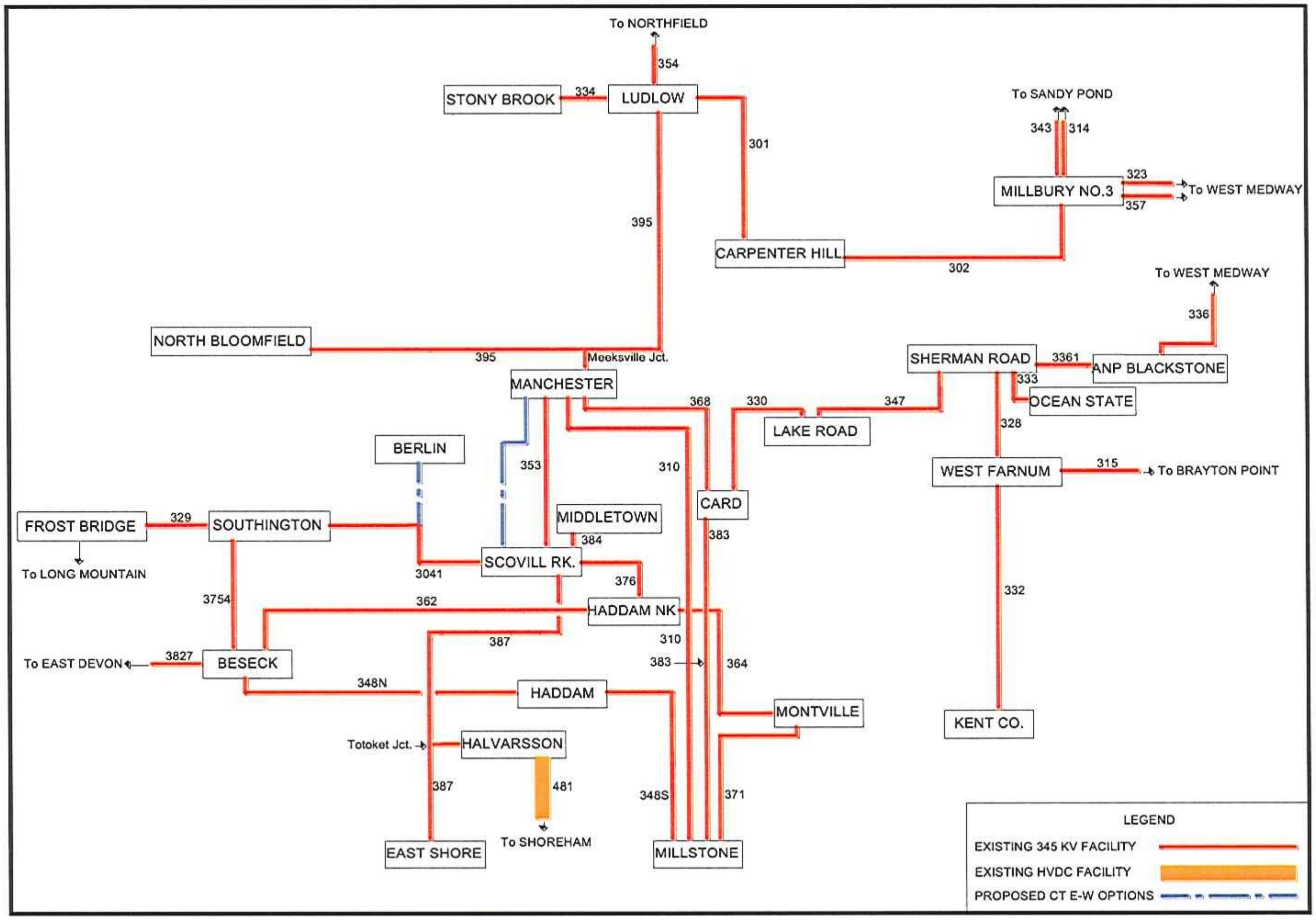

Figure 6-2: Connecticut East–West Option B—345 kV line from Manchester to Scovill Rock with a tap to a new 345 kV substation in Berlin.

Figure 6-3 depicts Connecticut East–West Option C, adding a 345 kV line from North Bloomfield to Frost Bridge. This option makes use of the new Springfield 345 kV supply into North Bloomfield by further extending the 345 kV line from North Bloomfield to the Frost Bridge substation. The Frost Bridge substation, similar to the Southington substation, serves as a source into the southwest Connecticut load pocket.

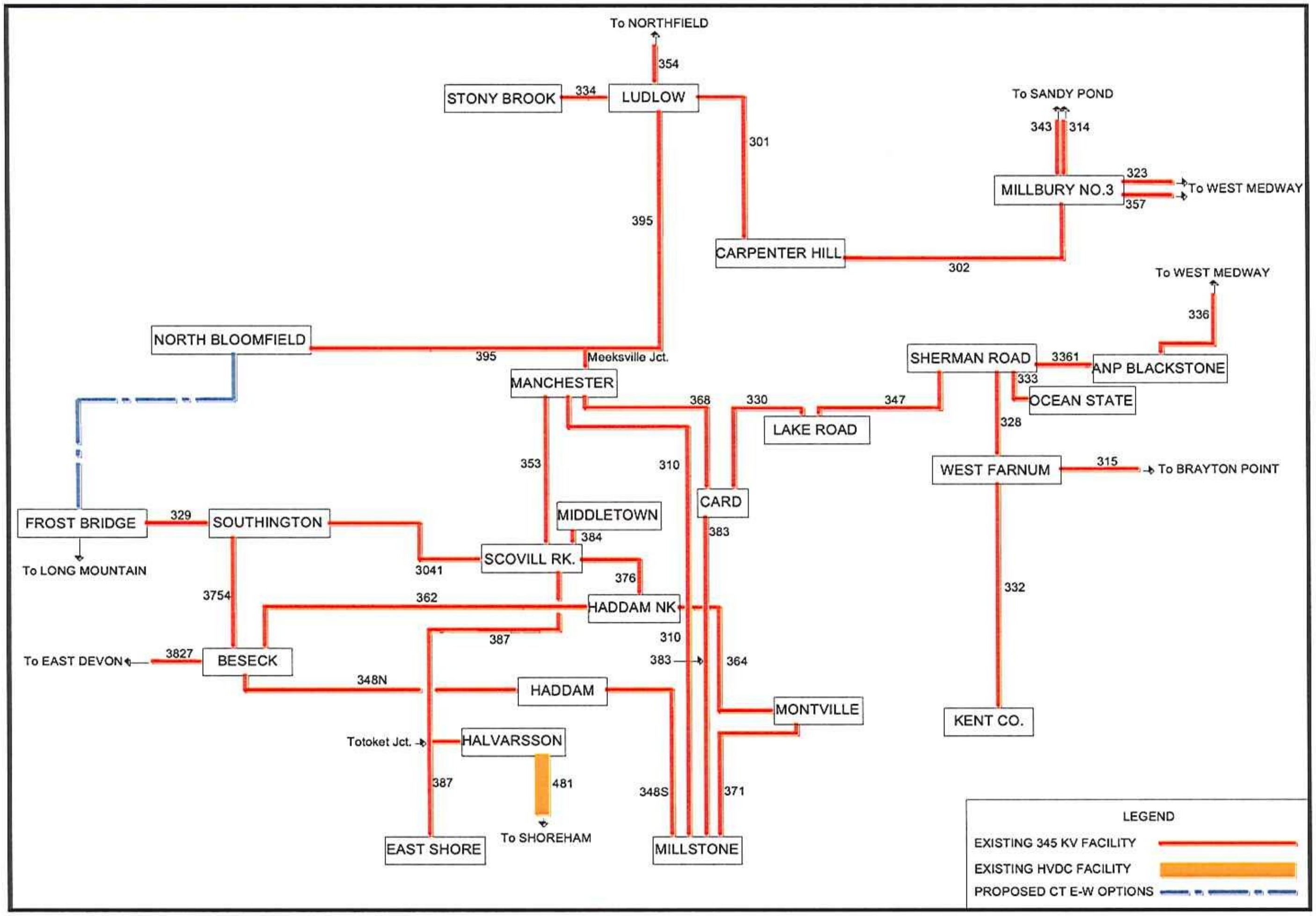

Figure 6-3: Connecticut East–West Option C—345 kV line from North Bloomfield to Frost Bridge.

6.2 Comparison of Connecticut East–West Options

Table 6-1 displays the results of the second-contingency transfer-capability analysis into western Connecticut. Estimating western Connecticut load at 18% to 20% of New England load results in a required transfer capability for 2012 of roughly 2,750 to 3,350 MW under second-contingency system conditions. These figures show that all three options selected with any of the four AC Interstate options will satisfy the 2012 needs. With load growing at about 100 MW per year in western Connecticut, however, Option C can result in a longer lifetime by seven years.

Table 6-1
Connecticut East–West 2012 N-1-1 Transfer Capability (MW)

Interstate Option	CT East–West Option A	CT East–West Option B	CT East–West Option C
A	3,493	3,560	4,117
B	3,744	3,576	3,947
C	3,781	3,461	3,834
D	3,928	3,586	4,291

The working group presented the details of the Connecticut east-west options to Operations personnel from ISO New England and CONVEX at a joint Planning-Operations meeting. The operators, who were not presented with any information concerning cost, environmental, or routing impacts, preferred Option C for the following reasons:

- It provides a solid 345 kV path into the Connecticut 345 kV grid west of the Southington substation. (This is considered beneficial because Southington is an old substation, and upgrades over the years have created some operating issues.) Operators would prefer that new facilities stay clear of the Southington substation
- Option B requires a fifth autotransformer installation at Southington, which is not considered advantageous.
- It allows a greater degree of flexibility in northwestern Connecticut for future development possibilities (e.g., transmission expansion, generator leads, etc.).

6.3 Connecticut East–West Component Conclusion

In summary, three of the four options to eliminate the second-contingency transmission security constraints in central Connecticut met reliability criteria standards for 2012 and beyond. Connecticut East–West Option C achieves higher transfer capabilities regardless of which Interstate option is selected. This option should therefore maintain reliability standards farther into the future. However, Connecticut East–West Options A and B also are viable.

Section 7
Springfield Component Options

As discussed in Section 2, the Springfield, Massachusetts, area has significant transmission reliability concerns, including thermal overloads and voltage problems under numerous contingency scenarios. The severity of these problems increases as the system attempts to move power into Connecticut from the rest of New England. 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. This sentence has been redacted and may be accessed by calling ISO New England Customer Service at (413) 540-4220.

A wide range of transmission reinforcement options were considered to alleviate thermal and voltage problems in the Springfield area. These options included extensive 115 kV reinforcements, additional 345/115 kV transformers, new 345 kV lines, new bulk power sources, and phase shifters. Some of the reinforcement options investigated did not fully meet the area reliability requirements or were not considered to be effective long-term solutions. Other options were not sufficiently compatible with the overall SNE transmission reinforcement plans.

The working group determined that three 345 kV expansion options would fully meet the reliability requirements of the Springfield area and be consistent with the long-term expansion plans for southern New England. Each of the 345 kV options has a number of 115 kV variations, resulting in 12 distinct options. A complete listing of the upgrades that are part of these 12 options can be found in Appendix A.

7.1 Description of the Springfield 345 kV Options

The Springfield area option expansion plans include three 345 kV transmission reinforcement options that are highly compatible with the overall southern New England bulk transmission reinforcement plans. These options are as follows:

- A new 345 kV line from Ludlow to Agawam and from Agawam to North Bloomfield
- A new 345 kV line from Ludlow to North Bloomfield
- A new 345 kV line from Ludlow to Manchester

Each of the above options reinforces the electrical connection between western Massachusetts and Connecticut, which provides benefits to both the Springfield and Connecticut areas. These 345 kV options along with their associated 115 kV reinforcements all meet the required reliability standards.

7.1.1 Springfield Option A—345 kV Line from Ludlow to Agawam to North Bloomfield

This option consists of building new 345 kV lines from Ludlow to Agawam and Agawam to North Bloomfield with 345/115 kV transformation at Agawam. Springfield Option A provides another bulk transmission supply point for the Springfield area. The Springfield area requires other 115 kV transmission reinforcements to meet reliability requirements. Figure 7-1 is a 345 kV one-line diagram of Springfield Option A.

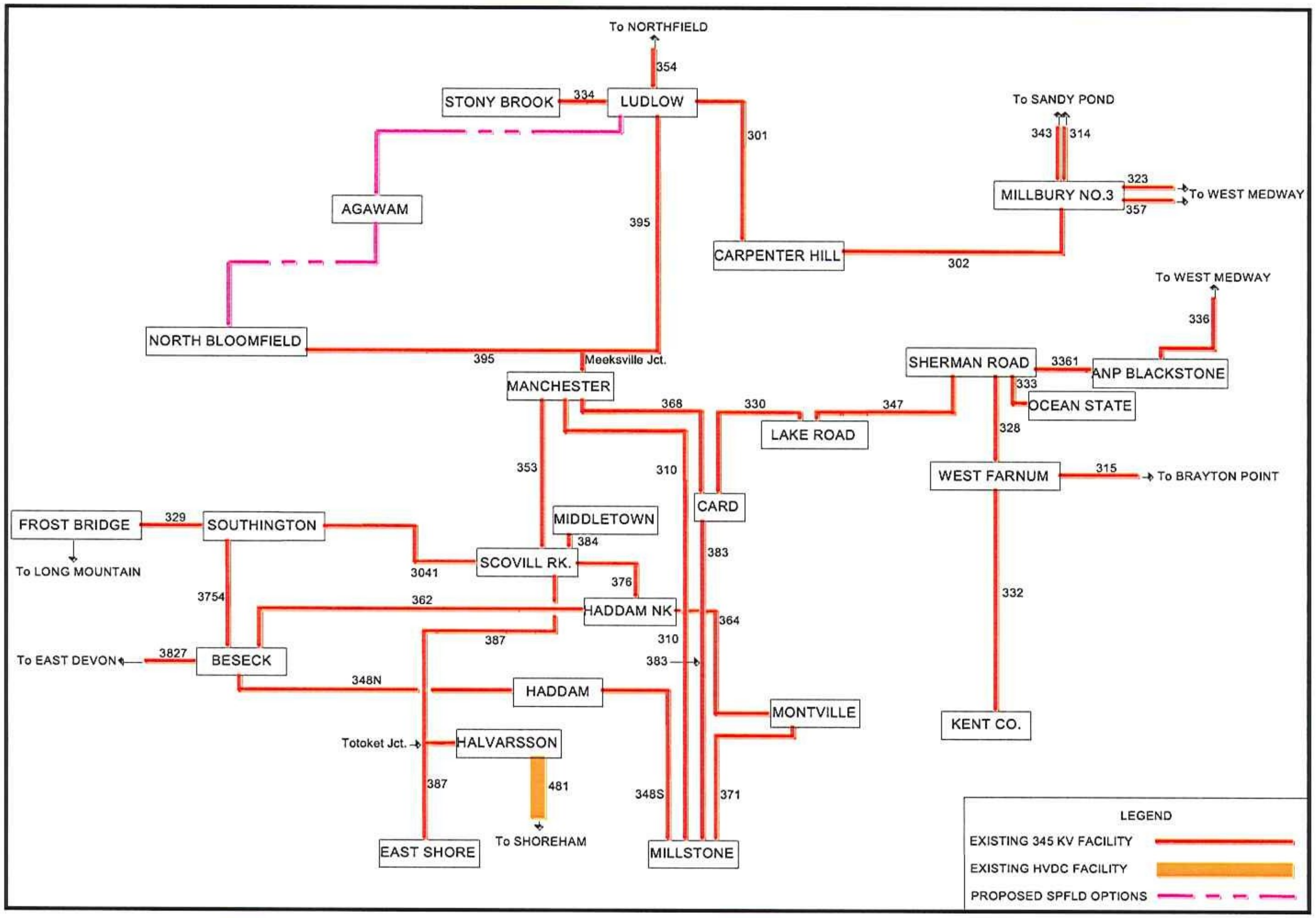

Figure 7-1: Springfield Option A—345 kV line from Ludlow to Agawam to North Bloomfield.

7.1.2 Springfield Option B—345 kV line from Ludlow to North Bloomfield

Springfield Option B includes building a new 345 kV line from Ludlow to North Bloomfield. It is primarily a backup to the existing 345 kV line 395, decreasing the amount of power being wheeled through the Springfield 115 kV system.[11] Springfield Option B requires phase shifters at North Bloomfield on the 115 kV ties between western Massachusetts and Connecticut to further restrain the power flow through the Springfield area. The Springfield area requires other 115 kV transmission reinforcements to meet reliability requirements. Figure 7-2 depicts the 345 kV portion of Springfield Option B.

[11] *Wheel through* refers to the transmission of power through an area to supply load in another area.

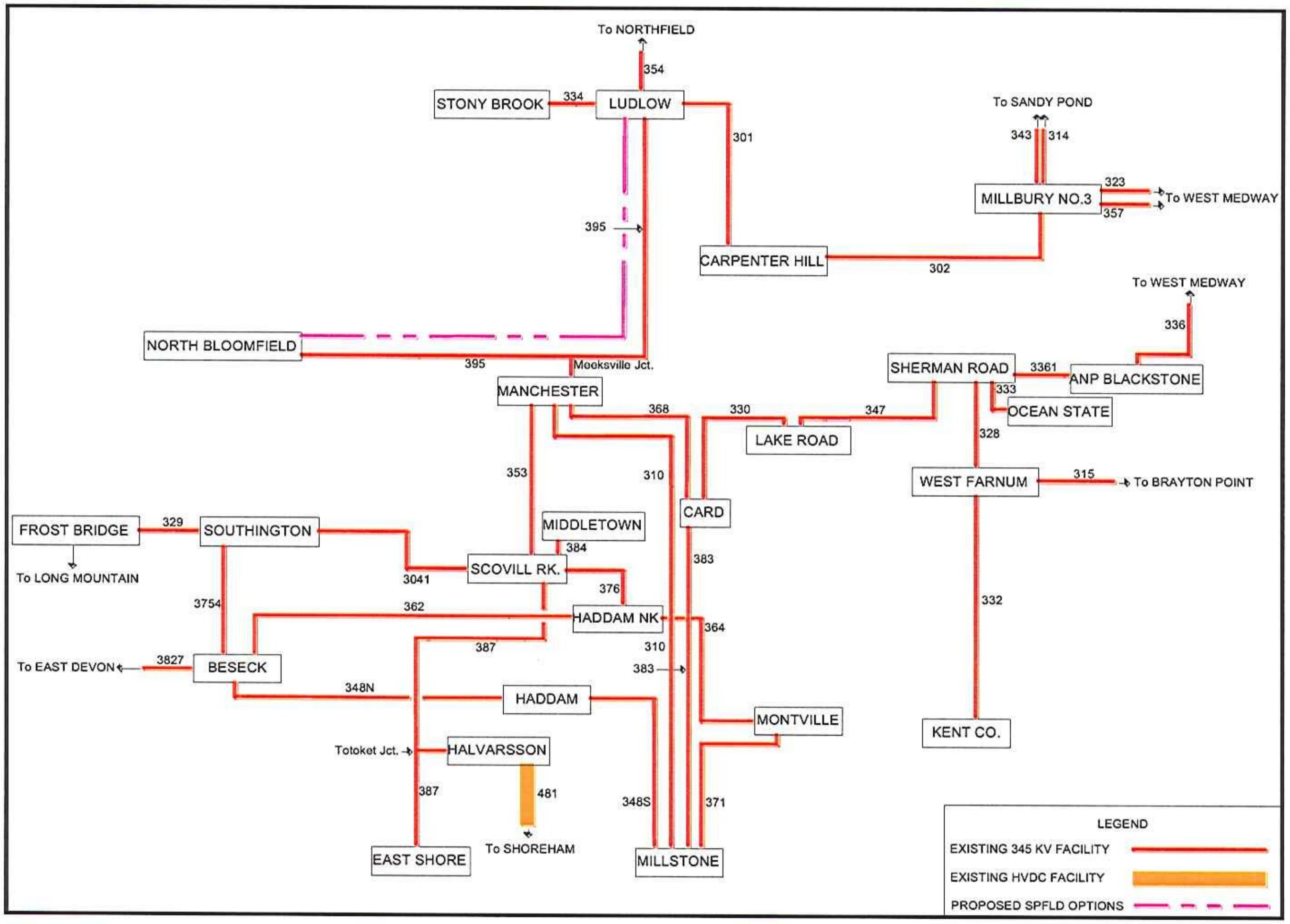

Figure 7-2: Springfield Option B—Ludlow to North Bloomfield 345 kV line.

7.1.3 Springfield Option C—Ludlow to Manchester 345 kV Line

Springfield Option C consists of building a new 345 kV line from Ludlow to Manchester. It also primarily is a backup to the existing 345 kV line 395, decreasing the amount of power being wheeled through the Springfield area. Springfield Option C requires the installation of phase shifters at North Bloomfield on the 115 kV ties between western Massachusetts and Connecticut to further restrain the power flow through the Springfield area. The Springfield area requires other 115 kV transmission reinforcements to meet reliability requirements. Figure 7-3 depicts Springfield Option C.

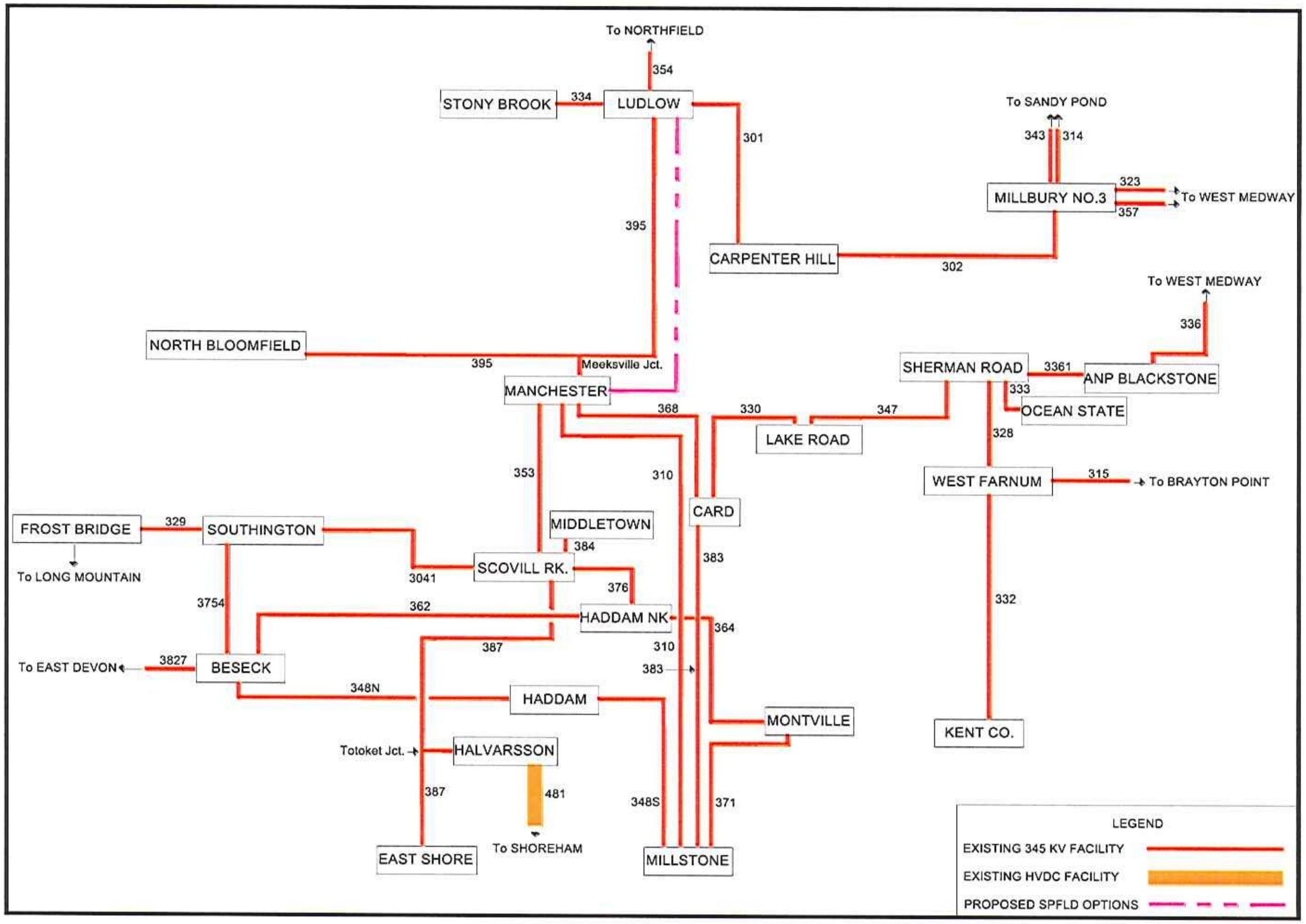

Figure 7-3: Springfield Option C—Ludlow to Manchester 345 kV line.

7.2 Comparison of Springfield Options

The three Springfield area 345 kV options (A, B, and C) and their various associated 115 kV reinforcement options were formulated into a total of 12 transmission reinforcement options. The following subsections discuss the features, benefits, and disadvantages of these options. Appendix A provides a complete list of reinforcements for each option.

The capital letter in each option name (A, B, or C) refers to the 345 kV solution that serves as the backbone of the option. The number and small letter following the capital letter signify the varying 115 kV improvements associated with each of the 345 kV options. Sequential numbers that appear to be missing were assigned to alternatives that were previously eliminated.

7.2.1 Springfield Option A Variations

Eight variations of Springfield Option A remained after the elimination process.

7.2.1.1 Springfield Option A Variation 3a

The major system improvements of this option, in addition to the new 345 kV lines from Ludlow to Agawam and Agawam to North Bloomfield, include three 345/115 kV autotransformers at Agawam, three 115 kV phase shifters in series with the Agawam autotransformers, and the replacement of both 115 kV cables from Breckwood to West Springfield and from Breckwood to East Springfield. This option also would separate the 115 kV ties between western Massachusetts and Connecticut in the South Agawam–North Bloomfield area.

The benefits of this option are as follows:

- Less 115 kV work would be required.
- Phase shifters would facilitate more power flow through the Agawam autotransformers, which would further limit power flow through the Springfield area system.
- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The new 345 kV source at Agawam would provide an alternate path for power to flow into the Springfield-area 115 kV system.
- The weak 115 kV western Massachusetts/Connecticut ties would be replaced with a stronger 345 kV tie.
- The North Bloomfield 2A substation would be more reliable.

One disadvantage of this option is the possibility that additional studies may need to be conducted periodically to optimize the phase-shifter settings.

7.2.1.2 Springfield Option A Variation 3b

This option is similar to the 3a variation except that it ties the Stonybrook 115 kV station into the Springfield 115 kV system. It also allows the output of the Stonybrook plant to be injected directly into the Springfield load pocket as opposed to passing it through the Ludlow 345 kV substation and down the autotransformers.

Variation 3b of Springfield Option A has the following additional benefits:

- The Stony Brook fast-start units would improve the area's non-spinning reserves.[12]
- The severity of extreme contingencies would be reduced or minimized because the Stony Brook–Fairmont lines are on a right-of-way separated from the other Springfield lines.

7.2.1.3 Springfield Option A Variation 6a

In addition to the new 345 kV lines from Ludlow to Agawam and Agawam to North Bloomfield, which is inherent to the Option A variations, this variation includes the following measures:

- Replacing the Breckwood–East Springfield 115 kV cable
- Adding a new 115 kV cable from East Springfield to Clinton
- Eliminating the three-terminal lines at East Springfield Junction (lines 1254 and 1723)
- Installing a breaker-and-one-half substation configuration at Fairmont
- Separating and rebuilding double-circuit lines from Ludlow to East Springfield
- Separating and rebuilding the double-circuit lines from East Springfield to Fairmont
- Separating the western Massachusetts/Connecticut 115 kV ties

No phase shifters would be installed with this variation, and one of the Agawam autotransformers would be replaced with a third autotransformer at Ludlow.

The benefits of this option are as follows:

- The new 345 kV source at Agawam would provide an alternate path for power to flow into the Springfield-area 115 kV system.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The weak 115 kV western Massachusetts/Connecticut ties would be replaced with a stronger 345 kV tie.
- The North Bloomfield 2A substation would be more reliable.

One disadvantage of this option would be that the flexibility to restrain power flow through the Springfield area, which variable phase shifters provide, would not be available.

7.2.1.4 Springfield Option A Variation 6b

This option is similar to the 6a variation except that it ties the Stonybrook 115 kV station into the Springfield 115 kV system, as in the 3b variation (Section 7.2.1.2), instead of separating and rebuilding the double-circuit 115 kV lines from Ludlow to East Springfield to Fairmont.

This option has the following benefits:

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[12] *Non-spinning* (non-synchronized) operating reserves are off-line, fast-start resources that can be electrically synchronized to the system and quickly reach rated capability. *Spinning* (synchronized) operating reserve is generation that already is on line, is synchronized to the system, and can increase output.

- The new 345 kV source at Agawam would provide an alternate path for power to flow into the Springfield-area 115 kV system.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The weak 115 kV western Massachusetts/Connecticut ties would be replaced with a stronger 345 kV tie.
- The Stony Brook fast-start units would improve the area's non-spinning reserves.
- The severity of extreme contingencies would be reduced or minimized because the lines from Stony Brook to Fairmont would be on a right-of-way separated from the other Springfield lines.
- The North Bloomfield 2A substation would be more reliable.

Similar to Option 6a, one disadvantage of Option 6b would be that the flexibility to restrain power flow through the Springfield area, which variable phase shifters provide, would not be available.

7.2.1.5 Springfield Option A Variation 6c

This option is similar to the 6b variation except that it installs a third 115 kV cable from West Springfield to Clinton and a new 115 kV line from Ludlow to Fairmont as opposed to tieing the Stonybrook 115 kV station into the Springfield 115 kV system.

The benefits of the 6c variation of Springfield Option A are as follows:

- The new 345 kV source at Agawam would provide an alternate path for power to flow into the Springfield area 115 kV system.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The weak 115 kV western Massachusetts/Connecticut ties would be replaced with a stronger 345 kV tie.
- The North Bloomfield 2A substation would be more reliable.

Similar to 6a and 6b, one disadvantage of this option would be that the flexibility to restrain power flow through the Springfield area, which variable phase shifters provide, would not be available.

7.2.1.6 Springfield Option A Variations 8a, 8b, and 8c

These options are very similar to the 6a, 6b, and 6c variations except that the third Ludlow 345/115 kV autotransformer and the Fairmont substation work is replaced with a 115 kV line from Stonybrook to Ludlow. Accordingly, the benefits and the disadvantage are similar also.

7.2.2 Springfield Option B Variations

Three variations of Springfield Option B remained after the elimination process.

7.2.2.1 Springfield Option B Variation 7a

In addition to adding the new 345 kV line from Ludlow to North Bloomfield, the major system improvements of this option include adding phase shifters at North Bloomfield on the western Massachusetts/Connecticut 115 kV tie lines, replacing the cable from Breckwood to East Springfield, adding a new cable from East Springfield to Clinton, eliminating the three-terminal lines at East Springfield Junction (lines 1254 and 1723), installing a breaker-and-one-half substation configuration at Fairmont, and separating and rebuilding the double-circuit lines that run from Ludlow to East Springfield and from East Springfield to Fairmont.

The benefits of the 7a variation of Springfield Option B are as follows:

- Phase shifters would help restrain the power flow through the Springfield-area 115 kV system.
- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The North Bloomfield 2A substation would be more reliable.

The disadvantages of this option are that another 345 kV connection into the Springfield load center would not be provided. Additionally, to avoid future problems and system upgrades, operating studies may need to be conducted periodically for properly adjusting the phase-shifter setting of the variable phase shifter.

7.2.2.2 Springfield Option B Variation 7b

This option is similar to the 7a variation except that it ties the Stonybrook 115 kV station into the Springfield 115 kV system, as in the 3b and 6b variations of Option A, instead of separating and rebuilding the double-circuit 115 kV lines that run from Ludlow to East Springfield to Fairmont. This option also adds a third 115 kV cable from West Springfield to Clinton.

The option has the following benefits:

- Phase shifters would help restrain the power flow through the Springfield area 115 kV system.
- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The Fairmont substation would be more reliable and better able to provide voltage support in to the surrounding area.
- The North Bloomfield 2A substation would be more reliable.
- The Stony Brook fast-start units would improve the area's non-spinning reserves.
- The severity of extreme contingencies would be reduced or minimized because the lines from Stony Brook to Fairmont would be on a right-of-way separated from the other Springfield lines.

The disadvantages of the 7b variation of Springfield Option B are the same as those for the 7a variation.

7.2.2.3 Springfield Option B Variation 7c

This option is similar to the 7b variation except that it installs a new 115 kV line from Ludlow to Fairmont as opposed to tieing the Stonybrook 115 kV station into the Springfield 115 kV system.

The benefits of this variation of Springfield Option B are as follows:

- Phase shifters would help restrain the power flow through the Springfield-area 115 kV system.
- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The North Bloomfield 2A substation would be more reliable.

The disadvantages of this option are the same as for the 7a and 7b variations of Option B.

7.2.3 Springfield Option C Variation

Only variation 5b of Springfield Option C was deemed to be viable.

In addition to the new 345 kV line from Ludlow to Manchester, the major system improvements of this option include adding 115 kV phase shifters at North Bloomfield in series with each of the three western Massachusetts/Connecticut tie lines, replacing the 115 kV cable from Breckwood to East Springfield, and adding a new 115 kV cable from East Springfield to Clinton and a third 115 kV cable from West Springfield to Clinton. The three-terminal lines at East Springfield Junction (lines 1254 and 1723) would be eliminated, and a breaker-and-one-half substation configuration would be installed at Fairmont. This option ties the Stonybrook 115 kV station into the Springfield 115 kV system.

The benefits of this variation are as follows:

- The phase shifters would help restrain the power flow through the Springfield-area 115 kV system.
- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The Stony Brook fast-start units would improve the area's non-spinning reserves.
- The severity of extreme contingencies would be reduced or minimized because the lines from Stony Brook to Fairmont would be on a right-of-way separated from the other Springfield lines.

The disadvantages of the 5b variation of Springfield Option C are that the Hartford area would require additional 115 kV reinforcements, including underground cable circuits; the North Bloomfield 2A substation would not be more reliable; and another 345 kV connection into the Springfield load center would not be provided. Additionally, to avoid future problems and system upgrades, operating studies may need to be conducted periodically for properly adjusting the phase-shifter setting of the variable phase shifter.

7.2.4 Input from Operations Personnel

The working group presented the details of the Springfield options to Operations personnel from ISO New England and CONVEX at a joint Planning Operations meeting. The operators, who were not presented with any information concerning cost, environmental, or routing impacts, preferred Option A, variation 6b (installing a Ludlow–Agawam–North Bloomfield 345 kV line and a 115 kV tie to the Stony Brook generating station with no phase shifters at either Agawam or North Bloomfield) for the following reasons:

- It relies less on the smaller-conductor 115 kV lines heading north out of North Bloomfield.
- The operation of phase-shifters would be burdensome (i.e., they would require daily adjustments) and add an unknown degree of operating complexity.
- It offers a 345 kV source to Agawam and provides an injection point more centrally located in the Springfield load pocket.
- It reduces reliance on the Ludlow autotransformers, which are roughly 40 years old and have a known design deficiency.
- Separating the Connecticut and Massachusetts 115 kV feeds at North Bloomfield is desired as a result of all the operating problems experienced with this through the years.
- A tie to Stony Brook allows power from Stony Brook to flow to the Springfield load center directly, even with the Ludlow substation out of service. (Currently, Stony Brook ties radially into Ludlow.)
- A tie to Stony Brook provides a redundant path for power flowing on the 345 kV to enter the Springfield 115 kV system.
- Currently, all power to the 115 kV system in this area comes through the Ludlow substation. The tie to Stony Brook will allow some power to flow directly to the 115 kV system from the generator, reducing reliance on the Ludlow autotransformers, which are roughly 40 years old and have a known design deficiency.
- Stony Brook autotransformers are single-phase banks, which can be replaced more quickly than three-phase banks at Ludlow providing greater reliability.

7.3 Springfield Component Conclusion

A wide range of transmission reinforcement options were considered to remedy problems in the Springfield area. The 12 options developed were selected for their ability to meet area reliability requirements. They all provide reliability and supply benefits to both Springfield and Connecticut and are compatible with the long-term expansion of the southern New England electric transmission system.

All the Springfield area reinforcement options include a new 345 kV connection between western Massachusetts and Connecticut as well as other associated 115 kV reinforcements to bring the Springfield area electric system into compliance with reliability standards. The main differences among these options are whether they provide another area bulk supply point, eliminate the weak western Massachusetts/Connecticut 115 kV ties, or use phase shifters to restrain power being wheeled through the area.

Section 8
Option Relationships and the Selection of the Preferred Options

Selecting a long-term option to upgrade a complex, integrated transmission grid extending over three states is a difficult and complicated process. Various relationships and points of distinction exist due to the behavior of the transmission grid over a wide range of system conditions. For example, system conditions in one area might affect the performance in an adjacent area, and solving this area's criteria violations may actually eliminate its dependence on the adjacent area. The following list explains these relationships and points of distinction among the options of the four components of the NEEWS plan.

- **Interstate Component**—The selection of the preferred Interstate option of the five available options is totally independent of which of the other components' improvements are selected. Because the Interstate option can be selected independent of any of the other components' improvements, it can be selected during the first stage of the NEEWS selection process.

- **Rhode Island Component**—Because some improvements in the Rhode Island component depend on the Interstate option selected, the Rhode Island component improvements will be selected and eliminated as a result of the Interstate option selected. The remaining improvements of the Rhode Island component are independent of any other component's selection process and can be selected during the first stage of the selection process.

- **Connecticut East–West Component**—The improvements in this component are independent of the preferred selections for any of the other components. However, some 115 kV improvements are needed in the Hartford area, which depend on the preferred options for the Springfield and Connecticut East–West components.

- **Springfield Component**—Although a number of the improvements for this component are primarily needed to address existing system conditions, they have been designed to consider the other components. These improvements are independent of the preferred Interstate component and can be selected during the first stage of the selection process. One exception is that if Interstate Option D is selected, additional Springfield upgrade(s) will be required.

Section 9
Next Steps

The next part of the overall process is for the participating transmission owners to analyze the environmental, cost, constructability, and routing aspects of each option within each component. After this information is gathered and formulated, selections can be made on the basis of all pertinent information.

Appendix A
Listing of Reinforcements by Components

Table A-1
Interstate Component Reinforcements

Interstate Reinforcements	Interstate Option Designation				
	A	B	C	D	E
Build 345 kV circuit, Card–Lake Road	X				
Build 345 kV circuit, Lake Road–W. Farnum	X				
Build 345 kV circuit, W. Farnum–Millbury	X				
Build 345 kV circuit, Montville–Kent County		X			
Build 345 kV circuit, Manchester–Carpenter Hill			X		
Build 345 kV circuit, Carpenter Hill–Millbury			X	X	
Build 345 kV circuit, Ludlow–Carpenter Hill				X	
Build 345 kV circuit, Manchester–Meekville Junction; Split 395 to attach new line				X	
Reconductor line 395, Ludlow–Manchester with bundled 1272 ACSR				X	
Build a HVDC bipole, Millbury–Southington					X
Build a Connecticut East–West solution, see alternate table	X	X	X	X	
Separate line 310, Card–Manchester, and line 368, Card–Millstone	X	X	X	X	X
Replace terminal equipment on line 368 at Manchester	X	X	X	X	X
Replace terminal equipment on line 1272 at Bunker Hill	X	X	X	X	X
Place 14.4 MVAR capacitor at Killingly 115 kV substation	X	X	X	X	X
Loop line 310 from Millstone to Manchester into Card	X	X	X	X	
Replace terminal equipment on line 353 at Manchester	X	X	X	X	
Replace terminal equipment at both terminals on line 376, Haddam Neck–Scovill Rock	X	X	X	X	
Reconductor 345 kV line 3361, Sherman Rd. to ANP Blackstone		X			
Upgrade terminal equipment on Sherman Rd.–ANP Blackstone line 3361	X		X	X	
Upgrade terminal equipment on Sherman Rd.–W. Farnum line 328		X			
Reconductor 345 kV line 347, Sherman Rd. to CTX Border	X			X	
Upgrade terminal at W. Farnum and reconductor line T-172N on W. Farnum–W. Farnum tap	X	X	X	X	X
Reconductor Carpenter Hill–Belchertown 301 line		X			

Interstate Reinforcements	Interstate Option Designation				
Reconductor Millbury–Carpenter Hill 302 line		X			
Reconductor W. Charlton–Little Rest W-175		X			X
Reconductor Little Rest–Palmer W-175		X	X		

Table A-2
Rhode Island Component Reinforcements

Rhode Island Reinforcements	Interstate Option Designation				
	A	B	C	D	E
Build 345 kV circuit, Kent County to W. Farnum	X	X	X	X	X
Install one additional 345/115 kV autotransformer at Kent County	X	X	X	X	X
Install one additional 345/115 kV autotransformer at Kent County	X	X	X	X	X
Build 345/115 kV substation that connects line 303 with lines C-181 and D-182 (including a 345/115 transformer and a 115 kV capacitor bank)	X	X	X	X	X
Build 345 kV circuit, Sherman Rd. to W. Farnum (2nd line)			X	X	X
Uprate Drumrock terminals on Drumrock to Amtrak I-187 line	X	X	X	X	X
Uprate Drumrock terminals on Drumrock–Kilvert line J-188	X	X	X	X	X
Uprate Brayton terminal on line E-183E from Brayton to Merxman Jct.	X	X	X	X	X
Uprate Chartley Pond terminal on line C-181S from Brayton to Chartley Pond	X	X	X	X	X
Uprate breakers and switch on Kent County T3 345/115kV autotransformer	X	X	X	X	X
Uprate Hartford Ave. terminal on Johnston–Hartford Ave. S-171S		X			
Uprate Hartford Ave. terminal on Johnston-–Hartford Ave. T-172S		X	X		X
Reconductor Johnston–Hartford Ave. S-171S; uprate Hart Ave. terminal	X		X	X	X
Reconductor Johnston–Hartford Ave. T-172S; uprate Hart Ave. terminal	X			X	
Upgrade Kent County terminal on G-185N line from KentT1 to Kent County	X	X	X	X	X
Upgrade Kent County terminal on K-189 line, KentT7–Kent County	X	X	X	X	X
Upgrade both terminals and reconductor Pawtucket–Somerset T7 line	X	X	X	X	X
Upgrade bus work disconnects and breakers on W. Farnum T174 345/115kV autotransformer	X	X	X	X	X
Upgrade breakers on W. Farnum T175 345/115kV autotransformer	X	X	X	X	X
Upgrade terminal at W. Farnum on the S-171N W. Farnum–W. Farnum tap	X	X	X	X	X
Reconductor Drumrock–Kent County G-185N	X	X	X	X	X
Reconductor MPLP–Depot St. C-129		X		X	
Reconductor Medway–Depot St. D-130		X	X	X	X
Upgrade terminal equipment Brayton Pt.–Warren E-183		X			

Rhode Island Reinforcements	Interstate Option Designation				
	A	B	C	D	E
Upgrade terminal equipment Mink St.–Wampanoag E-183		X			
Upgrade terminal equipment Wampanoag–Phillipsdale E-183		X			
Upgrade terminal equipment Phillipsdale–Franklin Sq. E-183	X	X	X	X	X
Upgrade Franklin Sq. 115 kV breakers Phillipsdale–Fr. Sq. E-183		X			
Upgrade terminal equipment at South Wrentham	X	X	X	X	X
Reconductor Somerset–Swansea W4		X	X	X	X
Install two 63 MVAR 115 kV capacitors at Kent County	X		X	X	X

Table A-3
Connecticut East–West Component Reinforcements

Connecticut East–West Reinforcements	Connecticut East–West Option Designation		
	A	B	C
Build 345 kV circuit, Manchester–Southington	X		
Build 345 kV circuit, Manchester–Scovill Rock		X	
Tap 362 line at Has Brook Junction; build 3-breaker ring bus		X	
Build 345 kV circuit, Hans Brook Junction–Berlin		X	
Add three 200 MVA single-phase transformers at Berlin		X	
Build 345 kV circuit, North Bloomfield–Frost Bridge			X
Add three 200 MVA single-phase transformers at Southington	X	X	
Increase reactor size from 4 to 6.67 ohms on line 1910, Southington–Todd	X		
Increase reactor size from 4 to 6.67 ohms on line 1950 line, Southington–Canal	X		
Reconductor line 1810 from Southington to Chippen Hill with 795 ACSR	X	X	
Replace terminal equipment at Chippen Hill on line 1810	X	X	
Reconductor line 1783 from North Bloomfield to Northeast Simsbury with 954 ACSR		X	
Replace terminal equipment on line 362 at Haddam Neck		X	
Add three 200 MVA single-phase transformers at Frost Bridge			X
Reconductor line 1777 from North Bloomfield to Bloomfield with 795 ACSR	X	X	
Reconductor line 1786 from East Hartford to the tap with 1590 ACSR			X
Reconductor line 353 from Kleen Energy to Scovill Rock with bundled 954 ACSR			X

Table A-4
Springfield Component Reinforcements

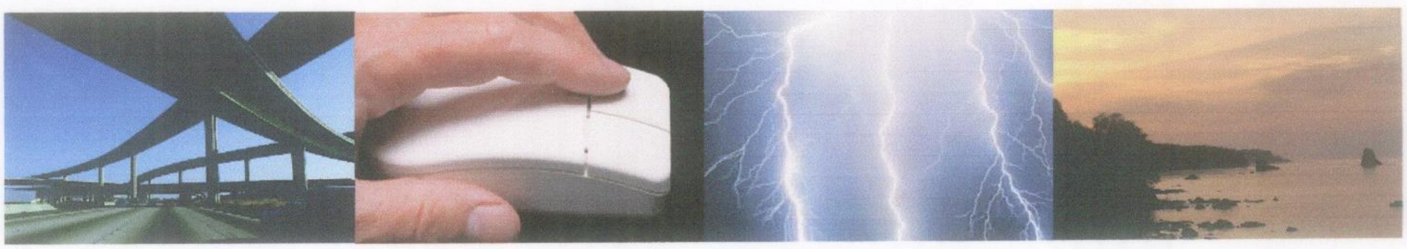
Springfield Reinforcements	3a	3b	5b	6a	6b	6c	7a	7b	7c	8a	8b	8c
	Springfield Option Designation											
Associated 345 kV Option:	**A**	**A**	**C**	**A**	**A**	**A**	**B**	**B**	**B**	**A**	**A**	**A**
345 kV												
Build Ludlow–Agawam 345 kV circuit #1	X	X		X	X	X				X	X	X
Build Agawam–N. Bloomfield 345 kV circuit #1	X	X		X	X	X				X	X	X
Build Ludlow–Manchester 345 kV circuit #1			X									
Build Ludlow–North Bloomfield 345 kV circuit							X	X	X			
Transformers												
Install Agawam 345/115 kV transformer #1	X	X		X	X	X				X	X	X
Install Agawam 345/115 kV transformer #2	X	X		X	X	X				X	X	X
Install Agawam 115 kV phase shifters circuit #s 1–2 (in series with transformer)	X	X										
One spare 115 kV phase shifter	X	X	X				X	X	X			
Replace N. Bloomfield 345/115 kV transformer #1 (CT)	X	X		X	X	X	X	X	X	X	X	X
Install N. Bloomfield 345/115 kV transformer #2 (CT)	X	X		X	X	X	X	X	X	X	X	X
Install N. Bloomfield–S. Agawam phase shifters #s 1–2			X				X	X	X			
Add N. Bloomfield–Southwick phase shifter			X				X	X	X			
Reconnect Ludlow 345/115 kV transformer #1 into bay	X	X	X	X	X	X	X	X	X	X	X	X
Reconnect Ludlow 345/115 kV transformer #2 into bay	X	X	X	X	X	X	X	X	X	X	X	X
Install Ludlow 345/ 115 kV transformer #3				X		X	X			X		X
115 kV												
Rebuild/reconductor Ludlow–Shawinigan				X						X		
Separate/rebuild E. Springfield–Orchard-Ludlow and E. Springfield–Ludlow				X			X			X		

	Springfield Option Designation											
Springfield Reinforcements	**3a**	**3b**	**5b**	**6a**	**6b**	**6c**	**7a**	**7b**	**7c**	**8a**	**8b**	**8c**
Associated 345 kV Option:	**A**	**A**	**C**	**A**	**A**	**A**	**B**	**B**	**B**	**A**	**A**	**A**
Separate or rebuild W. Springfield–Agawam circuit #s 1 & 2	X	X										
Upgrade West Springfield–Agawam circuit #s 1 & 2				X		X				X		
Rebuild S. Agawam–Silver circuit #s 1 & 2 **or** add circuit # 3			X				X	X	X			
Rebuild Silver–Agawam circuit #s1 & 2 **or** add circuit # 3			X				X	X	X			
Replace Breckwood–W. Springfield cable circuit	X	X										
Replace Breckwood–E. Springfield cable circuit	X	X	X	X	X	X	X	X	X	X	X	X
Replace Breckwood reactors	X	X	X	X	X	X	X	X	X	X	X	X
Rebuild/reconductor Woodland–Pleasant line circuit #1	X		X	X	X	X	X	X	X	X	X	X
Rebuild Agawam–Piper Rd. circuit #1	X	X			X							
Install new Clinton–E. Springfield cable circuit			X	X	X	X	X	X	X	X	X	X
Clinton reactor			X	X	X	X	X	X	X	X	X	X
Install 3rd Clinton– W. Springfield cable circuit			X			X		X	X			
Upgrade Ludlow–E. Springfield circuit #1						X						X
Build new Stony Brook–Ludlow 115 kV line		X									X	
Build new 115 k lines 1 and 2, Stony Brook–Five Corners		X	X		X			X			X	
Rebuild 115 kV lines 1 and 2, Five Corners–Fairmont		X	X		X			X			X	
Build new 115 kV line, Ludlow–Fairmont						X			X			X
Disconnect CT/WMASS 115 kV ties	X	X		X	X	X				X	X	X
Reconductor E. Springfield Jct.–Fairmont N.											X	
Separate/Rebuild 1254/1723	X									X		
Undo 3-terminal line 1254/1723; rebuild lines from E. Springfield Jct. to Fairmont			X	X	X	X	X	X	X			
Separate/Rebuild (Fairmont–Shawinigan)/ (Fairmont– E. Springfield)			X	X			X	X				
Reconductor E. Springfield Jct.–Shawinigan											X	X

	Springfield Option Designation											
Springfield Reinforcements	**3a**	**3b**	**5b**	**6a**	**6b**	**6c**	**7a**	**7b**	**7c**	**8a**	**8b**	**8c**
Associated 345 kV Option:	**A**	**A**	**C**	**A**	**A**	**A**	**B**	**B**	**B**	**A**	**A**	**A**
Reconductor Fairmont–Shawinigan					X	X						
Upgrade E. Springfield Jct.–Chicopee											X	
Reconductor E. Springfield Jct.–Piper Rd.	X	X									X	X
Reconductor Fairmont–Piper Rd.					X	X						
Upgrade Fairmont S.–Holyoke			X		X	X					X	
Upgrade Pineshed–Fairmont N.												X
Upgrade Blandford–Granville Jct.	X	X	X	X	X	X	X	X	X	X	X	X
Upgrade Southwick–N. Bloomfield							X		X			
Upgrade Pleasant–Blandford			X	X	X	X	X			X	X	X
Create breaker-and-one-half substation configuration at Fairmont			X	X	X	X	X	X	X			
Build second underground 115 kV line, Northwest Hartford–Southwest Hartford	X	X	X	X	X	X	X	X	X	X	X	X
Build second underground 115 kV line, Southwest Hartford–South Meadow	X	X	X	X	X	X	X	X	X	X	X	X
Build a new 115 kV line from Manchester to East Hartford with 2% or 2.65 ohm reactor	X	X	X	X	X	X	X	X	X	X	X	X
Build a new 115 kV line from Manchester to South Meadow with a 1.5 ohm reactor			X									
Reconductor line 1783 from Farmington to Newington with 556 ACSR			X									
Reconductor line 1785 from Berlin to Newington with 795 ACSR			X									
Add 1% or 1.5 ohm reactor on line 1704			X									
Add 1% or 1.5 ohm reactor on line 1722			X									

EX.3 Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Greater Springfield Reliability Project, September 2008 (redacted to secure Critical Energy Infrastructure Information)

Assessment of Non-Transmission Alternatives to the NEEWS Transmission Projects: Greater Springfield Reliability Project
Redacted Public Version



Prepared for:

Northeast Utilities Service Company

Prepared by:

ICF International

September 2008

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EXECUTIVE SUMMARY

I. Introduction

The Greater Springfield Reliability Project (the "Project") is a transmission upgrade project proposed by Northeast Utilities Service Company ("NUSCO") on behalf of The Connecticut Light and Power Company and Western Massachusetts Electric Company to alleviate transmission constraints in the greater Springfield, Massachusetts and the north central Connecticut areas. The Project consists of a set of transmission upgrades that are designed to reinforce major constraints or limiting elements in the area. The Project is part of the larger New England East-West Solution (NEEWS) which, in addition to the Greater Springfield Reliability Project, includes three other major transmission projects:

- Interstate Reliability Project
- Rhode Island Reliability Project
- Central Connecticut Reliability Project

The four NEEWS projects were selected in combination as the most effective approach to address five major weaknesses which ISO New England (ISO-NE), the regional transmission organization (RTO) serving the New England electricity market, identified in its 2007 Regional System Plan (RSP).[1] The geographical location of the weaknesses is shown in Exhibit ES-1, as are the four projects which comprise NEEWS. Each of the four projects includes the installation of a new 345-kV line among other components, and each individually addresses at least one of the key weaknesses that ISO-NE identified. The four projects have been designed to be complementary. Therefore, the benefits of the NEEWS projects as a whole far exceeds those of the four component projects considered individually. The Project is designed specifically to alleviate both thermal and voltage violations and also to increase the area's access to the 345-kV bulk transmission system.

ICF Resources LLC (ICF) was retained by NUSCO and National Grid to prepare an analysis considering the potential for alternative resources, on both the supply and demand side, to displace or defer the need for the Project and the other NEEWS projects.

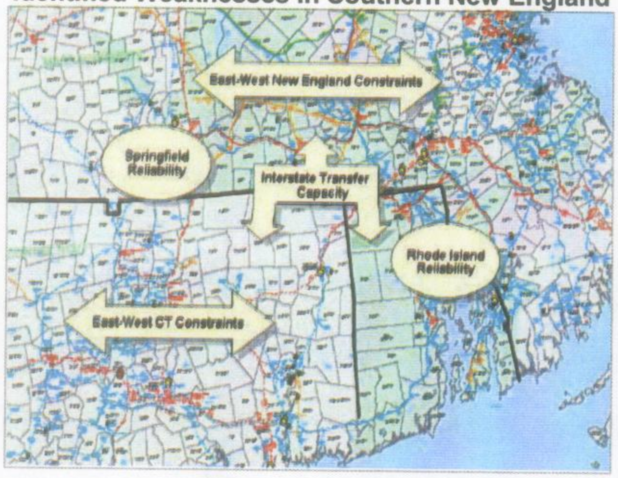
To perform the analysis of the effect of non-transmission alternatives on the Project, ICF has considered the addition of demand resources (including distributed generation), traditional generation supply, and combined heat and power supply options and examined the impact of a large total combined penetration of these resources on the overall reliability of the area as determined through power-flow modeling analysis at peak conditions for pre- and post-Greater Springfield Reliability Project cases. In addition, given the synergies of the four projects, ICF has examined a similar set of power-flow cases, pre- and post-NEEWS, for the impact on the local Springfield area constraints as well as the system. While the first set of cases isolates the direct impact

[1] "2007 Regional System Plan," October 18, 2007, ISO New England.

of the Greater Springfield Reliability Project, the latter provides an assessment of the interaction of the Project with the other components of NEEWS.

Exhibit ES-1
Identified Weaknesses in Southern New England and the Four Major Components of NEEWS

Identified Weaknesses in Southern New England



Four Major Components of NEEWS

Sources: ISO New England's "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008; and NUSCO web site: http://www.transmission-nu.com/residential/projects/NEEWS/default.asp#

This report is focused on the Greater Springfield Reliability Project solution. The remainder of this Executive Summary will briefly describe ICF's approach to analyzing alternatives to the Project, conducting the power-flow analysis, and the conclusions of the power-flow analysis.

II. Background

In terms of reliability, ISO-NE is obligated to meet, at a minimum, the electric industry reliability standards set by the North American Electric Reliability Corporation (NERC), the electric reliability standards development and enforcement body for North America. NERC has established rules and criteria for all geographic areas in North America. The performance of the New England transmission system is also governed by reliability standards and criteria established by the Northeast Power Coordinating Council, Inc. (NPCC), and ISO-NE. NPCC is one of eight regional entities under NERC. As the regional entity for Northeastern North America (that is, New England, New York and eastern Canada), NPCC sets rules and criteria particular to the Northeast. ISO-NE has also developed rules and criteria specific to New England.

The reliability standards address both local (Area Transmission Requirements) and regional (Transmission Transfer Capability) concerns. The Area Transmission Requirements specify that the transmission system be capable of delivering power to consumers under anticipated outage conditions. Transmission Transfer Capability addresses the need for the transmission system to be capable of transferring power within the ISO-NE region and between ISO-NE and its neighbors. The standards define the system conditions and contingencies that must be evaluated when performing a reliability assessment of the transmission grid.[2] These standards were incorporated in ICF's study.

As part of its regional transmission planning process, ISO-NE evaluates whether any areas within its footprint or border regions may violate NERC standards within the 10-year planning horizon. In the 2007 RSP, ISO-NE highlighted concern over future reliability violations within Southern New England. Encompassing the states of Connecticut, Massachusetts and Rhode Island, Southern New England represents 80% of New England's load.[3] During the last 10 years, various drivers such as strong load growth and increased generation have begun to strain the existing transmission system in this region. Despite planned upgrades in key load pockets, local and regional reliability violations may occur as early as 2009.[4] Furthermore, local and regional reliability are often interrelated and "individual solutions in one area must be evaluated to ensure that they do not produce unintended consequences in another area."[5]

Given the complex and interdependent nature of the Southern New England transmission network and the long lead time needed to implement transmission solutions, ISO-NE explored this issue focusing on the system's reliability needs for 10 years from 2007 to 2016 with a focus on the summers of 2009 and 2016. ISO-NE created a reference case simulation for its analysis that included currently planned transmission upgrades expected to be online by 2009.[6] With increasing demand growth, the ISO-NE simulations identified violations of reliability criteria during the study horizon with respect to stability, steady state, and fault-current scenarios.[7] The results of these studies show that by 2009, "area transmission capabilities will be inadequate to meet NERC…reliability standards and criteria for the projected load and generation conditions in the Connecticut, Springfield, and Rhode Island areas."[8]

ISO-NE formed a working group, which included National Grid and NUSCO, to conduct the studies necessary to analyze the system upgrade options to the transmission problems identified in the 2007 RSP for the southern New England region. The studies show that by 2009, load deficits occur for Connecticut and Springfield even in normal operating conditions and for Rhode Island during emergency conditions. By 2016, however, deficits occur for all three areas during normal operating conditions.[9] A load

[2] ISO New England Planning Procedure No. 3, Reliability Standards for the New England Area Bulk Power Supply System, October 13, 2006

[3] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 2.

[4] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 11.

[5] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page ii.

[6] The Reference Case included the following planned transmission improvements: 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 Projects; and Killingly Reliability Project.

[7] The results of this analysis by ISO New England can be found in "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008.

[8] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 31.

[9] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 11.

deficit is the amount of load unable to be served reliably because of transmission constraints.[10]

ISO-NE concludes that these deficits and the five weaknesses "demonstrate a need to construct new transmission facilities to significantly improve the reliability of the transmission grid serving Connecticut, Rhode Island, and western Massachusetts. Given the lead times necessary for permitting and other pre-construction activities, as well as the time required for construction itself, these problems constitute needs that should be addressed now."[11]

In a separate report, ISO-NE identified potential solutions and assessed each option based on system performance characteristics.[12]

III. Greater Springfield Reliability Project

In the 2007 RSP, the Springfield area was determined to be at risk of violating reliability standards. 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.[13] Severe line overloads and low voltages in the Springfield area are caused by local single outages, double-circuit tower outages, and stuck breaker outages. Power flows from the Springfield area to Connecticut either through the 345-kV tie line or the Springfield 115-kV transmission system. When the 345-kV line is out of service, flows on the 115-kV system increase, which leads to numerous overloads on that system. The combination of limited 345-kV transmission between western Massachusetts and Connecticut and capacity on the 115-kV system makes the Springfield area vulnerable to line and equipment overloads and area voltage violations under contingency conditions (particularly for N-1-1 second contingency conditions).

The goal of the Greater Springfield Reliability Project is to eliminate both thermal and voltage violations in the Springfield area, while also increasing the area's access to the 345-kV bulk transmission system.[14] To alleviate these problems, the working group considered a wide range of transmission options that included 115-kV reinforcements, additional 345/115-kV autotransformers, new 345-kV lines, new bulk power sources, and phase shifters.[15] After eliminating options that did not meet the reliability requirements or were not effective long-term solutions, three 345-kV options, called Options A, B, and C remained under consideration for the Springfield area[16]. Two of the three options have three or more 115-kV alternatives, yielding a total of 12 distinct options. Each of the three options reinforces the electrical connection between western Massachusetts and Connecticut, which benefits both the Springfield and Connecticut

[10] Note that references to Connecticut, Springfield and Rhode Island do not refer to state or city boundaries or coincide with definitions used by ISO New England for operational purposes. The names refer to areas specifically delineated for the above referenced needs analysis.

[11] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 31.

[12] The results of ISO New England's analysis are found in "New England East–West Solutions, Report 2, Options Analysis."

[13] "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 4.

[14] "New England East–West Solutions, Report 2, Options Analysis," June 2008, ISO New England, page 5.

[15] "New England East–West Solutions, Report 2, Options Analysis," June 2008, ISO New England, page 41.

[16] "New England East–West Solutions, Report 2, Options Analysis," June 2008, ISO New England, pages 41-46.

areas. ICF analyzed a variation of Option A, that is described in NUSCO's Proposed Plan Applications (PPA) submitted to ISO-NE on ISO Form I.3.9.

In addition to other upgrades, the variation submitted for approval proposes the following significant changes:

- A new 345-kV line from Ludlow to Agawam and from Agawam to North Bloomfield
- Two new 345/115-kV transformers at Agawam
- Rebuilding the 115-kV Agawam to Silver to South Agawam transmission line segments.
- Addition of new 345-kV switchyards at North Bloomfield and Agawam Substations and a new autotransformer at North Bloomfield.
- Replacement of the autotransformers at Ludlow.
- Opening the Breckwood Substation 115-kV bus
- Installing a breaker-and-one-half 115-kV bus configuration at Fairmont, separating and rebuilding double-circuit lines from Ludlow to East Springfield, separating and rebuilding the double-circuit lines from East Springfield to Fairmont, separating the western Massachusetts/Connecticut 115-kV ties

For the purposes of this study the Greater Springfield project was defined to include the separation of the #395 345-kV circuit and the #1448 115-kV circuit currently on common structures between Manchester Substation and Meekville junction.

IV. Analytical Approach and Key Assumptions

IV.1. Assessment of Alternatives to Transmission under Reliability Planning

Transmission lines and systems are designed to provide reliable power delivery from source to the distribution delivery point supporting the end-user. Reductions in end-use demand, or less centralized placement of generation may reduce the utilization of lines on the transmission system. In assessing the potential for alternative resources to displace or defer the Project, ICF considered three distinct options:

1. Combined Heat and Power Resources ("CHP"): These reflect the resources that would be located on site, typically at larger industrial or commercial locations with both steam and electric power needs, and would be used as the primary source of power for that location such that there is no direct demand from the location for regional generation sources and hence no demand for transmission services.
2. Demand-Side Management ("DSM") Resources: Demand-Side Management resources represent a large block of options that tend to reduce the demand for system generation and transmission services either through direct

reductions in the load, or the addition of generation as a distributed source, i.e., distributed generation[17]. Demand reductions may either be passive, such as energy efficiency programs that are tied to use of highly efficient equipment, or they may be active. Active resources reflect loads that can be responsive to system conditions or prices such as interruptible load contracts or distributed/emergency generators.

3. Generation: Generation resources located closer to the load demand centers may also help reduce the overall load on the transmission system.

These three options, alone or in combination, have the potential in some circumstances to defer or displace the need for upgrades to the existing transmission system, while maintaining the same level of reliability. However, they may not offer the same certainty offered through transmission projects. For example, to provide reliability benefits, active demand resources must be dispatched. Many of these resources can only be called on for short periods of time, and may take 30 minutes or longer to respond, if they do respond. Hence, they do not offer the same certainty as transmission lines and other components of the grid that are always present and have a very high availability.

IV.2. Reliability Planning Criteria and Power-Flow Approach

The performance of the New England transmission system is governed by reliability standards and criteria established by NERC, the Northeast Power Coordinating Council, Inc. (NPCC), and the ISO-NE. Operating within these standards ensures that electric power customers in New England will be served with reliable electric power. Similar to the ISO-NE Southern New England Transmission Reliability study[18], ICF's study was designed to test the operation and reliability of the New England transmission system under these standards and criteria.

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

Once the set of reasonable non-transmission alternatives was established, the reliability assessment for the Greater Springfield Reliability Project was carried out by comparing the performance of the local area and broader regional transmission system with and without the Project under various conditions. ICF modeled the New England transmission system under normal and emergency conditions for both cases. The emergency conditions tested included possible N-1 and N-1-1 contingency conditions and further considered the same contingencies under a generation stress case. The analysis was conducted for the year 2013 to coincide with the planned in-service date of the Project.

Chapter One provides additional details on the analytical approach to the alternatives assessment and power-flow modeling.

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17 As used in this study, distributed generation resources refer to small generation units connected to the distribution system.

18 "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England.

3. Key Assumptions for the Alternatives Analysis

Combined Heat and Power Resources: The decision on the type of CHP resource to add and location of the resource was based on an assessment of technical potential and the economics of various CHP options. A review of the technical potential was conducted on a state level through assessing the potential locations that currently are not served by CHP sources. ICF utilized its own projections for forward market prices to assess the economics of the CHP options in combination with market surveys of the penetration rates for the equipment. The resulting additions in the state of Massachusetts and in western Massachusetts were 193 MW and 33 MW, respectively, of CHP.

Demand-Side Management Resources: ICF projected DSM savings based on publicly available projections for the maximum technically achievable DSM and the market information revealed through the ISO-NE Forward Capacity Auction (FCA) process. The FCA has been very successful at attracting demand resources in the New England market area. Roughly 2,500 MW of demand resources cleared in the first Forward Capacity Auction for 2010/2011. The second auction has yet to occur, but demand resources have already submitted to qualify to participate in that auction. The total of demand resources cleared in the first FCA and those showing interest in the second FCA is just over 4,200 MW. This total represents approximately 12% of the peak capacity requirement in the 2011/12 commitment period throughout New England. The West Central Massachusetts (WCMA load zone) resources that were selected in the 2010/2011 auction amounted to 327 MW or 8.4% of the expected WCMA normal summer peak load in 2010. We assume that the total committed demand resources in Massachusetts will grow at the same rate as the technical potential found in other sources such as the January 2008 Connecticut Integrated Resource Plan (IRP) DSM Focus Case, a self-described highly aggressive scenario, and the growth in resources submitting to the FCA between auction periods, which yields an annual growth rate of 17%. This assumed growth rate results in a total of 527 MW of peak DSM in 2013 and a peak penetration of DSM resources of 12.8% of the normal conditions expected in WCMA area.

This report uses the term “load zone” to refer to the eight zones for which prices for load are calculated under Standard Market Design (SMD). SMD is a settlement system utilized within ISO-NE for energy and capacity pricing purposes. SMD settlement includes a zonal characterization in which zones are aggregations of nodes. Generation is priced nodally, while load in a zone will pay a price that is uniform for its zone.

The SMD load zones generally follow the political boundaries of the six New England states, except that Massachusetts is sub-divided into three separate load zones, West Central Massachusetts (WMCA), Southeast Massachusetts (SEMA), and Northeast Massachusetts/Boston (NEMA/BOS). These are reflected in Exhibit ES-2 below. The WCMA zone includes the Greater Springfield area.

Exhibit ES-2
New England SMD Load Zones

In contrast, the regional transmission planning process focuses on 13 zones defined by congestion areas. There is some, but not perfect overlap between the SMD load zones and the RSP transmission planning zones. The analysis herein is primarily focused on the RSP planning zone for Western Massachusetts (WMA), however, for select resource projections, SMD load zones are utilized consistent with the market operations. In particular, load reduction programs are driven in large part through the SMD zonal pricing signals and thus forecasts for load reduction programs are generated at the SMD zonal level. Consistent with this market driven approach, the load reduction estimates utilized herein are estimated at the load zone level rather than the RSP planning zone level.

WCMA roughly reflects the combination of the WMA and Central Massachusetts/Northeastern Massachusetts (CMA/NEMA) RSP zones with the following exceptions: 1) the southeast corner of New Hampshire is contained in the CMA/NEMA zone but not WCMA; 2) the southwest corner of New Hampshire is part of WMA but not WCMA; 3) a small portion of north-central Connecticut is part of WMA but not WCMA; and 4) the WCMA contains a small portion of the northwest corner of the Boston RSP zone, near the cities of Lawrence and Billerica Massachusetts.

New Generation Assets: Supply-side resources were also reviewed to ensure that adequate supply was maintained for generation planning purposes. The options considered included traditional generation supply such as combined cycles, combustion turbines, fossil steam units and renewable units. The decision on the type of resource necessary to add to maintain adequate reserves was based on a high level assessment of the economics of these options. The requirement that load-serving entities face in much of New England to satisfy renewable portfolio standard obligations was also considered in the decision. The resulting additions in the western Massachusetts area were 642 MW of renewable generation[19].

As described above and analyzed, the total resources available as generation or demand side options were examined in combination to determine the total penetration of these resources under aggressive penetration assumptions. This approach resulted in a total amount of resource additions which were included in all cases. Another approach was also examined. This second approach considered the following question: Given the system in its existing configuration, what total amount of demand reductions would be necessary to achieve the reliability identified from the Project under the already assumed level of aggressive penetration?

IV.4. Key Assumptions for the Power-flow Modeling

The starting point for the alternatives to transmission analysis was the 2012 power-flow planning case from ISO-NE. This information was provided to ICF under confidentiality restrictions by NUSCO so as to protect Critical Energy Infrastructure Information (CEII) in accordance with FERC requirements. Since the study year for the alternatives analysis was 2013, there were several modifications that were made to the case to reflect 2013 conditions. These modifications were reflected in both the pre- and post-project implementation cases and additional stressed generation scenarios.

The key assumptions for the power-flow modeling include:

- **Load Projections:** The original power-flow case provided was based on a 2006 vintage forecast for load growth. ISO-NE released a revised forecast in April 2008[20] which was adopted for purposes of this analysis. To modify the peak load input, the load at each node was scaled by the ratio of the 2006 and 2008 vintage forecasts. In compliance with standard transmission reliability planning methods, ICF used the extreme weather peak demand forecast (also known as the 90/10 forecast). Under the 90/10 forecast, the western Massachusetts peak demand is estimated to be 2,490 MW in 2013 based on the 2008 vintage forecast. The values used in the original power-flow were 2,445 MW for the 2012 year, which is a close match to the 2013 demand predicted by the current 2008 forecast. The same approach was applied to all areas within New England. Additional factors and assumptions affecting load predictions include:
    - **Dispatchable DSM Resources:** For modeling purposes, the dispatchable DSM resources such as the emergency generators and demand response are assumed to be reserved for emergency conditions and are not

[19] Source; ICF, Integrated Planning Model (IPM®).
[20] "2008-2017 Forecast Report of Capacity, Energy, Loads, and Transmission," April 2008, ISO New England.

removed from the ISO-NE peak load projection in the power-flow cases.[21] Thus, the western Massachusetts peak load is only decremented by 225 MW to account for the non-dispatchable DSM resources for the power-flow analysis, accounting for about 43% of the total western Massachusetts DSM projection. Since the ISO-NE load projections are at the generator level, load decrements for DSM include reserve margin requirements and transmission losses.

- **Transmission Losses:** The ISO-NE load projections are based at the generator bus-bar and hence include both transmission and distribution losses. In contrast, power-flow load inputs reflect the load at the distribution transfer point rather than at the generator level. As such, we have adjusted the ISO-NE load projections to remove transmission losses to reflect the distribution load levels. This allows for the power-flow to internally determine the transmission sector losses.

- **Existing Generating Capacity:** ICF relied on the generation capacity for existing units as provided directly in the power-flow case. The capacity included in the power-flow case reflects the maximum summer-rated capacity for each unit. Modifications were then made to first establish a view of system dispatch under normal peak-day conditions such that system operations were not stressed for the Reference Case. Additional modifications were made to ensure that adequate supply resources were available to satisfy the expected realized peak load in 2013.

- **Forced Outage Rate and Spinning Reserves:** From the dispatch perspective, forced outages and spinning reserves were accounted for in the dispatch. The forced outage rate assumed for western Massachusetts was 7 percent of the total zonal capacity. To implement the forced outage in the power-flow model, ICF turned off selected generation units to reach 7 percent of the total capacity such that these units were assumed to not be available to meet system demand. The same forced outage rate assumption was used for each zone in New England. A spinning reserve requirement of approximately 15 percent of total capacity was also implemented in the power-flow model across New England. This represents generation capacity that is made available to respond to system contingencies and reflects roughly the largest generation contingency in each zone. The 15 percent spinning reserve was implemented in each zone with the exception of the SEMA/Rhode Island area. Since the SEMA/Rhode Island area is a net exporting region, it is expected that all generation units within that area will be operating at their available capacities on a peak summer day.

- **Generation Asset Lifetime:** Assumptions regarding the useful life of existing generating assets were also made.

[21] ISO-NE views dispatchable DSM as supply side resources

- **Age-Related Retirements:** ICF assumed that any non-hydro asset within New England that reached the age of 60 years by 2013 would retire. No generators in western Massachusetts and Connecticut were affected by this age related retirement assumption.

- **Performance-Related Retirements:** Performance related assumptions were also considered in addition to the age based retirements. Specifically ICF assumed that generation units under RMR contracts will retire if their current RMR payment is above the cost of new entry as determined in the ISO-NE capacity markets and the unit online date was earlier than 2004. This affects the Berkshire Power, ConEd – West Springfield GTs, Altresco Pittsfield units in western Massachusetts and Norwalk Harbor and Bridgeport Harbor in Connecticut. The total retirements assumed in the run is conservative for two primary reasons, first, the assumption is limited to a review of the capacity value only, such that operational costs and compliance issues which may significantly affect plants operational value are not considered, and second, even though considering the capacity value, the cost of new entry is generally considered to be above the expected clearing price for capacity in the market such in an off itself the cut-off point we use to determine retirements likely exceeds the value the units will earn in the market.

V. Conclusions

Based on the results of the analysis performed for this study that included projected new generation, DSM, and CHP resources, the Greater Springfield Reliability Project was determined to be critical to the reliable operation of the New England transmission grid, and in particular, the western Massachusetts and north-central Connecticut transmission system. Non-transmission alternatives to the Greater Springfield Reliability Project were not found to be satisfactory or sufficient in nature to displace or defer the need for the Project. This conclusion is supported by results of the power-flow analysis which indicate that, despite the addition of generation, DSM, and CHP resources previously described, numerous transmission facility overloads could still potentially occur under contingency conditions.

This was evident in both the reference case, with generation facilities under normal operation, and the generation outage scenarios. The analysis further demonstrated that the transmission reinforcements from the Greater Springfield Reliability project would improve the performance of the system in the area of study and resolve line overloads.

It should be noted that these conclusions are based on conservative assumptions used to generate the Reference Case. Less conservative assumptions would result in greater line overloads than were determined in this study. The conservative nature of these assumptions is focused on both the supply and the demand side including the following:

- ISO-NE has an admitted history of under-forecasting peak demand. Based on studies conducted by the ISO itself, the average forecast error for the fifth year (the relevant year for our study) is biased to a 4.2% under estimate of peak.

    - This under-forecasting seems to be a continuing trend on its face given that the peak projections for the 2008 weather normal forecast are not only below the 2007 forecast but are well below the 2006 forecast as well.
- ICF's analysis under the Reference Case reflects a normal peak-day operation for the system assuming that adequate spinning reserves are maintained and further that no active demand resources are called on. These conditions do not reflect the standard which suggests that transmission planning be performed under stress conditions. ICF further examines several generation stress cases in comparison to the Reference Case.
- In estimating which generators currently operating under RMR agreements could be expected to retire for economic reasons after RMR agreements expire in 2010, ICF did not treat the Montville Connecticut and Middletown Connecticut units, which have an aggregate 1,263 MW capacity, as retirements. However, those units are confronting environmental as well as economic challenges, and their owner, NRG Energy Inc, stated in a July 2008 interrogatory response to the Connecticut Siting Council that the Council "should assume for planning purposes" that the units at Montville Station and Middletown Station would be retired within the Council's forecast period "if they are not re-powered under long term contracts or other market based arrangements that provide certainty of revenues".
- ICF's assumed generation outages do not reflect the extreme generation outage conditions which have occurred on occasion in New England. Thus the equipment overloads found under ICF's cases can be reasonably expected to occur under such extreme conditions.

The conservative nature of these assumptions further reinforces the conclusions above given that even under these conservative assumptions, the reliability of the system must be addressed through the proposed transmission upgrade. The conservative nature of these assumptions is further elaborated on in Chapter One.

CHAPTER ONE: OPTIONS FOR AND ASSESSMENT OF TRANSMISSION SYSTEM ALTERNATIVES

1.1 Greater Springfield Reliability Project Background

In the 2007 Regional System Plan (RSP) for New England, the Springfield area was determined to be at risk of violating reliability standards. 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.[22] Severe line overloads and low voltages in the Springfield area are caused by local single outages, double-circuit tower outages, and stuck breaker outages. Power flows from the Springfield area to Connecticut either through the 345-kV tie line or the Springfield 115-kV transmission system. When the 345-kV line is out of service, flows on the 115-kV system increase, which leads to numerous overloads on that system. The combination of limited 345-kV transmission between western Massachusetts and Connecticut and capacity on the 115-kV system makes the Springfield area vulnerable to line and equipment overloads and area voltage violations under contingency conditions (particularly for N-1-1 second contingency conditions).

The goal of the Greater Springfield Reliability Project (the "Project") is to eliminate both thermal and voltage violations in the Springfield area, while also increasing the area's access to the 345-kV bulk transmission system.[23] To alleviate these problems, the working group considered a wide range of transmission options that included 115-kV reinforcements, additional 345/115-kV autotransformers, new 345-kV lines, new bulk power sources, and phase shifters.[24] After eliminating options that did not meet the reliability requirements or were not effective long-term solutions, three 345-kV options, called Options A, B, and C remained under consideration for the Springfield area[25]. Two of the three options have three or more 115-kV alternatives, yielding a total of 12 distinct options. Each of the three options reinforces the electrical connection between western Massachusetts and Connecticut, which benefits both the Springfield and Connecticut areas. ICF analyzed a variation of Option A, that is described in NUSCO's Proposed Plan Applications (PPA) submitted to ISO-NE on ISO Form I.3.9.

In addition to other upgrades, the variation submitted for approval proposes the following significant changes:

- A new 345-kV line from Ludlow to Agawam and from Agawam to North Bloomfield
- Two new 345/115-kV autotransformers at Agawam
- Rebuilding the 115-kV Agawam to Silver to South Agawam transmission line segments.
- Addition of the new 345-kV switchyards at North Bloomfield and Agawam Substations and a new autotransformer at North Bloomfield.

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22 "Southern New England Transmission Reliability Report 1 Needs Analysis," January 2008, ISO New England, page 4.
23 "New England East–West Solutions, Report 2, Options Analysis," June 2008, ISO New England, page 5.
24 "New England East–West Solutions, Report 2, Options Analysis," June 2008, ISO New England, page 41.
25 "New England East–West Solutions, Report 2, Options Analysis," June 2008, ISO New England, pages 41-46.

- Replacement of the autotransformers at Ludlow.
- Opening the Breckwood Substation 115-kV bus
- Installing a breaker-and-one-half 115-kV bus configuration at Fairmont, separating and rebuilding double-circuit lines from Ludlow to East Springfield, separating and rebuilding the double-circuit lines from East Springfield to Fairmont, separating the western Massachusetts/Connecticut 115-kV ties

For the purposes of this study the Greater Springfield project was defined to include the separation of the #395 345-kV circuit and the #1448 115-kV circuit currently on common structures between Manchester Substation and Meekville junction.

The Project is part of the larger New England East-West Solution (NEEWS) which, in addition to the Project, includes three other major transmission projects:

- Interstate Reliability Project
- Rhode Island Reliability Project
- Central Connecticut Reliability Project

These four projects were selected in combination as the most effective approach to address major transmission system weaknesses which ISO New England (ISO-NE), the regional transmission organization (RTO) serving the New England electricity market, identified in its 2007 RSP.[26] [27] The Project is designed specifically to eliminate both thermal and voltage violations in the Springfield area, while also increasing the area's access to the 345-kV bulk transmission system. However, there are significant synergies resulting from the combined implementation of the four NEEWS projects which further reinforce the transmission system.

ICF was retained by Northeast Utilities Service Company ("NUSCO"), on behalf of The Connecticut Light and Power Company and Western Massachusetts Electric Company, and National Grid, the sponsors of the NEEWS projects, to prepare an analysis considering the potential for alternative resources, on both the supply and demand side, to displace or defer the Project.

1.2 Options for Non-Transmission Alternatives to the Greater Springfield Reliability Project

Transmission and distribution lines and systems are designed to provide reliable power delivery from source to end-user. As demand for electrical energy grows, utilization of a transmission system also grows and upgrades may be required to continue to serve load reliably over time. Alternatively, additional generation sources nearby the load demand areas, or reductions in the load at key demand areas may alleviate the load on the transmission system and help to defer or displace transmission upgrades otherwise necessary. In assessing the potential for alternative resources to displace or defer the Project, ICF considered three distinct options:

[26] "2007 Regional System Plan," October 18, 2007, ISO New England.
[27] "2007 Regional System Plan," October 18, 2007, ISO New England.

1. **Combined Heat and Power Resources:** These reflect the resources that would be located on site, typically at larger industrial or commercial locations with both steam and electric power needs, and would be used as the primary source of power for that location such that there would no longer be any direct demand from the location for regional generation sources and hence no demand for transmission services.

2. **Demand-Side Resources:** Demand-Side Management resources represent a large block of options that tend to reduce the demand for system generation and transmission services either through direct reductions in the load, or the addition of generation as a distributed source. Demand reductions may be passive, such as energy efficiency programs which may rely on replacing older less efficient equipment with newer more efficient equipment. In this case, all else equal, to provide the same function from the equipment, less energy would be consumed. Demand resources may also be active resources. Active resources reflect loads such as interruptible load contracts that can be responsive to system conditions or prices. Additionally, distributed or emergency generators are considered responsive demand resources in this analysis.[28]

3. **Generation:** Generation resources located closer to the load demand centers may also help reduce the overall load on the transmission system. Local generation sources will help reduce the transmission load provided that they are appropriately sized and that they are operating at the time of need. It should be noted that a generator that is sized too large may have an undesired effect by creating additional constraints in trying to move generation in the opposite direction of traditional flows and hence impacting the overall system directional flows and utilization. So although they may help alleviate constraints in one area, generation resources may result in constraints in other areas.

These three options alone, or in combination have the potential in some circumstances to defer or displace the need for upgrades to the existing transmission system while maintaining the same level of reliability. However, the reliability benefits from transmission upgrades are likely to be greater and more dependable than those of any of these alternatives. Outages on the transmission system tend to be shorter than those of generation assets when both types of facilities are adequately maintained, and in particular are less frequent than distributed generation options. Even more so, the reliability benefits of the savings from demand resources are much less predictable than the benefits of generation or transmission options. The duration of active demand-side resources tends to be somewhat short-lived, such that if the transmission system overloads are greater than 3 to 5 hours, the demand resources may no longer be available. Further, transmission adds benefits beyond strict reliability considerations, such as helping to reduce system losses and also helping to move output from lower cost resources located in non-local areas to the local demand centers. Such additional benefits may not be available from the non-transmission alternatives.

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[28] As used in this study, distributed generation resources refer to small generation units connected to the distribution system.

1.3 Approach to Considering Non-Transmission Alternatives to the Greater Springfield Reliability Project

To assess the potential for CHP, DSM, or generation options to defer or displace the Project in 2013, ICF considered the potential for each separately. The evaluation first considered the potential for CHP resources and DSM resources in isolation from each other. Once this potential was determined, ICF considered the potential for generation resources. Each of these analyses is described in detail in the chapters that follow. In summary, the expected potential in each of these areas based on both the technical potential and the economic potential were considered. Once these data were estimated, the expected resource potential was input into a power-flow case for 2013. Assuming that these resources were available, ICF examined if a reliability need as established by ISO-NE in their transmission planning process continued to exist. Additionally, ICF used another approach which examined the total load reduction that would be necessary to achieve the same or similar reliability levels as exist with the Project. That is, within a power-flow case which did not contain the upgrades associated with the Project, the load levels were decremented until a reasonably close reliability level to that of the Project was achieved. ICF also examined generation resource addition scenarios to determine if a similar effect could be achieved by locating new generation facilities in the areas of interest.

1.4 Approach to Power-Flow Reliability Analysis

Power-flow studies are important in the operation and planning of the transmission grid. The studies are based on detailed models of the power system that include representations of generation units, load, transmission facilities, substations and other components. Computer simulations using powerful software models are then used to determine the performance of the system under various conditions. The results of such simulations include power flows or loading on transmission lines, dispatch of generation units, and voltages at substations. Power-flow simulations can be used to analyze variations in system performance due to changes in configuration. For example, in ICF's study, simulations were used to determine how the power flowing on transmission lines would change if other key transmission lines were taken out of service.

ICF's study was designed to test the operation of the New England transmission system under the ISO-NE standards and criteria, which require that the system reliably continue to serve its load during anticipated transmission facility outages. The standards and criteria also require that the New England transmission system maintain adequate capability to transfer power within New England and between New England and neighboring markets.

The reliability assessment for the Project was carried out by comparing the performance of two separate configurations of the New England regional transmission system. The first case, referred to as the pre-GSRP Case, represents the New England transmission system assuming the Project, as well as the other components of the NEEWS, is not implemented. The second case, referred to as the Greater Springfield Case represents the transmission system assuming the Project was implemented. Both cases were developed from power-flow models of the New England transmission system and were representative of a summer peak demand period in 2013.

To determine the ability of the system to continue to serve its load during anticipated facility outages, ICF performed a detailed power-flow analysis of the system assuming both normal and emergency conditions. Normal conditions imply that all generation and transmission facilities continue to operate as expected on a peak summer day. First, ICF assessed system performance under normal conditions assuming no unplanned failure of a transmission element such as a transmission line, a transformer, a circuit breaker, or a pair of transmission lines on a multiple circuit transmission tower. Next, the process was repeated for the unexpected failure of key transmission elements.

A similar analysis was then conducted to evaluate system performance under emergency conditions, that is, following the outage of a single transmission element a second element was then considered to fail. In this analysis, the transmission system was first allowed to adjust the flows of power following the single element loss.

System performance was measured by monitoring transmission lines for overloads. To continue to operate reliably, the power flowing on each transmission line should remain below the appropriate ratings of the line. If a line exceeds its limit, operator action may be taken to relieve the overload; if the overload persists, protective devices in the network may activate to take the line out of service to prevent damage to the line. Emergency actions taken by operators or automatic measures to relieve one line's overload could overload other transmission system elements, worsen system conditions, and result in severe power outages or a blackout. It is therefore important to ensure that the system is designed to operate within limits under anticipated emergencies. Similarly, substation voltages must remain within acceptable limits specified by the operator.

Furthermore, ICF assessed the ability of the system to operate reliably if selected generation facilities in the study area were out of service. In each case a generation unit was taken out of service and other generation facilities adjusted to replace the lost output. The performance of the system was then examined as described above.

The loss of a single transmission element is referred to as an N-1 contingency. The loss of a single transmission component followed by the loss of a second component is referred to as an N-1-1 contingency.

A detailed discussion of the power-flow cases and input assumptions is provided in Chapter Five.

CHAPTER TWO: COMBINED HEAT AND POWER RESOURCE ALTERNATIVES

Combined Heat and Power ("CHP") resources reflect the resources that would be located on site, typically at larger industrial or commercial locations with both steam and electric power needs, and would be used as the primary source of power for that location such that there would no longer be any direct demand from the location for regional generation sources and hence no demand for transmission services.

The potential for CHP resources in New England was determined as a multi-step process which included first assessing the technical potential, then assessing the economic break-even point, and finally assessing the market penetration based on user adoption rates and economics.

- *Technical potential* represents the total capacity potential from existing and new facilities that are likely to have the appropriate physical electric and thermal load characteristics that would support a CHP system with high levels of thermal utilization during business operating hours.

- *Economic potential* reflects the share of the technical potential capacity (i.e., the customer base) that would consider the CHP investment economically acceptable according to a procedure that is described in more detail below.

- *Cumulative market penetration* represents an estimate of CHP capacity that will actually enter the market between 2008 and 2023. This value discounts the economic potential to reflect non-economic screening factors and the rate that CHP is likely to actually enter the market.

A detailed discussion of each step is provided below.

2.1 Technical Potential for CHP

The technical potential for CHP is considered in three broad sectors: 1) industrial, 2) commercial/institutional, and 3) multi-family residential. Two different types of CHP market segments were included in the evaluation of technical potential. Both were evaluated for high load factor (80% and above) and low load factor (51%) applications resulting in four distinct market segments that are analyzed. These markets are considered individually because both the annual load factor and the installation and operation of thermally activated cooling has an impact on the system economics.

- **Traditional CHP** – electric output is produced to meet all or a portion of the base load for a facility and the thermal energy is used to provide steam or hot water. Depending on the type of facility, the appropriate sizing could be either electric or thermal limited. Industrial facilities often have "excess" thermal load compared to their on-site electric load. Commercial facilities almost always have excess electric load compared to their thermal load. Two sub-categories were considered:

- **High load-factor applications** – This market provides for continuous or nearly continuous operation. It includes all industrial applications and round-the-clock commercial/institutional operations such as colleges, hospitals, hotels, and prisons.

- **Low load-factor applications** – Some commercial and institutional markets provide an opportunity for coincident electric/thermal loads for a period of 3,500 to 5,000 hours per year. This sector includes applications such as office buildings, schools, and laundries.

- **Combined Cooling Heating and Power (CCHP)** – All or a portion of the thermal output of a CHP system can be converted to air conditioning or refrigeration with the addition of a thermally activated cooling system. This type of system can potentially open up the benefits of CHP to facilities that do not have the year-round thermal load to support a traditional CHP system. A typical system would provide the annual hot water load, a portion of the space heating load in the winter months and a portion of the cooling load during the summer months. Two sub-categories were considered:

  - **Low load factor applications** – These represent markets that otherwise could not support CHP due to a lack of thermal load.

  - **Incremental high load factor applications** – These markets represent round-the-clock commercial/institutional facilities that could support traditional CHP, but with cooling, incremental capacity could be added while maintaining a high level of utilization of the thermal energy from the CHP system. All of the market segments in this category are also included in the high load factor traditional market segment, so only the incremental capacity for these markets is added to the overall totals.

The following basic steps were used to estimate the technical potential in these sectors for the four types of CHP segments:

1. **Identify applications where CHP provides a reasonable fit to the electric and thermal needs of the user.** Target applications were identified based on reviewing the electric and thermal energy (heating and cooling) consumption data for various building types and industrial facilities. Data sources include the DOE EIA *Commercial Buildings Energy Consumption Survey (CBECS),* the DOE *Manufacturing Energy Consumption Survey (MECS)* and various market summaries developed by DOE, Gas Technology Institute (GTI), and the American Gas Association. Existing CHP installations in the commercial/institutional and industrial sectors were also reviewed to understand the required profile for CHP applications and to identify target applications.

2. **Quantify the number and size distribution of target applications.** Once applications that could technically support CHP were identified, the iMarket, Inc. *MarketPlace Database* and the *Major Industrial Plant Database* (MIPD) from IHS

Inc.[29] were utilized to identify potential CHP sites by Standard Industrial Classification (SIC) code or application, and location (county). The SIC code is a United States government system for classifying industries by a four-digit code. The *MarketPlace Database* is based on the Dun and Bradstreet financial listings and includes information on economic activity (8 digit SIC), location (metropolitan area, county, electric utility service area, state) and size (employees) for commercial, institutional and industrial facilities. In addition, for select SICs limited energy consumption information (electric and gas consumption, electric and gas expenditures) is provided based on data from Wharton Econometric Forecasting (WEFA). MIPD has detailed energy and process data for 16,000 of the largest energy-consuming industrial plants in the United States. The *MarketPlace Database* and MIPD were used to identify the number of facilities in target CHP applications and to group them into size categories based on average electric demand in kiloWatt-hours.

3. **Estimate CHP potential in terms of MW capacity.** Total CHP potential was then derived for each target application based on the number of target facilities in each size category. It was assumed that the CHP system would be sized to meet the average site electric demand for the target applications unless thermal loads (heating and cooling) limited electric capacity. There are two distinct applications and two levels of annual load making for four market segments in all. In traditional CHP, the thermal energy is recovered and used for heating, process steam, or hot water. In cooling CHP, the system provides both heating and cooling needs for the facility. High load factor applications operate at 80% load factor and above; low load factor applications operate at an assumed average of 4500 hours per year (51%) load factor. The high load factor cooling applications are also applications for traditional CHP, though the cooling applications have 25-30% more capacity than traditional. These differences are directly accounted for in the analysis.

4. **Estimate the growth of new facilities in the target market sectors**. The technical potential included economic projections for growth through 2023 by means of state by state 15-year growth factors. The growth factors used in the analysis for growth between the present and 2023 are shown in Exhibit 2-1. These growth projections were used in this analysis as an estimate of the growth in new facilities. In cases where an economic sector is declining, it was assumed that no new facilities would be added to the technical potential for CHP. Note, existing CHP is subtracted from the identified sites to determine the remaining incremental technical market potential.

[29] IHS (NYSE: IHS) is a leading global source of energy, product lifecycle management, environmental and security information.

Exhibit 2-1
New England State CHP Growth Projections Through 2023

State	15-year average annual growth
CT	1.193%
MA	1.028%
ME	1.367%
NH	1.834%
RI	1.153%
VT	1.217%

The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class. The technical potential as outlined is useful in understanding the potential size and size distribution of the target CHP markets in the state. The estimated technical potential by county and size of unit is provided in Exhibit 2-2.

Exhibit 2-2
Massachusetts CHP Technical Potential by County and Size of Unit, 2013

	Size Range Capacity Totals (MW)					
County	**50-500 kW**	**500-1 MW**	**1-5 MW**	**5-20 MW**	**>20 MW**	**Total**
Barnstable	37.8	37.5	15.8	7.9	0.0	99.0
Berkshire	17.7	24.3	40.3	11.0	0.0	93.4
Bristol	47.1	90.4	84.5	17.7	23.7	263.4
Dukes	4.0	2.8	0.0	0.0	0.0	6.8
Essex	64.9	107.3	137.2	82.8	0.0	392.2
Franklin	9.3	7.2	22.1	9.9	0.0	48.4
Hampden	40.0	72.7	112.8	40.0	77.9	343.3
Hampshire	13.3	27.8	29.6	25.6	0.0	96.3
Middlesex	119.8	222.0	301.3	50.5	94.6	788.2
Nantucket	3.3	3.2	0.0	0.0	0.0	6.5
Norfolk	59.1	96.6	124.1	23.7	23.7	327.1
Plymouth	41.4	62.1	58.0	0.0	0.0	161.5
Suffolk	61.2	128.5	170.1	94.7	115.1	569.6
Worcester	64.0	135.2	170.6	42.8	47.3	459.8
Total	583.0	1,017.6	1,266.2	406.5	382.3	3,655.6

2.2 Economic Potential for CHP

Economic potential is determined by an evaluation of the competitiveness of CHP versus purchased fuel and electricity. The projected future fuel and electricity prices and the cost and performance of CHP technologies determine the economic competitiveness of CHP in each market. CHP technology and performance assumptions appropriate to each size category and region were selected to represent the competition in that size range (Exhibit 2-3). Additional assumptions were made for the competitive analysis. Technologies below 1 MW in electrical capacity are assumed to have an economic life of 10 years. Larger systems are assumed to have an economic life of 15 years. Capital related amortization costs were based on a 10% discount rate. Based on their operating characteristics, each category and each size bin within the category have specific assumptions about the annual hours of CHP operation (80-90% for the high load factor cases with appropriate adjustments for low load factor facilities), the share of recoverable thermal energy that gets utilized (80%-90%), and the share of useful thermal energy that is used for cooling compared to traditional heating. The economic figure-of-merit chosen to reflect this competition in the market penetration model is simple payback.[30] While not the most sophisticated measure of a project's performance, it is nevertheless widely understood by all classes of customers.

Exhibit 2-3
Technology Competition Assumed within Each CHP Size Category

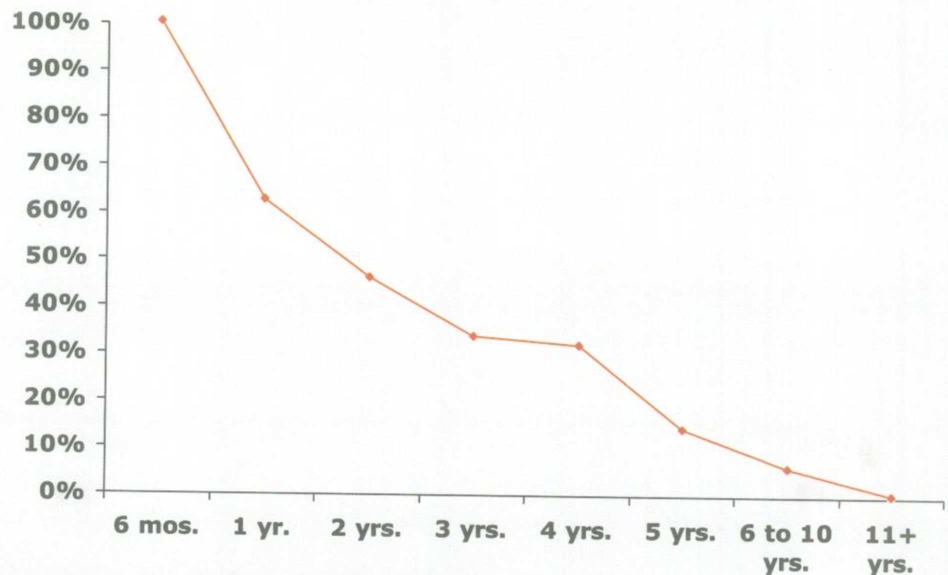
Market Size Bins	Competing Technologies
50 – 500 kW	100 kW Recip Engine
	70 kW Microturbine
	150 kW PEM Fuel Cell
500 - 1,000 kW	300 kW Recip Engine (multiple units)
	70 kW Microturbine (multiple units)
	250 kW MC/SO Fuel Cell (multiple units)
1 – 5 MW	3 MW Recip Engine
	3 MW Gas Turbine
	2 MW MC Fuel Cell
5 - 20 MW	5 MW Recip Engine
	5 MW Gas Turbine
20 – 100 MW	40 MW Gas Turbine

Rather than use a single payback value, such as 3-years or 5-years as the determinant of economic potential, we have based the market acceptance rate on a survey of commercial and industrial facility operators concerning the payback required for them to consider installing CHP. Exhibit 2-4 shows the percentage of survey respondents that would accept CHP investments at different payback levels.[31] As can be seen from the figure, more than 30% of customers would reject a project that promised to return their initial investment in just one year. A little more than half would reject a project with a payback of 2 years. This type of payback translates into a project with an ROI of between 49-100%. One possible explanation for rejecting a project with such high returns is that the average customer does not believe that the results are real and is protecting himself from this perceived risk by requiring very high projected returns

[30] Simple payback is the number of years that it takes for the annual operating savings to repay the initial capital investment.
[31] "Assessment of California CHP Market and Policy Options for Increased Penetration", California Energy Commission, July, 2005.

before a project would be accepted. Another possible explanation is that the facility is very capital limited and is rationing its capital raising capability for higher priority projects (market expansion, product improvement, etc.).

Exhibit 2-4
Customer Payback Acceptance Curve



Source: *Primen's 2003 Distributed Energy Market Survey*

For each market segment, the economic potential represents the technical potential multiplied by the share of customers that would accept the payback calculated in the economic competition module.

ICF considered 2 cases for economic penetration, the first assumed incentives of $400-500 per customer in Connecticut while the second case applied incentives throughout New England. The results of the economic potential for CHP in western Massachusetts for each case are shown in Exhibit 2-5.

Exhibit 2-5
Massachusetts Economic Potential for CHP Resources by Size, 2013

Case	50-500 kW	500kW-1,000kW	1-5 MW	5-20 MW	>20 MW	All Sizes
			(MW)			
Base Incentive Case	0	0	0	27	101	128
High Incentive Case	0	0	24	74	101	198

Detailed discussions of the assumptions driving the economic analysis are presented below. The primary drivers of the economic analysis are the electric prices and gas prices that the equipment installation would avoid, and the equipment cost itself.

2.2.1 Electric Prices

- Initial year price estimates are from EIA average retail price by state. Each additional year is calculated using the output of the ICF Integrated Planning Model™ (IPM®) model generation weighted industrial prices and then modified as described below for use in the CHP market penetration model. The industrial average prices for each 5-year period are shown in Exhibit 2-6.

- The electricity price assumptions for the high load factor CHP applications were as follows

  - 50-500 kW – 115% of the industrial average price
  - 500-1000 kW – Industrial average price
  - 1-5 MW – 90% of industrial average price (to reflect higher voltages and lower prices as customer size increases above the average industrial size used by EIA)
  - 5-20 MW – 81% of industrial average price
  - >20 MW – 81% of industrial average price

- Price adjustments for customer load factor were defined as follows:

  - High load factor – 90% of the estimated value
  - Low load factor – 100% of the estimated value
  - Peak cooling load – 150% of the estimated value

- For a customer generating a portion of its own power with CHP, standby charges are estimated at 15% of the defined average electric rate except for Connecticut where standby charges are waived as part of an ongoing incentive program. In the other New England states, when considering CHP, only 85% of a customer's rate can be avoided.

Exhibit 2-6
Input Price Forecast: Industrial Electric Price Estimation

Average Industrial Price	5 Year Average Prices $/kWh		
	2013	2018	2023
CT	$0.114	$0.106	$0.116
MA	$0.128	$0.119	$0.132
ME	$0.087	$0.081	$0.089
NH	$0.114	$0.106	$0.118
RI	$0.123	$0.114	$0.127
VT	$0.081	$0.075	$0.084

2.2.2 Natural Gas Prices

- The natural gas price assumptions are based on the forecast for delivered ISO-NE prices by state with estimated markups for other markets.

- Electric Sector and CHP price – equal to the ISO-NE 5-year average price for each state and 5-year time period
- Commercial Customer – -- $1.10/MMBtu (boiler fuel) above ISO-NE price
- Industrial Customer from City Gate -- $0.60/MMbtu (boiler fuel) above ISO-NE price

- The gas price assumptions are shown in Exhibit 2-7.

Exhibit 2-7
Natural Gas Price Assumptions ($/MMBtu)

Year	2013			2018			2023		
State	EG/ CHP	Ind.	Comm.	EG/ CHP	Ind.	Comm.	EG/ CHP	Ind.	Comm.
CT	$8.09	$8.69	$9.19	$7.24	$7.84	$8.34	$7.84	$8.44	$8.94
MA	$8.09	$8.69	$9.19	$7.24	$7.84	$8.34	$7.84	$8.44	$8.94
ME	$8.28	$8.88	$9.38	$7.43	$8.03	$8.53	$8.04	$8.64	$9.14
NH	$8.20	$8.80	$9.30	$7.35	$7.95	$8.45	$7.96	$8.56	$9.06
RI	$8.09	$8.69	$9.19	$7.24	$7.84	$8.34	$7.84	$8.44	$8.94
VT	$8.13	$8.73	$9.23	$7.27	$7.87	$8.37	$7.88	$8.48	$8.98

2.2.3 CHP Technology Cost and Performance

The CHP system itself is the engine that drives the economic savings. The cost and performance characteristics of CHP systems determine the economics of meeting the site's electric and thermal loads. A representative sample of commercially and emerging CHP systems was selected to profile performance and cost characteristics in combined heat and power (CHP) applications. The selected systems range in capacity from approximately 100 – 20,000 kW. The technologies include gas-fired reciprocating engines, gas turbines, microturbines and fuel cells. The appropriate technologies were allowed to compete for market share in the penetration model. In the smaller market sizes, reciprocating engines competed with microturbines and fuel cells. In intermediate sizes (1 to 20 MW), reciprocating engines competed with gas turbines.

Cost and performance estimates for the CHP systems were based on work being undertaken for the EPA.[32] The foundation for these updates is based on work previously conducted for the New York State Energy Research and Development Authority (NYSERDA)[33], on peer-reviewed technology characterizations that ICF[34] developed for the National Renewable Energy Laboratory[35] and on follow-on work

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32 EPA CHP Partnership Program, Technology Characterizations, December 2007 (under review).
33 *Combined Heat and Power Potential for New York State*, Energy Nexus Group (later became part of EEA), for NYSERDA, May 2002.
34 ICF's Energy and Environmental Analysis (EEA) group.
35 "Gas-Fired Distributed Energy Resource Technology Characterizations", NREL, November 2003, http://www.osti.gov/bridge

conducted by DE Solutions for Oak Ridge National Laboratory.[36] Additional emissions characteristics and cost and performance estimates for emissions control technologies were based on ongoing work conducted for EPRI.[37] Data is presented for a range of sizes that include basic electrical performance characteristics, CHP performance characteristics (power to heat ratio), equipment cost estimates, maintenance cost estimates, emission profiles with and without after-treatment control, and emissions control cost estimates. The technology characteristics are presented for three years: 2005, 2010, 2020. The 2007-2010 estimates are based on current commercially available and emerging technologies. The cost and performance estimates for 2010-2015 and 2015-2020 reflect current technology development paths and currently planned government and industry funding. These projections were based on estimates included in the three references mentioned above. NO_x, CO and VOC emissions estimates in lb/MWh are presented for each technology both with and without after-treatment control (AT). Which system is applicable in any size category (e.g., with after-treatment or without) is a function of the specific emissions requirements assumptions for each scenario. The installed costs in the following technology performance summary tables are based on typical national averages.

Exhibits 2-8 through 2-11 show the CHP technology cost and performance assumptions. For the cooling markets an additional amount is added to cover the cost of absorption chillers. This cost is a fitted function based on the amount of heat available that varies from \$50/kW for the large systems to over \$500/kW for the smallest systems analyzed.

[36] "Clean Distributed Generation Performance and Cost Analysis", DE Solutions for ORNL. April 2004.
[37] "Assessment of Emerging Low-Emissions Technologies for Distributed Resource Generators", EPRI, January 2005.

Exhibit 2-8
Reciprocating Engine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
100 kW	Installed Costs, $/kW	$2,210	$1,925	$1,568
	Heat Rate, Btu/kWh	12,000	10,830	10,500
	Electric Efficiency, %	28.4%	31.5%	32.5%
	Thermal Output, Btu/kWh	6100	5093	4874
	O&M Costs, $/kWh	0.022	0.013	0.012
	NO_x Emissions, lbs/MWh (w/ AT)	0.10	0.15	0.15
	CO Emissions w/AT, lb/MWh	0.32	0.60	0.30
	VOC Emissions w/AT, lb/MWh	0.10	0.09	0.05
	PMT 10 Emissions, lb/MWh	0.11	0.11	0.11
	SO_2 Emissions, lb/MWh	0.0068	0.0064	0.0062
	After-treatment Cost, $/kW	incl.	incl.	incl.
800 kW	Installed Costs, $/kW	$1,640	$1,443	$1,246
	Heat Rate, Btu/kWh	9,760	9,750	9,225
	Electric Efficiency, %	35.0%	35.0%	37.0%
	Thermal Output, Btu/kWh	2313	3791	3250
	O&M Costs, $/kWh	0.013	0.01	0.009
	NO_x Emissions, lbs/MWh (w/ AT)	0.5	1.24	0.93
	CO Emissions w/AT, lb/MWh	1.87	0.45	0.31
	VOC Emissions w/AT, lb/MWh	0.47	0.05	0.05
	PMT 10 Emissions, lb/MWh	0.10	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0068	0.0057	0.0054
	After-treatment Cost, $/kW	300	190	140
3000 kW	Installed Costs, $/kW	$1,130	$1,100	$1,041
	Heat Rate, Btu/kWh	9,492	8,750	8,325
	Electric Efficiency, %	35.9%	39.0%	41.0%
	Thermal Output, Btu/kWh	3510	3189	2982
	O&M Costs, $/kWh	0.011	0.0083	0.008
	NO_x Emissions, lbs/MWh (w/ AT)	1.52	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.78	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.34	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0057	0.0051	0.0049
	After-treatment Cost, $/kW	200	130	100
5000 kW	Installed Costs, $/kW	$1,130	$1,099	$1,038
	Heat Rate, Btu/kWh	8,758	8,325	7,935
	Electric Efficiency, %	39.0%	41.0%	43.0%
	Thermal Output, Btu/kWh	3046	2797	2605
	O&M Costs, $/kWh	0.009	0.008	0.008
	NO_x Emissions, lbs/MWh (w/ AT)	1.55	1.24	0.775
	CO Emissions w/AT, lb/MWh	0.75	0.31	0.31
	VOC Emissions w/AT, lb/MWh	0.22	0.10	0.10
	PMT 10 Emissions, lb/MWh	0.01	0.01	0.01
	SO_2 Emissions, lb/MWh	0.0054	0.0049	0.0047
	After-treatment Cost, $/kW	150	115	80

Exhibit 2-9
Microturbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
60 kW	Installed Costs, $/kW	$2,739	$2,037	$1,743
	Heat Rate, Btu/kWh	13,891	12,500	11,375
	Electric Efficiency, %	24.6%	27.3%	30.0%
	Thermal Output, Btu/kWh	6308	3791	3102
	O&M Costs, $/kWh	0.022	0.016	0.012
	NO_x Emissions, lbs/MWh (w/ AT)	0.15	0.14	0.13
	CO Emissions w/AT, lb/MWh	0.24	0.22	0.20
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.22	0.20	0.19
	SO_2 Emissions, lb/MWh	0.0079	0.0074	0.0067
	After-treatment Cost, $/kW			
250 KW	Installed Costs, $/kW	$2,684	$2,147	$1,610
	Heat Rate, Btu/kWh	13,080	11,750	10,825
	Electric Efficiency, %	2.6%	29.0%	31.5%
	Thermal Output, Btu/kWh	4800	3412	2625
	O&M Costs, $/kWh	0.015	0.013	0.012
	NO_x Emissions, lbs/MWh (w/ AT)	0.43	0.24	0.13
	CO Emissions w/AT, lb/MWh	0.26	0.26	0.24
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.18	0.18	0.16
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0064
	After-treatment Cost, $/kW	500	200	90

Exhibit 2-10
Fuel Cell Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
200 kW PAFC in 2005 150 kW PEMFC in out years	Installed Costs, $/kW	$6,310	$4,782	$3,587
	Heat Rate, Btu/kWh	9,480	9,480	8,980
	Electric Efficiency, %	36.0%	36.0%	38.0%
	Thermal Output, Btu/kWh	4250	3482	3281
	O&M Costs, $/kWh	0.038	0.017	0.015
	NO_x Emissions, lbs/MWh (w/ AT)	0.06	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.07	0.07
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0056	0.0053
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
300 kW MCFC	Installed Costs, $/kW	$5,580	$4,699	$3,671
	Heat Rate, Btu/kWh	8,022	7,125	6,920
	Electric Efficiency, %	42.5%	47.9%	49.3%
	Thermal Output, Btu/kWh	1600	1723	1602
	O&M Costs, $/kWh	0.035	0.02	0.015
	NO_x Emissions, lbs/MWh (w/ AT)	0.1	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.07	0.05	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0057	0.0042	0.0041
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.
1,200 kW MCFC	Installed Costs, $/kW	$5,250	$4,523	$3,554
	Heat Rate, Btu/kWh	8,022	7,110	6,820
	Electric Efficiency, %	42.5%	48.0%	50.0%
	Thermal Output, Btu/kWh	1583	1706	1503
	O&M Costs, $/kWh	0.032	0.019	0.015
	NO_x Emissions, lbs/MWh (w/ AT)	0.05	0.05	0.04
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.03
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.00	0.00	0.00
	SO_2 Emissions, lb/MWh	0.0044	0.0042	0.0040
	After-treatment Cost, $/kW	n.a.	n.a.	n.a.

Exhibit 2-11
Gas Turbine Cost and Performance Characteristics

CHP System	Characteristic/Year Available	2007-2010	2010-2015	2016-2020
3,000 KW GT	Installed Costs, $/kW	$1,690	$1,560	$1,300
	Heat Rate, Btu/kWh	13,100	12,650	11,200
	Electric Efficiency, %	26.0%	27.0%	30.5%
	Thermal Output, Btu/kWh	5018	4489	4062
	O&M Costs, $/kWh	0.0074	0.0065	0.006
	NO_x Emissions, lbs/MWh (w/ AT)	0.68	0.38	0.2
	CO Emissions w/AT, lb/MWh	0.55	0.53	0.47
	VOC Emissions w/AT, lb/MWh	0.03	0.03	0.02
	PMT 10 Emissions, lb/MWh	0.21	0.20	0.18
	SO_2 Emissions, lb/MWh	0.0070	0.0069	0.0069
	After-treatment Cost, $/kW	210	175	150
10 MW GT	Installed Costs, $/kW	$1,298	$1,342	$1,200
	Heat Rate, Btu/kWh	11,765	10,800	9,950
	Electric Efficiency, %	29.0%	31.6%	34.3%
	Thermal Output, Btu/kWh	4674	4062	3630
	O&M Costs, $/kWh	0.007	0.006	0.005
	NO_x Emissions, lbs/MWh (w/ AT)	0.67	0.37	0.2
	CO Emissions w/AT, lb/MWh	0.50	0.46	0.42
	VOC Emissions w/AT, lb/MWh	0.02	0.02	0.02
	PMT 10 Emissions, lb/MWh	0.20	0.18	0.17
	SO_2 Emissions, lb/MWh	0.0069	0.0064	0.0059
	After-treatment Cost, $/kW	140	125	100
40 MW GT	Installed Costs, $/kW	$972	$944	$916
	Heat Rate, Btu/kWh	9,220	8,865	8,595
	Electric Efficiency, %	37.0%	38.5%	39.7%
	Thermal Output, Btu/kWh	3189	3019	2892
	O&M Costs, $/kWh	0.004	0.004	0.004
	NO_x Emissions, lbs/MWh (w/ AT)	0.55	0.2	0.1
	CO Emissions w/AT, lb/MWh	0.04	0.04	0.04
	VOC Emissions w/AT, lb/MWh	0.01	0.01	0.01
	PMT 10 Emissions, lb/MWh	0.16	0.15	0.15
	SO_2 Emissions, lb/MWh	0.0054	0.0052	0.0051
	After-treatment Cost, $/kW	90	75	40

2.3 Market Penetration Analysis

ICF has developed a CHP market penetration model that estimates cumulative CHP market penetration in 5-year increments. For this analysis, the forecast periods are 2013, 2018, and 2023. The target market is comprised of the facilities that make up the economic market potential. Based on this calculated economic potential, a market diffusion model is used to determine the cumulative market penetration for each 5-year time period.

The estimation of market penetration includes both a non-economic screening factor and a factor that estimates the rate of market penetration (diffusion.) The non-economic screening factor was applied to reflect the share of each market size category (i.e., applications of 50 to 500 kW, applications of 500 to 1,000 kW, etc) within the economic potential that would be willing and able to consider CHP at all. These factors range from 32% in the smallest size bin (50-500 kW) to 64% in the largest size bin (more than 20 MW.) These factors are intended to take the place of a much more detailed screening that would eliminate customers that do not actually have appropriate electric and thermal loads in spite of being within the target markets, do not use gas or have access to gas, do not have the space to install a system, do not have the capital or credit worthiness to consider CHP investment, or are otherwise unaware, indifferent, or hostile to the idea of adding CHP. The specific value for each size bin was established based on an evaluation of EIA facility survey data and gas use statistics from the Market database.

The rate of market penetration is based on a *Bass diffusion curve* with allowance for growth in the maximum market. This function determines cumulative market penetration for each 5-year period. Smaller size systems are assumed to take a longer time to reach maximum market penetration than larger systems. Cumulative market penetration using a Bass diffusion curve takes a typical S-shaped curve. In the generalized form used in this analysis, growth in the number of ultimate adopters is allowed. The curve's shape is determined by an initial market penetration estimate, growth rate of the technical market potential, and two factors described as *internal market influence* and *external market influence*.

The cumulative market penetration factors reflect the economic potential multiplied by the non-economic screening factor (maximum market potential) and by the Bass model cumulative market penetration estimate.

Exhibit 2-12
Massachusetts Cumulative Market Penetration for CHP Resources by Size, 2013

Case	50-500 kW	500kW-1,000kW	1-5 MW	5-20 MW	>20 MW	All Sizes
	(MW)					
Base Incentive Case	2	7	41	32	55	136
High Incentive Case	5	19	66	49	55	194

For purposes of the analysis considered herein, the penetration projections for the High Incentive Case are used.

CHAPTER THREE: DEMAND SIDE ALTERNATIVES

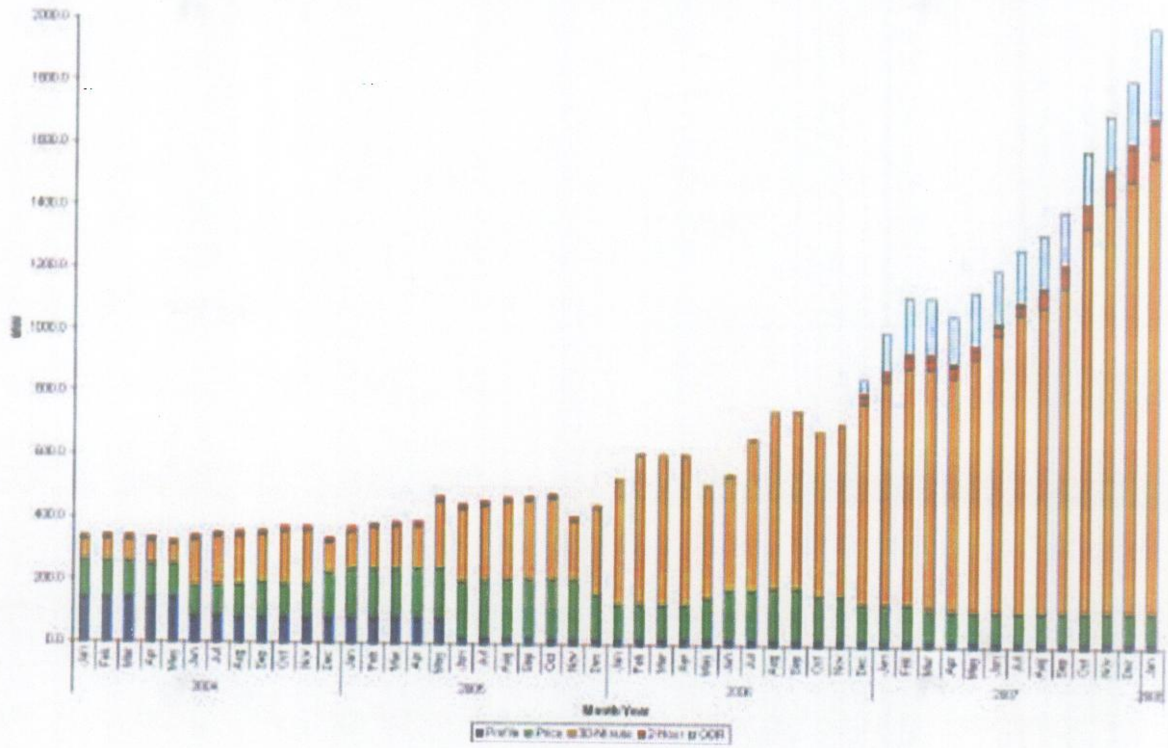
Demand side resources represent a large block of resource options that tend to reduce the demand for system generation and transmission services either through direct reductions in the load, or the addition of generation as a distributed source, i.e., distributed or emergency generation. Demand reductions may either be passive, such as energy efficiency programs that are tied to use of highly efficient equipment, or they may be active. Active resources reflect loads such as interruptible load contracts or distributed/emergency generators that can be responsive to system conditions or prices. Active resources are considered dispatchable by ISO-NE, though the performance of active resources programs, particularly non-generation specific programs, has not been tested under conditions in which they would be frequently called on, such as the large penetration levels considered in this analysis.

For this analysis, ICF projected DSM savings based on publicly available projections for the maximum technically achievable DSM and the market information revealed through the ISO-NE Forward Capacity Auction (FCA) process.

3.1 Background on Demand Resources in New England

Demand side resources have expanded considerably in the last several years. Exhibit 3-1 provides an overview of the growth in demand resources enrolled with ISO-NE between January 2004 and January 2008. As can be seen, there has been significant growth in 30-minute responsive reserves and Other Demand Resources (ODRs). ODRs reflect energy efficiency, emergency generation, and load management resources that can participate in the recently initiated forward capacity market in New England.

Exhibit 3-1
Demand Resources Enrolled with ISO-NE January 2004 – January 2008



This growth reflects an unprecedented amount of demand resources participating in the market. To participate as real-time resources, the demand resources must offer reductions as individual or grouped resources with a minimum reduction of 100 kW. They must be able to respond to real time capacity deficiency instructions from the system operator within either 30-minutes or 2-hours of the system operator's request, depending on the resource classification. Further, the resources need to offer a guaranteed 2 hour minimum reduction time. Resources will be compensated through both an energy and capacity mechanism. The energy mechanism reflects the greater of the real-time wholesale price of a guaranteed minimum of $0.50/kWh for 30-minute response and $0.35/kWh for 2-hour response. The capacity payment reflects a monthly payment ($/kW) based on the Forward Capacity Market Settlement Agreement.

To date, demand resources have performed well and have enhanced system reliability. However, the number of hours that the resources have been called on has been very limited. With the increasing volume of Demand Resources participating in the wholesale electricity markets, new planning and operational challenges are emerging. The 2010/2011 Forward Capacity Auction resulted in over 2,500 MW of demand resource capacity cleared, which reflected roughly 70 percent of the total resources which bid in that same auction. Resources submitting in the 2011/2012 forward capacity market reflect 4,218 MW or roughly 14% of the anticipated peak load. This continued growth is alarming from an overall resource adequacy and reliability planning standpoint, given that as demand resources grow in proportion to total resources, they will be relied upon to maintain system reliability. As demand response resources replace generation, there will be fewer generators available to satisfy the load and reserve requirements. Further, load reductions from demand response resources will be called upon more frequently to maintain the reserve requirements for a given expected load level. That is, as demand resources grow and displace generation resources, demand reductions will be called to perform in more hours.

Given that there is no history of performance, and the expectation for the initial auctions would not have accounted for the expansion in number of hours a demand resource is called to perform, there is a large question regarding the ability of the resources to perform for extended periods at more frequent rates.

Analysis performed by ISO-NE showed that if a total of 4,218 MW of demand resources cleared for the 2011/2012 period, demand resources would be required to be active in more than 200 hours under the 50/50 load growth projection for that resource year. In a case with roughly the 2,500 MW available from the 2010/2011 auction, the number of hours the resources would be called on was roughly 50. This reflects not only a quadrupling of the hours of need, but also implicit in this is the fact that the resources would be needed for longer durations under peak conditions. That is, the resources would be called on in consecutive peak days for a longer period of days (for example 7 consecutive days instead of 2 days) which places an extra performance burden on the load reduction resources.

Additional performance concerns exist for the demand resources, even beyond the extreme cases of need. Under conditions with heavy penetration of demand resources they would not only be called on in peak months, but would also be called on in shoulder periods to compensate for planned outages of generation units. This places an extra performance burden on the demand resources to reduce load in periods where the ability to do so might be limited. That is, the consumption levels may already be low when not driven up by weather conditions. Therefore, the ability to get the resource to respond on a timely basis could be limited.

These issues with demand resources reflect uncertainties which will need to be carefully considered and addressed going forward. Further, this calls into doubt the ability of demand resources, at such high penetration levels, to act as critical resources which would be able to provide surety of performance. Hence, the reliability benefit of demand resources at such penetration levels needs to be discounted for planning purposes.

3.2 Demand Side Resource Projections and Power-flow Assumptions

Demand resources as used herein reflect measures that result in verifiable reductions in end-use consumption of electricity. These resources include both passive and active resources. Passive demand resources (Passive DR) save energy (MWh) during peak hours, are not dispatchable and may include on-peak and seasonal peak FCM resources. Active demand resources (Active DR) are designed to reduce peak loads (MW). These active resources can reduce load based on real-time system conditions or ISO instructions. They include critical peak, Real-Time Demand Response (RTDR), and Real-Time Emergency Generation (RTEG) in the FCM.

The FCM auction has been very successful at attracting demand resources in New England. Roughly 2,500 MW of demand resources cleared in first FCA (2010/2011). Of these, 700 MW or 31% represent Passive DR and 1,579 MW or 69% represent Active DR.

The second auction has yet to occur, but resources have submitted to qualify to participate. The total of demand resources in first FCA and those showing interest in the second FCA is over 4,200 MW. This represents approximately 14% of the peak requirement in the 2011/12 commitment period. Active resources reflect approximately 9% of the peak requirement.[38]

ICF has relied on the results of the first FCA and show of interest in the second as a basis for determining the DSM projections for 2013 used in the power-flow analysis. Further, where publicly available, ICF utilized current projections for resource potential for specific areas. Most publicly available projections were somewhat dated and inconsistent with the FCA results; however, the Connecticut 2008 Integrated Resource Plan did have analysis which was relied on as a basis for the Connecticut projections. The aggressive case growth assumptions in the Connecticut IRP reflected the highest growth rates of other technical studies for DSM potential in the New England area that were found in the public domain.

The Connecticut IRP presented two cases, a Reference Case, and a DSM Focus Case. The DSM Focus case reflects the more aggressive of the two and was relied on for this analysis as a conservative assumption for the power-flow analysis. That is, the aggressive DSM penetration has a more significant effect on reducing the need for transmission capacity and hence reflects a conservative assumption from the perspective of transmission planning. Exhibit 3-2 presents the DSM focus case from the Connecticut IRP. The resources labeled EE reflect non-dispatchable or passive energy efficiency resources while those labeled DR reflect active resources as per the descriptions above. Further detail regarding the DSM Focus Case, and the aggressive level of penetration associated with it, is provided in section 3.3 below.

Exhibit 3-2
DSM Focus Case Connecticut January 2008 IRP (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UI EE	10	13	24	38	57	81	107	131	157	182	208	234
UI DR	20	42	92	103	108	113	118	118	119	120	121	122
CLP EE	36	50	96	154	224	308	401	501	594	668	723	768
CLP DR	346	380	447	453	476	496	506	506	506	506	506	506
Total	410	484	658	748	865	998	1131	1257	1376	1476	1558	1630

Page D-15, Table D-4 CT IRP January 1, 2008, The Brattle Group.

Under the aggressive (DSM Focus Case) DSM resources grow in total by 134% between 2008 and 2013, reflecting a 19% annual average growth in each of the next five years. This aggressive growth target was applied to the West Central

[38] 14% reflects the share of the 2008 CELT/RSP ISO-NE forecast for peak. 9% is ISO-NE's estimate, which is believed to be based on the 2007 CELT/RSP forecast.

Massachusetts FCA results for the 2010/2011 period to determine the 2013 potential in the zone. Active and passive resources were assumed to grow at the growth rates applicable to energy efficiency and demand response respectively. These results were cross-referenced with the implied resource base submitting interest in the 2011/2012 forward capacity auction such that the auction results are reflected for 2011/2012 and the IRP growth rate applied thereafter. The resulting DSM trajectories for total, passive and active demand resources are shown in Exhibit 3-3.

Exhibit 3-3
West Central Massachusetts (WCMA) Projections for Demand Resources (MW)

Resource Type	2010	2011	2012	2013	2014	2015	2016
Total Resources	327	416	457	527	589	649	700
Passive Resources	89	128	164	225	288	347	398
Active Resources	238	288	293	302	302	301	302

2010 and 2011 results estimated based on share of resource type to total in 2010/2011 auction results and estimates of the 2011/2012 auction.
CT 2012 forward results based on DSM Focus case in 2008 IRP. All other areas assumed to remain flat in 2012 and grow at same rate as CT DSM Focus case as percent of peak thereafter.

These projections reflect the resources netted up for reserve margin and transmission losses (i.e., generation side) and hence these values reflect the distribution side load. The reserve margin gross-up used by ISO-NE for 2010/2011 was 14.3% and for 2011/2012 16.1%. ICF assumed the 2011/2012 gross up for later years.

The West Central Massachusetts Area (WCMA) is one of eight zones for which prices for load are calculated under Standard Market Design (SMD). SMD is a settlement system utilized within ISO-NE for energy and capacity pricing purposes. SMD settlement includes a zonal characterization in which zones are aggregations of nodes. Generation is priced nodally, while load in a zone will pay a price that is uniform for its zone.

The SMD load zones generally follow the political boundaries of the six New England states, except that Massachusetts is sub-divided into three separate load zones, West Central Massachusetts (WMCA), Southeast Massachusetts (SEMA), and Northeast Massachusetts/Boston (NEMA/BOS). These are reflected in Exhibit 3-4 below. The WCMA zone includes the Greater Springfield area.

Exhibit 3-4
New England SMD Load Zones

In contrast, the regional transmission planning process focuses on 13 zones defined by congestion areas. There is some, but not perfect overlap between the SMD load zones and the RSP transmission planning zones. The analysis herein is primarily focused on the RSP planning zone for Western Massachusetts (WMA), however, for select resource projections, SMD load zones are utilized consistent with the market operations. In particular, load reduction programs are driven in large part through the SMD zonal pricing signals and thus forecasts for load reduction programs are generated at the SMD zonal level. Consistent with this market driven approach, the load reduction estimates utilized herein are estimated at the load zone level rather than the RSP planning zone level.

WCMA roughly reflects the combination of the WMA and Central Massachusetts/Northeastern Massachusetts (CMA/NEMA) RSP zones with the following exceptions: 1) the southeast corner of New Hampshire is contained in the CMA/NEMA zone but not WCMA; 2) the southwest corner of New Hampshire is part of WMA but not WCMA; 3) a small portion of north-central Connecticut is part of WMA but not WCMA; and 4) the WCMA contains a small portion of the northwest corner of the Boston RSP zone, near the cities of Lawrence and Billerica Massachusetts.

Further discussion on the Connecticut IRP assumptions is provided in the next section.

3.3 Review of Demand Resource Plan in the January 2008 Connecticut Integrated Resource Plan

In January, 2008, the Brattle group published an Integrated Resource Plan (IRP) for Connecticut. Within this IRP, demand-side resource options were evaluated for their ability to meet future resource gaps.[39] Two levels of DSM efforts were considered. The "Reference Level" represents current and planned expenditures by the state and was identified within the study as already being "aggressive". The "DSM-Focus Level" represents a significant expansion beyond this reference scenario and assumes that the programs would:

- promote the most efficient cost-effective equipment available,
- accelerate early retirement programs,
- achieve operational efficiencies by integrating program design and delivery, and,
- coordinate with other state-wide initiatives.

This scenario was identified as a "very ambitious program that is unprecedented in New England" and would result in an actual reduction of demand below current levels by 2018. As an illustration of the aggressive nature of the estimate, it anticipates savings from emerging technologies not yet available to the mass market, such as LED general task lighting and heat-pump water heaters.

While the methodology used to develop this aggressive level is not highly detailed, the report indicates that one of the principal sources of the estimate was a study completed by GDS Associates.[40] This study was completed with the express purpose of estimating the long-term maximum achievable cost-effective potential within Connecticut and formed the foundation for the IRP's estimate. It arrives at this estimate by first estimating technical potential (i.e., all measures for which it is technically feasible to install them), then maximum achievable potential (i.e., 80% of technically feasible potential), and finally maximum achievable cost-effective potential (i.e., achievable potential that meets the total resource cost (TRC) test).

The assumption that 80% of technically feasible potential is achievable is very aggressive and reflective of the study's philosophy that this value represents what "would be adopted given unlimited funding, and by determining the maximum market penetration that can be achieved with a concerted, sustained campaign involving highly aggressive programs and market intervention". ICF's typical estimate of achievable potential varies by measure and study, but generally ranges from 5% to 45%. Among the factors considered in our approach for determining achievable potential is the customers' stated willingness to pay for a measure based solely upon its payback period.

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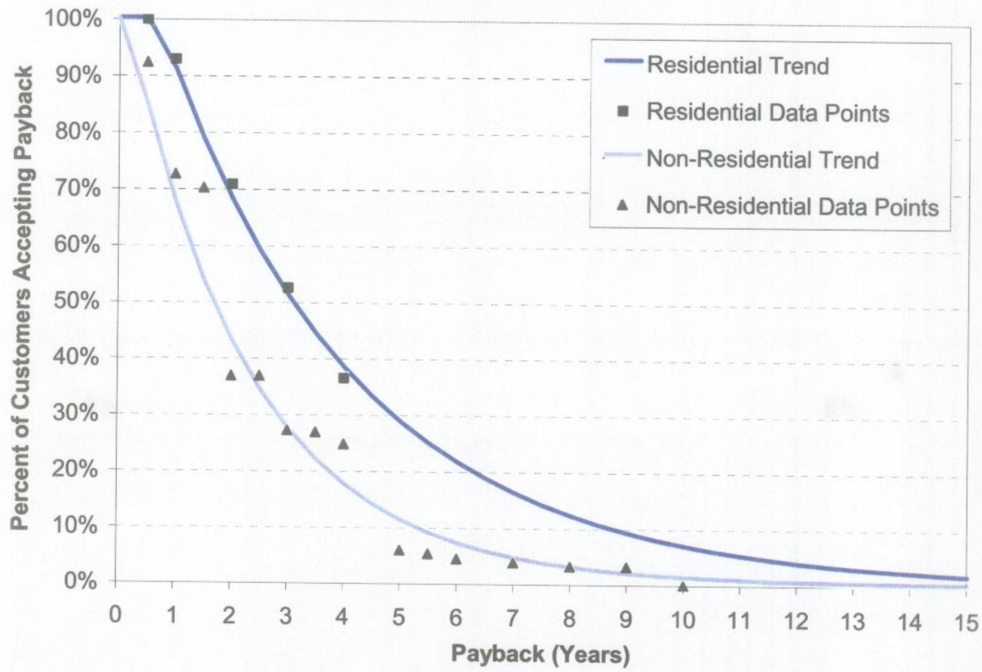
[39] Integrated Resource Plan for Connecticut, The Brattle Group, January 1, 2008.

[40] *Independent Assessment of Conservation and Energy Efficiency Potential for Connecticut and the Southwestern Connecticut Region*, **Final Report for the Connecticut ECMB, GDS Associates, Inc. and Quantum Consulting, June 2004**

Exhibit 3-5 shows the payback acceptance curves used by ICF and the data points used to derive them. The curve shows the percentage of consumers willing to pursue an energy-saving project at a given payback period. The complete curve was developed by a regression through the collected data points. The implication of the curve is that willingness to pursue a project drops off very quickly as the payback period rises. Though the vast majority of consumers would be willing to pursue a project with a payback of 1 year, only half are willing to accept a project with a 3-year payback.

Exhibit 3-5
Payback Acceptance Curves



Based upon this curve alone, substantial program incentives would be required to pay down payback periods to 0.5 to 1.5 years to achieve 80% of technical potential, and one would have to assume that participation is driven solely by payback period. More typical payback targets are 2 years. Also, as evidenced by the fact that much of the market has not transitioned to highly cost-effective fluorescent lighting, not all decisions are based upon payback alone. For these reasons, assuming that achievable potential is 80% is very aggressive.

In all, the IRP recognizes that the "DSM-Focus Level" scenario is an extremely aggressive level. As the study notes, the DSM ramp up rate is unprecedented, estimating a tripling of DSM activity in five years. Due to the GDS report's definition of achievable potential, its assumption of unlimited funding and highly aggressive marketing for cost-effective measures, the IRP's reliance upon emerging technologies to achieve savings, and the expectation that the scenario will result in eliminating more than 100% of load growth (an achievement that ICF is not aware of having occurred with any other utility), ICF considers this a highly-aggressive estimate of DSM potential.

Supply-side resources were also reviewed to ensure that adequate supply was maintained for generation planning purposes. The options considered included traditional generation supply such as combined cycles, combustion turbines, fossil steam units, nuclear units, and renewable units. The decision on the type of resource necessary to add to maintain adequate reserves was based on a high level assessment of the economics of these options. New generation capacity is primarily required to meet demand and reserve margin requirements and to satisfy the state level Renewable Portfolio Standards (RPS).[41] Some existing New England generation capacity is also expected to retire by 2013 due to changing market conditions and age of the units. Such retirements may be due to cost of operating aging units exceeding energy and capacity revenues, new technologies displacing aging fleets, or other factors. Details of the analysis are provided below.

4.1 Generation Capacity Additions

Generation additions for 2013 were based on public announcements for committed capacity and an assessment of basic capacity requirements based on a needs review. In assessing the need for new generation to meet demand requirements, consideration was first given to the DSM and CHP penetration within the market. That is, the peak load was considered after deducting the DSM and CHP resources which would serve to reduce the load requirements. Once the decremented load was determined, a basic analysis was performed to ensure that there would be adequate supply resources available to satisfy a reserve margin requirement. This was particularly important because increasing penetration of demand resources will reduce the need for generation capacity. For most of the New England market, ICF determined that due to the expected demand reduction from DSM and CHP, economic generation addition would comprise in large part minimal amounts of renewable energy sources which contribute to the state level RPS needs. This result is consistent with the New England forward capacity market auctions which reflect a depressed price for generation given the addition of significant demand resources. That is, the ability of the market to attract new generation at the prices cleared in the first capacity auction is extremely low relative to the capital required to construct such assets.

The western Massachusetts retail service provider (RSP) zonal load is expected to be less than 2.5 GW at peak in 2013, and is further reduced by DSM and CHP installations. The current supply is 3.5 GW of capacity, implying that there is a 40% reserve available and no additional local supply is needed to satisfy the reserve requirement.

In addition to looking at the reserve requirements, ICF reviewed requirements in the New England states for renewable generation resources (Renewable Portfolio Standards). Several of the New England states require that the load serving entities

[41] Renewable Portfolio Standards require that load serving entities supply a certain share of their load through renewable resources. If the load serving entities are not in compliance with these standards, a financial penalty is applicable.

serve a portion of their load through renewable resources and this percentage increases over time. Given that most states allow for the renewable resources to be located in neighboring areas, ICF evaluated the renewable need for New England as a whole. Further, we considered alternate compliance standards in the individual states which allow the load serving entities to pay a financial penalty rather than sourcing all or part of their requirement through renewable sources. To the extent that using renewable supply was more economic than the financial penalties for non-compliance, ICF determined the amount of renewable capacity which would be required in New England to satisfy the overall need.

This analysis was performed using ICF's Integrated Planning Model ™ (IPM®). IPM® is a widely used tool which simulates the operations of the power grid to optimally solve for dispatch, generation additions and retirements, compliance decisions, and power prices over time. Decisions on the timing and zonal location of new renewable resources are optimally made within IPM® based on the economics of the options available. Available options reflect options that are supported through the geographical and ambient conditions within the individual zones. ICF utilized its own capital and operating cost assumptions to consider the tradeoff between alternative compliance (or financial penalties) and new renewable capacity decisions.

The resulting need indicated approximately 642 MW of new renewable capacity would be needed in the western Massachusetts zone by 2013 to help satisfy RPS requirements.

To locate these additions appropriately for power-flow purposes, ICF reviewed the current announced capacity additions in the New England queue and selected sites which most closely reflected the additions. The ISO queue for western Massachusetts is shown in Exhibit 4-1 below. Of the 642 MW of renewable generation, 353 MW was sited on the 115-kV line between the Buck Pond and Pochassic substations, 280 MW was sited at the Stony Brook substation and 9 MW was sited at the Mt Tom substation. All three locations are in Hampden County.

Exhibit 4-1 also shows that there is 1,100 MW of new or upgraded generation in the western Massachusetts queue. However, historically less than 20% of the capacity in the queue is actually realized. Thus less than 220 MW of the 1,100 MW can be expected to come on-line.

Exhibit 4-1
ISO-NE Generation Queue for Western Massachusetts Zone

Request Date	Project Type	Fuel Type[1]	Summer Net MW	County	State	Projected Commercial Operation Date	Proposed Point of Interconnection
5/12/2003	Hoosac Wind Project	WND	30	Berkshire & Franklin	MA	9/1/2008	Line Y25S
8/19/2005	Biomass	WDS	55	Hampden	MA	6/30/2011	Blanford - Southwick - Elm 115-kV line
10/13/2006	Combined Cycle	NG, DFO	280	Hampden	MA	6/1/2012	345-kV Stony Brook Substation
12/22/2006	Gas Turbine	NG, DFO, KER	156	Hampden	MA	1/31/2010	W Mass. Mt. Tom 115-kV Substation
1/16/2007	Pump Storage Capacity Upgrade	WAT	1180 total 100 upgrade	Franklin	MA	6/30/2010	W. Mass Northfield 345-kV substation
6/27/2007	Biomass Project	WDS	61.5	Berkshire	MA	12/1/2010	Doreen 115 kV substation or F132 115-kV line
9/26/2007	Pump Storage Capacity Upgrade	WAT	333 total 33 upgrade	Berkshire	MA	3/31/2011	Bear Swamp 230-kV Substation
9/26/2007	Pump Storage Capacity Upgrade	WAT	333 total 33 upgrade	Berkshire	MA	3/30/2012	Bear Swamp 230-kV Substation
11/30/2007	Combined Cycle	NG, DFO	353	Hampden	MA	6/1/2012	115-kV line between Buck Pond and Pochassic substations-1302 line
12/7/2007	Landfill Gas	LFG	1.6	Worcester	MA	12/1/2009	13.8-kV distribution circuit

1, NG = Natural Gas; KER = Kerosene; LFG = Landfill gas; DFO = Distillate fuel oil; WAT = Water; WDS = Wood and wood waste; and WND = Wind.

4.2 Generation Capacity Retirements

Generation capacity retirement decisions were based on two main criteria:

1. the ability of generation units to meet their fixed and variable operating costs given expected market conditions, and
2. the age of the unit.

The former criteria (cost recovery) was specifically applied to generation facilities currently under Reliability Must-Run (RMR) contracts with ISO-NE since a reasonable estimate of their operating cost can be derived from publicly available market data as described below. The second criterion was applied to all non-hydro plants.

Reliability Must-Run (RMR) Units – For the units that ISO-NE identifies as being necessary to ensure system reliability, but that are unable to recover their operating costs under current market conditions, the ISO has authority to negotiate agreements for the purchase of electric energy at cost-based rates from these generation facilities. These agreements are called Reliability Must Run agreements, or RMR agreements. Such agreements are subject to FERC's approval.

Under a RMR agreement, the must-run unit is entitled to a monthly Fixed-Cost Charge, paid by the ISO for the generation resources, but can only bid energy and ancillary services into ISO-NE by the Stipulated Bid Costs, which are equal to:

$$\text{Stipulated Bid Cost} = (\text{Fuel Cost} + \text{VOM Cost} + \text{Environmental Cost}) \times \text{kWh}$$

Any revenue gained from market in excess of the Stipulated Bid Costs is to be subtracted from the monthly fixed-cost charge. This mechanism is comparable to that of the Forward Capacity Market (FCM). The capacity payment to generation and demand resources that have cleared in the FCM auction is the counterpart of the fixed-cost charge to RMR units. To mitigate market power in energy markets, the FCM also establishes a proxy unit with heat rate of 22,000 BTU/kWh. Any energy revenue in excess of the proxy heat rate multiplied by the indexed natural gas price will be deducted from the monthly capacity payments. This proxy unit implementation is similar to that of the Stipulated Bid Costs faced by an RMR unit.

Currently there are 10 RMR agreements in ISO-NE, all located in Connecticut or Massachusetts. All of them will be terminated on June 1, 2010, the first day of the first Commitment Period of the FCM. All RMR units are considered as existing units and need to participate in the FCM, unless they submit delist bids. Since they are treated as existing units, RMR units are price takers in a forward capacity auction, and are entitled to a monthly payment at the market clearing price. The first FCM auction had a clearing price of \$4.5/kW-month, which is lower than the fixed-cost charge received by any of the 10 RMR units.

In addition, the \$4.5/kW-month market clearing price is three quarters of the Cost of New Entry (CONE), which is \$7.5/kW-month and is estimated by the ISO to reflect capital and fixed O&M costs of a new peaking unit. CONE is an important parameter in the FCM, as the floor and ceilings of market clearing price is tied to the CONE. Hence, a low CONE is likely to result in a lower clearing price. Based on the FCM rules, the CONE for the second auction is \$6.0/kW-month. Technology advances will further bring down the costs of new peaking units. Though capital, labor, and other costs may be increased at times, the CONE for the first FCM auction is nevertheless a good benchmark for projecting the future capacity market prices.

Currently, six out of ten RMR units' fixed-cost charges exceed the CONE for the first FCM auction. Those units will likely receive lower capacity payments from FCM than from their RMR agreements. On the energy-market side, the RMR units cannot recover their operating costs if they are to be dispatched by the ISO. When the RMR agreements terminate and FCM is in effect beginning in June 2010, even though the RMR units do not have to bid the Stipulated Bid Cost, their high operating costs will still not favor them under economic dispatch. The RMR units may collect significant amount of profits during energy price spikes, given they are dispatched. However, the proxy-unit mechanism entailed by the FCM rule will limit such profits. Without the cost-recovery guaranteed energy revenue and with lower capacity market payments, the RMR units currently receiving high fixed-cost payments are likely to retire shortly after the commencement of FCM in June 2010, unless new RMR agreements are granted. With abundant new generation and demand resources participating in the first FCM auction, justifications for renewing the costly RMR agreements are diminishing.

ICF uses the CONE in the first FCM auction as a benchmark to derive the retirement assumptions on RMR units. Specifically ICF assumed that generation units under RMR contracts will retire if their current RMR payment is above the CONE in the first FCM auction. If these units do not retire, then these units would be forced to earn full compensation through the market, assuming no other regulatory source was available, and thus their operating costs would exceed their expected revenue. Among the six RMR agreements whose fixed-cost charges are above the first CONE ($7.50/kW-month), Milford is a relatively new unit (online in 2004). From a conservative point of view, we do not retire Milford in our study. The plants, Berkshire Power and ConEd – West Springfield, and two units of Altresco Pittsfield are considered to be retired in our contingency analysis. The remaining RMR units, Altresco Pittsfield Unit 3 and 4 (33 MW and 49 MW), Norwalk Harbor Unit 1 and 2 (162 and 168 MW), and Bridgeport Harbor (170 MW), are assumed to retire in 2013. Exhibit 4-2 shows the current RMR agreements, and our assumptions on RMR units' retirements.

Exhibit 4-2
RMR Agreements

Generator Name	State	Zone	2008 CELT Summer Capability (MW)	Fixed-Cost ($/kW-mo)	Capacity (MW)	Treatment
ConEd -- West Springfield 3	MA	WMA	94.28	6.23	114	
Berkshire Power	MA	WMA	229.28	9.45	272	Retired 2013
Pittsfield Gen. "Altresco"	MA	WMA	141.04	7.68	180	Retired 2013
ConEd -- West Springfield GT-1 GT-2	MA	WMA	74.34	10.99	120	Retired 2013
NRG -- Middletown 2-4, 10	CT	CT	770.12	5.37	787	
NRG -- Montville 5,6,10&11	CT	CT	493.70	4.84	495	
Milford 1 and 2	CT	SWCT	488.71	12.36	530	Not Retired
PSEG -- New Haven Harbor	CT	CT	447.89	6.98	460	
PSEG -- Bridgeport Harbor 2	CT	SWCT	130.50	8.95	170	Retired 2013
NRG -- Norwalk Harbor 1 & 2	CT	NOR	330.00	9.51	330	Retired 2013

Source: ISO-NE Reliability Agreements - Annual Fixed Costs Summary, updated through 06/02/2008.

Over 60-year units – The second criterion (age) was applied to all non-hydro units that will reach 60 years of operation before or in 2013. We assume these units are retired for purposes of the 2013 power-flow case. This assumption is consistent with that in

ISO-NE's system planning process. Under this assumption, a total of 207 MW in New England will reach the age of 60 years by 2013 and retire. Unit online dates are based on the ISO-NE 2008 CELT report. Exhibit 4-3 summarizes our assumptions on retirement of units that reach the age of 60 years by 2013. No units in western Massachusetts are affected by this assumption.

Exhibit 4-3
Retirement Assumptions on units reaching 60-year[1] service limit by 2013

Unit Name	Unit ID	Zone Name	Maximum Capacity (MW)	Age by 2013
Salem Harbor	1	BOSTON	81	62
Salem Harbor	2	BOSTON	78	62
Schiller	4	NH	48	62

Note: 1. 60 year old retirements based on online dates in ISO-NE CELT 2008 report.

The approach using these two criteria results in a conservative estimate of capacity retirements for several reasons. Rather than considering the operating costs for all units, we limit the review to only those units that are currently on RMR contracts. These units represent only a small amount of the total capacity which may be at risk of not being able to recover operating costs through realized market pricing. In particular, those units which are exposed to increasing cost requirements related to compliance with stricter air emissions standards such as a carbon reduction program are also at risk. Coal generation facilities in particular face these environmental risks, though other types of generators are affected as well. Estimates for the expected carbon allowance price ranges from roughly $5/ton to over $100/ton by 2013; this range is based on the severity and timing of the policies as well as the ability of resources to reduce carbon emission through control equipment (or reduction in output). Within the western Massachusetts RSP zone, there is one facility at risk due to possible tightening of air emission control policies. This is the Mount Tom facility which has a capacity of 146 MW of coal generation.

Chapter Five: Key Assumptions for the Power-Flow Modeling

This chapter provides additional detail regarding the overall assumptions used in the power-flow model. The power-flow case was based on the 2012 power-flow planning case from ISO-NE. The basic assumptions were updated to include more recent information available since the creation of that power-flow case and also to reflect the alternative assumptions described in the previous three chapters. Note the case was also updated to reflect the 2013 year rather than the 2012 year.

The key assumptions for the power-flow modeling include:

- Peak Load Characterization
  - 2013 Peak Demand Projection
  - Transmission Loss Adjustment
  - DSM and CHP Adjustments
- Supply Side
  - Existing Generating Capacity
  - Forced Outage Rate and Spinning Reserves
  - Capacity Additions and Retirements
  - Additional Dispatch Related Assumptions
  - Stressed Generation Capacity Case

5.1 Peak Load Characterization

5.1.1 2013 Peak Demand Projection

The ISO-NE load growth forecast issued in April 2008 is the source for the demand data used in this analysis. ISO-NE provides a reference load forecast that is characterized as having a 50 percent chance of being exceeded. An extreme weather peak demand forecast is also provided by ISO-NE that is characterized as having a 10 percent chance of being exceeded. In compliance with standard transmission reliability planning, ICF uses the extreme weather peak demand forecast (also known as the 90/10 forecast). Under the 90/10 forecast, the western Massachusetts peak demand is estimated to be 2,490 MW in 2013.

ICF believes that relying on the ISO-NE projection for the 2013 year is a conservative assumption based on ISO-NE's own statements that indicate that their load projections for 1, 3, and 5 years into the future have been below the actual realized load growth on a consistent basis. The average forecast error ISO-NE has documented for the fifth year (the relevant year for our study) is biased to a 4.2% under estimate of peak. For the western Massachusetts 90/10 case, this implies 104 MW of additional demand at peak, or a peak load of 2,594 MW rather than 2,490 MW.

5.1.2 DSM and CHP Adjustments

For power-flow modeling purposes, DSM and CHP resources are decremented from the peak demand level used in the model. The dispatchable DSM resources such as the emergency generators and demand response are assumed to be reserved for emergency conditions and are not removed from the ISO-NE peak load projection in the power-flow cases.[42] Thus, the western Massachusetts peak load is only decremented by 225 MW to account for the non-dispatchable DSM resources for the power-flow analysis, accounting for about 43% of the total western Massachusetts DSM projection. CHP resources are removed in total, reflecting an additional 33 MW decrement in peak demand. After accounting for the CHP and DSM resources, the power-flow peak modeling characterization is 2,232 MW for the western Massachusetts zonal peak.

5.1.3 Transmission Loss Adjustments

The ISO-NE load projections are based at the generator bus-bar and hence include both transmission and distribution losses. In contrast, power-flow load inputs reflect the load at the distribution transfer point rather than at the generator level. As such, we have adjusted the ISO-NE load projections to remove transmission losses to reflect the distribution load levels. This allows for the power-flow to internally determine the transmission sector losses.

5.2 Supply-Side Characterization

To establish a starting point for the Reference Case scenarios considered in the analysis, ICF first established a view of system dispatch under normal peak day conditions such that system operations were not stressed. This starting point dispatch utilizes the existing generation resources as reported by ISO-NE, and includes the ISO-NE typical generation unit forced outage rate and spinning reserve requirement.

5.2.1 Generation Capacity

ICF relied on the generation capacity for existing units as provided directly in the power-flow case. The capacity included in the power-flow case reflects the maximum summer-rated capacity for each unit. Additional modifications were made to account for capacity additions and retirements by 2013.

5.2.2 Forced Outage Rate and Spinning Reserve

The required forced outage rate in each zone is 7 percent of total capacity within the zone. To implement the forced outage in the power-flow model, ICF turned off selected generation units within each zone, to reach 7 percent of the total capacity. These units were considered not available to meet system demand.

A spinning reserve requirement of 15 percent of total capacity was also implemented in the power-flow model. This represents generation capacity that is made available to respond to system contingencies. The 15 percent spinning reserve was implemented in each zone with the exception of Rhode Island. Since Rhode Island is a net exporting

[42] ISO-NE views dispatchable DSM as supply side resources

region, it is expected that all generation units within that area will be operating at their available capacities on a peak summer day.

5.2.3 Capacity Additions and Retirements

Capacity additions and retirements as described in Chapter Four were incorporated into the power-flow cases.

5.2.4 Additional Dispatch Related Assumptions

Other unit specific dispatch requirements were modeled. For example, nuclear generation facilities are expected to operate at their full output on a typical summer peak day. Therefore in the model, all nuclear units throughout New England were fully dispatched.

5.2.5 Stressed Case Generation Characterization

The study also assessed the ability of the system to operate reliably following the loss of selected generation resources in the study area. In each generation outage scenario the system was allowed to adjust following the loss of the generator.

The consideration of generation outage scenarios in this report is limited to the outage of the Millstone unit 3 nuclear generation facility in Connecticut. This is because this facility is critical to electric transmission reliability in western Massachusetts. Under the current system configuration, severe transmission line overloads may occur when the Millstone 3 facility is out of service. This type of stress case is necessary to consider for reliability planning purposes and is consistent with the NERC guidelines for such.

Chapter Six: Detailed Results for the Greater Springfield Reliability Project

This section presents the results of the power-flow analysis to determine if non-transmission resources, such as DSM, CHP and new generation capacity, can displace or delay the need for the Greater Springfield Reliability Project. The power-flow analysis was conducted on the Pre-GSRP Case and the Springfield Case, and the results were compared to determine if the Project would provide reliability benefits above and beyond that of the non-transmission resources. In particular, ICF determined whether reliability violations existed in one or more sections of the transmission grid following the implementation of the non-transmission resources in the Pre-GSRP Case. ICF then evaluated system performance in the Springfield Case to determine the ability of the Project to resolve all the violations.

For both the Pre-GSRP Case and the Springfield Case, two main system conditions were examined – a Reference Scenario in which generation facilities were allowed to operate as would be expected during a peak summer period, and a stressed generation case, the Millstone Facility Outage Scenario, in which the Millstone Unit # 3 generation facility was assumed to be out of service. In both scenarios, the West Springfield and Berkshire generation facilities are assumed to be unavailable during the study period. This reflects the economic uncertainty regarding the continued operation of these units, given that their fixed-cost charge exceeds both the clearing price from the first FCM and the expected price for the second auction given the show of interest from demand resources. However, for completeness of the study, scenarios with the West Springfield and Berkshire generation facilities online were also analyzed. These scenarios are described later in the chapter.

The power flowing on each transmission line, also referred to as the line loading, was measured and compared to the thermal limit or capacity of the line to determine if the power grid would operate reliably and continue to serve all consumers under the conditions that were simulated. For reliable system operation, the loading on each transmission line should remain within the appropriate rating of the line. Similarly, substation voltages were measured and compared to the limits required for reliable system operation.

As described in detail below, ICF observed that the implementation of the non-transmission alternatives fail to resolve all the transmission line overloads that may occur in the Springfield area under anticipated operating conditions. This is particularly evident under contingency conditions, that is, during periods that one or more transmission facilities are out of service. Further, when the Millstone generation facility is out of service, severe transmission line overloads occur in the Pre-GSRP Case. The implementation of the Project resolves the reliability problems since it reinforces the Springfield area transmission backbone and also provides redundant transmission capacity across which power can be redistributed in case of a failure of other transmission elements.

In all cases, the contingencies shown in the following tables are those that result in the most severe overload for each monitored elements. The tables do not list all contingencies that impact the monitored element. The model simulation showed that in the Pre-GSRP cases, several different contingencies could cause overloads on the transmission elements shown.

6.1 Reference Scenario Results

Exhibits 6-1 through 6-3 summarize the performance of the Springfield area transmission grid in the Reference Scenario for both the Pre-GSRP Case and the Springfield Case. Exhibit 6-1 shows system operation during a peak summer period assuming all transmission facilities operate under normal conditions, that is, assuming no contingency outages occur. In Exhibit 6-2 one transmission element is allowed to fail to reflect a system contingency. Exhibit 6-3 shows system conditions if one transmission element is assumed to be out of service and an additional transmission element is allowed to fail to reflect a system contingency that occurs during the peak period. Exhibit 6-2 therefore displays results assuming a single transmission element is unavailable, while Exhibit 6-3 shows results if two transmission elements are unavailable.

As part of the Project, some sections of the Springfield area transmission grid will be reconfigured to improve system reliability. Therefore, the definition of transmission line contingencies and monitored elements will change with the change in configuration. For example, under the current configuration, the Holyoke substation connects directly to the Fairmont South bus. With the implementation of the Project, the line from the Holyoke substation will be re-routed to connect to the new Fairmont switching station and the East Springfield Junction 1254 will be eliminated. A direct comparison of some contingencies will therefore not be applicable. This is indicated in Exhibits 6-1 through 6-7 below. For example, in Exhibit 6-1, the 115-kV transmission line from East Springfield JCT 1254 to Shawinigan is no longer a relevant monitored element in the GSRP Case. As illustrated in Exhibit 6-4, however, ICF's analysis shows that with one exception, the project will resolve all the Pre-GSRP overloads.[43]. Exhibit 6-4 shows the expected loadings on some of the prominent transmission lines in the Springfield area under N-1 and N-1-1 contingency conditions after the system reconfiguration. As shown, line loadings are within the appropriate limits in the Springfield case.

The tables list transmission facilities that will be overloaded or heavily loaded under the simulated conditions. A description of the facility is given in the column labeled Monitored Element. In addition, the expected line loading for the selected transmission facility is given as a percentage of the limit of the line.

Exhibit 6-1 shows line loadings assuming no system contingencies. For example, [redacted] even assuming no transmission line contingencies[44] occur.

[43] The one exception involves an N-1-1 double circuit contingency.
[44] N-0 Conditions

However, with the implementation of the Project (Springfield Case), the loading on the line drops to less than 50% of its capacity.

Exhibit 6-1
Prominent Springfield Line Loadings – Reference Case, No Contingency (N-0)

Generator Out-of-Service	Monitored Elements				Line Loadings[1] (% of Normal Rating)	
	From Bus	From KV	To Bus	To KV	Pre-GSRP 2013	Springfield 2013
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	148%	< 50%
	[redacted]	[redacted]	[redacted]	[redacted]	112%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	103%	< 50%
	[redacted]	[redacted]	[redacted]	[redacted]	91%	N/A

[1] "N/A" indicates that a direct comparison is not applicable due to facility reconfiguration.

Exhibit 6-2 shows the line loadings under N-1 contingency conditions. For example, [redacted] This outage is therefore a severe contingency since it results in the loss of six transmission line segments and two distribution level transformer circuits. It involves a double-circuit system outage, but it is considered to be a single contingency event because of tower sharing. The Project eliminates the [redacted] outage. Similar information is shown in the rest of the table.

Exhibit 6-2
Prominent N-1 Springfield Line Loadings – Reference Case

Generator Out-of-Service	Worst Contingency	Monitored Elements				Line Loadings[1] (% of LTE Rating)	
	Line Name- ISO	From Bus	From KV	To Bus	To KV	Pre- GSRP 2013	Springfield 2013
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	280%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	244%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	144%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	115%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	110%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	109%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	104%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	100%	< 50%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	91%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86%	< 50%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	115%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	110%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	107%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	101%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	93%	<50%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89%	N/A

[1] "N/A" indicates that a direct comparison is not applicable due to facility reconfiguration.

Exhibit 6-3 shows that in the Pre-GSRP case if a single transmission element is out of service prior to the contingency outage of another transmission element several 115 kV transmission lines will be overloaded. The severity of the overloads will likely increase as demand increases in subsequent years. As shown in Exhibit 6-3, however, the implementation of the Project reduces line loadings on all the lines considerably, providing reserve transmission capacity to meet further growth in demand and/or other operating conditions that were not modeled. This is because the Project will provide transmission reinforcements in the Springfield area.

Exhibit 6-3
N-1-1 Springfield Line Overloads – Reference Case

Generator Out-of-Service	Line Out-of-Service	Worst Contingency	Monitored Elements				Line Loadings[1] (% of LTE Rating)	
	Line Name-ISO	Line Name - ISO	From Bus	From KV	To Bus	To KV	Pre-GSRP 2013	Springfield 2013
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	366%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	330%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	177%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	156%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	142%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	137%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	133%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	132%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	131%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	130%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	130%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	128%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	128%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	116%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	116%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	114%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	111%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	110%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	110%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	106%	NA
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	104%	NA

[1] "N/A" indicates that a direct comparison is not applicable due to facility reconfiguration.

Exhibit 6-4 shows the expected loadings on some of the prominent transmission lines in the Springfield area following the implementation of the Project. Some of the contingencies shown are not applicable to the Pre-GSRP Case, since these transmission elements are a direct result of the system reconfiguration under the Project. For example, in the East Springfield area, the Springfield Case introduces the new Cadwell switching station which connects to Fairmont switching station and Ludlow, Orchard and East Springfield substations. In the Pre-GSRP case, the East Springfield substation connected to the Fairmont North and Piper Road substations through Junction 1723.

As shown in the table, with the implementation of the Project, the line loadings in the Springfield Case remain within limits under N-1 and N-1-1 conditions.

Exhibit 6-4
Prominent Line Loadings in Springfield Case, N-1 and N-1-1

Generator Out-of-Service	Line Out-of-Service	Contingency	Monitored Elements				Line Loadings (% of LTE Rating)
	Line Name-ISO	Line Name - ISO	From Bus	From KV	To Bus	To KV	Springfield 2013
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	30%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	36%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	47%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	30%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	45%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	46%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	45%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	24%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	27%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	40%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	31%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	23%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	11%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	87%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	35%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	73%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	85%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	76%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	58%

6.2 Millstone Unit # 3 Outage Scenario Results

The 1357 MW Millstone Unit # 3 nuclear generation facility is the single largest generation unit in Connecticut. An assessment of system conditions assuming the outage of the Millstone Unit # 3 generation facility shows severe thermal violations in the Springfield area in the Pre-GSRP case.

Exhibits 6-6 and 6-7 summarize the expected system performance if the Millstone Unit # 3 generation facility is out of service during a peak summer period. As shown in Exhibit 6-6, the failure of a single transmission element will result in severe overloading on several transmission lines. For example, [redacted]

Similar to the Reference Case, the implementation of the Project results in significantly reduced line loadings on all the transmission facilities.

Exhibit 6-5
Location of Millstone Unit # 3

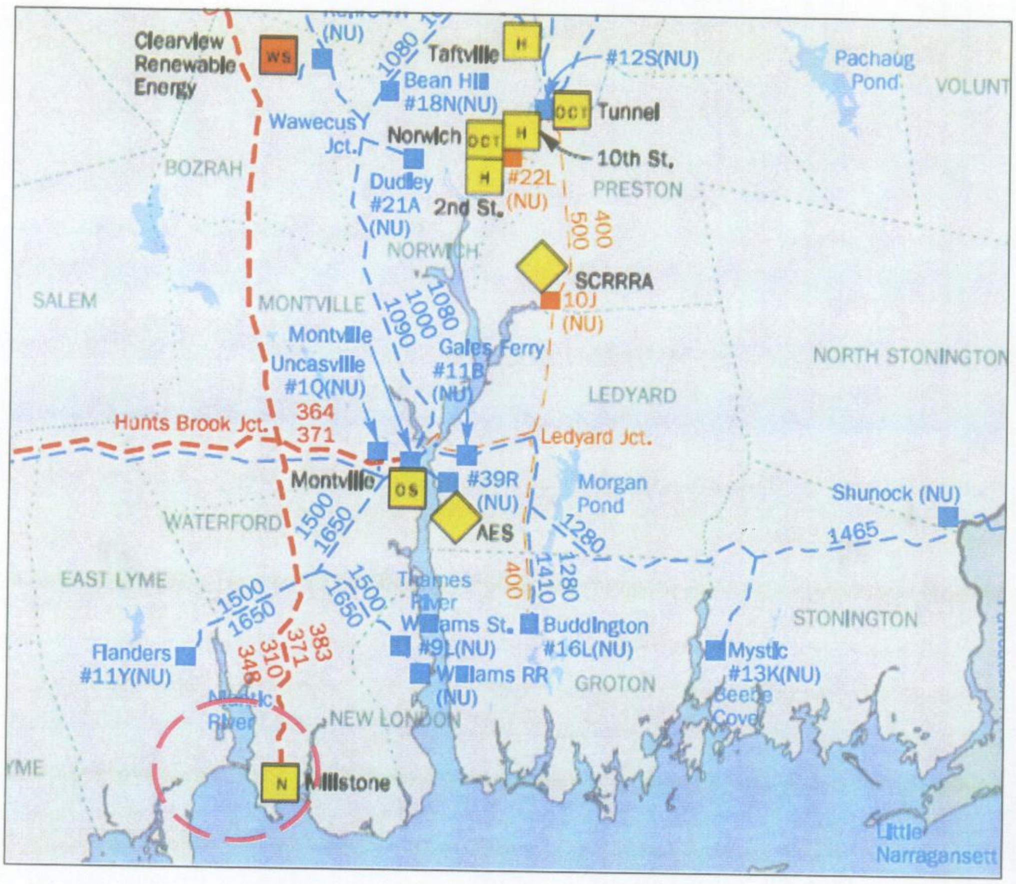


Exhibit 6-6
Prominent N-1 Springfield Line Loadings, Millstone Unit # 3 Outage Case

Generator Out-of-Service	Worst Contingency	Monitored Elements				Line Loadings[1] (% of LTE Rating)	
	Line Name- ISO	From Bus	From KV	To Bus	To KV	Pre - GSRP 2013	Springfield 2013
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	280%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	243%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	143%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	110%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	115%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	109%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	100%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	104%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86%	74%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	86%	< 50%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	92%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	89%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	88%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	90%	N/A

[1] "N/A" indicates that a direct comparison is not applicable due to facility reconfiguration.

The line overloads are even more severe if at least one transmission element is out of service prior to the failure of another transmission element. Exhibit 6-7 shows a representative sample of line overloads under N-1-1 conditions with the Millstone Unit #3 out of service. For example, [redacted]

Exhibit 6-7
N-1-1 Springfield Line Overloads, Millstone Unit # 3 Outage Case

Generator Out-of-Service	Line Out-of-Service	Worst Contingency	Monitored Elements				Line Loadings[1] (% of LTE Rating)	
	Line Name-ISO	Line Name - ISO	From Bus	From KV	To Bus	To KV	Pre – GSRP 2013	Springfield 2013
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	404%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	367%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	192%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	168%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	155%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	150%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	150%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	149%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	147%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	147%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	147%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	143%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	142%	N/A
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	141%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	138%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	138%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	135%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	133%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	133%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	133%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	133%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	126%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	121%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	121%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	119%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	119%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	119%	N/A
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	106%	< 90%
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	106%	N/A

[1] "N/A" indicates that a direct comparison is not applicable due to facility reconfiguration.

6.3 Demand-side Reduction Scenarios

The assumptions in the Reference Scenario regarding the penetration of additional demand and supply side resources over time are derived considering an aggressive demand side penetration in combination with a primarily economic driven generation addition.[45]

ICF considered an alternate approach to this to determine the total incremental amount of demand side resources which would need to be added in order to provide similar reliability benefits to those achieved in the Reference Case already including both transmission and non-transmission alternatives. This is a step in assessing whether there is a feasible alternative to the transmission solution beyond the penetration level already assumed; hence it supplements the Reference and unit outage cases examined.

Under this scenario, the full quantity of CHP, DSM, and generation resources included in the Reference Case were assumed to be online as a starting point. From this case, the peak load was then decremented to determine if all line overloads could be resolved and whether line flows similar to the Reference Case with the Project online could be achieved.

The findings, based on the power-flow analysis, indicated that the incremental load decrement which would need to be applied as a uniform percentage reduction to all load points in the Western Massachusetts zone would be in excess of 2000 MW. This would be more than 80 percent of the peak demand projected for the entire Western Massachusetts sub-area, over and above the 5 percent of peak demand already decremented for active DSM and CHP resources.

In addition, ICF assessed various non-transmission alternatives in the form of demand reduction, generation addition, and combinations thereof. A summary of the scenarios is shown in Exhibit 6-8. All the scenarios were examined under N-1 and N-1-1 conditions.

[45] Generation additions are primarily driven based on ensuring that adequate reserves are maintained over time. The types of resources added are those which would provide the least cost option to maintain reserves. In addition, units which may already be under construction, or units which are had been approved in non-marketed programs (such as the Kleen unit in Connecticut) at the time this analysis began are considered as generation additions.

Exhibit 6-8
Demand Reduction and/or Generation Addition Scenarios

Scenario No.	Description
1	Reduce Connecticut Zonal Demand by 1000 MW
2	Reduce Western Massachusetts Zonal Demand by 1000 MW which includes specific load reduction in certain substations[46]
3	West Springfield and Berkshire power plants operational and new 400-MW facility at Berkshire (Total of 854 MW in Springfield area)
4	West Springfield and Berkshire power plants operational, new 200-MW facility at Berkshire Power, and new 200-MW facility at Mount Tom (Total of 854 MW in Springfield area)
5	West Springfield and Berkshire power plants operational, new 400-MW facility at Berkshire Power, and new 200-MW facility at Mount Tom (Total of 1054 MW in Springfield area)
6	West Springfield and Berkshire power plants operational, reduce CT Zone demand by 500 MW, and curtail load at Chicopee, Clinton, East Springfield, Agawam, and Breckwood substations
7	Same as Case 6 but with West Springfield and Berkshire power plants unavailable

The non-transmission alternatives examined, although extreme and unrealistic, could not resolve system overloads even under N-1 conditions. Under N-1-1 conditions there were several line overloads in addition to those present under N-1 conditions. The detailed results of line overloads under N-1 and N-1-1 conditions for each of the demand reduction and/or generation addition scenarios are shown in Appendix A.

As shown in Scenario 1 of Exhibit 6-8, ICF considered additional demand decrement scenarios to determine if loop flows and exports to Connecticut may be contributing to the overloads. In this case, since the load reduction in Connecticut was not sufficient to relieve the overloads, a load reduction was applied in Western Massachusetts as well. The power-flow results indicated that a 1,000 MW reduction in Connecticut and an additional 1,000 MW reduction in Western Massachusetts failed to resolve all the overloads. Given that this amount of demand reduction is unrealistic, ICF found it unnecessary to pursue further demand reduction.

Given the importance of the location of load reductions on power-flow and line loadings, ICF further examined a scenario in which local load reductions were assumed at key load points rather than uniform load reductions. In cases where problems are isolated to specific geographical points, one would expect that a lesser total reduction would be necessary, i.e. one is attacking the problem at the source. This is described in Scenario 2 of Exhibit 6-8. Under this scenario, the Chicopee, Clinton, East Springfield, Agawam and Breckwood substations were identified as key contributors to the identified reliability issues, and the assumption was made that all load at these five substations was set to zero. This removed 273 MW of coincident peak load. With this change alone, overloads

[46] Specific substations include Chicopee, Clinton, East Springfield, Agawam and Breckwood.

continued to exist on the system and as such, further uniform decrements were applied to all points in the Western Massachusetts zone to address the overloads. A further decrement of load to a total of about 1000 MW was applied through curtailment or other means in addition to the 273 MW of site specific load in the Western Massachusetts zone. This still failed to resolve all the overloads, although it reflects over 40 percent of the 90/10 projected peak load for the Western Massachusetts zone in 2013. Our conclusion from this analysis was that the site specific loads which most contribute to the local line overloads are not significant enough to reduce line overload issues in the area, even in the extreme case where all local load was eliminated.

Further, ICF assessed the ability of generation addition at key locations in the Western Massachusetts zone to help alleviate the overloads. The scenarios, labeled Scenarios 3 to 7 of Exhibit 6-8, included the addition of 200 MW to 400 MW of new generation at Berkshire Power, 200 MW at Mount Tom, and the assumption that the existing West Springfield and Berkshire Power generation facilities are operational during the study period. This latter assumption implies that the West Springfield and Berkshire generation facilities must continue to be operated as RMR units during the summer peak period.

In all cases ICF found that the generation addition scenarios – individually and in combination – were not sufficient to relieve the overloads. An additional demand reduction of 1,000 MW in the Western Massachusetts zone failed to resolve all overloads in each of the cases. Given that this amount of demand reduction is unrealistic, ICF found it unnecessary to pursue further demand reduction.

The demand reduction that will be necessary in the Western Massachusetts zone based on these several cases reflects an unrealistic level of resources. The resulting peak demand in the Western Massachusetts sub-area would need to be below 500 MW to achieve the reliability benefits of the Project. This reflects a situation where in 2013, the peak load would need to be reduced by more than 80 percent of today's peak demand level, a situation not able to be technically achieved.

Chapter Seven: Conclusions

It is evident from this study that the Greater Springfield Reliability project is critical to the reliable operation of the New England transmission grid, and in particular, the western Massachusetts and north-central Connecticut transmission system. This conclusion is supported by results of the power-flow analyses, which indicate that the implementation of non-transmission resources alone will not be sufficient to resolve the numerous transmission facility overloads that could potentially occur when some key transmission elements are out of service.

The study has shown that the Project, coupled with expected non-transmission resources, will sufficiently resolve the overloads and violations. In addition, the transmission reinforcements from the Project will provide reserve transmission capacity that can be used to redistribute power in the event of a system emergency, and which will also be available to meet future system needs as demand grows in the western Massachusetts area.

ICF's study examined a Reference Scenario that reflected summer peak conditions in 2013, assuming all facilities operated as expected. Non-transmission resources, including DSM, CHP and new generation capacity, were implemented in this scenario. To a large extent, the grid would be able to serve consumer demand under these conditions if all transmission facilities remained in service. If one of a number of key facilities is out of service; however, the ensuing severe overloads would compromise the integrity of the grid in the western Massachusetts area. The Project will provide additional transmission capacity that will resolve these reliability problems.

The study also showed that system conditions worsen considerably if the Millstone Generation facility is out of service, especially if this is coupled with the outage of one of several transmission lines.

Since western Massachusetts has limited high voltage (345-kV level) connections to the rest of the New England 345-kV transmission backbone, and limited generation connected to the 115-kV system, the additional 345-kV capacity provided by the Project significantly improves the reliability of the western Massachusetts transmission grid.

The conservative nature of the assumptions used in the study further reinforces these conclusions. Even under these conservative assumptions, the reliability of the system must be addressed through the proposed transmission upgrade. Less conservative assumptions would result in greater line overloads than were determined in this study.

APPENDIX A: DEMAND REDUCTION/GENERATION ADDITION ALTERNATIVES FOR THE GREATER SPRINGFIELD RELIABILITY PROJECT (GSRP)

Exhibit A.1: Demand Reduction and/or Generation Addition Scenarios

Case	Case Description
1	Reduce Connecticut Zonal Demand by 1000 MW
2	Reduce Western Massachusetts Zonal Demand by 1000 MW which includes specific load reduction in certain substations[47]
3	West Springfield and Berkshire power plants operational and new 400-MW facility at Berkshire Power (Total of 854 MW in Springfield area)
4	West Springfield and Berkshire power plants operational, new 200-MW facility at Berkshire Power, and new 200-MW facility at Mount Tom (Total of 854 MW in Springfield area)
5	West Springfield and Berkshire power plants operational, new 400-MW facility at Berkshire Power, and new 200-MW facility at Mount Tom (Total of 1054 MW in Springfield area)
6	West Springfield and Berkshire power plants operational, reduce CT Zone demand by 500 MW, and curtail load at Chicopee, Clinton, East Springfield, Agawam, and Breckwood substations
7	Same as Case 6 but with West Springfield and Berkshire power plants unavailable

[47] Specific substations include Chicopee, Clinton, East Springfield, Agawam and Breckwood.

Exhibit A.2: N-1 Line Overloads in Springfield Area

Monitored Elements				Maximum Line Loading Observed[48] - (% of LTE Rating)							
From Bus	From KV	To Bus	To KV	Pre-GSRP 2013	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
[redacted]	[redacted]	[redacted]	[redacted]	280%	269%	179%	< 90%	< 90%	< 90%	115%	193%
[redacted]	[redacted]	[redacted]	[redacted]	244%	233%	180%	< 90%	< 90%	< 90%	119%	194%
[redacted]	[redacted]	[redacted]	[redacted]	144%	135%	< 90%	< 90%	< 90%	< 90%	< 90%	100%
[redacted]	[redacted]	[redacted]	[redacted]	92%	100%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	110%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	115%	117%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	104%	106%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	109%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	93%	126%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	100%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	108%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	91%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	119%	< 90%	116%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	118%	< 90%	116%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	111%	< 90%	109%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	111%	< 90%	108%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	110%	104%	117%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	110%	104%	117%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	110%	104%	117%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	110%	104%	117%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	< 90%	< 90%	103%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	100%	< 90%	110%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	111%	107%	121%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	< 90%	< 90%	106%	< 90%	< 90%

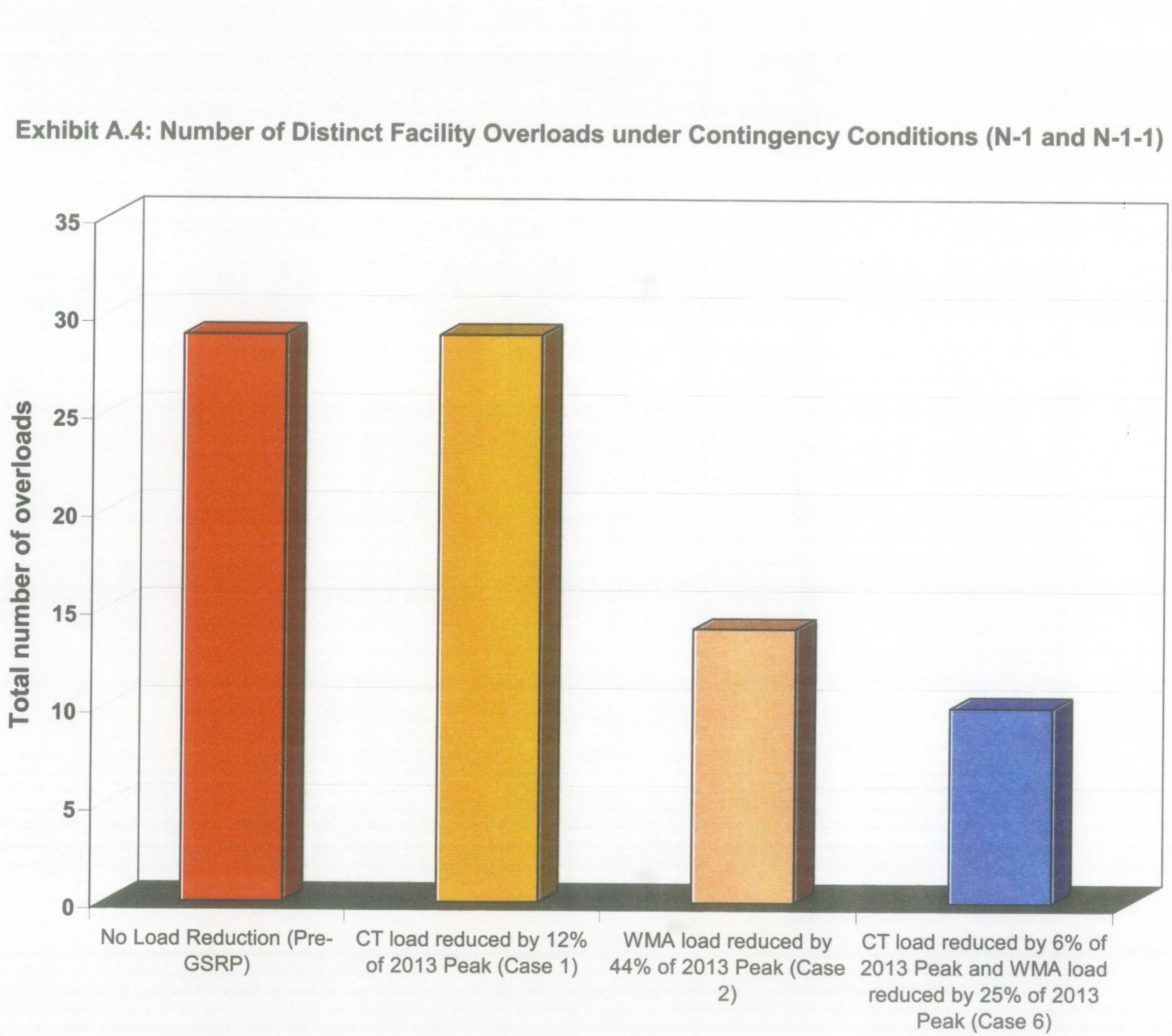
[48] The table shows the maximum overload on the specified element in each demand reduction/generation addition case. The maximum overload may be caused by different contingencies in each case.

Exhibit A.3: N-1-1 Line Overloads in Springfield Area

Monitored Elements				Maximum Line Loading Observed[49] - (% of LTE Rating)							
From Bus	From KV	To Bus	To KV	Pre-GSRP 2013	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7
[redacted]	[redacted]	[redacted]	[redacted]	366%	314%	248%	134%	127%	< 90%	127%	253%
[redacted]	[redacted]	[redacted]	[redacted]	330%	278%	250%	100%	93%	90%	129%	255%
[redacted]	[redacted]	[redacted]	[redacted]	177%	153%	112%	< 90%	< 90%	< 90%	< 90%	123%
[redacted]	[redacted]	[redacted]	[redacted]	156%	124%	112%	< 90%	< 90%	< 90%	< 90%	108%
[redacted]	[redacted]	[redacted]	[redacted]	142%	129%	91%	< 90%	< 90%	< 90%	< 90%	92%
[redacted]	[redacted]	[redacted]	[redacted]	137%	103%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	133%	93%	96%	< 90%	< 90%	< 90%	< 90%	102%
[redacted]	[redacted]	[redacted]	[redacted]	132%	145%	99%	< 90%	< 90%	93%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	131%	99%	96%	96%	< 90%	94%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	130%	103%	115%	< 90%	< 90%	< 90%	118%	114%
[redacted]	[redacted]	[redacted]	[redacted]	130%	103%	115%	< 90%	< 90%	< 90%	124%	114%
[redacted]	[redacted]	[redacted]	[redacted]	128%	117%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	128%	127%	< 90%	< 90%	< 90%	< 90%	< 90%	93%
[redacted]	[redacted]	[redacted]	[redacted]	116%	< 90%	120%	113%	< 90%	110%	< 90%	115%
[redacted]	[redacted]	[redacted]	[redacted]	116%	< 90%	120%	113%	< 90%	110%	< 90%	115%
[redacted]	[redacted]	[redacted]	[redacted]	114%	102%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	111%	110%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	110%	108%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	110%	108%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	106%	121%	128%	164%	161%	174%	118%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	104%	90%	119%	154%	152%	163%	114%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	99%	106%	110%	122%	< 90%	117%	< 90%	98%
[redacted]	[redacted]	[redacted]	[redacted]	99%	106%	110%	122%	< 90%	117%	< 90%	98%
[redacted]	[redacted]	[redacted]	[redacted]	95%	113%	102%	136%	131%	145%	97%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	95%	113%	102%	136%	131%	145%	97%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	95%	113%	102%	136%	131%	145%	97%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	95%	113%	102%	136%	131%	145%	97%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	94%	150%	147%	161%	118%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	114%	< 90%	131%	128%	143%	99%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	94%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	< 90%	< 90%	< 90%	100%	102%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	90%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%
[redacted]	[redacted]	[redacted]	[redacted]	< 90%	105%	< 90%	< 90%	< 90%	< 90%	< 90%	< 90%

[49] The table shows the maximum overload on a particular monitored element across different top-down cases. It could be that this maximum overload was caused by different contingencies across the cases.

Exhibit A.4: Number of Distinct Facility Overloads under Contingency Conditions (N-1 and N-1-1)



Bar heights in the chart are approximate. Note that the percent load reduction shown on the graph is in addition to the estimates from the focused DSM case (an addition of about 5% of peak load in Connecticut) that was modeled in all scenarios tested in the study.

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APPENDIX B: GLOSSARY OF TERMS

Active demand resources –Dispatchable demand-side resources.

Combined Heat and Power – Systems used typically at industrial or commercial sites to generate electricity and steam/heat for onsite operations and use, thus reducing the load on the generation and transmission system.

Contingency – A situation in which one or more elements of the power system have failed. These elements might include a generating station, transmission line, or a transformer.

Critical peak resources – Active demand-side resources which reduce their load during forecasted peak hours (realized in the day-ahead time frame) and shortage hours (realized in real-time).

Demand resources – A variety of techniques used to reduce electrical demand in order to reduce system-wide generation and transmission requirements. Demand resources are also referred to as **Demand-side Management**. Demand resources can be "active" or "passive."

Distributed generation – Generation resources directly connected to end-use customer load and typically located behind the end-use customer's billing meter. Distributed generation resources may be used for routine energy generation or for emergency use only, and typically have a capacity less than 5 MW.

Distribution-side load – A measure of the system load at the end-user point.

Emergency operating conditions – In this study, emergency operating conditions refer to a system state in which two components of the bulk power system have failed. Compare to **Normal operating conditions.**

Forced outage rate – The percentage of time that a given generating unit is unable to function due to unanticipated breakdown or emergency conditions.

Forward capacity auction (FCA) – The mechanism through which supply and demand resources are bid into and selected to participate in the Forward Capacity Market (FCM). The FCA is held two years prior to the commitment period for which the resources cleared in the market must provide the generating capacity or demand-side resources bid into the auction. In the New England market, commitments of up to five years are available for demand resources and units are paid the market-clearing electricity price during their demand-reduction actions.

Forward capacity market (FCM) – A market designed to procure capacity from willing providers of new generating resources and demand resources already available, but not used, in a system.

Generator bus-bar – Connects a given generator to the step-up transformer.

Load deficit – The amount of load unable to be served reliably.

Long-Term Emergency (LTE) Rating – The capacity rating of a transmission facility for infrequent, extended contingencies.

Market penetration – The measurement of the relationship between the total potential use of a product or technology in a given market and its actual use.

N-1 – Power system state where one component of the bulk power system has failed.

N-1-1 – Power system state where two components of the bulk power system have failed.

Normal operating conditions – In this study, normal operating conditions refer to a system state in which no more than one component of the bulk power system has failed. Compare to **Emergency operating conditions.**

Passive demand resources – A set of demand resources whose use are outside the direct control of the grid operator and not *necessarily* correlated to the relationship between demand and supply of energy in a system. Examples of passive demand resources include energy-efficient equipment, such as refrigerators and air conditioners, and compact fluorescent lights.

Payback – The number of years it takes for the annual operating savings to repay the initial capital investment of a particular technology or upgrade.

Power-flow case – a modeling representation of the physical power system, including generation units, load, transmission facilities, transformers, reactive compensation devices, DC lines, and phase angle regulators.

Real-time demand response – Resources which must reduce their load within 30 minutes of receiving instructions from the ISO, and wait until further instructions come before they may restore usage.

Real-time emergency generation – Distributed Generation Resources which must reduce their load within 30 minutes of receiving instructions from the ISO, and wait until further instructions come before they may restore usage. Limited to 600 MW system-wide in the NE-ISO.

Reliability Must-Run (RMR) – RMR units are generation facilities that are no longer economical to operate on an on-going basis, but that are required for system reliability purposes. These generating facilities enter into RMR agreements with NE-ISO and that provide for payments to the plants so the plant owner will maintain the units in a ready operating state in case the plants are required to maintain the reliability of the power system.

Renewable Standards Portfolio (RSP) – Policies under which many governments at the state level have mandated different levels of renewable generation to electric utilities within certain timeframes.

Spinning reserves – Supply available to serve load in the event of a contingency that are available on short notice, typically around 15 - 30 minutes time.

Substation – A facility containing switches, transformers and other equipment used to switch, change, regulate, and monitor voltage in the electric transmission and distribution system.

Voltage violation – An incident in which the voltage at a substation reaches levels outside of safe operating limits.

EX.4 Northeast Utilities "Solution Report for the Springfield Area The Greater Springfield Reliability Project Including The Springfield 115-kV Upgrades". *"GSRP Solution Report"* as of April 23, 2008.

NORTHEAST UTILITIES

SOLUTION REPORT FOR THE SPRINGFIELD AREA

THE GREATER SPRINGFIELD RELIABILITY PROJECT INCLUDING THE SPRINGFIELD 115-kV UPGRADES

(SPRINGFIELD SOLUTION REPORT)

(SUBMITTED TO ISO-NEW ENGLAND AS OF APRIL 23, 2008)

THE CONNECTICUT LIGHT AND POWER COMPANY

WESTERN MASSACHUSETTS ELECTRIC COMPANY

Connecticut Light & Power
The Northeast Utilities System

Western Massachusetts Electric
The Northeast Utilities System

EXECUTIVE SUMMARY

Solution Report for the Springfield Area 345/115-kV Transmission Reinforcements

For general information, the Solution Report contains Appendix A which reviews the history of the Southern New England Transmission Reinforcement (SNETR) study and describes the four component projects which comprise the New England East–West Solution (NEEWS). NEEWS is the work product of the ISO-NE-led SNETR Working Group which included Northeast Utilities (NU) and National Grid (NGrid).

One of the four NEEWS components addresses the transmission reliability and transfer problems identified by the Working Group in the Greater Springfield area. That component has the title the Greater Springfield Reliability Project (GSRP). Parts of the 115-kV reinforcements included in GSRP were separated from GSRP to accelerate approval and construction and became known as the Springfield 115-kV Advanced Projects. Included in this group were underground cable installations and replacements which became known as the Springfield Cables Project (SCP). All parts of the comprehensive reinforcement program which meets the Springfield area needs which were identified by the Working Group are now addressed in this Springfield Solution Report and are now referred to collectively as the "Springfield Solution".

Section 1 of the Solution Report states the purpose of the Solution Report: to review the many options considered for the Springfield Solution in a comprehensive way to assist ISO-NE in making a determination that the most-cost effective and reliable solution for the region has been found for the identified Springfield need. ISO-NE will make such a determination in accordance with the Regional System Planning Process as mandated under the terms of Attachment K of the ISO-NE OATT. Section 1 also summarizes the three principal aspects of the review in the Solution Report: a review of the history of the many study stages in the planning process, a "bottom-up" re-assessment of the principal options considered during the process, and a description how the Springfield Solution now converts the existing Springfield underground cable "through-paths" into a radial supply scheme, delaying the cable upgrades first proposed by the Working Group.

Section 2 recounts the history of the planning process and explains how the preferred solution evolved, during the several study stages, as more engineering and siting analyses were done. The *Southern New England Transmission Reinforcement, Report 1, Needs Analysis,* originally issued August 7, 2006, is described first, followed by reviews of:

- The October, 2006 analysis of options done by the SNETR Project Board (consisting of NU and NGrid);
- The December 15, 2006 presentation of options and initial selections made by ISO-NE, NU and NGrid to the ISO-NE Planning Advisory Committee (PAC);
- Project changes throughout 2007 resulting from more advanced engineering and siting analyses conducted by NU;
- The June 25, 2007 draft report, New England East-West Solution (NEEWS), Report 2—Options Analysis;
- The project configuration set forth in a proposed NU application to the Transmission Task Force on November 28, 2007;
- The December 3, 2007 presentation by NU of the total Springfield project to the PAC;
- The Petition to Construct filed by NU on December 21, 2007 with the Massachusetts Energy Facilities Siting Board for approval of the Springfield Cables Project; and
- The re-configuration of the Springfield Solution after an interactive review between NU and ISO-NE.

Section 3 explains how NU presently analyzes the 26 possible variations of the 12 principal options identified in the *New England East-West Solution (NEEWS), Report 2—Options Analysis*. The NU analysis is a step-by-step elimination process, removing one less favorable option after another, until the selection of the current Springfield Solution emerges. Options are compared on the basis of costs and other relevant factors, including impacts and siting risks where the latter are important considerations. A final section presents a spectrum of cost comparisons for a "short list' of possible options. Among the final options is the present re-configuration of the Springfield Solution, which no longer includes the SCP. The final re-configuration resulted from a process important enough to be separately reviewed in Section 4.

The design of the Springfield Solution, as proposed by NU at the end of 2007, was independently reviewed by ISO-NE in January and February, 2008. Section 4 describes that interactive review process. ISO-NE initiated that review and NU cooperated fully by responding to specific ISO-NE requests. Section 4 addresses the joint ISO-NE/NU effort to identify cost-effective opportunities to trade off higher cost upgrades, with marginally greater reliability benefits, for lower cost upgrades that keep the Springfield area in compliance with commonly accepted interpretations of regional reliability standards. Section 4 explains that the relatively high upgrade costs needed to protect the Springfield cable path from contingency overloads are not necessary if that path is “opened”. In short, the City’s existing cables, as a part of the re-designed Springfield Solution, will be converted to radial supply lines.

Section 5 describes the expected performance of the Springfield Solution and Section 6 sets forth the expected next steps in the review and approval process for the Springfield Solution.

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ATTACHMENTS

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Slides used at SNETR/NEEWS Project Board

1.0 PURPOSE AND SUMMARY

The purpose of the Northeast Utilities (NU) Solution Report for the greater Springfield, Massachusetts area (Springfield Solution Report) is to assist the Independent System Operator – New England (ISO-NE) in fulfilling its regional transmission system planning responsibilities under its Open Access Transmission Tariff (OATT), including transmission planning and solution review duties under the recently adopted Attachment K (Regional System Planning Process) to the OATT. The Springfield Solution Report offers this assistance with respect to the Greater Springfield area of Western Massachusetts.

The Springfield Solution Report will document a coordinated review process by ISO-NE and NU of the transmission needs and solutions for the Springfield area. All project components which meet a common Springfield area need are reviewed and included here. The common label used in this report for all these project components will be the "*Springfield Solution*". The Springfield Solution contains components identified with (i) the Southern New England Transmission Reliability (SNETR)[1] component for Springfield, known as the Greater Springfield Reliability Project (GSRP), and (ii) the GSRP elements which formed the Springfield 115-kV Advanced Projects[2]. Other elements now included in the Springfield Solution, but located in the Hartford, Connecticut area, were originally listed as a part of the Interstate Reliability Project, another of the four projects of an overall regional solution known as the New England East-West Solution (NEEWS)[3]. As much as possible, the SNETR studies were done on an integrated, region-wide basis and the options considered as components of the four NEEWS solutions were reviewed on an integrated, region-wide basis. In this context, the identifying and listing of components reflected geography and convenience and did not necessarily reflect common electrical needs or performance requirements. This Springfield Solution Report will list and explain how these components listed originally in the Interstate Reliability Project are included now in the Springfield Solution since they are a necessary part of meeting the Springfield area need. This Springfield Solution Report will also list and explain how elements listed in the GSRP originally are excluded in the Springfield Solution since they address independent needs or they have been determined upon further

[1] SNETR is the label attached to the regional studies of the reinforcement needs for Southern New England and the New England East-West Solution (NEEWS) is the label now attached to the four components of the upgrade solutions being planned to address the SNETR needs.

[2] The latter "advanced" projects are inclusive of the underground cable projects which became known as the Springfield Cables Project (SCP). The Springfield 115-kV Advanced Projects, inclusive of the SCP, were originally studied as a part of GSRP, but were given separate identities and different names to allow them to be advanced for siting and other review purposes.

[3] See: Appendix A, "The History of the SNETR Studies and the Scope of NEEWS".

analysis not to be required as a part of the most cost-effective and reliable solution to meet the Springfield need.

The Springfield Solution Report addresses how transmission needs were assessed, how options were identified and evaluated in terms of their ability to meet needs and how competing solutions which met needs were sorted in order to select the most cost-effective and reliable solution, with due consideration of all relevant impacts and siting factors, including environmental, human, socio-economic and other effects. In this regard, the Springfield Solution Report provides the following:

- A global review of all electrical options considered for GSRP and for the related local upgrades;
- A review of the history of the solutions process employed to identify and assess options;
- A review of the leading solutions at different stages of the process;
- A description of the multi-factor evaluation process for sorting options;
- A description of the interactive, independent review process between ISO-NE and NU concerning the proposed solutions;
- A "bottom-up" re-assessment of the selection process and a validation of the GSRP regional design solution;
- A discussion of how regional cost-effectiveness and regional reliability standards affect the local configuration in the balanced solution which has emerged as NU's preferred solution; and
- A presentation of that balanced solution which meets Attachment K requirements for the most cost-effective and reliable regional solution.

Section 1 provides background for the Springfield Solution Report, introducing transmission planning standards applicable to the GSRP, referencing the coordinated efforts of ISO-NE and the other stakeholders to date and describing the regulatory framework which controls decision-making by ISO-NE and regulated transmission owners such as NU.

Section 2 describes the planning process which was initiated in 2004 when NU first engaged ABB to study transmission needs and solutions in the Springfield area and which culminated with the ongoing ISO-NE review process begun in January, 2008 by ISO-NE to re-visit and review the full spectrum of options considered as solutions for the Springfield area.

Using terminology first applied by ABB and then adopted in the *Southern New England Transmission Reliability (SNETR) Report 2—Options Analysis*, Draft June 25, 2007 (Options Analysis), Section 2 documents the review progression over time that includes (i) the first preliminary selection of option 6b

South at the December 15, 2006 PAC presentations of ISO-NE, NU and NGrid; (ii) the subsequent switch in 2007, based on more detailed engineering and planning analyses of the primary competing routes, to option 6b North; (iii) the evolution of the enhanced option 6b North as presented on November 28, 2007 to the Transmission Task Force in the Proposed Plan Application Steady State Analysis; (iv) with the elimination of the Stony Brook interconnection, the switch to enhanced option 6a North, combined with the separation for advance siting and cost allocation purposes of the Springfield Cables Project (SCP); and (v) the present re-configuration of the Springfield Solution, the resolution of the role of the SCP, and the integration of all Springfield-related work, including 115-kV upgrades in the Hartford area needed as a result of the Springfield work, into a single preferred solution, which occurred after the interactive review between ISO-NE and NU in January and February, 2008.

Section 3 will provide a “bottom-up” re-assessment of the key choices made in designing the preferred Springfield solution. Section 3 also presents the cost comparisons for the current preferred solution and a “short-list” of the more realistic alternatives to that solution which have different routing and interconnection choices.

To complete the full Springfield solutions review, Section 4 will describe the re-consideration of project costs and local reliability standards conducted by ISO-NE and NU as a part of the interactive review process initiated by ISO-NE in December, 2007 (ISO-NE Review Process). Section 4 sets forth the decision of NU to drop the SCP and make changes in local configuration in order to present a balanced solution which assures the most cost-effective and reliable regional solution to transmission needs in the Springfield area.

1.1 TRANSMISSION RELIABILITY STANDARDS AND CRITERIA

The regional transmission system is designed to ensure its reliable operation in accordance with national and regional reliability standards, including standards of the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council, Inc. (NPCC) and ISO-NE.

The primary guidance on reliability testing is contained in NPCC’s “Basic Criteria for Design and Operation Of Interconnected Power Systems,” Document A-02 (revised May 6, 2004) (NPCC Basic Criteria); the NPCC’s "Bulk Power System Protection Criteria,” Document A-05 (revised January 30, 2006); ISO-NE Planning Procedure No. 3, “Reliability Standards for the New England Area Bulk Power Supply System” (ISO PP3) (effective date October 13, 2006); and ISO-NE Planning Procedure No. 5-3, “Guidelines for Conducting and Evaluating Proposed Plan Applications Analysis” (ISO PP5-3) In this regard, ISO PP3 initially notes as follows:

> "The reliability standards set forth herein have been adopted as appropriate for the New England bulk power supply system. Further, they are consistent with those established by the Northeast Power Coordinating Council in the NPCC "Basic Criteria for Design and Operation of Interconnected Power Systems" and the NPCC "Bulk Power System Protection Criteria." (ISO PP3, Section 1, at page 1).

The design criteria are stated in ISO PP3 as follows:

> "The New England bulk power supply system shall be designed for a level of reliability such that the loss of a major portion of the system, or unintentional separation of any portion of the system, will not result from reasonably foreseeable contingencies. Therefore, the system is required to be designed to meet **representative contingencies** as defined in these Reliability Standards. **Analyses of simulations of these contingencies** should include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse." (ISO PP3, Section 1, at page 2). (Emphasis added.)

"Representative contingencies", as noted above, are elaborated upon in Section 3 of ISO PP3 as follows:

> "The New England bulk power supply system shall be designed with sufficient transmission capacity to integrate all resources and serve area loads under the conditions noted in Sections 3.1 and 3.2.
>
> ***3.1 Stability Assessment***
>
> The New England bulk power supply system shall remain stable and damped in accordance with the criterion specified in Appendix C during and following the most severe of the contingencies stated below with due regard to reclosing, and before making any manual system adjustments. . . . .
>
> a. A permanent three-phase fault on any generator, transmission circuit, transformer, or bus section with normal fault clearing.
> b. Simultaneous permanent phase-to-ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition and other similar situations can be excluded on the

basis of acceptable risk, provided that the ISO specifically approves each request for exclusion. Similar approval must be granted by the NPCC Reliability Coordinating Committee.

c. A permanent phase-to-ground fault on any transmission circuit, transformer or bus section with delayed fault clearing. This delayed fault clearing could be due to circuit breaker, relay system or signal channel malfunction.

d. Loss of any element without a fault.

e. A permanent phase-to-ground fault in a circuit breaker, with normal fault clearing. (Normal fault clearing time for this condition may not be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault.

g. The failure of any SPS which is not functionally redundant to operate properly when required following the contingencies listed in "a" through "f" above.

The failure of a circuit breaker to operate when initiated by an SPS following: loss of any element without a fault; or a permanent phase to ground fault, with normal fault clearing, on any transmission circuit, transformer, or bus section."(ISO PP3, Section 3, at page 5)[4]

The "analyses of simulations of these contingencies" (ISO PP3, page 2, noted above), which are required to meet the applicable reliability criteria, are the subject of further explicit guidance in Section 3 of ISO PP3, both as to the conditions under which the simulations should be run and as to the number of sequential contingencies to be studied.

> "The New England bulk power supply system shall be designed with sufficient transmission capacity to integrate all resources and serve area loads under the conditions noted in Sections 3.1 and 3.2. **These requirements will also apply after any critical generator, transmission circuit, transformer, phase angle regulating transformer, HVDC pole, series or shunt compensating device has already been lost, assuming that**

[4] Section 3.2 of ISO PP3 does not contain any additional contingency but addresses steady state assessments as follows:
"3.2 STEADY STATE ASSESSMENT
Adequate reactive power resources with reserves and appropriate controls shall be installed to maintain voltages within normal limits for pre-disturbance conditions, and within applicable emergency limits for the system conditions that exist following the contingencies specified in Section 3.1.
Line and equipment loadings shall be within normal limits for pre-disturbance conditions and within applicable emergency limits for the system load and generation conditions that exist following the contingencies specified in Section 3.1."

> **the area resources and power flows are adjusted between outages**, using all appropriate reserve resources available in ten minutes and where applicable, any phase angle regulator control, and HVDC control."
>
> "With due allowance for generator maintenance and forced outages, design studies will assume power flow conditions with applicable transfers, load, and resource conditions that reasonably stress the system. Transfers of power to and from another Area, as well as within New England, shall be considered in the design of inter-Area and intra-Area transmission facilities." (ISO PP3, Section 3, at page 4). (Emphasis added.)

If any of the contingencies listed above occurs when all relevant elements of the grid are in service, the resulting condition is described as N-1. If such a contingency occurs when a line or generator has previously been removed from service, the resulting conditions are described as N-1-1.

It is clear from the above-cited guidelines in ISO PP3, and from the consistent, broader regional standards which are referenced, that contingency testing must include simulated conditions for forecasted load, regional (intra-New England) power transfers, and generation unavailability which "reasonably stress" the system. Furthermore, it is clear from the emphasized language in the first paragraph in the above citation that ISO-NE expects utility planners and operators to design transmission facilities to meet applicable reliability standards and to study second contingencies as a basis for testing the overall reliability of New England's bulk power system.

1.2 SOUTHERN NEW ENGLAND TRANSMISSION RELIABILITY NEED ANALYSIS AND OPTIONS ANAYLSIS

As explained in the Executive Summary to the ISO-NE report, *Southern New England Transmission Reliability (SNETR) Report 1—Needs Analysis*, January, 2008 (Needs Analysis), National Grid, Northeast Utilities and ISO-NE formed a working group to conduct a study to develop a 10-year plan for transmission system improvements for the southern New England (SNE) region (SNETR Working Group). The study was first prepared in draft form on August 7, 2006, and was recently finalized in the Need Analysis. The Needs Analysis will be described in greater detail in Section 2 of this Springfield Solution Report.

The resulting plan specifically addresses western and central Massachusetts (particularly the Springfield area), Rhode Island, and eastern and central Connecticut. The objective of the SNE plan is to achieve regional compliance with applicable criteria and reliability standards as described above in Section 1.1. The SNETR Working Group developed transmission system improvements in the SNE plan in conjunction with the ISO-NE's 10-year regional system planning (RSP) process[5], which has showed the likelihood of the region not meeting the applicable criteria and standards by 2009. The SNETR Working Group's plan is currently contained in *Southern New England Transmission Reliability (SNETR) Report 2—Options Analysis*, released as a Draft June 25, 2007 and to be issued in final form in the near future (Options Analysis), which will also be described in greater detail in Section 2 of this Springfield Solution Report.

1.3 ATTACHMENT K TO THE ISO-NE OPEN ACCESS TRANSMISSION TARIFF

Attachment K to the ISO-NE OATT describes the regional system planning process conducted by ISO-NE to ensure reliability in the New England Transmission System. Pursuant to Attachment K, ISO-NE undertakes assessments of system-wide and specific area needs, referred to as Needs Assessments, as defined in Section II.1 of the OATT. Pursuant to Section 4.2(a) of Attachment K, ISO-NE must consider market responses, such as generation, demand resources and merchant transmission, in the Needs Assessments. If market responses do not eliminate or address system-wide or area specific needs, then, pursuant to Section 4.2(b) of Attachment K, ISO-NE develops or evaluates regulated transmission solutions proposed in response to the Needs Assessments.

Attachment K also describes ISO-NE's process for the development of a Regional System Plan (RSP). The RSP is a compilation of the regional system planning process activities conducted by ISO-NE during a given year. As a result, the RSP addresses the system-wide and specific area needs determined by the ISO through its Needs Assessments and also addresses regulated transmission solutions to meet the needs identified in the Needs Assessments when market responses do not address such needs.

As indicated above, Section 4 of Attachment K specifically describes a study process for ISO-NE, in coordination with the proponents of regulated transmission solutions and other interested or affected stakeholders, to evaluate whether proposed regulated transmission solutions meet the system needs identified in Needs Assessments. "Through this study process, the ISO may identify the most cost-effective and reliable solution(s) for the region that meets a need identified in a Needs Assessment. This solution may differ from a transmission solution proposed by a transmission owner." Section 4.2(b), Attachment K.

NU intends that this Springfield Solution Report will assist ISO-NE in identifying NU's preferred solution as the most cost-effective and reliable regional solution for the needs identified in the Springfield

[5] With respect to the Springfield area, see, e.g., Regional System Plan 2005, page 89, Section 8.1.6 and page 92, Section 8.2.4; and Regional System Plan 2006, page 91, Section 8.2.2.2.

area. In addition, this Springfield Solution Report will provide additional support for NU's preferred solution in the related ISO-NE approval proceedings under the Section I.3.9 technical review process and the Transmission Cost Allocation review process.

2.0 THE SPRINGFIELD SOLUTION REVIEW PROCESS

This Section 2 describes the planning process which was initiated in 2004 when NU first engaged ABB to study transmission needs and solutions in the Springfield area and which culminated with the ongoing ISO-NE Review Process begun in January, 2008 by ISO-NE to re-visit and review the full spectrum of options considered as solutions for the Springfield area.

Using terminology first applied by ABB and then adopted in the Options Report, Section 2 documents the review progression over time that includes (i) the first preliminary selection of option 6b South at the December 15, 2006 PAC Presentations of ISO-NE, NU and NGrid; (ii) the subsequent switch in 2007, based on more detailed engineering and planning analyses of the primary competing routes, to option 6b North; (iii) the evolution of the more enhanced option 6b North as presented on November 28, 2007 to the NEPOOL Transmission Task Force in the Proposed Plan Application Steady State Analysis; (iv) the elimination of the Stony Brook interconnection and the switch to enhanced option 6a North, combined with the separation of the SCP for advance siting and cost allocation purposes; and (v) the present re-configuration of the GSRP, the resolution of the role of the SCP, and the integration of all Springfield-related work, including 115-kV upgrades in the Hartford area needed as a result of the Springfield work, into a single preferred solution, which occurred after the interactive review between ISO-NE and NU in January and February, 2008 .

2.1 REGIONAL SYSTEM PLANNING AND THE SNETR NEEDS ASSESSMENT FOR THE GREATER SPRINGFIELD AREA

As explained in the Executive Summary to the ISO-NE Needs Analysis[6], National Grid, Northeast Utilities and ISO-NE formed a working group[7] to conduct a study to develop a 10-year plan for transmission system improvements for the 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.

[6] ISO-NE conducts Needs Assessments pursuant to Section 4.1 of Attachment K to the ISO-NE OATT.
[7] Under Section 4.1(e) of Attachment K, ISO-NE is authorized to form study groups for the development of Needs Assessments.

In January, 2008, ISO-NE issued the final version of the *Southern New England Transmission Reliability (SNETR) Report 1—Needs Analysis* (Needs Analysis).

SNE accounts for approximately 80% of the New England load and the 345-kV bulk power transmission system integrates SNE's supply resources and load centers. The Needs Analysis notes that the studies conducted were a part of one of the most geographically comprehensive planning efforts in New England. Supplying that load is complex and presents numerous interrelated performance problems as described in the Needs Analysis at pages 2-3:

> "Supplying southern New England with electricity involves a number of complex and interrelated performance concerns. Connecticut's potential 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 strain the existing 345 kV network. These challenges are compounded further by transmission constraints in the Springfield and Rhode Island areas under contingency conditions. The following transmission transfer capabilities are all interrelated:
>
> - 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 interface
> - Connecticut import
> - Connecticut East–West interface
> - Southwest Connecticut (SWCT) import
>
> Transfers through these paths can contribute to heavy loadings on the same key transmission facilities.
>
> These relationships exist for both thermal and stability limits. Studies have identified the relationship 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 as a result of line reclosing also have become an issue in the SNE area. These behaviors illustrate the interdependent nature

of the SNE 345 kV network. Recent analyses have quantified an additional interdependence between the ability to import power into Connecticut and the ability to supply load in the Springfield area. Springfield's reliability issues must be studied within the context of the overall southern New England analysis to not 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 existing transmission system does not allow for delivering 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. The Springfield and Rhode Island areas have additional transmission reliability concerns, both thermal limitations and voltage violations, which lead to a set of interrelated concerns with respect to the reliability of transmission service across southern New England . . ."

Needs Analysis, pp. 2-3.

The studies addressed five interrelated problems in three states and multiple service territories. The Needs Analysis describes the methodology employed in the ISO-NE transmission planning process and the assessment of the projected SNE deficiencies in system performance which resulted from that planning process. Studies for the 10-year period (from 2007 to 2016) showed that the five interrelated reliability concerns are major. Numerous system deficiencies in transmission security also exist, specifically area transmission requirements and transfer capabilities.

The reliability concerns specifically relating to the Springfield area which are then documented in the Needs Analysis are as follows[8]:

- "Springfield Reliability: The Springfield, Massachusetts, area could be exposed to significant thermal overloads and voltage problems under numerous contingencies at or near summer peak-load periods. The severity of these problems would increase as the transmission system attempts to move power into Connecticut from the rest of New England."

The Needs Analysis identifies the following transmission security concerns related to meeting transfer capability and area transmission requirements which relate to Springfield[9]:

[8] Needs Analysis, Executive Summary, page iii.

Transfer Capability Concerns

- "Based on planning assumptions concerning future generation additions and retirements within the Connecticut area, an import level of 3,600 MW for N-1 conditions and 2,400 MW for N-1-1 conditions will be needed by 2016.
- Rhode Island and Springfield have insufficient import capability to meet their load margins through 2016.
- 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 because of either an unplanned or a planned outage. As a result, numerous overloads occur in the 2009 simulations. These overloads are exacerbated when Connecticut transfers increase.

Concerns about Area Transmission Requirements

- In the Springfield area, local double-circuit tower (DCT) outages[10], stuck-breaker outages, and single-element outages currently can result in severe thermal overloads and low-voltage conditions.
- The severity, number, and location of the Springfield overloads and low-voltage conditions highly depend on the area's generation dispatch. Additional load growth and unit outages in the Springfield area would significantly aggravate these problems. As a result, network constraints in the Springfield area limit the system's present ability to serve local load under contingency conditions."

For the Springfield area, the Needs Analysis notes area transmission deficiencies in both 2009 (Table 3.1) and 2016 (Table 3.2). In 2016, the area is shown in need of an additional 378 MWs of transfer capability under normal conditions. Transmission reliability testing under various contingencies for the Springfield area show numerous overloads and voltage violations in 2009 for N-1 conditions (Table 3.10) and for N-1-1 conditions (Table 3.12).

[9] Needs Analysis, Executive Summary, page v.
[10] This is a reference to the common outage of two transmission lines sharing a single structure that fails.

2.2 SNETR OPTIONS ANALYSES FOR THE SPRINGFIELD AREA

2.2.1 ABB Initial Draft Report, February, 2005

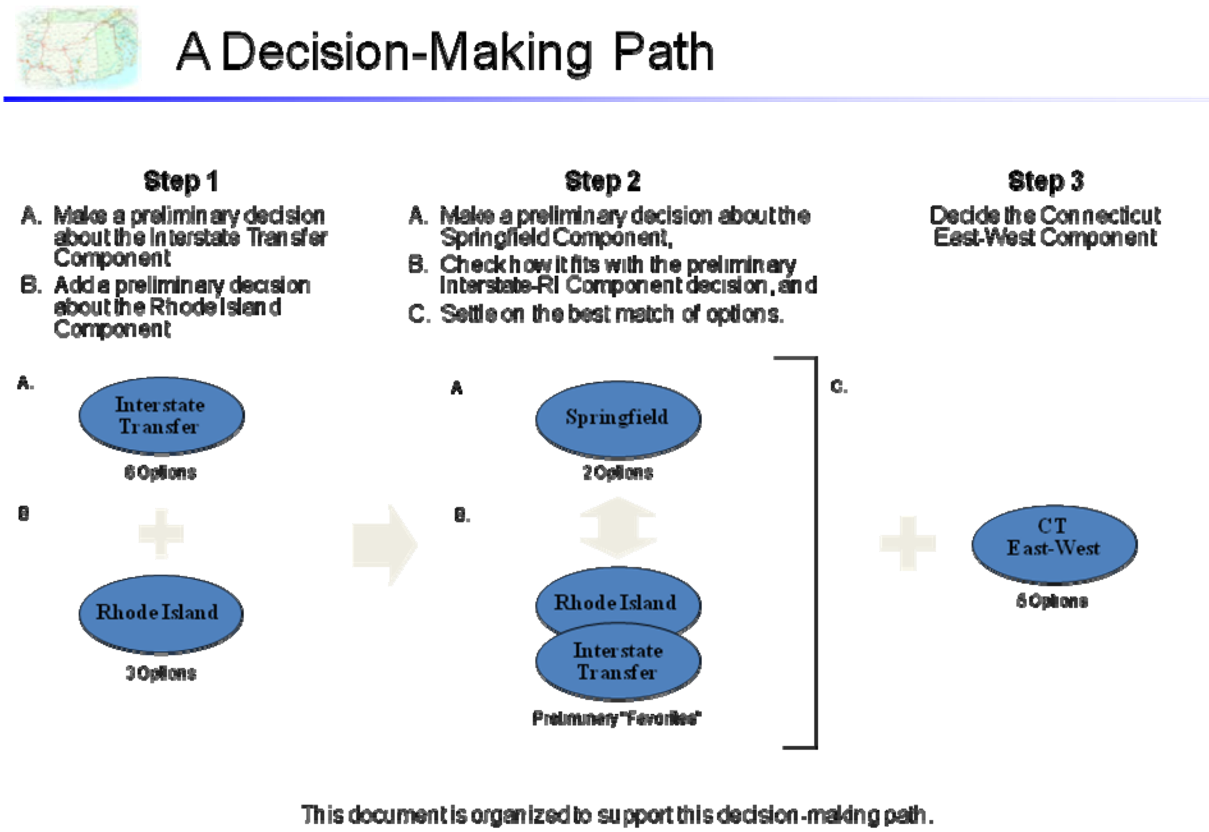
ABB, on behalf of NU, initiated a review of Springfield area transmission needs and solutions in 2004. An expansive variety of different options were explored to address the area reliability concerns. The ABB Draft Report February, 2005, discussed the options and narrowed choices for further study. The follow-up ABB report, dated February 27, 2007, is addressed below in Section 2.2.4.

2.2.2 Project Board, October, 2006 Meetings: Critical Options Evaluations - - Initial Iteration from Long List to Short List to Initial Solution Design

At the SNETR Project Board[11] meeting in October, 2006, the Project Board members reviewed the overall four-component solution to the SNETR needs. Before reviewing the options under study for each of the components, they addressed the critical interdependencies among those options. Since all four components of the SNETR were required to work together in order to satisfy the full SNE need, and since not all options were necessarily compatible with one another, it was necessary to test the interdependencies among options as an essential part of any decision path leading to the selection of options for each component. The Project Board members studied these independencies as follows:

[11] The SNETR Project Board consists of representatives of NU and National Grid (NGrid). The Project Board conducted its review of interdependencies among project options through the Working Group which included ISO-NE.

Slide #6: A Decision-Making Path



After reviewing the options for each component of the NEEWS solution, the Project Board members specifically endorsed the following option for the Springfield project component: Option A (with the 345/115-kV Agawam connection), series 6 (breaker-and-one-half re-configuration of Fairmont Switching Station), option 6b (Stony Brook 115-kV connection to Fairmont Switching Station), South Route for the Ludlow to Agawam to North Bloomfield 345-kV line creating a 345-kV "loop" between Ludlow, Agawam and North Bloomfield[12].

The choice was the end result of a three step process. The first step required the selection among three 345-kV electrical connection options as follows: (i) Option A, connecting three substations (Ludlow, Agawam and North Bloomfield); (ii) Option B, connecting two substations (Ludlow and North Bloomfield); or (iii) Option C, connecting two substations (Ludlow and Manchester). The first step choices were illustrated to the SNETR Project Board at the time in the below slide.

[12] The "eastern" portion of the loop shall include the Ludlow Substation, the Barbour Hill Substation in Connecticut (when its 345-kV facilities are completed in 2008) and the North Bloomfield Substation.

Slide #21: The Springfield Reliability Component

The Springfield Reliability Component

The Springfield Reliability Component has three 345-kV <u>electrical connection</u> options:

<u>Option A</u>
Connect 3 Substations:
Ludlow-Agawam-North Bloomfield

<u>Option B</u>
Connect 2 Substations:
Ludlow-North Bloomfield

<u>Option C</u>
Connect 2 Substations:
Ludlow-Manchester

Option A was selected as “far superior” to Option B and Option C based on the following reasons:

- It would establish a southern bulk power source for Springfield.
- In the event of an extreme contingency loss of the Ludlow Substation, power can flow north from North Bloomfield.
- Agawam Substation is in complementary position to the Ludlow Substation for providing voltage support to the Springfield area.
- Since all the area’s 115-kV lines tie into the Agawam Substation, it is a strategic location for limiting power flows through the Springfield area.
- Agawam is close to area load centers and would provide flexibility in expanding the 115-kV system to serve area growth.

The second step required the selection between two route options for making the three substation connection for Option A. The route options and their respective pro’s and con’s are described on the following slides from the October, 2006 SNETR Board Meeting.

Slide #24: Springfield: Option A-North

Springfield: Option A-North

Pros
- Keeps the Ludlow-Manchester ROW open for interstate options
- Affects one fewer municipality (7 vs. 8)
- Has one-third of the Natural Resources counts and half the Protected Lands counts of the South route
- Has slightly lower counts of Residences within 500' compared with the South route (593 vs. 632)

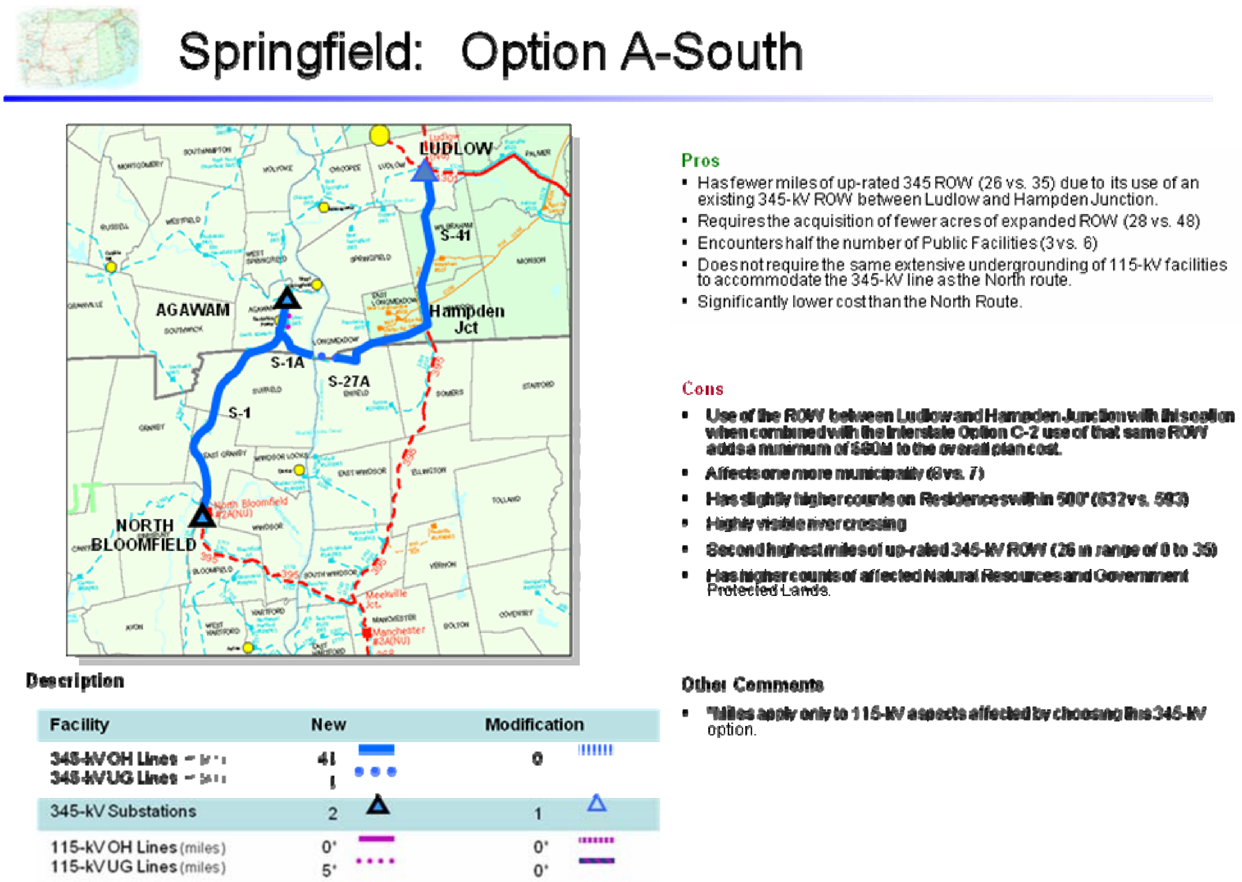
Cons
- Requires the acquisition of more acres of expanded ROW (48 vs. 28)
- Would require the undergrounding of 115-kV facilities (on Segment 27) to accommodate the 345-kV line.
- Significantly higher cost than the South Route.
- Has slightly more miles of up-rated 345 ROW (32 vs. 30)
- Encounters twice the number of Public Facilities (6 vs. 3)

Description

Facility	New	Modification
345-kV OH Lines	32	0
345-kV UG Lines	0	
345-kV Substations	2	1
115-kV OH Lines (miles)	0*	0*
115-kV UG Lines (miles)	13*	0*

Other Comments
- *Miles apply only to 115-kV aspects affected by choosing this 345-kV option.
- A gas pipeline shares the ROW and zig-zags along it

Slide #25: Springfield: Option A-South



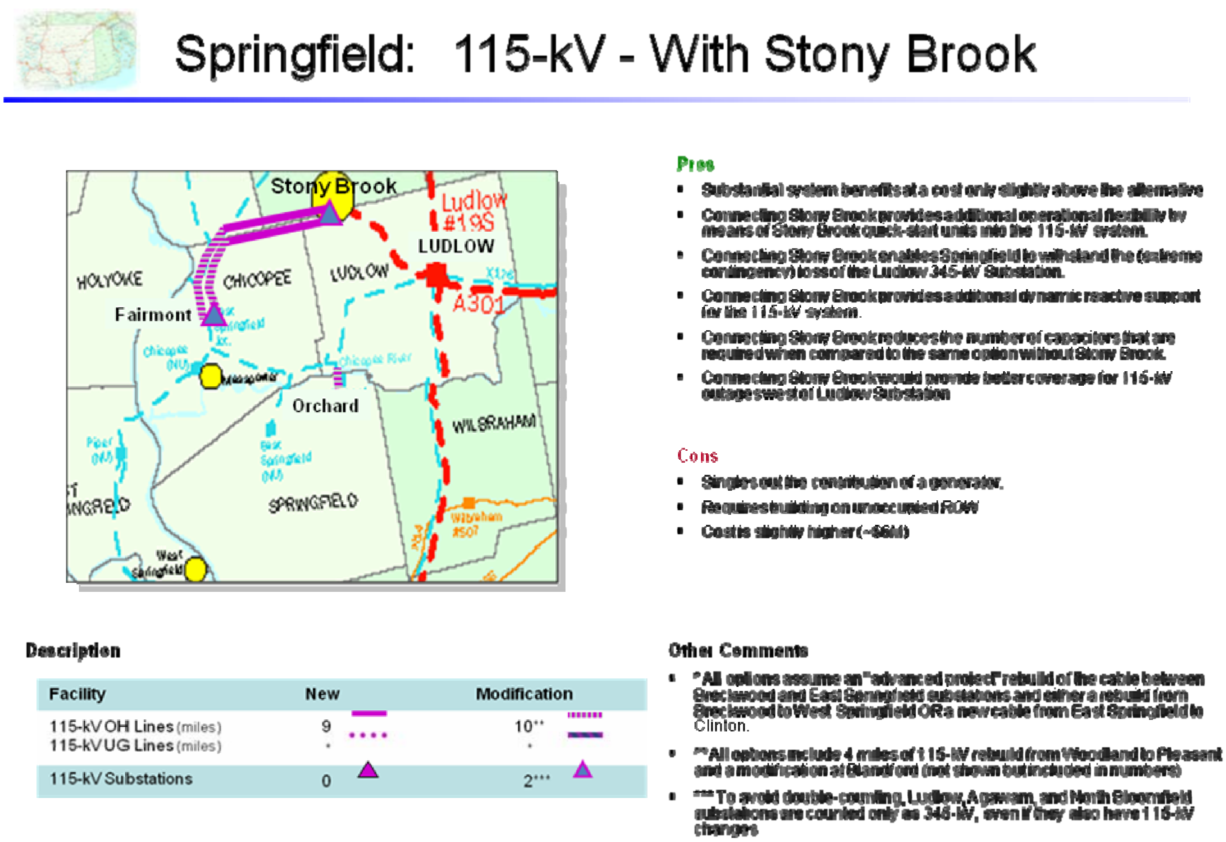
The choice was made for the Option A-South primarily based on the more favorable balance of advantages over disadvantages. As indicated above, of the following "Pro's" associated with the "South" Route, avoiding the significant undergrounding of 115-kV lines on the "North" Route and the lower cost carried the most weight:

Pros

- Has fewer miles of ROW occupied by one or more 345-kV lines (26 vs. 35) due to its partial use of an existing ROW between Ludlow and Hampden Junction.
- Requires the acquisition of fewer acres of expanded ROW (28 vs. 48)
- Encounters half the number of public facilities (3 vs. 6)
- Does not require the same extensive undergrounding of 115-kV lines to accommodate the 345-kV line as the North Route.
- Significantly lower cost than the North Route.

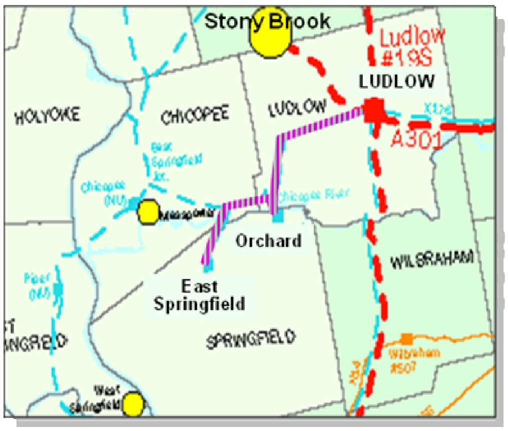
The third step required the selection between two options for adapting the 115-kV system to the new 345-kV modifications at the Ludlow Substation – options which either connected Stony Brook via a new right-of-way to the Fairmont Switching Station or upgraded and modified the Ludlow Substation and the existing 115-kV lines from Ludlow to the East Springfield Substation to accommodate the new 345-kV connection and the higher 115-kV power flows toward the East Springfield Substation. The "with" or "without" Stony Brook 115-kV connection was illustrated on the following slides from the October, 2006 SNETR Board Meeting:

Slide #29: Springfield: 115-kV – With Stony Brook



Slide #28: Springfield: 115-kV – Without Stony Brook

Springfield: 115-kV - Without Stony Brook



Pros

- Does not single out the contribution of any given generator
- Does not require building on unoccupied ROW.

Cons

- Requires a third autotransformer at Ludlow, which may limit future 345-kV connections
- Achieves none of the benefits of system of connecting
- Costs about $9M higher than connecting Stony Brook.

Description

Facility	New	Modification
115-kV OH Lines (miles)	0	18**
115-kV UG Lines (miles)	*	*
115-kV Substations	0	***

Other Comments

- * All options assume an "advanced project" rebuild of the cable between Breckwood and East Springfield substations and either a rebuild from Breckwood to West Springfield OR a new cable from East Springfield to Clinton.
- ** All options include 4 miles of 115-kV rebuild from Woodland to Pleasant and a modification at Blandford (not shown but included in numbers)
- *** To avoid double-counting, Ludlow, Agawam, and North Bloomfield substations are counted only as 345-kV, even if they also have 115-kV changes

The Stony Brook 115-kV interconnection was chosen at the October, 2006 SNETR Board meeting since the system performance benefits were thought to justify both the higher cost and the significantly higher impacts (primarily construction along an "unoccupied ROW"[13]). The benefits recognized at the time were the following:

- Substantial system benefits at a cost only slightly above the alternative
- Connecting Stony Brook provides additional operational flexibility by means of Stony Brook quick-start units into the 115-kV system.
- Connecting Stony Brook enables Springfield to withstand the (extreme contingency) loss of the Ludlow 345-kV sources to Ludlow Substation or to its two 345/115-kV autotransformers.
- Connecting Stony Brook provides additional dynamic reactive support for the 115-kV system.

[13] When studied further in 2007, the routing and siting analyses revealed that approximately 4.8 miles of new overhead 115-kV transmission lines along 3.4 miles of new right-of-way and 1.4 miles of existing transmission right-of-way would be needed from Stony Brook to a new connection point with 115-kV lines nearby to Five Corners Substation and the rebuilding of 4.9 miles of existing transmission lines between Five Corners Substation connection and the Fairmont Switching Station would also be needed. See: Section 3.4.2, below.

- Connecting Stony Brook reduces the number of capacitors that are required when compared to the same option without Stony Brook.
- Connecting Stony Brook would provide better coverage for 115-kV outages west of Ludlow Substation

During 2007, both the selection of the “South” Route over the “North” Route and the decision to connect Stony Brook to the 115-kV system were re-visited and ultimately, changed. See: Section 3.4 and Section 3.7, below.

2.2.3 PAC Presentation, December, 2006: 6b South with Related Springfield Advanced Projects

At the time of the December, 2006 PAC presentation[14], ISO-NE, NGrid and NU were given the opportunity to present the full SNETR study process, the study results and the preliminary SNETR options to the PAC.

ISO-NE presented the history and background of the SNETR study process, beginning in the 2002-2003 time frame. During the process leading to the Regional Transmission Expansion Plan (RTEP) 2004, the transfer and load-flow analyses were initiated. In the Regional System Plan (RSP) 2005, the preliminary problem statement, which could be summarized as five basic, interdependent problems, was identified. In this time frame, the preliminary problem statement was also presented to the PAC and the SNETR Working Group was formed. By the RSP 2006, the *Southern New England Transmission Reliability (SNETR) Report 1—Needs Analysis* (Draft, August 7, 2006) had been prepared.

ISO-NE reviewed the SNETR study assumptions on load, dispatch, contingencies and DSM. ISO-NE then presented to the December 2006 PAC the following “high level” statement of need, based on the 2009 system:

- Limited New England East-West transfer capability (in Connecticut, in Massachusetts and as part of a general interstate transfer limitation);
- Violations of 1st contingency transmission security for the Connecticut load zone;
- Rhode Island: Thermal Overloads and Voltage Problems;
- Springfield: Thermal Overloads and Voltage Problems; and

[14] The Planning Advisory Committee, or PAC, is established under Section 2.1 of Attachment K and, under Section 2.2, is given broad roles to provide input and feedback to ISO-NE in the regional planning process, including the development and review of Needs Assessments and the conduct of Solution Studies. The PAC is given specific duties to review and comment on the results of both Needs Assessments and Solution Studies.

- Violations of 2nd contingency transmission security for western Connecticut.

The problems were graphically illustrated in the familiar Figure 1-2 set forth below in the SNETR Study in Appendix A to this report.

After stating the problem and reviewing the numerous violations found during the study process, ISO-NE summarized for the December, 2006 PAC meeting the four primary components found as the preliminary SNETR study solution set as follows:

- Southern New England (SNE) Reliability Component[15]
- Greater Rhode Island Reliability Component
- Greater Springfield Reliability Component
- Central Connecticut Reliability Component

For each component of the four primary solutions, there was a long list of multiple options which were screened by the ISO-NE led planning team until a short list of competing options remained. ISO-NE presented the short list as follows:

The Southern New England (SNE) Reliability Component

Four 345-kV AC Options

- Option A: New Millbury-West Farnum-Lake Rd-Card St (Reconductor Sherman Road-CTRI Border 345-kV)
- Option B: New Kent County-Montville (Reconductor Sherman Road-ANP Blackstone 345-kV; Reconductor Millbury-Carpenter Hill-Belchertown 345-kV)
- Option C: New Millbury-Carpenter Hill-Manchester (New Sherman Road-West Farnum 345-kV)
- Option D: New Millbury-Carpenter Hill-Ludlow (Reconductor Sherman Road-CTRI Border 345-kV; New Sherman Road-West Farnum 345-kV)

One AC/HVDC Combined Option

- Option E: New Millbury-Southington HVDC Line (New Sherman Road-West Farnum 345-kV)

[15] Sometimes now referred to as the Interstate Reliability Project.

Greater Rhode Island Reliability Component

- New West Farnum – Kent County 345-kV line
  - Preferred from electrical performance perspective
  - Other Options Studied:
- Brayton Point – Franklin Square – Kent County 345-kV
  - Part of an unsuccessful, overall interstate option
  - Pushed too much power out of Brayton
  - Certain contingencies created numerous overloads and low voltages
- Two 115-kV cables from Franklin Square – Sockannaset
  - Poor performance, especially under line-out testing
  - Significant overloads and low 115-kV voltages

Greater Springfield Reliability Component[16]

Table 2-1: Remaining Springfield Options

	345-kV Portion	Stony Brook 115-kV interconnections	115-kV Phase Shifters	Fairmont 115-kV Station Rebuild	Separation of CT and Western MA 115-kV ties
Option 3A	Ludlow – Agawam – NB	No	Yes	No	Yes
Option 3B	Ludlow – Agawam – NB	Yes	Yes	No	Yes
Option 5B	Ludlow – Manchester	Yes	Yes	Yes	No
Option 6A	Ludlow – Agawam – NB	No	No	Yes	Yes
Option 6B	Ludlow – Agawam – NB	Yes	No	Yes	Yes
Option 6C(*)	Ludlow – Agawam – NB	No	No	Yes	Yes
Option 7A	Ludlow – NB	No	Yes	Yes	No
Option 7B	Ludlow – NB	Yes	Yes	Yes	No
Option 7C(*)	Ludlow – NB	No	Yes	Yes	No
Option 8A	Ludlow – Agawam – NB	No	No	No	Yes
Option 8B	Ludlow – Agawam – NB	Yes	No	No	Yes
Option 8C(*)	Ludlow – Agawam – NB	No	No	No	Yes

Central Connecticut Reliability Component

- Manchester – Southington 345-kV line
  - Performed well
  - Became Option A
- Manchester – Scovill Rock 345kV line

[16] ISO-NE December 15, 2006 PAC Presentation, Slide 53.

  - Initial poor performance which was corrected with the addition of the Hans Brook – Berlin 345-kV line
  - Became Option B
- Montville – Haddam Neck 345-kV line
  - Eliminated due to poor performance not easily corrected
- North Bloomfield – Frost Bridge 345-kV line
  - Performed extremely well
  - Became Option C

The December, 2006 PAC presentation by the transmission owners, NU and NGrid, emphasized the respective roles of ISO-NE and the transmission owners. An ISO-NE-led planning team screens a long list of potential electrical solutions and identifies a short list of the "Top System Solutions". The Top System Solutions represent high performing electrical solutions which meet the specified need and satisfy applicable reliability criteria. The transmission owners screen a long list of routing options which implement the electrical solutions and identify a short list of the "Top All-Around Solutions". The Top All-Around Solutions represent the best solutions taking into account not only additional electrical performance analyses but also analyses of routing alternatives. Starting with 39 Top System Solutions, the transmission owners developed routing alternatives for each system solution, reaching a total of over 860 system/route combinations for evaluation. Over 500 miles of route alternatives were screened against key criteria such as cost, human and environmental impacts, constructability, licensing timelines and in-service deadlines.

The December, 2006 PAC was presented the Five Key Criteria used by the transmission owners in reviewing the 500 miles of route possibilities in the following slide:

Slide #13: Step 3: Critically Evaluating the Better Options

Step 3: Identify the Top All-Around Solutions

Step 3: Critically Evaluating the Better Options

Five Key Criteria, based on siting requirements in MA, RI, and CT, guided the evaluation of possible solutions:

Network Performance & Long-term Flexibility

The potential impact to the long-term reliability, flexibility, and expendability of the network must be considered so that, over their lifetime, the new facilities (i) will be able to solve currently identified problems, (ii) will be able to meet future interconnection and demand needs and (iii) will improve the competitive power markets, including access to renewable energy.

Human Environment Considerations

The potential impact on customers and local community interests must be taken into account by considering the impact of the new facilities on the communities they will serve and the communities where they will be sited.

Natural Environment Considerations

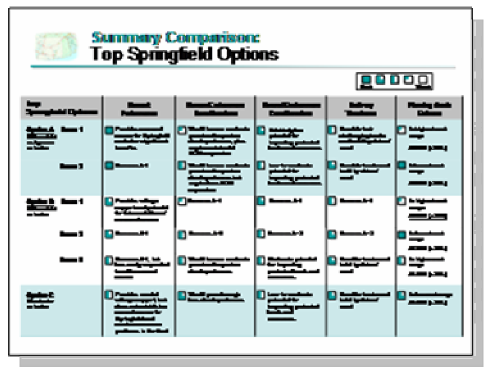
The potential impact on the surrounding natural environment must be considered, as well as the ability of the option to meet environmental laws and regulations.

Delivery Timeframe

The likelihood of permitting and building the new facilities in time to meet identified needs must be considered.

Cost Considerations

As stewards of our customers' and shareholders' investment in the new facilities, we must consider costs in the evaluation process, including giving consideration to the full lifetime costs and the anticipated longevity of the electrical solution.



The Key Criteria were applied to the Top Springfield Options in the following slide set below. The reasons for NU's choice emerged from the entries in the slide.

Slide #22: Summary Comparison: Top Springfield Reliability Options

Summary Comparison:
Top Springfield Reliability Options

Best Worst

Top Springfield Options		Network Performance	Human Environment Considerations	Natural Environment Considerations	Delivery Timeframe	Planning Grade Estimate
Option A N Bloomfield ⇔ Agawam ⇔ Ludlow	Route 1	Provides a second source for Springfield and other significant benefits	Would have a moderate perceived impact on developed areas, plus require substantial ROW expansion	Relatively low potential for impacting protected lands and resources	Feasible-but-challenging to site and build by date of need	In the highest cost range $500M (±25%)
✓ Preferred to-date. Subject to PAC input.	Route 2	Same as Option A-Route 1	Would have a moderate perceived impact on developed areas but require less ROW expansion	Low-to-moderate potential for impacting protected lands and resources	Feasible to site and build by date of need	In the lowest cost range $350M (±25%)
Option B	Route 1	Provides voltage support and potential for future addition of a second source	Same as Option A-Route 1	Same as Option A-Route 1	Same as Option A-Route 1	In the highest cost range $500M (±25%)
	Route 2	Same as Option B-Route 1	Same as Option A-Route 2	Same as Option A-Route 2	Same as Option A-Route 2	In the lowest cost range $350M (±25%)
	Route 3	Same as Option B-Route 1, but less easily expanded to add a second source	Would have a moderate perceived impact on developed areas	Moderate potential for impacting protected lands and resources	Feasible to site and build by date of need	In the higher cost range $450M (±25%)
Option C Manchester ⇔ Ludlow		Provides needed voltage support, but does not establish a second source for Springfield and creates some new problems in Hartford	Would pass through less-developed areas	Low-to-moderate potential for impacting protected lands and resources	Feasible to site and build by date of need	In the low cost range $400M (±25%)

During the transmission owners' portion of the December 15, 2006 PAC presentation, as the "check" on the above slide indicates, NU set forth its initial choice of Option 6b, South Route. NU summarized how its preferred choice scored on the key criteria as follows:

NETWORK PERFORMANCE:

- This option substantially improves system reliability in the Springfield area and brings it into compliance with national reliability criteria.
- This option would establish a separate, independent, southern bulk power source for Springfield – a 345-kV loop for Springfield.
- The Agawam Substation is in complementary position to the Ludlow Substation for providing voltage support to the Springfield area.
- This option reduces Springfield's dependence on local generation.
- Since all the area's 115-kV lines tie into the Agawam Substation, this option makes use of Agawam's strategic location for limiting power flows through the Springfield area.

- This option replaces the weak 115-kV ties with Connecticut with a strong 345-kV interconnection.
- In the event of an extreme contingency loss of the Ludlow Substation, power can flow north from North Bloomfield to Agawam.
- Agawam is close to area load centers and would provide flexibility in expanding the 115-kV system to serve area growth.
- This option reduces reliance on the Ludlow autotransformers.
- This option allows power from Stony Brook to flow directly to Springfield load center, even with Ludlow out of service.
- This option provides a separate path for power flowing on the 345-kV system to enter the Springfield 115-kV system.

HUMAN ENVIRONMENT:

- Possible routes pass by few public facilities.
- Possible routes require the acquisition of some acres for expanding the ROW.

NATURAL ENVIRONMENT:

- Possible routes have a relatively low-to-moderate potential for impacting natural resources.

DELIVERY TIMEFRAME:

- It is feasible to site and build by date of need.

COST:

- The estimate for this option is in the lowest cost range of all possible options, with significantly more system benefit.

2.2.4 NU Engineering and Planning 2007/2008: Critical Options Evaluations - - Second Iteration and Re-Design of the Initial 2006 Solution

After the December 15, 2006 PAC presentation, NU with the assistance of ABB and its consulting engineers Burns & McDonnell Engineering (BMcD) and their respective subconsultants and agents, continued throughout 2007 with the technical, engineering and siting analysis of the GSRP options. On February 27, 2007, ABB produced a second draft report which, like its earlier version, assisted the ISO-NE SNETR Working Group in its analyses, identifying solution options and helping the Working Group to prepare a SNETR Options Analysis that was released in June 2007. The ABB report explored twenty-nine (29) different ways to reinforce the Springfield area transmission system, work which led to several key insights for solutions, and then four solution strategies guided by those insights, as follows:

1. Building a 345-kV loop around Springfield, so, a high voltage path past Springfield is still available with one 345-kV line out. The Springfield 115-kV system can then be fed from more than one location on the 345-kV loop without wheeling large amounts of power through the 115-kV system for an N-1 outage. A phase-shifting transformer (i.e., phase-angle regulator) can be used to reduce the amount of wheeling further.
2. Connecting more points in the Springfield 115-kV system to the 345-kV system, but on the 345-kV side, feed each point radially from the Ludlow 345-kV bus. The 115-kV system will thus be fed essentially from one 345-kV location, and would not provide a path for wheeling power between two locations in the 345-kV system.
3. Upgrading the existing 115-kV lines and cables and adding additional 115-kV circuits to handle the anticipated flows through the system.
4. Dividing the Springfield 115-kV system into islands that are separately fed from the 345-kV system, but, not connected to each other. No 115-kV path is then available for wheeling power through Springfield.[17]

Five (5) basic alternative expansion plans based upon these four strategies were selected for further study, each with variations. In addition, a variation to include the interconnection of the Stony Brook generating plant (480 MW) into the Springfield area 115-kV transmission system was considered for each plan, and a variation to include a new Ludlow to Fairmont 115-kV line was considered for three of the expansion plans. Thus, a total of thirteen (13) plans emerged for the Working Group to study further with a variety of generation dispatches. Twelve (12) of the 13 options were developed in the Options Analysis dated June 25, 2007. See: Section 2.2.5, below.

Some of the decisions which emerged as a result of the more detailed analyses that occurred during the development of the Options Analysis in 2007 were later reviewed in greater detail in the "bottom-up" re-assessment of options set forth in Section 3, below.

In brief summary, during 2007, as a result of the more detailed analyses and the investigation of potential solution options, certain determinations were made, as follows:

[17] Dividing Springfield into electrical islands was captured in a wide-ranging Option 24-2, which eliminated various overhead line connections and addressed more than the cable radial supply change presented by NU in Section 4, below. Option 24-2 was dropped early in the analysis reviewed in this ABB Second Draft Report. "Early in the analysis it became apparent that a strategy that separates the Springfield 115-kV system into islands by opening some of the existing connections would be unworkable with N-1-1 outages, which open even more connections." ABB Second Draft Report, footnote 3, page 42.

- Planning and engineering analysis demonstrated that 345/115-kV structure-sharing on the North Route was feasible;
- The ability to place a 115-kV circuit on the North Route on shared structures substantially reduced the estimated cost of the North Route, because previous cost estimates had assumed that it would be necessary to take one or more 115-kV circuits off the right-of-way and reconstruct them underground, in order to provide room for the new 345-kV line on the right-of-way;
- Comparison of the North Route versus the South Route as to the scope and nature of impacts on all of the corridors affected by both the 345-kV and the 115-kV work revealed much greater overall impacts with the use of the South Route;
- ROW expansion analyses on the North Route were conducted;
- Route selection and analysis for the Stony Brook connection to Fairmont was pursued, including ground survey work, where permitted;
- Additional and more detailed Stony Brook cost, impacts and reliability comparisons were made;
- Second contingency analyses for the GSRP on the North Route with structure-sharing revealed overloads requiring replacement of the existing Breckwood Substation to the West Springfield Substation cable circuit on an earlier-than-expected timeframe;
- Detailed routing and engineering analyses of the Springfield Cables Project occurred;
- Engineering and cost analyses indicated the superiority of re-locating the switching station function from the East Springfield Substation site to a new Cadwell Switching Station site about one-half mile to the northeast of the East Springfield Substation site;
- Additional second contingency analyses were conducted on the SCP;
- As a result of additional analyses on the SCP, a second Breckwood to East Springfield cable was proposed to prevent loss of local load upon the second contingency loss of both the single Breckwood Substation to East Springfield Substation cable circuit and the single Breckwood Substation to West Springfield Substation cable circuit.

2.2.5 Draft SNETR Options Analysis, June 25, 2007

The SNETR Working Group presented the *Southern New England Transmission Reliability (SNETR) Report 2—Options Analysis*, on June 25, 2007 (to be released soon in final form, Options Analysis). While the Options Analysis does not select among the 12 system alternatives presented for the GSRP, it did identify certain system benefit advantages and disadvantages of those 12 Options. References in this Springfield Solution Report shall be taken to refer to the final form of the Options Analysis, unless otherwise indicated.

In the Options Analysis, ISO-NE considers a wide range of reinforcement options to remedy the significant overloads and voltage problems which are caused by numerous contingencies at or near summer peak-load periods. The reinforcement plans also address the area transfer deficiencies recognized in the Needs Analysis for both 2009 (Table 3.1) and 2016 (2016) (Table 3.2). See: Section 2.1, above. All options provide reliability and supply benefits to both Springfield and Connecticut. All options include a new 345-kV connection between Massachusetts and Connecticut and associated 115-kV reinforcements in the Springfield area which bring the areas into compliance with reliability standards.

The main differences among the options are two-fold. The first difference is whether or not they provide another 345-kV supply point to the Springfield 115-kV system. The Option A candidates provide that supply point at the Agawam Substation, while the Option B candidates bring the new 345-kV line to the North Bloomfield Substation in Connecticut without going to the Agawam Substation and the Option C candidates similarly bring the new 345-kV line to the Manchester Substation in Connecticut without going to the Agawam Substation.

The second main difference is whether they eliminate the weak western Massachusetts/Connecticut 115-kV ties or they retain the ties and use phase shifters to restrain power being wheeled through the area on the 115-kV system. All options which cut the ties are associated with providing another 345-kV source at the Agawam Substation (Options A). The options which retain the ties install phase shifters at North Bloomfield Substation (Options B and C). One Option A variation which cuts the ties also installs phase shifters at the Agawam Substation to restrain further the flow on the 115-kV system.

A number of variations fill out the total of twelve (12) options reviewed by ISO-NE in the Options Analysis. Some variations address whether and how the Stony Brook generation station should be connected to the 115-kV system in the Springfield area. Four variations make no connection (the “a” series) and include alternative modifications at the Ludlow Substation. Four variations make the new connection at the Fairmont Switching Station by means of the construction or re-building of overhead 115-kV lines along 9.5 miles of right-of-way, including 3.4 miles of virgin right-of-way. Three variations also make no Stony Brook connection but do build a new 115-kV line from Ludlow Substation to the Fairmont Switching Station along the existing right-of-way.

Operations personnel from ISO New England and CONVEX reviewed the Springfield options. The Options Analysis reports that the operators, who were not presented with any information concerning cost, environmental, or routing impacts, preferred Option A, variation 6b, the same option preferred by NU at the time of the December, 2006 PAC presentation. See: Section 2.2.3, above. While preliminary information concerning cost, environmental, or routing impacts was available in 2006 about the Stony Brook connection, when more detailed information in each of these categories became available to NU during 2007, NU in January, 2008 reversed its original preference for the Stony Brook connection and switch its preference to Option A, variation 6a. See: Section 3.4, below.

It should be noted that the Options Analysis shows in its Appendix A that upgrades to the cable paths in the City of Springfield were an integral part of the great majority of the twelve (12) GSRP options reviewed. In this regard, 10 of the 12 options included "*Install new Clinton - East Springfield cable circuit*". Moreover, 12 of the 12 options included, "*Replace Breckwood - E. Springfield cable circuit*"[18]. Strengthening the "through-path" on the 115-kV system from the East Springfield Substation to the West Springfield Substation was common in the solution choices for the Springfield area.

From the core nature of these cable upgrades in the collaborative Options Analysis, the idea arose among NU planners to advance the siting and engineering for a cables project while the other components of the GSRP were studied further. Advance siting of a cables project had operating advantages later when outages on the overhead segments of the Springfield 115-kV system were needed to construct the GSRP. As indicated above in Section 2.2.4, detailed routing and engineering analyses of the Springfield Cables Project began in earnest in the summer, 2007. See: Section 2.2.8, below, the Springfield Cables Project.

The discussion of all twelve (12) Springfield area options is excerpted from the Options Analysis in Appendix B to this Springfield Solution Report. In addition, Table A-4 in Appendix A to the Options Analysis itself consists of a component matrix and summary of option elements. Table A-4 is also reproduced in Appendix B to this report.

2.2.6 TTF November 28, 2007 Proposed Plan Application (PPA Project)

During the second half of 2007, the option presented during the December 15, 2006 PAC meeting as the initial preferred solution for the Springfield area, designated as Option A, 6b South, in the ISO-NE Options Analysis set forth in Section 2.2.5, underwent significant change. In Section 2.2.4, the reasons to move away from the South Route were summarized. Detailed engineering and planning during the second half of 2007 studied the option of using new 345/115-kV shared structures on the North Route. Cost savings and significant reductions in overall impacts were seen as the new preferred option, designated as Option A, 6b North in the ISO-NE Options Analysis, was studied.

[18] Four of the 12 options added a third cable to the foregoing two, "*Install 3rd Clinton – West Springfield cable circuit*". The two options which replaced the Breckwood to East Springfield cable, but did not include a new Clinton to East Springfield cable, also replaced the Breckwood to West Springfield cable circuit.

By November 28, 2007, NU had prepared a Final Report, Proposed Plan Application, Steady State Analysis and presented it to the Transmission Task Force (TTF). The Springfield option set forth in this report will be referred to in the following sections of this Springfield Solution Report as the PPA Project. In Section 1.2.4 of the Final Report, the components of the project proposed for the Springfield area were presented in two lists, the first dealing with the proposed work relating to the 345-kV system and the second dealing with the Springfield Advanced 115-kV work, as follows:

> "1. Build a new 345-kV transmission line from Ludlow 19S to the Agawam 16C substation, approximately 16.42 miles. This transmission line should be built with bundled 1590 kcmil ACSR conductors.
>
> 2. A new 345 kV circuit will be built from Agawam 16C substation to North Bloomfield 2A substation. The overhead section of the line, approximately the first 8.9 miles and the last 5.7 miles, should be built with bundled 1590 ACSR conductor.
>
> 3. The underground section, approximately 5.0 miles, should be built with 3 cables of 3500 kcmil XLPE cross bonded cable. Only two cables will be in-service at any one time. . . . A variable 90 MVAR reactor with a minimum of 45 MVAR (45 MVAR fixed) should be placed on each cable at the switching station nearer to North Bloomfield. The transition stations will have circuit breakers and pre-insertion resistors for each underground circuit.
>
> 4. Two (2) 345/115 kV 600 MVA auto-transformers will be installed at Agawam 16C substation.
>
> 5. Two 115 kV lines will be built from Stony Brook 54B generating station to tap points on lines 1113/1134 using 2-1590 ACSR conductors per phase.
>
> 6. The 115-kV lines 1113/1134 will be rebuilt from Fairmont 16H substation to the Stony Brook tap points using 2-1590 ACSR conductors per phase.
>
> 7. A second 345/115 kV 600 MVA auto-transformer will be installed at North Bloomfield 2A substation. The substation will have to be built as a GIS. . . .
>
> 8. The Southwick – North Bloomfield 115 kV line 1768 and South Agawam – North Bloomfield double-circuit 115-kV line 1821/1836 will be disconnected at North Bloomfield. Line 1836 will also be disconnected at South Agawam. Lines 1768 and 1821 will be connected (joined) at Granby Junction (approximately 5 miles north of North

Bloomfield) to form a new Southwick to South Agawam 115 kV line. The line portion from South Agawam to the CT/MA border, approximately 3.0 miles, will be placed on the same structures as the new Ludlow to North Bloomfield 345-kV line and will utilize 1590 kcmil ACSR conductor. The portion from the CT/MA border to Granby Junction, approximately 7.47 miles, will cross bundle the existing circuits 1821/1836. The other portion from Granby Junction to Southwick, approximately 5.3 miles, will utilize the same conductors on the existing structures. Also, the reactor at South Agawam in series with line 1821 will be disconnected. This will separate the Western Massachusetts / Connecticut **115 kV** ties.

9. Rebuild line 1781/1782 using 1590 kcmil ACSR conductor for each circuit. Circuit 1781 will share the same structures as the new Agawam to North Bloomfield 345 kV line. Circuit 1782 will be built using new single circuit structures.

10. Replace the West Springfield – Breckwood cable with 3500 kcmil XLPE cable and reconnect the 4% (on 100 MVA base) reactor in series

11. Rebuild / reconductor the Woodland to Pleasant 115 kV line 1371. The portion from Woodland to Pleasant Junction, approximately 2.39 miles, will be rebuilt using 1590 kcmil ACSR conductor, and the remaining portion from Pleasant Junction to Pleasant 16B substation, approximately 1.74 miles, will be reconductored using 957 kcmil ACSS/TW conductor on existing structures.

12. Upgrade the Pleasant to Blandford 115 kV line 1421

13. Upgrade the Blandford to Granville Junction portion of the 3-terminal line 1512

14. Reconductor the West Springfield to Agawam lines 1311/1412 using 657.2 kcmil ACSS conductor.

15. Modify the Ludlow 19S 345-kV substation to accommodate the new 345-kV line. . . .

16. Build an Agawam 16C 345-kV substation to connect two 345 kV lines and two auto-transformers. . . .

17. Build a North Bloomfield 345 kV substation to connect the existing line 395, the new 345 kV line from Agawam, the new Frost Bridge 345 kV line, and two 345/115 kV auto-transformers. . . .

18. Modify the Agawam 16C 115-kV substation by adding a complete breaker-and-a-half bay. Line 1781 will be disconnected from its present position and reconnected into the new bay as well as one of the new autotransformers. The second autotransformer will be connected into the position vacated by line 1781. . . . .

19. Modify the North Bloomfield 2A 115-kV substation. . . .

20. Modify Scitico 27H substation to establish a ring bus, and install two (2) 14.4 MVAR capacitor banks. . . .

21. Modify the Stony Brook 115-kV substation . . . to accommodate the two new 115 kV lines.

The Springfield Advanced 115-kV projects assumed in service are:

1. Rebuild Ludlow to Shawinigan circuit 1845 (6.24 miles) using 2-1272 kcmil ACSR conductors per phase. This 115-kV circuit will share the same double-circuit structures as the new Ludlow – Agawam 345 kV line.

2. Rebuild Ludlow to East Springfield circuit 1481 (7.80 miles) using 2-1272 kcmil ACSR conductors per phase.

3. Rebuild Orchard to East Springfield circuit 1426 (3.61 miles) using 2-1272 kcmil ACSR conductors per phase.

4. Rebuild Ludlow to Ochard circuit 1552 (5.47 miles) using 2-1272 kcmil ACSR conductors per phase.

5. Undo the 3-terminal lines 1254/1723 at East Springfield Junction and bring the resulting four circuits into Fairmont substation. Rebuild Shawinigan to Fairmont (4.70 miles) and East Springfield to Fairmont (5.75 miles) circuits on separate structures using 2-1272-kcmil ASCR conductors per phase for each circuit. The East Springfield to Fairmont circuit will share the same double-circuit structures as the new Ludlow – Agawam 345 kV line.

Rebuild Chicopee to Fairmont (2.54 miles) and Piper Road to Fairmont (5.92 miles) circuits on separate structures using 1590 kcmil ACSR conductor for each circuit. The Chicopee to Fairmont circuit will share the same double-circuit structures as the new Ludlow – Agawam 345 kV line.

6. Rebuild Chicopee to Agawam circuit 1314 (7.12 miles) using 1590 kcmil ACSR conductor. This 115-kV circuit will share the same double-circuit structures as the new Ludlow – Agawam 345 kV line.

7. Rebuild Piper Road to Agawam circuit 1230 (3.60 miles) using 1590 kcmil ACSR conductor.

8. Build a new cable circuit with a spare duct bank [~4.5 miles each] from East Springfield 5J substation to Clinton 21S substation using 3500 kcmil XLPE cable with a 5% series reactor; summer ratings: 250 MVA normal, 371 MVA LTE

9. Build two new cable circuits [~2.8 miles each] from East Springfield 5J substation to Breckwood 20A substation each using 3500 kcmil XLPE cable; summer ratings: 250 MVA normal, 371 MVA LTE

10. Decommission the existing low-capacity cable circuit 1322 [2.41 miles]

11. Rebuild Fairmont 16H substation using a breaker-and-a-half arrangement with five bays; one feeder to Prospect 24B substation will be connected into a bay and the other will be connected to the end of one of the buses

12. Build-out Clinton 21S substation into a 4-breaker ring-bus configuration (existing straight-bus)

13. Build-out Breckwood 20A substation into a 4-breaker ring-bus configuration (existing straight-bus)

14. Build a new Cadwell 50F substation approximately 0.5 miles north of the existing East Springfield 5J substation using a breaker-and-a-half arrangement. The existing lines into East Springfield 5J substation will be disconnected from that substation and reconnected into the new Cadwell 50F substation.

> 15. Reconfigure East Springfield 5J substation into a distribution substation to be fed from the new Cadwell 50F substation.
>
> 16. Connect a new 4% reactor in series with the Breckwood 20A – West Springfield 8C circuit 1433, and reconnect the cable circuit to the new position at Breckwood 20A substation."
>
> Final Report, Proposed Plan Application, Steady State Analysis, presented to the TTF, November 28, 2007, pages 12-14

The color coding in the above listings has been added to highlight two different facts. The "blue" coded entries, items 11 through 13 in the first part of the list, are smaller component upgrades in the far western part of Massachusetts. These upgrades had been listed as a part of the Springfield component options in the ISO-NE Options Analysis and are shown in the Appendix A, Table A-4 of that report (reproduced as Appendix B to this GSRP Solution Report). However, they have been determined to be independent of the need for a Springfield area solution. In the final preferred Springfield Solution set forth below in Section 2.2.10, these smaller independent components will again be color-coded and footnoted as independent projects. In Section 3.9, below, the independent components will also be color-coded and footnoted as both independent and excluded from the Total Cost Estimates.

The "yellow" coded entries are additions to the component options which are listed in the ISO-NE Options Analysis, Appendix A, Table A-4 for Option A, 6b (Appendix B to this report). The additional work was required primarily on account of the use of the North Route and the associated line-structure sharing, right-of-way constraints and contingencies which involved the loss of the 345- and 115-kV circuits sharing structures. With respect to the last reason, the replacement of the cable from the West Springfield to the Breckwood Substations was accelerated by the need to relieve an overload on the underground cable circuit #1433 when the 345- and 115-kV circuits sharing structures experience a common event failure on the path from Ludlow to Agawam Substations. The addition of the second new underground cable circuit between the East Springfield and the Breckwood Substations had a different cause. As set forth below in Section 4, NU chose to protect against loss of the Breckwood Substation load in the event that a double contingency resulted in the loss of both of the underground cable circuits serving the substation.

Item #14 in the second list for the Springfield Advanced 115-kV projects involved the construction of a new switching station at a WMECO-owned site approximately 0.5 miles north of the existing East Springfield Substation and was required by site constraints at the 3.2-acre existing site. The existing site would need to accommodate new cable interconnections. Engineering analysis determined that re-building the East Springfield Substation as a conventional air-insulated substation (AIS) in a breaker-and-a-half bus configuration could not be done within the existing footprint, which could not be expanded. The existing facility would have to be largely demolished and re-constructed as a more compact gas-insulated-substation (GIS) at a cost of approximately $62 million, with an estimated construction duration of 18 to 25 months. On the other hand, an AIS could be constructed at the Cadwell site connecting the three new cable circuits from the Clinton and Breckwood Substations to the three existing overhead 115-kV circuits originating at substations to the north. Connections would then be made to two new 115-kV overhead circuits interconnecting the Cadwell Switching Station to the existing distribution transformers at the East Springfield Substation. The cost of all Cadwell-related work, including the cable-circuit extensions to the site and the overhead 115-kV line modifications, was estimated at approximately $40 million, with an estimated construction duration of 12 to 18 months. After a detailed assessment of all advantages and disadvantages of the two options, the Cadwell Switching Station was selected.

Finally, the capacitor requirements for the Springfield area were not listed in the ISO-NE Options Analysis.

Specific reasons for each of the project components added to the PPA Project, in comparison to the components in Option A, 6b (as presented in Appendix A, Table A-4, as of the ISO-NE Options Analysis) are set forth below in the Comment column of Table 2-2, the matrix comparing these two options.

Table 2-2 Springfield Reinforcement Options

Springfield Reinforcements	6b	PPA	COMMENTS
Associated 345-kV Option:	**A**	**A**	
345-kV			
Build Ludlow - Agawam 345-kV ckt #1	X	X	
Build Agawam - N. Bloomfield 345-kV ckt#1	X	X	
Build Ludlow - Manchester 345-kV circuit #1			
Build Ludlow - North Bloomfield 345-kV circuit			
Transformers			
Install Agawam 345/115-kV Transformer #1	X	X	
Install Agawam 345/115-kV Transformer #2	X	X	
Install Agawam 115-kV Phase shifters ckt 1-2 (in series with transformer)			
One (1) spare 115-kV Phase shifter			
Replace N.Bloomfield 345/115-kV Transformer #1 (CT)	X		Option 6b was based on assumed Central CT 345kV line from Manchester to Southington.

Springfield Reinforcements	6b	PPA	COMMENTS
			Not needed in PPA since Central CT North Bloomfield to Frost Bridge 345-kV line was selected.
Install N.Bloomfield 345/115-kV Transformer #2 (CT)	X	X	
Install N.Bloomfield - S.Agawam Phase Shifters 1-2			
N.Bloomfield - Southwick Phase Shifter			
Reconnect Ludlow 345/115-kV Transformer #1 into bay	X		
Reconnect Ludlow 345/115-kV Transformer #2 into bay	X		
Install Ludlow 345/115-kV Transformer #3			
115-kV			
Rebuild / Reconductor Ludlow - Shawinigan		X	Added due to ROW constraints
Separate / Rebuild E. Springfield-Ochard-Ludlow & E. Springfield-Ludlow		X	Added to Springfield 115 as a result of modified dispatch 7 as a request of ISO-NE, West Springfield #3 placed in-service during TTF process
Separate or Rebuild W. Springfield - Agawam ckt #1 & #2			
Upgrade West Springfield - Agawam ckt #1 & 2		X	Required as a result of addition of second East Springfield to Breckwood cable and updated impedances on overhead lines
Rebuild S. Agawam - Silver ckt 1&2 or add ckt 3		X	Add for ROW constraints
Rebuild Silver - Agawam ckt 1&2 **or** add ckt 3		X	Add for ROW constraints
Replace Breckwood - W. Springfield cable circuit		X	Accelerated as a result of new 345-115 DCT contingency
Replace Breckwood - E. Springfield cable circuit	X	X	
Replace Breckwood reactors	X	X	
Rebuild / reconductor Woodland - Pleasant line ckt #1	X	X	[independent project, not in Springfield]
Rebuild Agawam - Piper ckt #1	X	X	
Install new Clinton - E. Springfield cable circuit	X	X	
Clinton series reactor	X	X	
Install 3rd Clinton - West Springfield cable circuit			
Upgrade Ludlow-E. Springfield circuit #1			
Build new Stony Brook - Ludlow 115-kV line			
Build new Stony Brook - Five Corners 1 & 2 115-kV lines	X	X	
Rebuild Five Corners - Fairmont 1 & 2 115-kV lines	X	X	
Build new Ludlow - Fairmont 115-kV Line			
Disconnect CT/WMASS 115-kV ties	X	X	
Reconductor E. Springfield Jct. - Fairmont N.			
Separate / Rebuild 1254/1723 circuits			
Undo three-terminal line 1254/1723 circuits	X	X	
Separate / Rebuild (Fairmont - Shawinigan) / (Fairmont - E. Springfield)		X	Required as a result of ROW constraints
Reconductor E. Springfield Jct - Shawinigan			

Springfield Reinforcements	6b	PPA	COMMENTS
Reconductor Fairmont - Shawinigan	X		For PPA included in separate / rebuild row above
Upgrade E. Springfield Jct - Chicopee			
Reconductor E. Springfield Jct. - Piper			
Reconductor Fairmont - Piper	X	X	
Rebuild Fairmont - Chicopee		X	Required as a result of ROW constraints
Upgrade Fairmont S. - Holyoke 115 kV	X	X	
Upgrade Pineshed - Fairmont N.			
Upgrade Blandford - Granville Jct.	X	X	[independent project, not in Springfield]
Upgrade Southwick - N. Bloomfield			
Upgrade Pleasant - Blandford	X	X	[independent project, not in Springfield]
Create breaker-and-half bus configuration at Fairmont	X	X	
Rebuild Agawam – Chicopee		X	Placed on DCT with new 345 kV circuit
Rebuild East Springfield (or new Cadwell) substation		X	Required because of short circuit duty, since it needed to be upgraded and under this plan would have had 6 circuits connected to it; based on ISO-NE proposed PP9 guideline, the decision was to rebuild as breaker-and-a-half. East Springfield site required GIS. Alternate site for breaker-and-a-half 115-kV switchyard was Cadwell. Cadwell was less expensive than a GIS rebuild at East Springfield
New BPS stations: • Agawam 115 kV and 345 kV • Barbour Hill 115 kV • Breckwood • Fairmont • Orchard • West Springfield • Clinton • Cadwell		X	Required as a result of BPS testing
115-kV P&C stations upgrades: • South Agawam (including reactors) • Shawinigan • Chicopee • Piper • Orchard • Pineshed	X	X	Required for new 115kV line terminations
1.) Agawam-West Springfield 1311 line requires a second high speed protection group.		X	Required as a result of BPS stability
2.) Agawam-West Springfield 1412 line requires a second high speed protection group.		X	Required as a result of BPS stability
3.) Ludlow-Shawinigan 1845 line requires a second high speed protection group.		X	Required as a result of BPS stability
4.) Fairmont-Shawinigan 1604 line requires a second high speed protection group.		X	Required as a result of BPS stability
Clinton Ring Bus		X	Added because of additional circuits based on PP9 guideline
Breckwood Ring Bus		X	Added because of additional circuits based

Springfield Reinforcements	6b	PPA	COMMENTS
			on PP9 guideline
2nd East Springfield - Breckwood cable		X	Added to prevent long term loss of load as result of loss of other two sources to Breckwood which are old pipe-type cables.
Fairmont the two bays with lines from Stony Brook require 4000-amp breakers (230-kV class)	X	X	Needed to accommodate Stony Brook – Fairmont lines using bundled 1590-kcmil ACSR conductors
Assumptions			
1. All substation costs included in line upgrades (relaying, breakers, etc.)			
2. Line sizes for 115-kV are as in Springfield 115-kV Reinforcement Project TPS and in Greater Springfield TPS			

2.2.7 Springfield Area Solution PAC Presentation, December 3, 2007

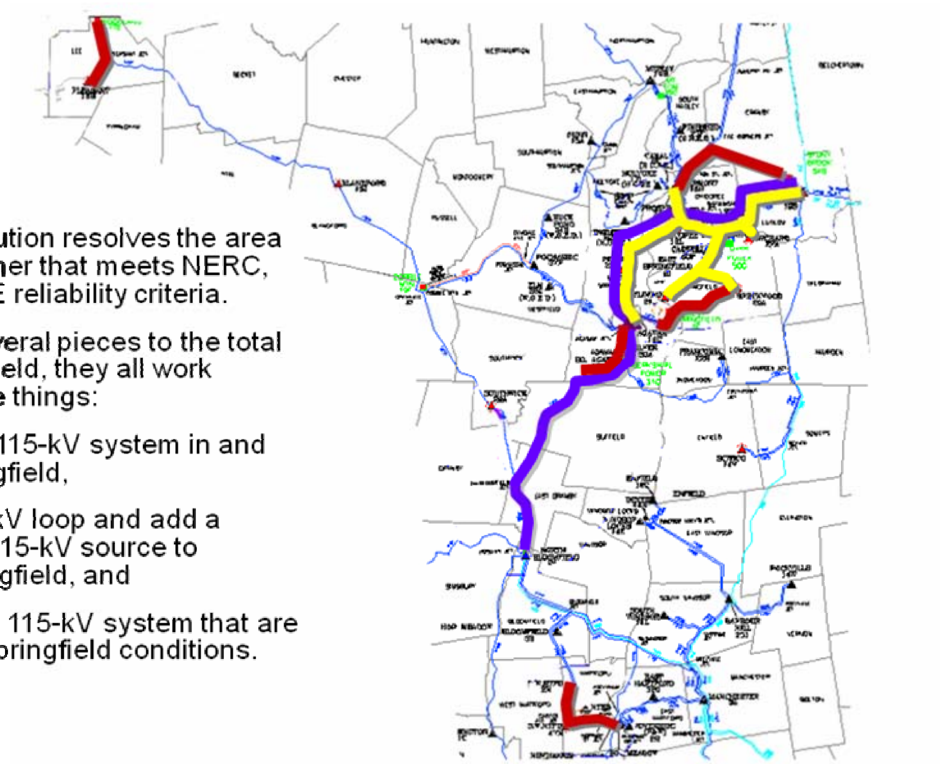
In this December 3, 2007 PAC presentation by NU, the scope of the total solution for the Springfield area problems was described, including both the Springfield 115-kV Projects and the NEEWS GSRP.

The wide geographic scope of the Springfield Solution and the common goal of the several components[19] of the Springfield Solution were illustrated on Slide 16 as follows:

[19] The components of the Springfield Solution in this PAC Presentation were the same as those set forth in the PPA Project in Section 2.2.6. In fact, the components in far western Massachusetts which have now been determined to be independent of the final Springfield Solution are still shown here. In addition, two new underground cable circuits in the City of Hartford (Hartford Cables), formerly included in the NEEWS Interstate Reliability Project, are shown here. As examined in greater detail in Section 2.2.10, below, the Hartford Cables were included in the planning of all Springfield options, Option A, Option B and Option C in the Options Analysis (Section 2.2.4, above), but up to this point in time, had not been shown as a part of the Springfield projects. See: Section 2.2.10, below for a discussion of how the Hartford Cables were subsequently replaced with the lower costs Manchester to Meekville separation as a result of the ISO-NE Review Process conducted by NU and ISO-NE and described below in Section 4.

Slide #16: Summary: Many Pieces that Together Do Three Things

Summary:
Many Pieces that Together Do Three Things



- The Springfield solution resolves the area problems in a manner that meets NERC, NPCC, and ISO-NE reliability criteria.
- While there are several pieces to the total solution for Springfield, they all work together to do three things:
  1. Upgrade the 115-kV system in and around Springfield,
  2. Close a 345-kV loop and add a second 345/115-kV source to support Springfield, and
  3. Reinforce the 115-kV system that are affected by Springfield conditions.

A fundamental part of the presentation was the NU explanation how its work in 2007 had reversed the initial selection of the South Route for the 345-kV line between Agawam and Ludlow. When NU determined that a 115-kV circuit on the North Route could be reconstructed overhead on the same right-of-way on common structures shared with the new 345-kV line, the principal disadvantage of the North Route, the undergrounding cost and difficulties, was removed. Lower costs and lower environmental impacts were achieved when the route selection was reversed.

Much of the December 2007 PAC presentation involved the wide-spread work that was required on the 115-kV system in the Springfield area. On the presentation slides that 115-kV work was summarized as follows:

115-kV Transmission Lines

- Rebuild Ludlow-Fairmont-Agawam 115-kV OH circuits on existing ROWs
- Reconductor two Agawam-West Springfield 115-kV OH circuits on existing ROWs

- Install new East Springfield-Clinton 115-kV underground cable circuit
- Replace East Springfield-Breckwood 115-kV underground cable circuit
- Rebuild two Agawam-Silver-South Agawam 115-kV OH circuits on existing ROW
- Bundle South Agawam to Bloomfield Junction 115-kV line to one circuit
- Separate CT/WMass 115-kV ties at North Bloomfield Junction and reconnect Southwick to South Agawam
- Build new Northwest Hartford-Southwest Hartford 115-kV underground circuit
- Build new Southwest Hartford-South Meadow 115-kV underground circuit
- Rebuild Woodland-Pleasant 115-kV line
- Minor structure and line work between Blandford Substation and Pleasant Junction
- Build two new Stony Brook-WMECO tap 115-kV OH circuits (new ROW needed)
- Rebuild two Fairmont-Stony Brook/WMECO tap 115-kV OH circuits
- Replace Breckwood-West Springfield 115-kV underground cable circuit

Substation Work

- Rebuild Fairmont Switching Station in a ring-bus configuration
- Install 6% series reactors in two 115-kV lines at South Agawam Substation
- Expand Breckwood Substation into a ring-bus configuration
- Expand Clinton Substation into a ring-bus configuration
- Build Cadwell Switching Station as an extension of the East Springfield Substation, with Cadwell in a breaker-and-a-half configuration[20]
- Install a second East Springfield-Breckwood 115-kV underground cable circuit
- Expand 345-kV facilities at North Bloomfield Substation and install a 2nd 345/115-kV autotransformer
- Expand Scitico Substation into a ring-bus configuration
- Install two 115-kV, 14.4-MVAR shunt capacitors at Scitico Substation

[20] If it is assumed that the East Springfield Substation, with six 115-kV lines and three step-down power transformers connected there, should have a breaker-and-a-half bus design, the total cost of relocating this substation's 115-kV switching station functions to a new Cadwell Switching Station was found to be less than the cost of converting East Springfield Substation to this design. See: Section 2.2.6, above. Keeping and expanding the existing 115-kV ring-bus design at East Springfield Substation is another option that was considered; however, the post-GSRP short-circuit duty would in that case require replacing or upgrading all of the 115-kV bus, circuit breakers, disconnect switches and ground grid at East Springfield Substation. In this case, a new Cadwell Switching Station with a ring bus also costs less.

With regard to its 345-kV line route change, NU indicated that the superiority of the North Route with 345/115-kV structure-sharing was clear. Superiority was based on the following factors:

- The shorter distance for the new 345-kV lines, 34.9 miles for the North Route versus 40.5 miles for the South;
- The dramatic drop in the total miles of impacted overhead corridors, a total for the North of 41.9 miles versus a total of 64.5 miles for the South (the sum of the 345-kV line's corridor length of 40.5 miles plus the 24.0 miles on the North Route where the existing corridor would be impacted by overhead 115-kV line upgrade work);
- The lower anticipated construction cost;
- Lower environmental impacts;
- Fewer property abutters;
- Lower acreage clearing required;
- Reduced risk of underground location of 345-kV lines in Connecticut; and
- The same system benefits.

At slide 17, those system benefits were described as follows:

- Substantially improves system reliability in the Springfield area and brings it into compliance with national and regional reliability criteria.
- Establishes a separate, independent, southern bulk power source for Springfield – a 345-kV loop for Springfield.
- The Agawam Substation is in complementary position to the Ludlow Substation for providing voltage support to the Springfield area.
- Since all the area's 115-kV lines tie into the Agawam Substation, this solution makes use of Agawam's strategic location for limiting power flows through the Springfield area.
- Agawam is close to area load centers and would provide flexibility in expanding the 115-kV system to serve area growth.
- Provides a separate path for power flowing on the 345-kV system to enter the Springfield 115-kV system
- Reduces Springfield's dependence on local generation. Compatible with other regional transmission reliability solutions.
- Replaces the 115-kV ties with Connecticut with a stronger 345-kV interconnection.

- In the event of an extreme contingency loss of the Ludlow Substation, power can flow north from North Bloomfield to Agawam.
- Reduces reliance on the Ludlow autotransformers.
- Allows power from Stony Brook to flow directly to Springfield load center, even with its 345-kV lead line to Ludlow out of service.
- Eliminates thermal and voltage problems in Springfield.
- Facilitates New England's competitive electric energy market.

2.2.8 Springfield Cables Project Massachusetts Energy Facilities Siting Board (EFSB) Petition, December 21, 2007

Western Massachusetts Electric Company (WMECO) filed its Petition to Construct the SCP on December 21, 2007. The SCP entailed the following six components:

1. Breckwood Substation to East Springfield Substation: Existing Cable Retirement. The existing 53-year old underground 115-kV high-pressure fluid-filled (HPFF) pipe-type cable circuit (#1322 cable circuit) between WMECO's Breckwood and East Springfield Substations will be retired from service.
2. Breckwood Substation to East Springfield Substation: New Cable. A new, 3.7-mile-long, double-circuit underground 115-kV solid dielectric transmission cable system will be constructed between these two substations[21].
3. Clinton Substation to East Springfield Substation: New Cable. Between these two substations, a new, 4-mile-long, single-circuit underground 115-kV solid dielectric transmission cable system will be constructed.
4. East Springfield Substation to Proposed Cadwell Switching Station: Overhead Transmission Line Reconstruction. WMECO proposes to reconstruct a 0.5-mile segment of existing overhead 115-kV lines on a 200-foot wide transmission line ROW between the existing East Springfield Substation and the proposed Cadwell Switching Station. The reconstruction will involve replacing two existing double-circuit 115-kV lattice tower lines with three monopole lines. These lines will carry the three new Clinton and two Breckwood circuits overhead to the Cadwell Switching Station, and two new 115-kV source circuits interconnecting the

[21] For the reasons explained in Section 4.2.2, NU chose to add a second new cable from the new Cadwell Switching Station to the Breckwood Substation. No option reviewed in the Options Analysis provided for two new cables. Under all options in the Options Analysis, the Breckwood Substation would continue to be served by two cables. With the addition of a second cable circuit from the Cadwell Switching Station in the SCP to the existing cable supply from the West Springfield Substation, NU sought to enhance the level of service to the Breckwood Substation in order to protect against the double-contingency loss of the two-cable supply.

Cadwell Switching Station to the existing power distribution transformers at the East Springfield Substation.

5. Breckwood, Clinton, East Springfield, and South Agawam Substations: Modifications. WMECO will modify each of these substations to accommodate the new transmission facilities. At South Agawam Substation, the required change is to replace series reactors in two circuits.

6. Proposed New Cadwell Switching Station. WMECO proposes to construct a new 115-kV switching station at WMECO's existing East Springfield Work Center, which is located on Cadwell Drive, approximately 0.5 miles north of the East Springfield Substation, and adjacent to an existing overhead transmission line ROW.

Inclusive of escalation and a 40% contingency, the SCP was expected to cost approximately $350 million. The SCP solved overloads on cable circuit #1322 between the East Springfield Substation and the Breckwood Substation caused by numerous single and double contingencies on the present transmission system, as well as by certain dispatches under normal conditions. The SCP provided a set of cable "through-paths" to the West Springfield Substation and from there to the Agawam Substation which would facilitate the transmission of power during the construction period outages that would occur while the GSRP was being installed. After the GSRP was installed, the SCP would protect both the Clinton Substation and the Breckwood Substation from the loss of load in the event that their present two-cable supply systems failed.

2.2.9 Additional Progress on the Springfield Cables Project: MEPA Certificate and the Commencement of the ISO-NE Review Process

During this period, in addition to the preparation and filing of the SCP Petition at the EFSB, substantial progress on the SCP was also being made on two other fronts.

Under the Massachusetts Environmental Policy Act (MEPA), a project as large as the SCP is exposed to a comprehensive environmental review process which could require the preparation of one or more state environmental impact reports. In order to assess whether impact reports are needed, the MEPA process requires the filing of an Environmental Notification Form (ENF), followed by public notice in the Environmental Monitor (EM) for Massachusetts, a public comment period, and a determination by the Secretary of Energy and Environmental Affairs. On November 28, 2007, NU filed the ENF accompanied by a large Supplemental Report reviewing the SCP, its alternatives, impacts and proposed mitigation measures. After notice in the EM and the receipt of public comments, the Secretary of Energy and Environmental Affairs on January 9, 2008 issued his Certificate on the ENF, determining as follows: "I find that the potential impacts of this project do not warrant the preparation of an [Environmental Impact Report]. No further MEPA review is required." ENF Certificate, page 4.

Progress was also made preparing for the ISO-NE technical and cost review processes. In December, 2007, ISO-NE and NU commenced a comprehensive discussion of not only the SCP but also all other aspects of the Springfield Solution that had been presented to the December 3, 2007 PAC meeting. This ISO-NE Review Process is described below in Section 4.

2.2.10 The Springfield Solution (March 2008): The Preferred Solution Re-Configured After the First Quarter 2008 ISO-NE Review Process

Introduction

NU, with the encouragement and assistance of ISO-NE, conducted a fundamental re-assessment of all of the options that had been, or could be, considered to address the Springfield area needs identified by the Needs Analysis described in Section 2.1, above. That review process was conducted cooperatively between ISO-NE and NU in the first quarter of 2008 and has been defined as the ISO-NE Review Process in this Springfield Solution Report. The ISO-NE Review Process is described in greater detail below in Section 4.

In brief summary, ISO-NE, in NU's view, sought to implement Attachment K to its OATT to assure that ISO-NE can identify the "most cost-effective and reliable solution(s) for the region that meets a need identified in a Needs Assessment"[22]. In this regard, ISO-NE requested that NU consider: (1) achieving Springfield cost reductions while trading off only modest reductions in reliability; and (2) applying a more common regional interpretation of applicable reliability standards which allows for the temporary loss of load under second contingency events where the loss of load effects are restricted to local subareas and have no area-wide consequences. To achieve ISO-NE's goal and to respond to the requests, NU performed a "bottom-up" re-assessment of the Springfield solution options and made a presentation of its review to ISO-NE on February 18, 2008. That re-assessment continued after the meeting and the final results are now reported in the following Section 3 of this NU Springfield Solution Report.

The Major Re-Configurations to the Springfield Solution

After reviewing and estimating the cost and reliability impacts of a variety of less significant changes[23], NU reviewed and found acceptable the reliability impacts of temporary loss of load under second contingency events where the loss of load effects were restricted to the local subareas around the Clinton

[22] See: Attachment K, Section 4.2(b).
[23] See: Section 4.2.2, below.

and Breckwood Substations. As a result, a three-cable supply system to each of those substations was not needed under this more common interpretation of regional reliability standards[24]. Significant cost savings could be achieved by dropping the PPA components for a new underground cable circuit between the East Springfield and Clinton Substations and for a second new underground cable circuit between the East Springfield and Breckwood Substations.

Other underground cable circuit upgrades remained significant parts of the PPA project, with significant associated cost estimates. The underground cable upgrades were replacement underground cable circuits between the East Springfield and Breckwood Substations and between the Breckwood and the West Springfield Substations[25]. Strengthening the underground cable "through-path" on the 115-kV system in Springfield from the East Springfield to the Breckwood to the West Springfield Substations in some way[26] was a feature of most of the Springfield 115-kV options in the Options Analysis[27]. Many first and second contingency failures overloaded the existing cables.

Cable upgrades would be required in all cases unless a fundamental re-configuration occurred. At ISO-NE's request, NU assessed such a re-configuration, the opening of the underground cable-circuit "through-path" at the Breckwood Substation bus such that the Breckwood Substation load would be split and served radially. In this regard, upgrading the Springfield cable "through-path" becomes unnecessary since the Springfield supply is converted to a radial supply immune to "through-path" overloads which might be caused by contingencies.

Converting the existing Springfield cables system into a radial supply system achieved significant cost savings for the Springfield Solution as follows:

[24] The third cable circuit to the Clinton Substation was the new cable circuit from the new Cadwell Switching Station. That cable circuit was originally proposed as an integral part of option 6b selected by NU from among the 12 options in the Options Analysis for the Springfield area. As such, it played an overall role in strengthening the 115-kV system in the Springfield area and was not proposed for its fortuitous virtue of adding protection from the second contingency failure of the other two cable circuits serving the Clinton Substation from the West Springfield Substation. Dropping this third cable circuit to the Clinton Substation had ramifications which would be addressed by a fundamental re-configuration of the Springfield Solution explained below in this Section 2.2.10.

[25] The switch to the North Route accelerated the need to replace the West Springfield to Breckwood cable since, with the North route, a second contingency outage of the 345-kV and the 115-kV circuits sharing common structures could result in an overload of the subject cable circuit. See: Section 2.2.7, above.

[26] Most options in the Options Analysis did this strengthening by upgrading the cable circuit segment from the East Springfield to the Breckwood Substations and by adding a parallel cable route from the East Springfield Substation to the Clinton Substation (which was already connected by two cable circuits to the West Springfield Substation).

[27] See: Section 2.2.6, above, and further discussion in Section 4.2.1, below.

- The replacement underground cable circuit between the East Springfield and Breckwood Substations was eliminated;
- The replacement underground cable circuit between the Breckwood and West Springfield Substations was eliminated;
- Modifications to the East Springfield, Breckwood and West Springfield Substations could be re-designed, reducing scope and cost;
- Planned re-building of overhead 115-kV circuits in the corridor between the East Springfield Substation, Orchard Junction and the Ludlow Substation no longer required the placement of three sets of separate transmission line structures in an expanded right-of-way since placing two 115-kV circuits on a line of double-circuit structures could not result in a second contingency overload of the “opened” through-path any longer;
- Land acquisition costs and the risk of regulatory delay if eminent domain proceedings were required were reduced as a result of a reduction in corridor expansion.

In order to investigate whether additional cost savings were possible, analysis was also done on the 115-kV reinforcements in the Hartford area that were caused by the Springfield upgrades. The savings realized and the alternatives considered are reviewed in greater detail in the subsection that follows.

Hartford Reinforcements Caused by Options A, B and C for the Springfield Project

SNETR studies reviewed the impacts throughout SNE of all four of the NEEWS component projects[28]. The SNETR studies were designed and executed on a fully integrated basis, so that the administrative “baskets” in which the smaller project components were placed had no technical significance[29]. All of the Connecticut 115-kV projects, even those arising from the Springfield area upgrades, were grouped with the Interstate Reliability Project component of the NEEWS project as a matter of convenience, simply because the same planner was responsible for all of them.

However, as NU assembles the various NEEWS components into separate projects to pursue siting and other approvals, it is necessary that each separate project stand on its own in meeting a distinct need, and that each project include all of the elements required to provide its claimed system performance as both a separate project, and as a component of the total NEEWS plan. Accordingly, the reinforcements in the Hartford area, which are described below, are now properly included as part of the Springfield Solution. Moreover, for the purposes of the “bottom-up” analysis set forth below in Section 3, the alternative

[28] See: Appendix A, Section A.4, below.
[29] See: Appendix A, Section A.5, below.

Hartford area reinforcements associated with all of the Springfield Options A, B and C will be reviewed and compared, notwithstanding that all of these upgrades were originally recognized and considered in the Options Analysis as a part of the Interstate Reliability Project[30].

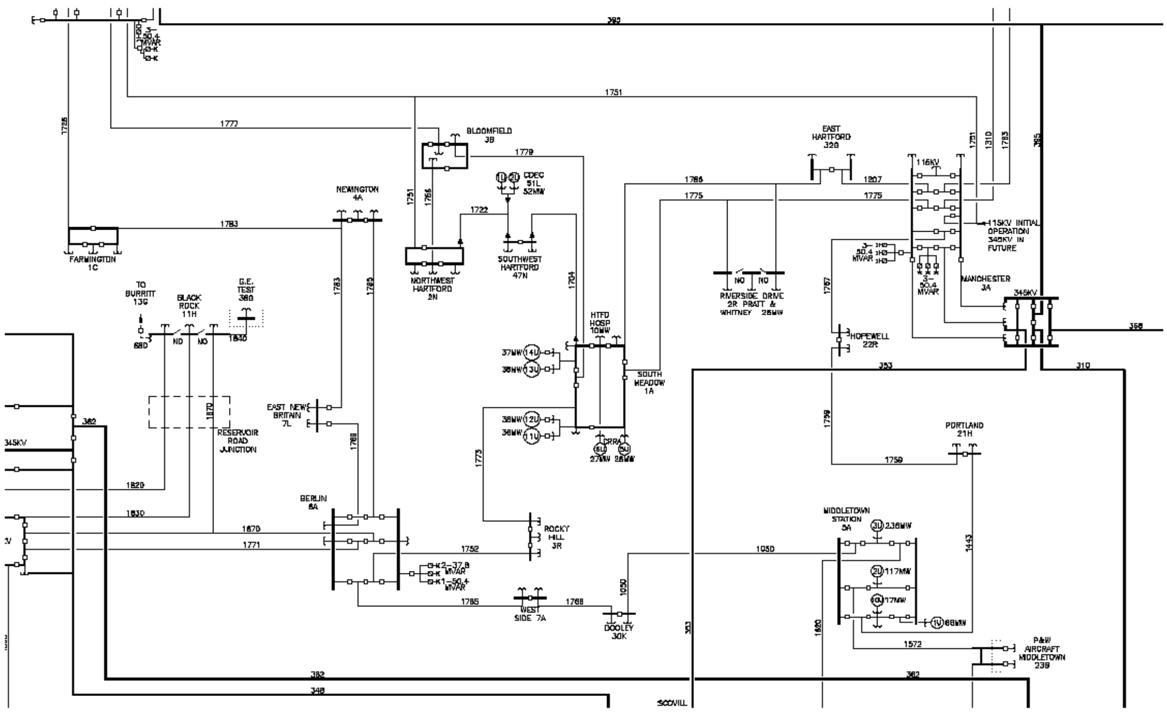
The Springfield area 345-kV options bring a new 345-kV line supply to either the Manchester Substation or the North Bloomfield Substation in central Connecticut. As set forth in the Options Analysis, the SNETR studies evaluated the potential regional impacts of the Springfield 345-kV Options A, B and C and identified contingencies that resulted in overloading elements of the 115-kV transmission system in and near Hartford, including:

- The #1775 overhead circuit between the Manchester Substation and the South Meadow Substation;
- The #1783 overhead circuit between the Farmington Substation and the Newington Substation;
- The #1785 overhead circuit between the Berlin Substation and the Newington Substation;
- The #1722 underground circuit between the Northwest Hartford Substation and the Southwest Hartford Substation;
- The #1704 underground circuit between the Southwest Hartford Substation and the South Meadow Substation;
- The #1786 overhead circuit between the East Hartford Substation and the South Meadow Substation; and
- The # 1207 overhead circuit between the Manchester Substation and the East Hartford Substation.

These circuits are illustrated on the following one-line diagram, Figure 2-1:

[30] An additional new 115-kV line from the Manchester Substation to the East Hartford Substation was originally also listed in Appendix A, Table A 1 of the Options Analysis (see Appendix B to this report) as a part of the Interstate Reliability Project. This line has now been determined to be needed independently of any of the NEEWS projects.

Figure 2-1: Hartford Area One-Line Diagram



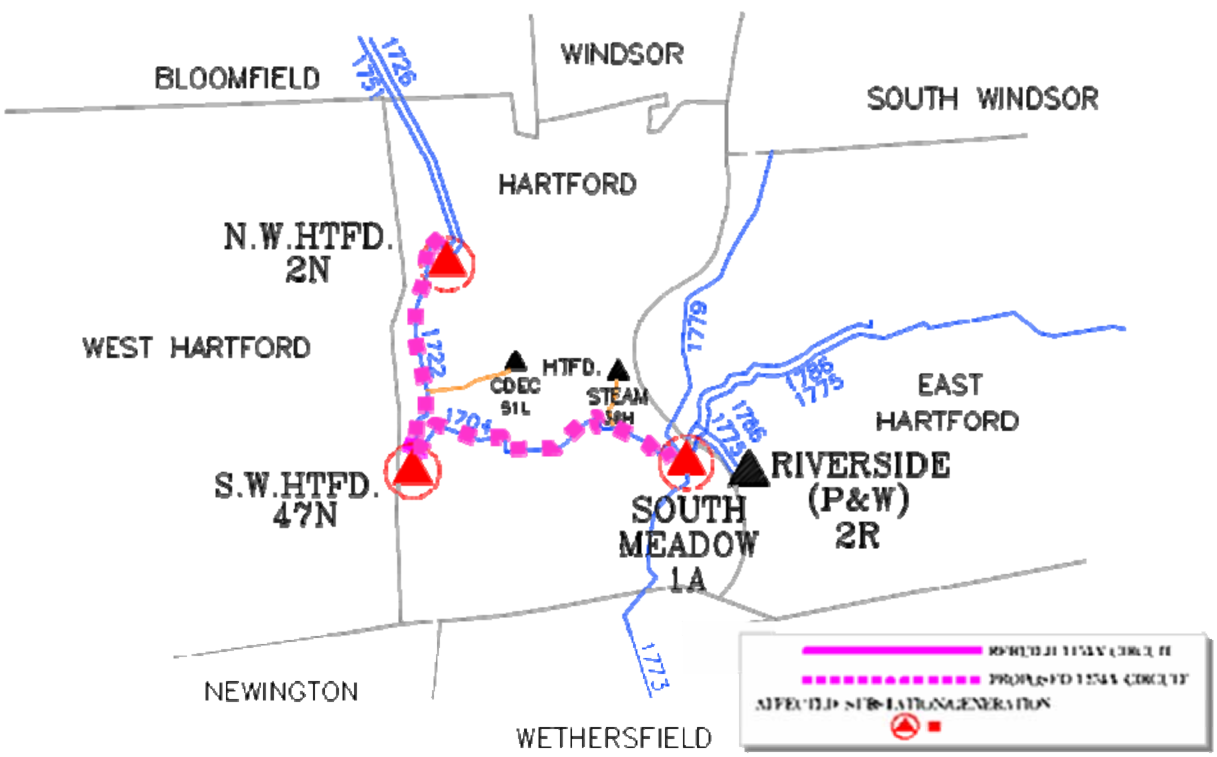
The Connecticut 115-kV Improvements - Required By Greater Springfield Reliability Project 345-kV Option C, Manchester to Ludlow

The Manchester to South Meadow, Manchester to East Hartford, Farmington to Newington, Berlin to Newington, and East Hartford to South Meadow circuit overloads were associated with only one of the Springfield 345-kV Options - Option C, the Manchester to Ludlow 345-kV solution. It was determined that these overloads could be avoided by (i) adding a second 115-kV circuit between the Manchester and South Meadow Substations (overhead or underground where it may be necessary); (ii) reconductoring the #1783 overhead circuit between the Farmington Substation and the Newington Substation with 556-kcmil ACSR conductors; and (iii) reconductoring the #1785 overhead circuit between the Berlin Substation and the Newington Substation with 795-kcmil ACSR conductors. This was the 115-kV work around Hartford that both ISO-NE and the transmission owners referred to in their December 15, 2006 PAC presentations as a disadvantage of the Greater Springfield Reliability Project Option C, as compared to Options A and B[31].

The Hartford Cables Project – Initially Associated With Greater Springfield Reliability Project 345-kV Options A, B, and C, and Replaced for Selected Option A with the Manchester to Meekville Line Separation

The SNETR studies identified other overloads of the central Connecticut 115-kV system that were associated with all three of the 345-kV Greater Springfield Options. These common overloads occurred on the existing #1722 underground cable circuit between the Northwest Hartford Substation and the Southwest Hartford Substation and the existing #1704 underground cable circuit between the Southwest Hartford Substation and the South Meadow Substation. The SNETR studies showed that these overloads would be eliminated by constructing additional circuits between these substations. In light of the densely developed urban location in which construction was required, such circuits would necessarily be constructed underground. Together, these two potential new circuits came to be known as the "Hartford Cables Project." The Hartford Cables Project is shown in the following Figure 2-2.

Figure 2-2: Hartford Cables Project



31 See: ISO-NE December 15, 2006 PAC presentation, Slide 59; NU and NGrid presentation, Slides 19-23; see also: Section 3.2, below.

Because the Hartford Cables Project would address overloads associated with all three 345-kV Options, the cost of the cables did not appear to provide a basis for a preference among Greater Springfield 345-kV Options A, B, and C. As ISO-NE stated in the Options Analysis, "The main differences between these plans [Options A, B, and C] are whether they provide another area bulk supply point, eliminate the weak western Massachusetts/Connecticut 115-kV ties, or utilize 115-kV phase shifters to restrain power being wheeled through the area." (Options Analysis, *§7.3* Springfield Plan Conclusion (see: Appendix B to this report)) At that time, the requirements of the different Options for 115-kV improvements in Connecticut were not recognized as one of the main points of difference among them.

However, when the cost of the Hartford Cables Project was estimated, it was substantial, even though the circuit between the Southwest Hartford and South Meadow Substations was designed so that a new HPFF cable circuit would be installed in an existing empty pipe conduit, thus avoiding new excavation. In January, 2008, a detailed cost estimate was developed that showed a cost for the Hartford Cables Project of approximately $103 million, in 2008 dollars.

Accordingly, with the encouragement of ISO-NE, NU undertook a search for an alternate, less expensive means to address the overloads on the Connecticut 115-kV system that were associated with the North Bloomfield – Agawam – Ludlow 345-kV configuration (Option A), which had by then been selected as the preferred 345-kV Option. Further studies showed that, if a section of the 345-kV overhead circuit #395 and overhead 115-kV circuit #1448[32], currently on common line structures between the Manchester Substation and Meekville Junction, were placed on separate line structures, those contingency overloads would be avoided. When the Manchester to Meekville 115-kV circuits are placed on separate line structures (Manchester to Meekville Line Separation), a single element failure does not result in two transmission paths from the Manchester area to the North Bloomfield area being taken out of service. Rather, one of the circuits with a Manchester to Meekville Junction segment would remain available to share the load that would otherwise all flow on the Manchester to South Meadow overhead line and then on the South Meadow to Southwest Hartford and Southwest Hartford to Northwest Hartford underground cable circuits, overloading the cables. Having either the overhead circuit #395 or the overhead circuits #1448 to #1751 still available reduces the flow on the Manchester to South Meadow circuits and avoids overloading the cables.

[32] The referenced circuit is currently a section of the # 1751 circuit, which will be renumbered to #1448 once the Rood Avenue Substation is completed and looped into the existing #1751 circuit

NU then determined not to pursue the Hartford Cables Project in connection with its selection of the 345-kV Option A for the Springfield Solution, but to propose the Manchester to Meekville Line Separation instead, the cost of which is estimated at $23 million in 2008 dollars.

Finally, when NU performed the “bottom-up” reevaluation of the Springfield project components[33], it determined that the line separation project could be used with Springfield Option B (North Bloomfield – Ludlow) as well as with Option A, but that Option C (Ludlow – Manchester) would still require construction of the Hartford Cables Project. This difference with respect to the Hartford Cables Project increased the overall cost difference between Options A and B and Option C with respect to the Hartford area 115-kV reinforcements (Hartford Cables Project for Option C: $103 million in 2008 dollars versus the Manchester to Meekville Line Separation for Option A: $23 million in 2008 dollars)[34]. In addition to the performance superiority[35], this confirmed other advantages of the selection of Option A and established the Manchester to Meekville Line Separation as a component of the Springfield Solution.

The Re-Configured Springfield Solution

With the elimination of the SCP and the other modifications to the PPA project, the Springfield Solution now has the following scope of components:

Item A	Build a new 345-kV line from Ludlow Substation to Agawam Substation (MA Only)
Item B	Build a new 345-kV line from Agawam Substation to North Bloomfield Substation (MA Only)
Item C	Build a new 345-kV line from Agawam Substation to North Bloomfield Substation (CT Only)
Item D	Rebuild the 1782 line from Agawam to South Agawam Junction
Item E	Place 1781 circuit on the Agawam to North Bloomfield 345/115-kV double circuit structures
Item F	Reconfigure the existing 115-kV system (1768/1836/1821)
Item G	Rebuild 115-kV circuit 1314 from Chicopee Substation Chicopee to Agawam Substation Agawam
Item H	Rebuild 115-kV circuit 1602 from E. Springfield Jct to Chicopee Substation
Item I	Break Three-Terminal Circuits 1254/1723 into Two-Terminal Circuits creating a total of four (4) circuits (1601-1604)
Item J	Build single-circuit monopole 115-kV circuit 1601 from E. Springfield Jct to Piper Substation
Item K	Build single-circuit monopole 115-kV circuit 1230 from Piper Substation to Agawam Substation
Item L	Rebuild circuit 1481
Item M	Rebuild circuit 1845 on new monopoles
Item N	Bundle the conductors for the existing circuits 1481/1552/1426 into higher capacity portions of circuits 1552/1426
Item O	Rebuild circuits 1426 and 1552 from Orchard Tap to Orchard Substation on new monopoles
Item P	Ludlow 19S 345/115-kV Substation Changes
Item Q	Agawam 16C 345/115-kV Substation Additions
Item R	North Bloomfield 345-kV GIS and a second 345/115-kV autotransformer
Item S	Fairmont (Greenfield breaker-and-a-half switching station)

[33] See: Section 3, below.
[34] See: Section 3.2 for the full cost differential between Option C and Option A with respect to the Hartford area 115-kV reinforcements.
[35] See: Section 2.2.2 (Option A was “far superior” in electrical performance).

Item T	[Intentionally Deleted]
Item U	W. Springfield to Agawam Circuit 1311 second high speed protection group
Item V	W. Springfield to Agawam Circuit 1412 second high speed protection group
Item W	Ludlow to Shawinigan Circuit 1845 second high speed protection group
Item X	Fairmont to Shawinigan Circuit 1604 second high speed protection group
Item Y	Split Breckwood Substation bus, add breakers and load transfer
Item Z	Fairmont, bay with line from Shawinigan requires 4000-amp breakers(230-kV class)
Item AA	Shawinigan, 2 X 4000-amp breakers(230-kV class) required between lines
Item GG	Rebuild/reconductor the Woodland to Pleasant 1371 line
Item HH	Upgrade the Pleasant to Blandford 1421 line to the full 556-kcmil ACSR conductor rating
Item II	Upgrade the Blandford to Granville Junction portion of line 1512 to the full 556-kcmil ACSR conductor rating
Item JJ	Separate and Rebuild West Springfield to Agawam double-circuit line 1311/1412

Note: (1) The "blue coded" entries above are independent projects and will be subject to separate siting and other approvals. (2) The Manchester to Meekville Line Separation (defined above in this Section 2.2.10) in Connecticut will be added to the above scope.

A Comparison of the PPA Project (November, 2007) and the Springfield Solution (March, 2008)

A comparison of the Springfield Solution as set forth above in this Section 2.2.10 to the PPA Project as described above in Section 2.2.6 follows:

Table 2-3: Comparison of the Springfield Solution

Springfield Reinforcements	6n	PPA	COMMENTS (6n means 6a North, with no cables)
Associated 345-kV Option:	**A**	**A**	
345 kV			
Build Ludlow - Agawam 345-kV ckt #1	X	X	
Build Agawam - N. Bloomfield 345-kV ckt#1	X	X	
Build Ludlow - Manchester 345-kV circuit #1			
Build Ludlow - North Bloomfield 345-kV circuit			
Transformers			
Install Agawam 345/115-kV Autotransformer #1	X	X	
Install Agawam 345/115-kV Autotransformer #2	X	X	
Install Agawam 115-kV Phase Shifters ckt 1-2 (in series with transformer)			
One (1) spare 115-kV Phase Shifter			
Replace N.Bloomfield 345/115-kV Autotransformer #1 (CT)			
Install N.Bloomfield 345/115-kV Autotransformer #2 (CT)	X	X	
Install N.Bloomfield - S.Agawam Phase Shifters 1-2			
N.Bloomfield - Southwick Phase Shifter			
Reconnect Ludlow 345/115-kV Autotransformer #1 into bay			
Reconnect Ludlow 345/115-kV Autotransformer #2 into bay	X		Needed in 6n to defer the third 345/115 kV transformer
Install Ludlow 345/115-kV Autotransformer #3			

Springfield Reinforcements	6n	PPA	COMMENTS (6n means 6a North, with no cables)
115 kV			
Rebuild / Reconductor Ludlow - Shawinigan	X	X	
Separate / Rebuild E. Springfield-Ochard-Ludlow & E. Springfield-Ludlow	X	X	
Separate or Rebuild W. Springfield - Agawam ckt #1 & #2	X		Separating to prevent DCT from dropping Clinton and West Springfield load
Rebuild S. Agawam - Silver ckt 1&2 or add ckt 3	X	X	
Rebuild Silver - Agawam ckt 1&2 or add ckt 3	X	X	
Replace Breckwood - W. Springfield cable circuit		X	
Replace Breckwood - E. Springfield cable circuit		X	
Replace Breckwood reactors		X	
Rebuild / reconductor Woodland - Pleasant line ckt #1	X	X	
Rebuild Agawam - Piper ckt #1	X	X	
Install new Clinton - E. Springfield cable circuit		X	
Clinton series reactor		X	
Install 3rd Clinton - West Springfield cable circuit			
Upgrade Ludlow-E. Springfield circuit #1			
Build new Stony Brook - Ludlow 115 kV line			
Build new Stony Brook - Five Corners 1 & 2 115-kV lines		X	
Rebuild Five Corners - Fairmont 1 & 2 115-kV lines		X	
Build new Ludlow - Fairmont 115-kV Line			
Disconnect CT/WMASS 115-kV ties	X	X	
Reconductor E. Springfield Jct. - Fairmont N.			
Separate/Rebuild 1254/1723 circuits			
Undo three-terminal line 1254/1723 circuits	X	X	
Separate / Rebuild (Fairmont - Shawinigan) / (Fairmont - E. Springfield)	X	X	NOTE for 6n Fairmont to Shawinigan will be bundled 1590-kcmil rather than bundled 1272-kcmil in PPA
Reconductor E. Springfield Jct - Shawinigan			
Reconductor Fairmont - Shawinigan			
Upgrade E. Springfield Jct - Chicopee			
Reconductor E. Springfield Jct. - Piper			
Reconductor Fairmont - Piper	X	X	
Rebuild Fairmont - Chicopee	X	X	
Upgrade Fairmont - Holyoke 115-kV circuit	X	X	
Upgrade Pineshed - Fairmont 115-kV circuit			
Upgrade Blandford - Granville Jct. 115-kV circuit	X	X	
Upgrade Southwick - N. Bloomfield 115-kV circuit			
Upgrade Pleasant – Blandford 115-kV circuit	X	X	
Create breaker-and-half bus configuration at Fairmont	X	X	
Rebuild Agawam – Chicopee	X	X	

Springfield Reinforcements	6n	PPA	COMMENTS (6n means 6a North, with no cables)
Rebuild East Springfield (or new Cadwell) substation	X	X	
New BPS stations: • Agawam 115 kV and 345 kV • Barbour Hill 115 kV • Breckwood • Cadwell • Clinton • Fairmont • Orchard • West Springfield	X	X	Required as a result of BPS testing(have to verify for 6n)
1.) Agawam-West Springfield 1311 line requires a second high speed protection group.	X	X	Required as a result of BPS stability(have to verify for 6n)
2.) Agawam-West Springfield 1412 line requires a second high speed protection group.	X	X	Required as a result of BPS stability(have to verify for 6n)
3.) Ludlow-Shawinigan 1845 line requires a second high speed protection group.	X	X	Required as a result of BPS stability(have to verify for 6n)
4.) Fairmont-Shawinigan 1604 line requires a second high speed protection group.	X	X	Required as a result of BPS stability(have to verify for 6n)
Clinton Ring Bus		X	Added because of additional circuits based on PP9 guideline
Breckwood Ring Bus		X	Added because of additional circuits based on PP9 guideline
2nd East Springfield - Breckwood cable		X	Added to prevent long term loss of load as result of loss of other two sources to Breckwood which are old cables.
Replace Ludlow 345/115-kV autotransformer #1 with high impedance auto	X		Needed because of short-circuit breaker duty (63 kA 115-kV breakers already being used)
Replace Ludlow 345/115-kV autotransformer #2 with high impedance auto	X		Needed because of short-circuit breaker duty (63 kA 115-kV breakers already being used)
Split Breckwood, add load transfer scheme	X		Being done instead of replacing existing Breckwood cables
Fairmont substation, bay with line from Shawiningan requires 4000-amp breakers (230-kV class)	X	X	Needed to accommodate Shawinigan – Fairmont line using bundled 1590-kcmil ACSR conductors
Shawinigan 2 X 4000-amp breaker (230-kV class) required between lines	X	X	Needed to accommodate Shawinigan – Fairmont line using bundled 1590-kcmil ACSR conductors
Fairmont the two bays with lines from Stony Brook require 4000-amp breakers (230-kV class)		X	Needed to accommodate Stony Brook – Fairmont lines using bundled 1590-kcmil ACSR conductors
Assumptions			
1. The Manchester to Meekville Line Separation will replace the Hartford Cables Project as a part of the Springfield Solution.			

Note: The “blue coded” entries above are independent projects and will be subject to separate siting and other approvals.

3.0 KEY CHOICES AMONG GSRP SOLUTION OPTIONS

3.1 INTRODUCTION: 'BOTTOM-UP' RE-ASSESSMENT OF OPTIONS IN FEBRUARY 2008

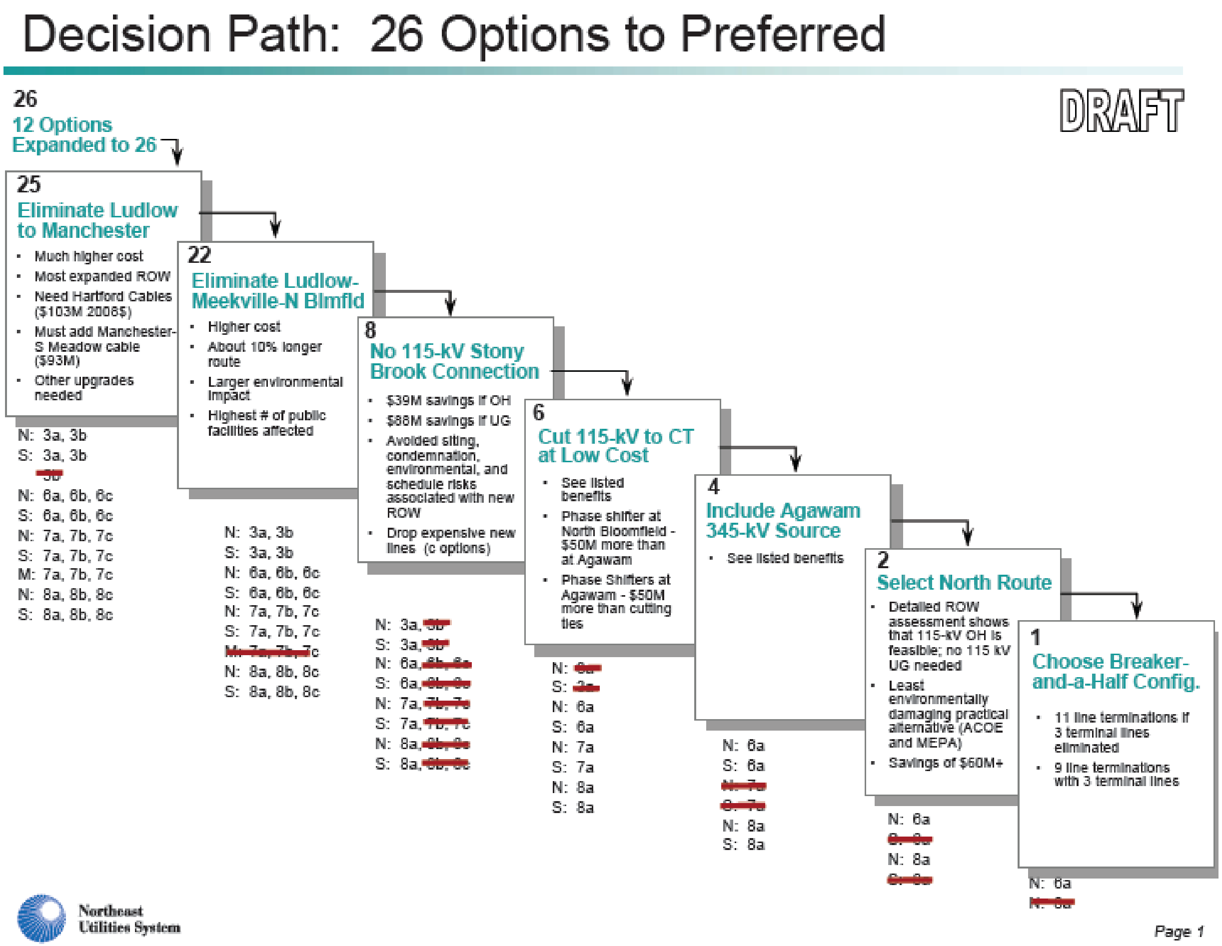
As a result of interactions between NU and ISO-NE, described more fully below in Section 4, the ISO Review Process covering the GSRP (inclusive of the SCP) was initiated by ISO-NE in January, 2008. With respect to the GSRP, NU and ISO-NE addressed both the foundations of the original GSRP need and the wide range of the early analyses of options.

In connection with the recent review process with ISO-NE, on February 18, 2008, NU presented to ISO-NE a "bottom-up" re-assessment of its GSRP option selection. That "bottom-up" re-assessment is described below in this Section 3. In doing so, NU expanded the 12 GSRP options presented in the *Options Analysis* to include a total of 26 options with the following designations borrowed from the Report's terminology:

- For the North Route to North Bloomfield (N): 3a, 3b, 6a, 6b, 6c, 7a, 7b, 7c, 8a, 8b and 8c
- For the South Route to North Bloomfield (S): 3a, 3b, 6a, 6b, 6c, 7a, 7b, 7c, 8a, 8b and 8c
- For the South Route to Manchester (Man): 5b
- For the Meekville Route to North Bloomfield (M): 7a, 7b and 7c

Routes and associated options were then re-assessed and deliberately dropped until the choice of the preferred Springfield Solution, as described below, emerged. The Decision Path for the "bottom-up" review is illustrated graphically in the following Figure 3-1.

Figure 3-1: Decision Path: 26 Options to Preferred



3.2 OPTION C: DROP SOUTH ROUTE TO MANCHESTER PRINCIPALLY ON BASIS OF COSTS, IMPACTS AND RELATED UPGRADES

Option C, upon further analysis, had progressed from one of the lower cost options[36] to one of the higher cost options without offsetting benefits. At the December 15, 2006 PAC presentation, ISO-NE had originally noted the following "Pros & Cons" with respect to Option C, Ludlow to Manchester:

- "Requires additional 115 kV reinforcements, including underground cable circuits, in the Hartford area;
- Does not increase reliability at North Bloomfield;
- Does not provide another 345 kV connection into the Springfield load center"
- (ISO-NE, PAC December 15, 2006, slide 58).

[36] See: NU/NGrid, "Solution Projects" presentation to the PAC, December 15, 2006, slide 22.

As set forth above in Section 2.2.10, additional planning and cost estimation refined the Hartford 115-kV reinforcements and the disadvantages associated with Option C compared to Options A and B.

The additional 115-kV reinforcements referenced here for Option C included, as of 2006, the following: a new 115-kV circuit between the Manchester and South Meadow Substations (which could be entirely underground); reconductoring of the #1783 115-kV circuit from Farmington Substation to Newington Substation; and reconductoring of the #1785 115-kV circuit from Berlin Substation to Newington Substation. At the time, two (2) new underground circuits in Hartford (the Hartford Cables Project, as defined in Section 2.2.10), one from the Northwest Hartford Substation to the Southwest Hartford Substation and the other from the Southwest Hartford Substation to the South Meadow Substation, were not considered a disadvantage of Option C since it was understood in 2006 that all three Options, A, B and C, required the addition of the Hartford Cables Project. As explained in Section 2.2.10, when additional studies were recently performed for Options A and B, it was determined that the line separation of circuits #1751 and #395 from Manchester Substation to Meekville Junction (the Manchester to Meekville Line Separation, as defined in Section 2.2.10) was a less expensive alternative to the Hartford Cables Project for Options A and B, both of which brought the new 345-kV line to North Bloomfield, but not for Option C. Currently, then the cost differential between the higher cost Hartford Cables Project and the lower cost Manchester to Meekville Line Separation is an additional disadvantage which is unique to Option C.

As set forth above in Section 2.2.10, the total additional construction that Option C would require, as compared with Options A and B, would include the following scope[37]:

- A second 115-kV circuit between Manchester and South Meadow($93 million in 2008 dollars);
- The Hartford Cables Project, consisting of: a second underground 115-kV circuit between Southwest Hartford and South Meadow; and a second underground 115-kV circuit between Northwest Hartford and Southwest Hartford ($103 million in 2008 dollars);
- Reconductoring the #1783 Farmington to Newington line with 556-kcmil ACSR conductors ($8.5 million in 2008 dollars); and
- Reconductoring the #1785 Berlin to Newington circuit with 795-kcmil ACSR conductors ($17.2 million in 2008 dollars).

[37] The costs associated with these scope items are parenthetically included here in 2008 $.

The total cost of this work was estimated at $221.7 million, or $198.7 million more than the cost of the Manchester to Meekville Separation required for Option A (estimated to cost $23 million in 2008 dollars). This comparative disadvantage strongly reinforced the decision to eliminate Option C[38].

With respect to impacts, the 31.63 segment miles of the Option C 345-kV line route had been found to involve the most right of way expansions among the options.

In light of the foregoing, Option C (designated 5b, above) was the first option to be dropped in this re-assessment.

3.3 OPTION B LUDLOW TO NORTH BLOOMFIELD VIA MEEKVILLE: DROP LUDLOW TO NORTH BLOOMFIELD VIA MEEKVILLE ROUTE PRINCIPALLY ON BASIS OF COSTS AND IMPACTS

Option B entailed a 345-kV line connection between Ludlow and North Bloomfield without a 345-kV connection at Agawam and could, in theory, be accomplished along two routes. The routes via Meekville Junction were designated 7a, 7b and 7c (Meekville) and involved 42.52 circuit miles of 345-kV line, 31.48 of which were in Connecticut, where there was the possibility of 10.56 miles of 345-kV underground cables.

Of all of the options studied, only Option A, South, has more miles of new 345-kV construction than Option B via Meekville (43.7 miles versus 42.5 miles, respectively). Other variations of Option B have routes from North Bloomfield Substation on existing right-of-way to South Agawam Junction where the Option B route could then follow the Springfield Solution on the North route (Option B, North) or in the alternative, join the South route at South Agawam Junction proceed east toward Hampden Junction and then north to the Ludlow Substation (Option B, South). Option B, South, has 37.3 miles of new 345-kV construction and Option B, North, has the same 35.0 miles as the Springfield Solution. Option B, South, and Option B via Meekville generally have the same associated set of 115-kV reinforcements in Connecticut and in Massachusetts. Option B, South, was found to be somewhat more costly than Option A, North, the predecessor to the Springfield Solution[39]. The extra 5.2 miles of new 345-kV construction

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38 Option C has the lowest number of miles of new 345-kV construction, 31.63 miles. This relatively low number of miles did not, however, create cost savings which offset the large cost disadvantage of approximately $198.7 million associated with the extra costs of the 115-kV reinforcements needed in Connecticut for Option C. The final option selected, Option A, North (which without any Springfield underground cable circuits is referred to as the Springfield Solution), entails 35.0 miles of new 345-kV construction, resulting in only 3.4 miles of 345-kV construction costs savings in favor of Option C. See: Section 3.11, below, for an estimate of such savings based on cost/mile data.

39 See: Section 3.9, Table 3-8. Compare the first column for option 6a North to the last column for 7a South.

which Option B via Meekville has in comparison to Option B, South (42.5 miles less 37.3 miles) makes Option B via Meekville even more costly than Option A, North.

The Option B via Meekville route is significantly longer than the other Option B routes, and involves higher costs than the Option A, North, route, and results in higher impacts than all other routes with the possible exception of Option A, South. The early elimination of options 7a, 7b and 7c via Meekville is confirmed.

3.4 STONY BROOK 115-kV CONNECTION TO FAIRMONT: DROP STONY BROOK CONNECTION PRINCIPALLY ON BASIS OF COSTS, IMPACTS TO VIRGIN ROW, SCHEDULING AND SITING RISKS, INCLUDING LIKELIHOOD OF EMINENT DOMAIN PROCEEDINGS

For each option, the "b" designation referred to the connection of the Stony Brook Generating Station at 115-kV via two new overhead circuits, 4.8 miles in length along an existing 1.4 mile right-of-way emanating in a northward direction from the generating station miles and then traveling on a new right-of-way for 3.4 miles in a northwest direction to a new point of interconnection with the #1113 and #1134 circuits near to NGrid's Five Corners Substation in Granby, Massachusetts. Existing 115-kV circuits #1113 and #1134 would also be re-conductored for 4.9 miles from the connection point to the Fairmont Switching Station in Chicopee.

At the October, 2006 meeting of the SNETR Project Board, NGrid and NU recognized the following pro's and con's regarding a 115-kV connection for the Stony Brook Generating Station:

"Pro's:

- Substantial system benefits at a cost only slightly above the alternative
- Connecting Stony Brook provides additional operational flexibility by means of Stony Brook quick-start units into the 115-kV system.
- Connecting Stony Brook enables Springfield to withstand the (extreme contingency) loss of the Ludlow 345/115-kV Substation.
- Connecting Stony Brook provides additional dynamic reactive support for the 115-kV system.
- Connecting Stony Brook reduces the number of capacitors that are required when compared to the same option without Stony Brook.
- Connecting Stony Brook would provide better coverage for 115-kV circuit outages west of Ludlow Substation.

Con's

- Singles out the contribution of a generator.
- Requires acquiring new ROW to build the 115-kV lines, or partial undergrounding in streets.
- Cost is slightly higher (~$6M)"

(SNETR Board, October, 2006)

In its PAC December 15, 2006 presentation, ISO-NE noted that the Stony Brook interconnection was under consideration and noted the improvement of area (non-spinning) reserves with the quick-start units and the reduction/minimization of the severity of the extreme contingencies with Stony Brook connected via a separate right-of-way[40].

Throughout the detailed engineering and siting analyses conducted by NU during 2007[41], the Stony Brook connection was a part of the preferred option being actively studied. NU project engineers, BMcD, prepared a formal "Route Selection Study for the Stony Brook to Five Corners Project" in September, 2007 where the following table appeared:

Table 3-1: Overhead versus Underground Line-Route Comparison

Criteria	Overhead Route (A3)	Underground Route
Length (miles)	4.9 total	4.8 total (3.2 UG/1.6 OH)
New ROW (length in miles)	3.4	0
New ROW (acres)	42	0
Expanded ROW (length in miles)	0	0
Expanded ROW (acres)	0	0
Wetland impacts (acres)	5.7	0.4 (20' x length)
Estimated Cost	$34.8M	$61.5M

In order to continue the formal environmental and engineering analysis, formal surveying permission was required from 67 abutting or nearby property owners who would be required to grant easements for the new right of way. However, permission was obtained from only 21 of the 43 owners who were contacted. Difficulty obtaining the 3.4 miles of new right-of-way without instituting eminent domain proceedings was apparent based on the early reaction and opposition to the preliminary surveying effort.

[40] See: ISO-NE, "Southern New England Transmission Reinforcement" presentation to the PAC, December 15, 2006, slide 59.

[41] See: NEEWS Final Report, Proposed Plan Application, Steady State Analysis, presented to the NEPOOL Transmission Task Force November 28, 2007 (TTF Final Report), page 12, Item 5. See: Section 2.2.6, above.

3.4.1 Cost Differentials

Additional efforts were made to refine the cost of the Stony Brook interconnection options. More detailed engineering costs estimates were developed which compared the costs of the Stony Brook interconnection to the alternative modifications required at the Ludlow Substation. Those alternative modifications included replacing the two existing autotransformers at the Ludlow Substation and rebuilding overhead 115-kV lines #1481, #1426, #1552 from the Ludlow to the East Springfield Substations.

The final cost comparisons were developed by the engineering team. The cost differential remained as originally estimated at approximately $6 million. The components of that cost differential are as follows:

Alternate A - With Stony Brook Lines - OH

Build New Stony Brook to Five Corners 115-kV Lines	$29,400,000
Rebuild Five Corners to Fairmont 115-kV (1113/1134 circuits)	$22,000,000
Stony Brook Substation Upgrade	$3,500,000
Ludlow Substation Replace One Auto Transformer	$24,100,000
Construction Subtotal	**$79,000,000**

Alternate B Without Stony Brook

Replace 2 Autotransformers at Ludlow	$39,700,000
Rebuild Lines 1481, 1426, 1552 from Ludlow to East Springfield Substation	$33,200,000
Construction Subtotal	**$72,900,000**

The above cost table assumes (i) that the GSRP 345-kV line would be built on the North Route and (ii) that most 115-kV overhead line work associated with GSRP in the corridor from the Ludlow Substation to the East Springfield Substation would be required only if the decision was made to exclude the Stony Brook interconnection. The latter assumption is most favorable to the Stony Brook interconnection since use of the North Route will require significant re-building and re-conductoring of the overhead 115-kV lines which presently occupy the North Route ROW. It is possible that some associated 115-kV overhead line work would still be required if the Stony Brook interconnection was made. Not assigning overhead 115-kV upgrade costs in the corridor from the Ludlow Substation to the East Springfield Substation to the Stony Brook interconnection is a very conservative assumption which favors the interconnection. Notwithstanding the conservative assumption in favor of the interconnection, a cost disadvantage exists for including the Stony Brook interconnection and is equal to approximately $6 million of raw construction costs. In addition, significant environmental impacts and high risk of delays would be encountered with the interconnection[42]. See: Section 3.4.2, below.

However, an additional analysis was conducted to see if the cost differential between the decision to include or to exclude the Stony Brook interconnection would vary if the South Route was chosen for the 345-kV transmission line. In general, connecting Stony Brook at 115-kV to Fairmont would cause greater flows on the 115-kV system from Fairmont south and result in more re-building and re-conductoring in the Fairmont to Agawam corridor. Conversely, excluding the Fairmont interconnection at 115-kV for Stony Brook and modifying the Ludlow Substation (and others) as an alternative would, in general, cause greater flows on the 115-kV overheard circuits between the Ludlow Substation and the Shawinigan Switching Station and between the Ludlow and Orchard Substations and then between the Orchard and East Springfield Substations. Those greater flows would result in the need for more re-building and re-conductoring. Compare: *Options Analysis*, Appendix A, Table A-4, Option 6a to Option 6b (both assume use of the South Route) (see: Appendix B to this report).

For the South Route analysis, the associated 115-kV overhead line work added costs to either decision regarding Stony Brook. The net effect for project configurations which included the cable components was that a smaller cost disadvantage resulted from including the Stony Brook connection. When the cable components were removed from the overall project and a comparison was run for the South Route between including and excluding the Stony Brook interconnection, a cost advantage resulted from adding the Stony Brook interconnection. See: Table 3-8, Section 3.9, below. However, even with a cost advantage from including the Stony Brook interconnection when the South Route was used and no cables were installed, significant environmental impacts and high risk of delays would be encountered with the connection. See: Section 3.4.2, below.

3.4.2 System Benefits and Environmental Impacts

Recognition that the Stony Brook tie would significantly increase the cost of each option caused NU to re-assess the system benefits and environmental impacts of constructing the tie. This reassessment was undertaken in December, 2007 and January, 2008. The following conclusions were reached:

[42] If impacts and/or delays caused NU to put all or part of the new lines from Stony Brook to Five Corners underground, or if the EFSB ordered the line to be put underground, the cost differential would dramatically increase from approximately $6 million up to as high as $60 million in favor of not including the Stony Brook interconnection.

System Benefits:

The construction and re-building of 115-kV overhead transmission lines for the Stony Brook interconnection would:

- Provide additional operational flexibility by means of connecting the Stony Brook quick-start units into the greater Springfield area's 115-kV system.
- Enable the Springfield 115-kV system to withstand the extreme contingency loss of the Ludlow 345-kV Substation.
- Provide additional dynamic reactive support the Springfield 115-kV system.
- Reduce the number of substation capacitor banks connected to the Springfield 115-kV system.
- Provide improved reliability following single or multiple 115-kV circuit outages west of Ludlow Substation.

In contrast, the substation modifications alternate would:

- Provide a solution which, when combined with the other components of the GSRP, would result in an integrated GSRP with the same electric reliability as the alternative GSRP design which includes the 115-kV Stony Brook lines.
- Not single out the contribution of any given generator nor require construction on virgin right-of-way (ROW).

Siting and Environmental Impact:

The construction and re-building of the 115-kV overhead transmission lines would span 9.5 miles of ROW including 3.4 miles of virgin ROW. This transmission line option would be the more environmentally damaging alternative and would require new ROW resulting in a higher risk of opposition during siting, permitting and land acquisition. The new line would impact areas of potential threatened and endangered species and wetlands, and it would require upwards of 30 acres of tree removal.

The virgin ROW would require approximately 1.7 million square feet or approximately 40 acres of easements traversing through residential and forested land. The easements would be difficult to acquire as evidenced by the number of field survey refusals. The land acquisition team approached many of the property owners to acquire survey access. Approximately 21 of the 43 total property owners that were contacted denied access to conduct field surveys. Approximately 67 properties would require easement acquisition. The risk of condemnation would be high along the new ROW and therefore, the siting risk would be heightened. A consolidated proceeding for condemnation and siting approval would be likely to be delayed by the opposition of owners whose properties were being condemned. Construction of all parts of the GSRP solution would be delayed by such opposition. If condemnation proceedings followed the siting approval, the full solution would not be constructed and energized until the second proceeding concluded.

The proposed substation modifications will be completed within WMECO property lines. Thus, there will be minimal to no additional environmental impacts associated with the additional substation modifications.

3.4.3 Stony Brook Interconnection: Conclusion

In January, 2008, NU concluded that the system benefits were no longer justified in light of the significantly higher impacts and risks of the interconnection. More specifically, the risk to scheduling was too significant to be ignored and the GSRP was deemed to be too important to be delayed by the difficulties expected in effecting the Stony Brook interconnection. This conclusion eliminates the following options: 3b, 6b, 7b and 8b for all affected routes, whether using the North or the South alternative for the 345-kV line.

It should be stressed that alternatives to the Stony Brook interconnection, and the interconnection itself, when assessed for the South Route, involved re-building or building along different parts of the overhead 115-kV path from the Ludlow Substation to the Agawam Substation. As indicated above, those cost differentials were taken into account in the final decision making for Stony Brook in the two cases designated as options “a” and “b”. A third option related to Stony Brook had been included in the Options Analysis: the “c” variation for options 6c, 7c and 8c. This option involved the construction of a new 115-kV overhead line along the corridor from the Ludlow Substation to the Fairmont Switching Station. Not only did this option present constructability issues with regard to the need to expand the right-of-way to accommodate all of the related work, the “c” option entailed the highest incremental costs for overhead 115-kV line work on the Ludlow to Fairmont corridor and was eliminated from the South Route analysis on the basis of these extra costs alone.

For the North Route, right-of-way width limitations and structure-sharing with the overhead 345-kV lines on the same right of way triggered the re-building of the overhead 115-kV lines along the whole of that path from Ludlow Substation to Agawam Substation. As a result, use of the North Route did not produce a cost differential related to the re-building of different parts of the overhead 115-kV lines that might have otherwise affected the cost comparisons for the exclusion option “a” or the inclusion option “b” for the Stony Brook interconnection. Furthermore, use of the North Route for the 345-kV lines made the addition of a new 115-kV overhead line in the “c” options from the Ludlow Substation to the Fairmont

Switching Station impractical from both a cost and related impacts point of view. Accordingly, options 6c, 7c and 8c were eliminated from consideration for both the North and the South routes, along with 6b, 7b and 8b.

3.5 REDUCE 115-kV POWER FLOWS TO CONNECTICUT: CUT 115-kV TIES BETWEEN STATES AT NORTH BLOOMFIELD IN PLACE OF PHASE SHIFTERS PRINCIPALLY ON BASIS OF COSTS

The GSRP puts in place a new 345-kV supply path to Connecticut. Under present conditions,

> ". . . 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 as a result of a forced or planned outage. For all years simulated, this leads to the appearance of numerous overloads on the Springfield 115 kV system, and increased Connecticut imports aggravate the thermal loadings in Springfield."
>
> Needs Analysis (January, 2008), page 24.

With the new source of 345-kV power to Connecticut, transfer of power on the 115-kV system into Connecticut should be limited. Three ways were available to limit 115-kV power transfers to Connecticut as follows:

- Install three (3) phase shifters in series with the new autotransformers at Agawam (option 3a and 3b – "Phase shifters would facilitate more power flow through the Agawam autotransformers, which would further limit power flow through the Springfield area system." Options Analysis, June 25, 2007, page 38;
- Install phase shifters at North Bloomfield on the western Massachusetts/Connecticut 115-kV tie lines (option 7a, 7b and 7c – "Phase shifters would help restrain the power flow through the Springfield area 115-kV system." Options Analysis , page 40; or
- Separate the 115-kV ties between western Massachusetts and Connecticut in the South Agawam-North Bloomfield area (Option 3a, 3b, 6a, 6b, 6c, 8a, 8b and 8c – "The weak western Massachusetts/Connecticut ties would be replaced with a stronger 345-kV tie." Options Analysis, page 38.

The preferred option among these three was easily selected on the basis of cost. Differences in reliability and impacts were considered to be minimal. The preferred option is the third, cutting the weak 115-kV Massachusetts/Connecticut ties. The selected option is approximately $50 million less expensive than the closest option, installing phase shifters at Agawam, which in turn is approximately $50 million less expensive than the most expensive option, installing phase shifters at North Bloomfield. Cutting the weak 115-kV Massachusetts/Connecticut ties can be effected as follows:

- Bundle circuits #1821 and #1836 from South Agawam Substation to Granby Junction into a single circuit; and
- Separate the 115-kV Massachusetts/Connecticut ties at Granby Junction and reconnect circuit #1768 from Southwick to the new bundled circuit to South Agawam.

NU, “The Springfield Area Solution” PAC presentation, December 3, 2007, slide 12.

This choice gave reason for the elimination of options 3a, 7a and 7c for all the affected routes, whether the North or the South route.

3.6 OPTION A VERSUS OPTION B: MAKE 345/115-kV CONNECTION AT AGAWAM PRINCIPALLY ON BASIS OF RELIABILITY BENEFITS AND LOW COSTS AND IMPACTS

The choice between all variations of Option A and all variations of Option B is the choice to include or exclude a second 345-kV source of supply to the Springfield 115-kV system at Agawam. A second source of supply at Agawam was recognized at an early stage to be “far superior”[43] to the alternatives which did not include that supply (both Option B and Option C). Option A has the following attributes:

- It would establish a southern 345-kV bulk power source for Springfield’s 115-kV system.
- In the event of the extreme contingency loss of the 345 to 115-kV connection at Ludlow Substation, power can flow north from the North Bloomfield Substation on the 345-kV system.
- Agawam Substation is in a complementary position to the Ludlow Substation for providing voltage support to the Springfield area.
- Since all the area’s 115-kV lines tie into the Agawam Substation, it is a strategic location for limiting power flows through the Springfield area.
- Agawam is close to area load centers and would provide flexibility in expanding the 115-kV system to serve area growth.

[43] SNETR Project Board, October, 2006 Meeting Presentation, slide 22. See: Section 2.2.2, above.

The history of the option selection process shows the early recognition of the benefits of Agawam as a source.

> "At the ISO's suggestion, system operators from ISO, CONVEX, and REMVEC met to compare the options. On November 3, 2006, they also strongly favored the Ludlow-Agawam-North Bloomfield solution and drafted a list of the benefits they saw.
>
> . . .
>
> **Benefits of Option A**
> **Identified by System Operators**
> (November 3, 2006)
>
> - Relies less on the smaller-conductor 115-kV lines heading north out of North Bloomfield.
> - Operation of phase-shifters included in Option B would be burdensome (daily adjustments) and add an unknown degree of operating flexibility.
> - Offers 345-kV source to Agawam, and provides an injection point centrally located in the Springfield load pocket.
> - Reduces reliance on the Ludlow Substation's [autotransformers].
> - [Breaking] the CT and MA 115-kV feeds [] is desirable due to all the operating problems experienced with this over the years.
>
> February 18, 2008, "Springfield Solution Planning Review", slides 12 and 13) ("February Planning Review").

With respect to costs, Option B via Meekville has been found to be more expensive than Option B, South[44], which in turn has been found somewhat more expensive than Option A, North[45]. A final cost comparison can be made between Option B, North, and Option A, North, each of which has the same route and associated 115-kV reinforcements in Connecticut and Massachusetts. The principal differences in scope between these two options can be summarized as follows:

- No expansion of the Agawam Substation to accommodate transformation to 115-kV is required for Option B, North, since no connection to the 115-kV system is made at Agawam with Option B, North; and
- In place of the transformers at the Agawam Substation for Option A, North, Option B, North, requires much more costly phase shifters installed at the North Bloomfield Substation in

[44] See: Section 3.3, above

[45] See: Section 3.9, Table 3-8, below. Compare the first column for option 6a North to the last column for 7a South.

Connecticut. In place of these expensive phase shifters, Option A, North, uses a low cost approach of re-configuring 115-kV lines going south from the South Agawam Substation into Connecticut and cutting these lines off from the North Bloomfield Substation to prevent power from flowing into the Connecticut 115-kV system there.

The cost differences associated with these principal differences are as follows:

(i) for Option A, North, expand the Agawam Substation for 345-kV/115-kV transformation, and implement the low cost re-configuration of the 115-kV lines which go south into Connecticut but no longer deliver power at 115-kV to the North Bloomfield Substation at a raw construction cost of $46.4 million and $1.6 million, respectively, for a total cost of approximately $48.0 million[46];

versus

(ii) for Option B, North, install phase shifters, including a spare, at the North Bloomfield Substation at a raw construction cost of $103.6 million[47].

This large difference in raw construction costs, of approximately $55.6 million, provides a second strong prong of support for the decision to prefer Option A to Option B. Not only do the system benefits associated with Option A make it "far superior" to Option B in performance, but it is also more economic than the best variation for Option B.

With this decision, an additional reason existed to eliminate the options in the series "7", including all options 7a, 7b and 7c, whether on the North, the South route or the Meekville route, each of which did not include the Agawam source of supply to the 115-kV system for Springfield.

3.7 NORTH ROUTE VERSUS SOUTH ROUTE: SELECT NORTH PRINCIPALLY ON BASIS OF COSTS AND IMPACTS

Two feasible 345-kV line routes remain between the Ludlow and the Agawam Substations (where the 345/115-kV connection would be made), and between the Agawam and the North Bloomfield Substations: option 6a North and 6a South. Both take advantage of existing rights-of-way with 115-kv overhead circuits. Each was assessed, and compared with the other, on five (5) Key Criteria developed

[46] See: Column one for option 6a North in Table 3-8, below.
[47] The cost of phase shifters at North Bloomfield Substation would be the same for all Option B routes. Accordingly, see: Column seven for option 7a South in Table 3-8, below.

for the NEEWS Project by NU and NGrid based on siting requirements in Massachusetts, Rhode Island and Connecticut.

Those criteria were described by NU and NGrid at the December 15, 2006 PAC presentation (slide 13) as follows:

- "Network Performance & Long-term Flexibility - The potential impact to the long-term reliability, flexibility, and expandability of the network must be considered so that, over their lifetime, the new facilities (i) will be able to solve currently identified problems, (ii) will be able to meet future interconnection and demand needs and (iii) will improve the competitive power markets, including access to renewable energy.
- Human Environment Considerations - The potential impact on customers and local community interests must be taken into account by considering the impact of the new facilities on the communities they will serve and the communities where they will be sited.
- Natural Environment Considerations - The potential impact on the surrounding natural environment must be considered, as well as the ability of the option to meet environmental laws and regulations.
- Delivery Timeframe - The likelihood of permitting and building the new facilities in time to meet identified needs must be considered.
- Cost Considerations - As stewards of our customers' and shareholders' investment in the new facilities, we must consider costs in the evaluation process, including giving consideration to the full lifetime costs and the anticipated longevity of the electrical solution."

At the December 15, 2006 PAC presentation, NU had originally selected the South Route based on the following Summary Comparison of the "Top Springfield Reliability Options" (slide 22):

Slide #22: Summary Comparison: "Top Springfield Reliability Options"

Best … Worst

Top Springfield Options		Network Performance	Human Environment Considerations	Natural Environment Considerations	Delivery Timeframe	Planning Grade Estimate
Option A N Bloomfield ⇔ Agawam ⇔ Ludlow	Route 1	Provides a second source for Springfield and other significant benefits	Would have a moderate perceived impact on developed areas, plus require substantial ROW expansion	Relatively low potential for impacting protected lands and resources	Feasible-but-challenging to site and build by date of need	In the highest cost range $500M (±25%)
✓ Preferred to-date. Subject to PAC input.	Route 2	Same as Option A-Route 1	Would have a moderate perceived impact on developed areas but require less ROW expansion	Low-to-moderate potential for impacting protected lands and resources	Feasible to site and build by date of need	In the lowest cost range $350M (±25%)
Option B [illegible]	Route 1	Provides voltage support and potential for future addition of a second source	Same as Option A-Route 1	Same as Option A-Route 1	Same as Option A-Route 1	In the highest cost range $500M (±25%)
	Route 2	Same as Option B-Route 1	Same as Option A-Route 2	Same as Option A-Route 2	Same as Option A-Route 2	In the lowest cost range $350M (±25%)
	Route 3	Same as Option B-Route 1, but less easily expanded to add a second source	Would have a moderate perceived impact on developed areas	Moderate potential for impacting protected lands and resources	Feasible to site and build by date of need	In the higher cost range $450M (±25%)
Option C Manchester ⇔ Ludlow		Provides needed voltage support, but does not establish a second source for Springfield and creates some new problems in Hartford	Would pass through less-developed areas	Low-to-moderate potential for impacting protected lands and resources	Feasible to site and build by date of need	In the low cost range $400M (±25%)

As noted by the (✓) mark, the choice of the South Route was based on engineering and planning information known at the time and was largely explained by the initial engineering assessment that approximately thirteen (13) miles of 115-kV circuits along the corridor between the Ludlow Substation and the Agawam Substation would require relocation underground if the North Route was used. The SNETR Project Board had been presented a summary of this analysis in October, 2006 as follows:

Slide #16: Comparison of Options – Scope

Scope

Springfield Options	345-KV Lines (c-miles) New OH+UG	345-KV Lines (c-miles) Modified	345-kV Substations New	345-kV Substations Modified	115-kV Lines[1] (c-miles) New OH+UG	115-kV Lines[1] (c-miles) Modified OH+UG	115-kV Substations New	115-kV Substations Modified	Equipment A – Autotransformer P – Phaseshifter
345-kV North Route	32+0	11	2	1	0+13	0	0	0	
345-kV South Route	41+1	4	2	1	0+5	0	0	0	

Environmental Characteristics

Municipals Count	Springfield Options	ROW Acquisition New (Acres)	ROW Acquisition Expanded (Acres)	Residences Number w/i 500'	Residences Clusters w/i 500'	Public Facilities Number w/i 500'	ROW Upgrade Miles of New[1] 345 ROW	Government Protected Lands Parks	Government Protected Lands Acres Traversed	Natural Resources Wetland Acres	Natural Resources R/T/E Acres
7	345-kV North Route	0	48	593	38	6	32	6	49	76	179
8	345-kV South Route	0	28	632	43	3	30	13	101	201	527

These summary characteristics had been developed by NU in September, 2006, when the following tables were prepared:

Table 3-2: Springfield Option A – South

Segment	Length (Miles)	Cross Sections	Right of Way Acquired (Acres)	115kV Underground (Miles)	345kV Underground (Miles)	Reconfig-uration Distance (Miles)	Number of Line Crossings	Number of River Crossings
1	14.40	5	28.08	0	0	0	0	0
1A	3.57	4	5.57	4.60	0	3.57	0	0
27A	11.75	12	0	0	1.45	0	0	1
41	11.04	1	0	0	0	0	4	0

Table 3-3: Springfield Option A – North and B – North

Segment	Length (Miles)	Cross Sections	Right of Way Acquired (Acres)	115kV Underground (Miles)	345kV Underground (Miles)	Reconfig-uration Distance (Miles)	Number of Line Crossings	Number of River Crossings
1	14.40	5	28.08	0	0	0	0	0
1A	3.57	4	5.57	4.80	0	3.57	0	0
27	20.62	23	19.03	9.46	0	16.63	0	1

Throughout 2007, more detailed engineering, planning, routing and environmental analyses were conducted. Of most importance was a detailed engineering and siting assessment of the structure clearances, structure options and electrical characteristics along the North Route which led to the conclusion that the new 345-kV circuits could share structures with re-built 115-kV overhead circuits on the North Route. No 115-kV circuit undergrounding would be required.

Cost estimates and environmental impact assessments dropped for the North Route in comparison to the equivalent estimates and assessments when the new 345-kV lines and the re-conductored or re-built 115-kV overhead lines were sited on the mostly separate rights of way associated with using the South Route for the 345-kV line.

After the 2007 work, analyses do show that the North Route can accommodate the 345-kV facilities and is superior because of its:

- The likelihood or probability of timely siting;
- The shorter distance for the new 345-kV lines, 34.9 miles for the North Route versus 40.5 miles for the South;
- The dramatic drop in the total miles of impacted overhead corridors, a total for the North of 41.9 miles versus a total of 64.5 miles for the South (the sum of the 345-kV corridor length of 40.5 miles plus the 24.0 miles on the North Route where the existing corridor would be impacted by overhead 115-kV line upgrade work);
- Anticipated lower cost;
- Fewer environmental impacts;
- Fewer property abutters;
- Lower acreage clearing;
- Similar system benefits to meet load demand; and
- Proximity to the Fairmont Switching Station where nine (9) 115-kV lines interconnect, allowing future system expansion options such as adding a 345/115-kV autotransformer at Fairmont for injection or supply of power from or to the 115-kV system.

The following subsections of this Section 3.7 present a summary of the route selection and engineering studies which show this superiority of the North Route to the South Route based on the principal criteria, costs and impacts.

3.7.1 The 345-kV Overhead Line Route Selection Process

To facilitate the assessment and scoring of the transmission line route alternatives, NU developed Project-specific evaluation criteria that address environmental, human and social, land use, and engineering/technical factors that are relevant to making a choice between the North Route and the South Route for the GSRP. Table 3-4 lists these evaluation criteria, the data metric for each criterion, and the source for the applicable data for the 345-kV overhead line. For the potentially viable Project route alternatives, NU applied numeric data metrics that were as objective as possible to obtain a numerical score (or ranking) for each alignment based on the evaluation criteria. The data were translated to a common scale for summing purposes and the totals were then summarized and sorted, resulting in a raw, unweighted score for each potential line route option. Based on the evaluation criteria, the best scoring potential options represented routes with potentially fewer impacts, less challenging circumstances, and/or other more favorable conditions and were, accordingly, preferable routes.

Table 3-4: Project Evaluation Criteria and Associated Data Metrics – Overhead 345-kV Lines

Evaluation Criteria	Data Metric	Available Data Source
Total route length	Feet	GIS analysis
Length NOT paralleling existing linear facilities	Feet	Visual review using aerial photography in GIS
Length by land use (Commercial/Industrial)	Feet	MassGIS land use
Length by land use (Undeveloped Land)	Feet	MassGIS land use
Length by land use (Residential)	Feet	MassGIS land use
Length by land use (Park/School/Open Space)	Feet	MassGIS Protected and Recreational Open Space Parcel data
Length through private easement	Feet	Parcel data
Length through stream or wetland	Feet	DEP wetlands and streams
Length through environmental sensitive area	Feet	NHESP priority habitats of protected species
Railroad crossings	Number	Visual review using aerial photography in GIS
Stream crossings	Number	Visual review using aerial photography in GIS
Cultural resources predictive modeling analysis	Qualitative score (1 to 3)	UMass Report
Residences w/in ROW	Number	Visual review using aerial photography in GIS
Residences w/in 100 feet of edge of ROW	Number	Visual review using aerial photography in GIS
Residences w/in 101 to 300 feet of edge of ROW	Number	Visual review using aerial photography in GIS
Businesses w/in ROW	Number	Visual review using aerial photography in GIS

Evaluation Criteria	Data Metric	Available Data Source
Businesses w/in 100 feet of edge of ROW or centerline	Number	Visual review using aerial photography in GIS
Businesses w/in 101 to 300 feet of edge of ROW	Number	Visual review using aerial photography in GIS
Public Facilities w/in 300 feet of edge of ROW	Number	MassGIS infrastructure Visual review using aerial photography in GIS
Public Facilities w/in 301 to 1,200 feet of edge of ROW	Number	MassGIS infrastructure Visual review using aerial photography in GIS
Visibility	Rating	Visual review using aerial photography in GIS

For the 345-kV overhead lines, each of two alternate Agawam to Ludlow line routes on existing ROWs, together with the North Bloomfield to Agawam line, would establish the required North Bloomfield-Agawam-Ludlow 345-kV connection. Although the majority of these two routes differ geographically, each route between North Bloomfield Substation and the Connecticut state border and from the border to Agawam Substation would follow the same existing overhead transmission line ROW. The alternate routes for the new 345-kV Agawam to Ludlow transmission line, referred to herein as a preferred "North" Route and a noticed-alternative "South" Route, each of which includes a common route segment from North Bloomfield from Agawam, are described as follows:

The preferred "North" Route would extend from North Bloomfield Substation to Agawam Substation following existing ROWs, and then would continue north from Agawam Substation, still on existing ROWs to Ludlow Substation.

The noticed-alternative "South" Route would extend from North Bloomfield Substation to the Agawam Substation and then south from the Agawam Substation to the South Agawam Junction. For a portion of this segment in Agawam, approximately 1.1 miles of the ROW is too narrow and would have to be widened by approximately 65 feet to share the ROW with the new North Bloomfield to Agawam 345-kV line. The line then turns east at South Agawam Junction, following existing ROWs generally paralleling the Connecticut/Massachusetts border, before turning north (at Hampden Junction) to reach the Ludlow Substation.

Comparing the "North" and "South" alternate routes between Agawam and Ludlow, NU considered that the ROWs along the "North" Route would be affected in any case by the required re-construction of the existing 115-kV lines between Agawam, Piper, Chicopee, Shawinigan, and Ludlow. There are currently two 115-kV circuits from Agawam to Piper to Chicopee, two from Chicopee to the Exit 6 Junction near Shawinigan, two from East Springfield Junction to Fairmont, three from the Exit 6 Junction near

Shawinigan to East Springfield Substation, and three from Shawinigan to Orchard Junction to Ludlow. These circuits are supported by various types of single- and double-circuit line structures (i.e., two circuits share common supporting structures). These 115-kV circuits will all have larger conductors to yield higher circuit capacity. The new 345-kV line can be constructed on these ROW as part of the same overall construction effort, and it can share structures with one of the 115-kV circuits in each segment of the North Route.

The "North" and "South" Routes are illustrated below in Figure 3-1 and Figure 3-2, respectively. The following Table 3-5 compares the North and South Routes, illustrating miles of affected ROW in both Massachusetts and Connecticut.

Table 3-5: North vs. South Route Comparison

ROW Segment	Affected ROW if Both New 345-kV & Reconstructed 115-kV lines located on North Route (miles/location by state)	Affected ROW if 115-kV lines on North Route & New 345-kV line on South Route (miles/location by state)
N. Bloomfield/ Agawam	18 miles (6 miles in MA and 12 miles in CT)	18 miles (6 miles in MA and 12 miles in CT)
Agawam/Piper-Chicopee/Ludlow	17 (MA)	17 (MA)
S. Agawam/ Hampden/Ludlow	N/A	22 (5 miles in CT and 17 miles in MA)
115-kV Spurs	4 (MA)	4 (MA)
Total Affected ROW[48]	39 (12 miles in CT and 30 miles in MA)	61 (17 miles in CT and 44 miles in MA)

[48] The circuit miles of new 345-kV construction for the North is 34.8 miles and for the South is 43.6 miles (inclusive of 3.2 miles in the North Bloomfield to Agawam segment (above) and another 3.2 miles in the segment which goes from Agawam to South Agawam Junction). Note: for the South route, two sets of structures for 345-kV lines are required in the segment from South Agawam Junction to Agawam Substation in order to make the connection at the Agawam Substation and then to return to the South route segment which goes from South Agawam Junction to Hampden Junction to Ludlow Substation.

Figure 3-2: Preferred "North" Route

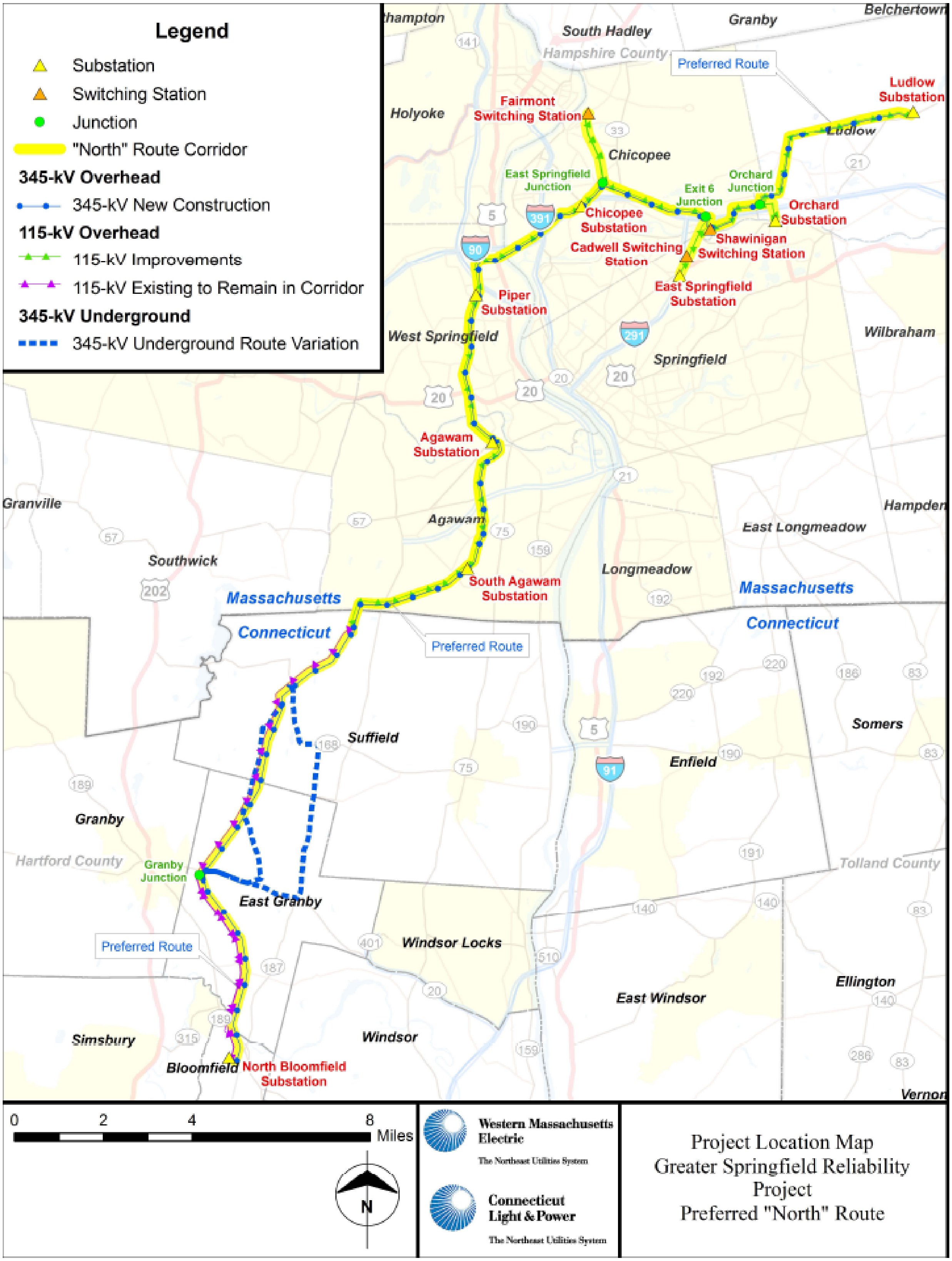
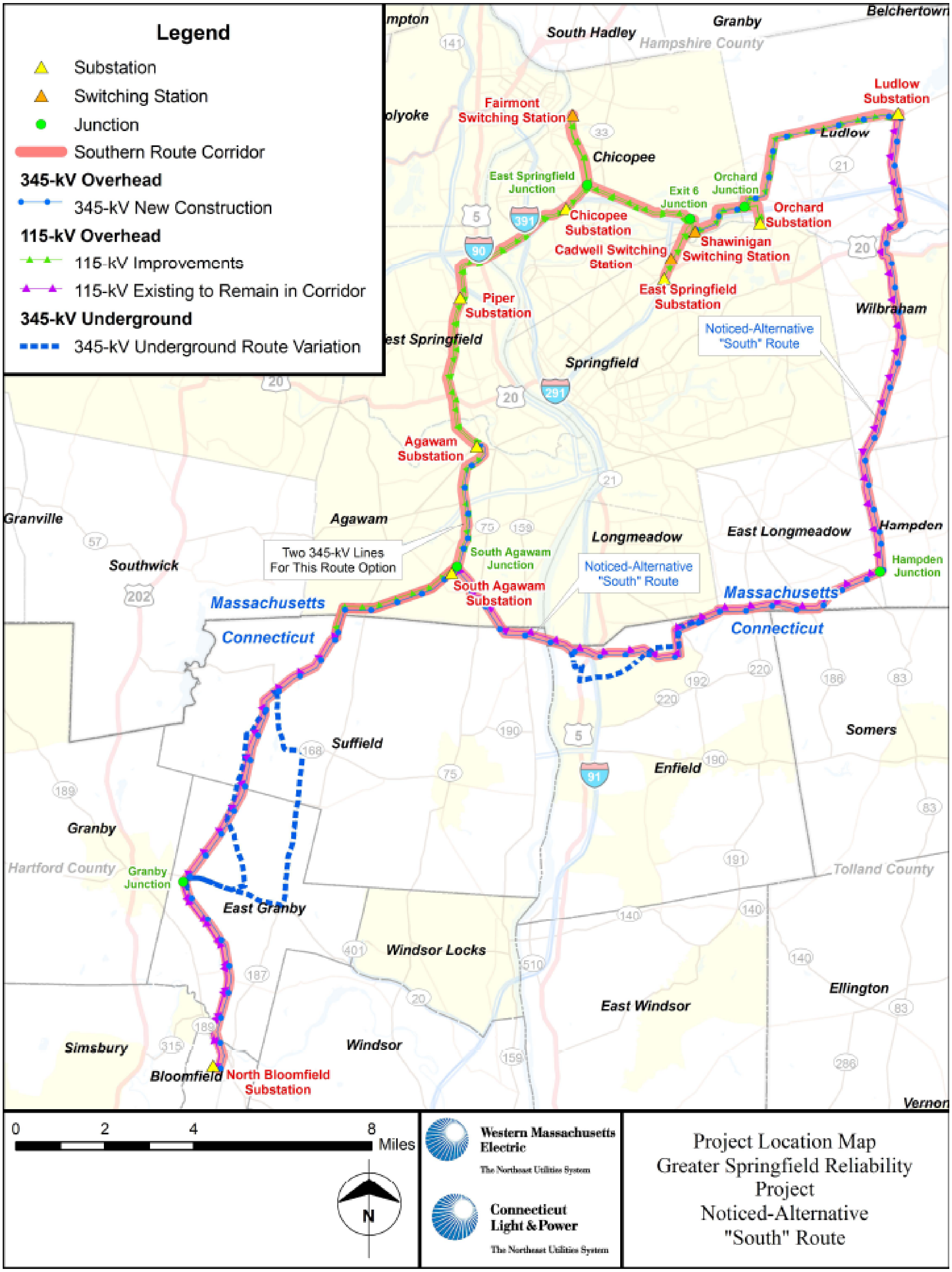


Figure 3-3: Noticed-Alternative "South" Route



Accordingly, if the "South" Route were selected for the 345-kV connection between Agawam and Ludlow, a total of 64.5 miles of existing overhead transmission line ROW would have to be disturbed for activities such as vegetation clearing, building new or widening existing access roads for use during construction, excavation for structure foundations, and other construction tasks. On the other hand, use of the "North" Route would involve only 42 miles of transmission line ROW disturbance, avoiding the disturbance of approximately 22.5 linear miles of ROW. The consolidation of the 345-kV and 115-kV line construction along the "North" Route also would require fewer construction support and staging areas and substation facilities.

The selected preferred and noticed-alternatives line routes were further compared as presented in Table 3-6. "Check marks" (✓) in each table identify the route which is superior for each of the evaluation criteria employed by NU.

Table 3-6: Comparative Summary of North and South 345-kV Overhead Line Routes Including 115-kV Line Improvements

Evaluation Criteria	North Route w/115-kV Improvements (Preferred Route)		South Route w/ 115-kV Improvements (Noticed-Alternative)	
Construction Schedule	36 months		36 months[49]	
Total Costs	$714 Million[50]	✓	$766 Million	
Easement & Potential Home Impacts	Fewer homes adjacent (one corridor)	✓	More homes adjacent (two corridors)	
Route Length	40 miles	✓	61 miles	
Tree Removal	Less tree clearing (one corridor)	✓	More tree clearing (two corridors)	
Streams/wetlands crossed	Approx. 16,000 linear feet	✓	Approx. 38,000 linear feet	
Threatened & Endangered Species Habitat crossed	Approx. 42,000 linear feet	✓	Approx. 96,000 linear feet	
Additional ROW width	Approx. 344,200 square feet	✓	Approx. 459,000 square feet	
Potential Cultural Resources	Less disturbance (one corridor)	✓	More disturbance (two corridors)	

[49] See: Section 5.1 for a footnoted discussion of performance advantages during construction if the decision were made to construct the 345-kV lines on the South Route prior to constructing the 115-kV improvements along the North Route. To gain that construction period performance advantage, however, the total construction duration would be longer than indicated here and costs would increase as well.

[50] Current cost comparisons are given in the following Section 3.9 are total cost including owner directs and indirects.

Structure sharing by the new 345-kV circuit and the 115-kV circuits on the same right of way results in clear advantages for the North Route over the South Route on each of the five (5) Key Criteria used by NU in making its final choice.

3.7.2 Current Cost Comparisons for the Final 345-kV Overhead Line Route Options 6a North (with and without the Cables) and 6a South (with and without the Cables)

NU, with the assistance of BMcD, has completed cost comparisons for the final solution options, including the preferred Springfield Solution which is identified, consistent with the Options Analysis, as Option A, 6a North (without cables) or in the following table, simply as 6n North. The results of those analyses are present below in Section 3.9 in Table 3-8.

For those options in the table which include “cables”, the final configuration of the cables was determined by NU at an interim stage of the ISO-NE Review Process. It must be distinguished from the more expansive and expensive SCP. The revised cables project includes one replacement underground 115-kV cable circuit from the East Springfield Substation to the Breckwood Substation and a second replacement underground cable circuit from the West Springfield Substation to the Breckwood Substation. In order to solve contingency overloads, while also reducing costs and maximizing the value of the remaining “through-path” to the West Springfield Substation, no new underground 115-kV cable circuit from the East Springfield Substation to the Clinton Substation was included. In effect, the replacement underground 115-kV cable circuit from the West Springfield Substation to the Breckwood Substation was the more cost effective and valuable alternative.

As shown in Table 3-8, the following results apply with respect to the North versus the South Route comparison:

- Each 6a option using the North Route is less expensive than its counterpart option using the South Route;
- For the Springfield Solution (without cables), the 6a option using the North Route is less expensive than the 6a option using the South Route by over $52 million; and
- If different options with respect to Stony Brook are compared on the North and the South Routes for the solutions without cables, the North Route is still superior to the South Route (for 6a option (without cables) on the North, i.e., the Springfield Solution, versus 6b option (without cables) on the South, the difference is about $20 million)

3.7.3 Conclusion on North versus South

In all relevant cases studied, the North Route is the less costly alternative to the South Route (Section 3.7.2).

With respect to the other Key Evaluation Criteria, the North Route is superior to the South Route by a significant margin. The dramatically lower number of miles of impacted right-of-way (Table 3-5) translates into significantly lower impacts on the human and the natural resource environment. In no category reviewed in Table 3-6, above, is the South Route superior to the North Route.

Although difficult to quantify, cost risk, schedule risk and licensing risk are considerably lower on the North Route as a result of its lower impacts. Risk of all character arises inevitably from the need to mitigate more impacts, to apply for more permits and to satisfy the concerns of more affected members of the community.

With respect to reliability and ability to meet the electric need, no measurable difference exists between the routes. On balance, the North Route is far superior to the South Route, just as Option A was found to be far superior to Options B and C in terms of system performance (Section 2.2.2 and Section 2.2.3[51]).

3.8 BREAKER-AND-A-HALF CONFIGURATION AT FAIRMONT: SELECTION BASED PRINCIPALLY ON OPERATING AND RELIABILITY BENEFITS

The Fairmont Switching Station is a major 115-kV station with nine connected circuits today. Five circuits connect to the Springfield network and the local generation at Mt. Tom, and four circuits are supplying radial loads at the Prospect, Five Corners, and Amherst Substations. The five network circuits (circuits #1254, #1723, #1525, #1428, and #1327) basically connect to all parts of the Greater Springfield area. For these reasons, this switching station requires a higher degree of reliability.

In its PAC presentation December 15, 2006, slide 61, ISO-NE recognized that re-building the Fairmont Switching Station to a breaker-and-a-half configuration has increased reliability and voltage support benefits. Since that time, NU has continued to work with CONVEX in its review of the operating advantages associated with re-building the Fairmont Switching Station with a breaker-and-a-half configuration.

That review shows that a continuation of the existing “separate” straight buses single breaker arrangement at the Fairmont Switching Station has the following disadvantages[52]:

[51] See also: Section 2.2.5, for the assessment of the operations personnel from ISO-NE and CONVEX as reported in the Options Analysis.

[52] If Option 8a were selected over Option 6a at this stage, the existing switching station could not remain without improvements. A short circuit study would be required to determine the full scope of that work. The system benefits of the breaker-and-a-half design are so strong that more detailed study on Option 8a does not seem justified. In addition to work at the Fairmont Switching Station, it is likely that some additional transmission line work would

- A bus fault will result in loss of all circuits connected to that bus; and
- A breaker failure will result in loss of all circuits connected to that bus.

The benefits of a breaker-and-a-half switching station are as follows:

- Higher service reliability and operating flexibility;
- Expansion flexibility;
- Either main bus can be isolated for maintenance without interruption of any circuit;
- Any breaker can be isolated for maintenance without interruption of any circuit;
- Double feed to each circuit results;
- The failure of a middle breaker results in the loss of two circuits, while the failure of outside breakers results in the loss of only one circuit; and
- A bus fault does not interrupt any circuit.

Consistent with the earlier recognition of ISO-NE, NU has selected the breaker-and-a-half re-construction of the Fairmont Switching Station based on the strong benefits listed. NU has also studied different breaker-and-a-half configurations, as listed in the following Table 3-7, and concluded that the "Greenfield" option captures the best balance of costs, impacts and reliability.

Table 3-7: Comparative Costs for Alternative Breaker-and-a-Half Configurations of the Fairmont Switching Station

Greenfield	Existing Original	Existing Option 1 (4 Bay)		Existing Option 2 (5 Bay)	
		All New CB	Existing and New CB	All New CB	Existing and New CB
$29,825,000	$30,935,667	$28,587,190	$26,210,440	$30,678,856	$28,353,106

Where the subject configurations have the following components:

- Greenfield Substation:
  - 5 bay breaker and a half
  - 2 28.8MVar Capacitor banks
  - Control House
  - Grading

also be required. Although not confirmed, it is possible that Option 8a would require additional capacitors at Fairmont, replacement of the main north and south bus (due to bundled lines coming in) and re-conductoring of the circuit from the Pineshed Substation to the Fairmont Switching Station. Other work might be required as well.

- Existing Original:
  - 5 bay breaker and a half
  - 1 additional position connected to the bus
  - 2 28.8MVar Capacitor banks
  - New Control House
- Existing Option 1 (4 Bay)
  - 4 bay breaker and a half (with and without replacing existing breakers)
  - 2 28.8MVar Capacitor banks
  - New Control House
- Existing Option 2 (5 Bay)
  - 5 bay breaker and a half (with and without replacing existing breakers)
  - 2 28.8MVar Capacitor banks
  - New Control House

NU views the strong system benefits as full justification for the costs to be incurred for the breaker-and-a-half configuration. The impacts associated with the re-building of the Fairmont Switching Station can be mitigated and provide no reason for the loss of such strong system benefits.

3.9 FINAL COST COMPARISONS FOR OPTIONS 6A NORTH (WITH AND WITHOUT CABLES), 6A SOUTH (WITH AND WITHOUT CABLES), 6B SOUTH (WITH AND WITHOUT CABLES) AND 7A SOUTH

Table 3-8 below contains cost estimates for seven (7) 345-kV route/Stony Brook connection pairs which NU considered as a feasible "short list" of alternative configurations for purposes of cost estimating in this Springfield Solution Report. As explained in Section 2.2.10, above (with further detail in Section 4), when NU decided to eliminate the SCP and all other cable upgrades in the City of Springfield, only the alternatives which include "no cables" were in the actual final "short list". However, the interim cable configuration (as of February, 2008) described in Section 3.7.2, above, was included in the table for comparison in order to show the significant total cost reduction associated with the elimination of all of the cable work in the City of Springfield.

Table 3-8 shows all of the results set forth in the North versus South comparison in Section 3.7.2 (which are repeated here), and in addition the following results:

- Each 6a option using the North Route is less expensive than its counterpart option using the South Route;

- For the Springfield Solution (without cables), the 6a option using the North Route is less expensive than the 6a option using the South Route by over $52 million; and
- If different options with respect to Stony Brook are compared on the North and the South Routes for the solutions without cables, the North Route is still superior to the South Route (for 6a option (without cables) on the North, i.e., the Springfield Solution, versus 6b option (without cables) on the South, the difference is about $20 million)
- Removing the cables[53] from option 6a North reduces costs by $148 million;
- Removing the cables from option 6a South reduces costs by $100 million;
- Removing the cables from option 6b South reduces costs by $135 million; and
- Options 6a South, 6b South and 7a South have approximate costs on the high end of the spectrum and no cost advantage can be associated with the loss of electrical performance associated with eliminating the Agawam 345/115-kV connection in option 7a.

[53] The "cables" being removed at this stage are those in the interim configuration of the cables project described above in Section 3.7.2, i.e., two (2) upgraded cable circuits, one from the East Springfield Substation to the Breckwood Substation and the other from the Breckwood Substation to the West Springfield Substation. These "cables" are not comparable to the three-cable SCP in scope or in cost. As for costs, Table 3-8 sets forth in the bottom rows different methods of calculating cost contingencies than the methods used in calculating the 40% contingencies for the SCP. Furthermore, costs for the SCP were escalated to the in-service date, while the estimates in the present Table 3-8 do not include such escalation and are stated in 2008 dollars ($2008). As for scope, see: Table 2-4 in Section 2.2.10 for a comparison of the scope differences between "option 6n" , whose cost is estimated in Table 3-8, and the PPA, described in Section 2.2.7. The PPA had four (4) cable circuits (the three (3) in the SCP and an additional cable circuit from the West Springfield Substation to the Breckwood Substation); the SCP as indicated had three (3); and the interim configuration had two (2).

Table 3-8: Electrical Alternative Cost Table

Description	Opinion of Probable Costs						
	6a North	6a South	6n North-Preferred	6n South-Noticed Alternate	6b South	6b South Cables	7a South
Build a new 345-kV line from Ludlow 19S Substation to Agawam 16C Substation (MA Only)	X	X	X	X	X	X	
Build a new 345-kV line from Ludlow 19S Substation to S. Agawam 42E Substation (MA Only)							X
Build a new 345-kV line from Ludlow 19S Substation to Agawam 16C Substation (CT Only)		X		X	X	X	
Build a new 345-kV line from S. Agawam 42E Substation to North Bloomfield 2A Substation (MA Only)							X
Build a new 345-kV line from Agawam 16C Substation to North Bloomfield 2A Substation (MA Only)	X	X	X	X	X	X	
Build a new 345-kV line from S. Agawam 42E Substation to North Bloomfield 2A Substation (MA Only)							X
Build a new 345-kV line from Agawam 16C Substation to North Bloomfield 2A Substation (CT Only)	X	X	X	X	X	X	X
Rebuild the 1781 line from Agawam to South Agawam Junction	X		X				
Place 1781 line on the Ludlow to Agawam 345/115-kV double circuit structures		X		X	X	X	
Place 1782 line on the Agawam to North Bloomfield 345/115-kV double circuit structures	X	X	X	X	X	X	
Reconfigure the existing 115-kV system (1768/1836/1821)	X	X	X	X	X	X	
Rebuild 115-kV circuit 1314 from Substation 18L Chicopee to Substation 16C Agawam	X		X	X	X	X	
Rebuild 115-kV circuit 1602 from E. Springfield Jct to Substation 18L Chicopee	X	X	X	X			
Break Three-Terminal Circuits 1254/1723 into Two-Terminal Circuits creating a total of four (4) circuits (1601-1604)	X	X	X	X	X	X	X
Build 115-kV circuit 1601 from E. Springfield Jct to Substation 21N Piper	X	X	X	X	X	X	
Build 115-kV circuit 1230 from Piper Substation to Agawam Substation	X		X	X	X	X	
Build two 115-kV single circuit lines from the existing Stony Brook 54B Substation to a connecting point on lines 1113 / 1134					X	X	
Rebuild the existing double circuit 1113/1134 line from Fairmont Substation to Five Corners Jct. as two single circuit lines					X	X	
Rebuild circuit 1481 from E. Springfield Substation to Ludlow Substation	X	X	X	X			X
Rebuild circuit 1845 from Shawinigan Substation to Ludlow Substation	X	X	X	X			
Bundle the conductors for the existing circuits 1481/1552/1426 into higher capacity portions of circuits 1552/1426	X	X	X	X			X
Rebuild circuits 1426 and 1552 from Orchard Tap to Substation 27A Orchard on new monopoles	X	X	X	X			X
Replace the West Springfield to Breckwood cable with 3500 kcmil XLPE cable and reconnect the 4% reactor in series	X	X				X	X
Install new cable circuit from 20A Breckwood to 5J East Springfield leaving old HPFF energized but opened	X	X				X	X
Ludlow 19S 345/115-kV Substation	X	X	X	X	X	X	X
Agawam 16C 345/115-kV Substation	X	X	X	X	X	X	
North Bloomfield 2A 345/115-kV GIS Substation	X	X	X	X	X	X	X
North Bloomfield to South Agawam/Southwick Phase Shifters							X
Spare Phase Shifter							X
Fairmont 16H (Greenfield)	X	X	X	X	X	X	X
Replace Breckwood Reactors	X	X				X	X
Southwick to N. Bloomfield Terminal Equipment, Protection, and Controls							X
W. Springfield to Agawam Line 1311 second high speed protection group	X	X	X	X	X	X	X
W. Springfield to Agawam Line 1412 second high speed protection group	X	X	X	X	X	X	X
Ludlow to Shawinigan Line 1845 second high speed protection group	X	X	X	X	X	X	X
Fairmont to Shawinigan Line 1604 second high speed protection group	X	X	X	X	X	X	X
Split Breckwood, add breakers and load transfer			X	X	X		
Fairmont substation, bay with line from Shawinigan requires 4000 amp breakers(230-kv class)			X		X	X	
Shawinigan substation, 4000 amp breakers (230-kv class) required between lines			X				
Cadwell Substation (replaces upgrades to E. Springfield Substation)	X	X	X	X	X	X	X
Springfield 115kV (Piper, Agawam, Shawinigan, Ludlow, Chicopee, Pineshed, Orchard and South Agawam)	X	X	X	X	X	X	X
South Agawam 42E 115-kV Substation	X	X	X	X	X	X	

Description	Opinion of Probable Costs						
	6a North	6a South	6n North-Preferred	6n South-Noticed Alternate	6b South	6b South Cables	7a South
Install new Clinton to E. Springfield cable circuit							
Clinton reactor							
2nd East Springfield to Breckwood Cable							
Clinton Ring Bus							
Breckwood Ring Bus							
Cadwell Substation (additional bays for cable circuits)	X	X				X	X
Rebuild Cadwell Substation to E. Springfield Substation overhead lines	X	X				X	X
Stony Brook Substation Upgrades					X	X	
Total Project Cost (all in)	**$862,086,166**	**$865,655,798**	**$714,095,486**	**$766,120,607**	**$734,510,467**	**$869,383,266**	**$865,317,807**

Notes:
1. Estimates are “All-In” dollars, escalated to future year of spend (assuming 2013 ISD).
2. Estimates are based on Burns & McDonnell Estimate dated 4-22-08

3.10 COST COMPARISON BETWEEN THE SPRINGFIELD SOLUTION (OPTION 6A NORTH WITHOUT CABLES) AND THE PPA (OPTION 6B NORTH WITH FOUR CABLES)

To illustrate the cost reduction resulting from the reduction in scope, NU has prepared a cost comparison between the Springfield Solution proposed and reviewed in this report (option 6n) and the reinforcements designated as the PPA Project. See: Section 2.2.6 for a listing of the components of the PPA Project. The PPA was the project presented at the PAC meeting on December 3, 2007 (see: Section 2.2.7). The components of the option 6n, the Springfield Solution, are presented in Section 2.2.10, where Table 2-4 contains a matrix comparing option 6n to the PPA Project, component by component.

The main reductions in scope between PPA Project and option 6n are as follows:

- The four cables in the PPA Project are all eliminated and no cables are installed or upgraded in option 6n as a result of the re-configuration of the existing Breckwood cable circuits to radial supply circuits;
- Without two new cable circuits terminating at the East Springfield Substation, no conversion to a breaker-and-a-half design is needed for option 6n;
- The more costly Stony Brook connection to the 115-kV system at the Fairmont Switching Station, with its construction and re-building of 115-kV overhead transmission lines for 9.5 miles, including 3.4 miles of virgin ROW[54], is eliminated in favor of the less expensive modifications at the Ludlow Substation;
- Without a cable circuit "through-path" in the City of Springfield and, therefore, without the prospect of contingencies which cause overloads of the Breckwood cable circuits, structure-sharing for the 115-kV overhead line circuits which must be re-built on the North Route becomes possible, resulting in fewer structures, less right-of-way expansion and lower costs[55]; and
- Substation and other modifications are eliminated or reduced in scope with the elimination of the four cable circuits.

As a result of these major scope reductions, savings in costs of approximately $336 million have been achieved. See: Table 3-9, below.

[54] In addition to the reduction in costs, the risk is reduced of eminent domain proceedings to acquire the virgin right-of-way and of related delays in siting.
[55] In addition to the reduction in costs, the risk is reduced of eminent domain proceedings to expand right-of-ways and of related delays in siting.

Table 3-9: PPA(6b North with cables) vs 6n (6a North without cables) Comparison

Electrical Alternative Summary		
Description	Opinion of Probable Costs	
	6n North	PPA
Build a new 345-kV line from Ludlow 19S Substation to Agawam 16C Substation (MA Only)	X	X
Build a new 345-kV line from Ludlow 19S Substation to S. Agawam 42E Substation (MA Only)		
Build a new 345-kV line from Ludlow 19S Substation to Agawam 16C Substation (CT Only)		
Build a new 345-kV line from S. Agawam 42E Substation to North Bloomfield 2A Substation (MA Only)		
Build a new 345-kV line from Agawam 16C Substation to North Bloomfield 2A Substation (MA Only)	X	X
Build a new 345-kV line from S. Agawam 42E Substation to North Bloomfield 2A Substation (MA Only)		
Build a new 345-kV line from Agawam 16C Substation to North Bloomfield 2A Substation (CT Only)	X	X
Rebuild the 1781 line from Agawam to South Agawam Junction	X	X
Place 1781 line on the Ludlow to Agawam 345/115-kV double circuit structures		
Place 1782 line on the Agawam to North Bloomfield 345/115-kV double circuit structures	X	X
Reconfigure the existing 115-kV system (1768/1836/1821)	X	X
Rebuild 115-kV circuit 1314 from Substation 18L Chicopee to Substation 16C Agawam	X	X
Rebuild 115-kV circuit 1602 from E. Springfield Jct to Substation 18L Chicopee	X	X
Break Three-Terminal Circuits 1254/1723 into Two-Terminal Circuits creating a total of four (4) circuits (1601-1604)	X	X
Build 115-kV circuit 1601 from E. Springfield Jct to Substation 21N Piper	X	X
Build 115-kV circuit 1230 from Piper Substation to Agawam Substation	X	X
Build two 115-kV single circuit lines from the existing Stony Brook 54B Substation to a connecting point on lines 1113 / 1134		X
Rebuild the existing double circuit 1113/1134 line from Fairmont Substation to Five Corners Jct. as two single circuit lines		X
Rebuild circuit 1481 from E. Springfield Substation to Ludlow Substation	X	X
Rebuild circuit 1845 from Shawinigan Substation to Ludlow Substation	X	X
Bundle the conductors for the existing circuits 1481/1552/1426 into higher capacity portions of circuits 1552/1426	X	X
Rebuild circuits 1426 and 1552 from Orchard Tap to Substation 27A Orchard on new monopoles	X	X
Replace the West Springfield to Breckwood cable with 3500 kcmil XLPE cable and reconnect the 4% reactor in series		X
Install new cable circuit from 20A Breckwood to 5J East Springfield leaving old HPFF energized but opened		X
Ludlow 19S 345/115-kV Substation	X	X
Agawam 16C 345/115-kV Substation	X	X
North Bloomfield 2A 345/115-kV GIS Substation	X	X

Electrical Alternative Summary		
Description	Opinion of Probable Costs	
	6n North	PPA
North Bloomfield to South Agawam/Southwick Phase Shifters		
Spare Phase Shifter		
Fairmont 16H (Greenfield)	X	X
Replace Breckwood Reactors		X
Southwick to N. Bloomfield Terminal Equipment, Protection, and Controls		
W. Springfield to Agawam Line 1311 second high speed protection group	X	X
W. Springfield to Agawam Line 1412 second high speed protection group	X	X
Ludlow to Shawinigan Line 1845 second high speed protection group	X	X
Fairmont to Shawinigan Line 1604 second high speed protection group	X	X
Split Breckwood, add breakers and load transfer	X	
Fairmont substation, bay with line from Shawinigan requires 4000 amp breakers(230-kv class)	X	X
Shawinigan substation, 4000 amp breakess(230-kv class) required between lines	X	
Cadwell Substation (replaces upgrades to E. Springfield Substation)	X	X
Springfield 115kV (Piper, Agawam, Shawinigan, Ludlow, Chicopee, Pineshed, Orchard and South Agawam)	X	X
South Agawam 42E 115-kV Substation	X	X
Install new Clinton to E. Springfield cable circuit		X
Clinton reactor		X
2nd East Springfield to Breckwood Cable		X
Clinton Ring Bus		X
Breckwood Ring Bus		X
Cadwell Substation (additional bays for cable circuits)		X
Rebuild Cadwell Substation to E. Springfield Substation overhead lines		X
Stony Brook Substation Upgrades		X
Construction/Eng Subconsultant/Mgmt	X	X
Engineering	X	X
Project Management	X	X
Siting & Permitting - Legal	X	X
NU Indirects	X	X
Contingency on Directs	X	X
Subtotal	X	X
Escalation	X	X
AFUDC	X	X
Total Project Cost (all in)	**$714,095,486**	**$1,049,762,103**

3.11 CALCULATION OF 345-kV OVERHEAD TRANSMISSION LINE COST PER MILE

Based on all the forgoing cost analyses, NU calculated the average cost per mile for the new overhead transmission line construction. That average cost for the different voltage and structure configurations is set forth in the last column of Table 3-10, below.

Table 3-10: Average Overhead Transmission Cost/Mile

Configuration	OH Transmission Costs	Structure Miles	Circuit Miles	OH Transmission Costs Per Structure Mile	OH Transmission Costs Per Circuit Mile
345 kV H-Frame	$41,796,107	12	12	$3,483,009	$3,483,009
345/115 kV Composite	$219,566,673	22.8	45.6	$9,630,117	$4,815,059
115 kV Single Circuit	$73,910,968	19.5	19.5	$3,790,306	$3,790,306
115 kV Double Circuit	$51,824,911	8.7	17.4	$5,956,886	$2,978,443
Project Average	$387,098,659	63	94.5	$6,144,423	$4,096,282

Total OH Transmission Project Cost	Total Project Corridor Length (mi)	Total Project Cost Per Corridors Mile
$387,098,659	38.9	$9,951,122.34

*Costs do not include EMF mitigation

4.0 THE INDEPENDENT ISO REVIEW PROCESS: REGIONAL COST-EFFECTIVENESS AND RELIABILITY

4.1 THE INDEPENDENT, INTERACTIVE ISO REVIEW PROCESS BETWEEN ISO-NE AND NU CONCERNING THE PROPOSED GSRP AND SCP SOLUTIONS

On behalf of Western Massachusetts Electric Company, the formal Petition for Approval to Construct (Petition to Construct) the SCP was submitted to the Massachusetts Energy Facilities Siting Board (EFSB) on December 21, 2007. The SCP entailed the six components described in Section 2.2.8, above.

Also in December, 2007, ISO-NE began a review of both the SCP and the broader GSRP, of which the SCP had originally been conceived to be a part. To move the review forward, ISO-NE quickly developed a set of questions for discussion with NU for an initial meeting which occurred on January 31, 2008.

NU understood that ISO-NE expected a fundamental re-assessment of all of the options that had been or could be considered to address the Springfield area needs identified by the SNETR study, to be executed interactively with ISO; and that the breadth of this reassessment was to include a re-evaluation of the application of the reliability standards to these needs.

In NU's view, ISO-NE sought to implement provisions of its recently adopted Attachment K to its Open Access Transmission Tariff (OATT) designed to assure that ISO-NE can identify the "most cost-effective and reliable solution(s) for the region that meets a need identified in a Needs Assessment"[56]. Through its participation in ISO-NE's interactive review, and by embracing this opportunity to present to ISO-NE this "NU Solutions Study", NU seeks the same end.

Such a broad-ranging and interactive review did occur, with two principal meetings on January 31, 2008 and February 18, 2008, and numerous opportunities for consultation between the meetings, as well as

[56] See: Attachment K, Section 4.2(b), which reads as follows: "(b) Evaluation and Development of Regulated Transmission Solutions in Solution Studies
The ISO, in coordination with the proponents of regulated transmission solutions and other interested or affected stakeholders, shall conduct or participate in studies to evaluate whether proposed regulated transmission solutions meet the system needs identified in Needs Assessments. The ISO, in coordination with affected stakeholders shall also identify regulated transmission projects for addressing the needs identified in Needs Assessments.

The ISO may form targeted study groups to conduct Solution Studies led by the ISO and including representatives of the proponents of regulated transmission solutions and of affected stakeholders. Through this process, the ISO may identify the most cost-effective and reliable solution(s) for the region that meets a need identified in a Needs Assessment. This solution may differ from a transmission solution proposed by a transmission owner.

Proponents of regulated transmission proposal(s) in response to Needs Assessments shall also identify any LSP plans that require coordination with their regulated transmission proposals addressing regional needs."

before and after the meeting dates. As a result of these interactions, NU conducted a fundamental re-assessment of the solution options considered for the GSRP. A presentation of a “bottom-up” re-assessment of the GSRP solution options was made to ISO-NE by NU on February 18, 2008. That re-assessment continued thereafter and is developed further in the preceding Section 3 of this NU Springfield Solution Report.

Furthermore, ISO-NE and NU jointly reviewed the basis for the need for the SCP and re-visited some of the fundamental interpretations of the applicable national and regional reliability standards when applied to local upgrades. That review of regional planning standards as applied to the instant case of the SCP is presented by NU for further consideration by ISO-NE in this Section 4.

4.2 REGIONAL COST-EFFECTIVENESS AND REGIONAL RELIABILITY AFFECTING THE LOCAL CONFIGURATION

Reliability criteria against which the need for transmission upgrades is judged are grounded, inter alia, in ISO Planning Procedure 3 (PP3). As set forth in the ISO-NE December 15, 2006 PAC Presentation (slides 12-14), Section 3 of PP3 deals with “Area Transmission Requirements” and provides that the area transmission system must be capable of delivering the generation to the load under facility outage events. Those same capabilities must also apply after the loss of a single element (the basis for line-out analysis). Voltage, line and equipment loadings shall be within applicable limits after outage events and any additional loss during line-out analysis. Section 4 of PP3 deals with “Transmission Transfer Capability” and provides that the interconnected transmission system must be designed with adequate inter-Area and intra-Area transfer capability – for both normal and emergency (line-out) conditions. As a result of the 2003 Blackout, a new emphasis on reliability has arisen and starting in 2007, mandatory reliability standards and potential civil penalties apply for non-compliance.

While regional reliability standards are common knowledge, the interpretation and application of those standards to localized upgrade questions may require a judgment concerning residual risks. The SCP is such a case.

At a time when its own 2004 transmission reliability standards were under active review, and for the reasons stated below, NU sought SCP upgrades which assured that there would be no loss of local load in the City of Springfield after second contingency events which might be long in duration. In reaction, ISO-NE reviewed the SCP in the interest of regional cost-effectiveness and reliability and requested that NU re-consider two issues: (1) the prospect of achieving significant cost-reductions while trading-off only modest reductions in reliability; and (2) the return to the more common regional interpretation of applicable reliability standards which allows for the temporary loss of load under second contingency events where the loss of load effects are restricted to local subareas and have no area-wide consequences. The following subsections of this Section 4.2 set forth the background of the SCP, recount NU's re-consideration of the subject issues and explain the conclusions which NU has reached in this process. Those conclusions are now offered for ISO-NE's further review and development.

4.2.1 The Framework of the SCP within the ISO-NE SNETR Report 2 – Options Analysis

In Section 2, above, "Appendix A, Table A 4 – Springfield Component Reinforcements" is reproduced from the ISO-NE *Options Analysis*. A collaborative product of the SNETR Regional Working Group, the Options Analysis shows in Appendix A that upgrades to the cable paths in the City of Springfield were an integral part of the great majority of the twelve (12) GSRP options reviewed. In this regard, 10 of the 12 options included "*Install new Clinton - East Springfield cable circuit*". Moreover, 12 of the 12 options included, "*Replace Breckwood - E. Springfield cable circuit*". Four of the 12 options added a third cable to the foregoing two, "*Install 3rd Clinton – West Springfield cable circuit*". The two options which replaced the Breckwood to East Springfield underground 115-kV cable circuit, but did not include a new Clinton to East Springfield underground 115-kV cable circuit, also replaced the Breckwood to West Springfield underground 115-kV cable circuit.

In short, the SNETR Working Group most often chose as a core part of the GSRP options to strengthen two of the existing three 115-kV through-paths[57] in the Springfield area from the Ludlow Substation to the Agawam Substation.

In this context, NU conducted first and second contingency analyses of the existing Springfield area 115-kV system and decided to install a new Clinton - East Springfield underground 115-kV cable circuit, replace the existing Breckwood - East Springfield underground 115-kV cable circuit and also to install a second underground 115-kV cable circuit at the same time between Breckwood and East Springfield[58]. Each new cable, except the second new cable circuit from East Springfield to Breckwood, was a part of that core of GSRP options. The new Clinton - East Springfield cable circuit was in that core and also

57 The three paths are westward from Ludlow in the direction of East Springfield Junction and then through Chicopee Station, Piper Substation to Agawam Substation; westward from Ludlow to East Springfield Substation and then through the Breckwood Substation to the West Springfield Substation and then to Agawam; and southerly from the Ludlow Substation to the Scitico Substation and then westward to the South Agawam Substation and then north to the Agawam Substation.

58 The replacement of the cable between West Springfield and Breckwood Substations was discovered to be required when the final GSRP configuration was studied. The use of the Northern route and the sharing of structures between the 345-kV and the 115-kV lines on the Northern route resulted, under certain double contingencies which involved the second contingency loss of the shared structures, in the overload of the existing cable.

meets other NU objectives explained in Section 4.2.2, below. The second cable circuit between the Breckwood and East Springfield Substations was not in that core, but did address the NU objective explained below.

4.2.2 Application of Reliability Standard to the Loss of Load in the City of Springfield

In designing the SCP, NU attempted to solve existing violations of reliability standards affecting the existing Breckwood to East Springfield 115-kV cable circuit under normal operating conditions and following first contingency events. Certain existing second contingency event violations were also addressed by the addition of all three of the proposed SCP underground cable circuits. During the construction of the other 345-kV and 115-kV components of the GSRP, the need for the new cables was also clear, i.e., while flow on the 115-kV system around the City of Springfield was limited by construction, many different unanticipated system element failures would result in overloads on the Springfield 115-kV underground cable through-paths without the addition of the new cables.

However, after the construction of the other 345-kV and 115-kV components of the GSRP, the need for the new cables was based solely on the second contingency loss of the existing two-cable sources of supply to the Clinton Substation and the Breckwood Substation.

In refusing to accept the loss of most of the load of the City of Springfield in such two-cable contingencies, NU was going beyond its own existing standards adopted in 2004. Such standards were under active review at all times relevant to the planning of the SCP.

In this regard, Section 4.2 of "TRANSMISSION RELIABILITY STANDARDS FOR NORTHEAST UTILITIES", January 2004, provides as follows:

> "**4.2 STEADY STATE ASSESSMENT**
>
> The **local area systems** shall be tested using the criteria stated below.
>
> Transmission line and equipment loadings shall be within normal **ratings** for predisturbance conditions and within applicable emergency **ratings** for the system load and **generation c**onditions that exist following the non-radial **contingencies** specified below and with due regard to electrical system reconfiguration:
>
> a. **Contingencies** listed in section 4.1.
>
> b. Overlapping loss of any two non-identical **elements** (i.e., autotransformer and transmission line).

Steady state assessment must also recognize the historical design philosophies and practices of the NU Operating Companies. In addition, the **bulk power system** can be subjected to **emergency** events which exceed in severity the **contingencies** listed above. Additional system planning studies will be conducted to determine the effect of the following **contingencies** on **local area systems** performance, as a measure of system **reliability**. Procedures will be developed, where appropriate, to reduce the probability of occurrence of such **contingencies**, or to mitigate the consequences, in due time, that are indicated as a result of the simulation of such **contingencies**.

c. For the outage of a radial transmission line, load loss up to 30 MW over a 24-hour load cycle, will be accepted.

d. For an **area** supplied by two overhead or underground transmission lines from a remote or common location, the outage of both lines (e.g. due to a line **contingency** or malfunctioning circuit breaker) will result in a complete loss-of-load in the **area** for the time required to repair one line. The maximum load supplied by two lines will be limited to the appropriate **rating** of the smaller of the two transmission lines adjusted for the load that can be readily transferred to an alternate source through distribution switching, but not to exceed 300 MW."

Under Section 4.2(d), above, of the NU Transmission Reliability Standards, the addition of the new Clinton to East Springfield underground cable circuit and the second new underground cable circuit from East Springfield to Breckwood would not be justified. However, planning for the SCP progressed at the time NU was still revising its existing NU Transmission Reliability Standards, a process that continues today. The NU revisions focus particularly on first contingency cable failures in cases where old, low capacity cables may be involved.

In its planning for SCP, NU took into explicit account both the age of the cables in question and the urban, commercial and inner city character of the local load that would be lost in the City of Springfield. In the first respect, NU admittedly introduced a probabilistic concept into its deterministic contingency review. The existing two 115-kV pipe-cable circuits to Clinton from West Springfield are over 40 years old and share common splice vaults where both cables are exposed to the risk of a fire or other common mishap which affected both cables at the same time. The two pipe-cable circuits cross underneath the Connecticut River. The single 115-kV pipe-cable circuit to Breckwood from West Springfield is over 50 years old and includes a separate crossing underneath the Connecticut River. Double-contingency loss of load appeared to NU to be more probable under these circumstances than in the average case, and in fact, one such event which dropped all load supplied by the Clinton Substation for several hours has previously occurred.

In the second respect, the local load which would be lost included area hospitals and emergency facilities such as police stations. The primary commercial center in the western part of Massachusetts could be without electrical power for an indefinite period which could be a matter of days or even weeks before ending.

In the Petition to Construct, NU described the N-1-1 loss of local load as follows:

> ***Breckwood Substation***
>
> The Breckwood Substation is currently fed by two 115-kV cable circuits. One originates at the West Springfield Substation and the other at the East Springfield Substation. Under N-1-1 analysis, the long-time outage of a single cable followed by the contingent loss of the second cable isolates the Breckwood Substation from the transmission grid. Therefore, all load fed from this substation is at least momentarily lost.
>
> For the Breckwood Substation, up to thirty percent (30%) of the load would be transferred as soon as possible to distribution feeders from other substations for some period of time. The bulk of the Breckwood load would be lost for the period required to make repairs to one or the other existing cables. Depending on the nature of the contingencies, repairs could take a matter of days or weeks as efforts were made to locate the failed cable section(s), freeze the insulating fluid, procure replacement cable and make all necessary splices.
>
> To eliminate this N-1-1 reliability problem, a second circuit from the new Cadwell Switching Station to Breckwood Substation will ensure that a reliable supply to an area of downtown Springfield is maintained under all design criteria contingencies. The addition of a second 115-kV supply into the Breckwood Substation increases the capability of this transmission path for power to move into and through the Springfield area.
>
> ***Clinton Substation***
>
> The Clinton Substation is currently fed by two 115-kV cable circuits originating at the West Springfield Substation. Both cables go under the Connecticut River and terminate at

the Clinton Substation just north of downtown Springfield. Under N-1-1 analysis, the long-term outage of a single cable followed by the loss of the second cable isolates the Clinton Substation from the transmission grid. Therefore, all load fed from this substation is at least momentarily lost. The loss of electric supply to major a portion of downtown Springfield could potentially last for an extended period of time and have significant adverse consequences. In this case for the loss of cables supplying the Clinton Substation, up to twenty percent (20%) of the load would be transferred as soon as possible to distribution feeders from other substations[59]. Repair times could be extended by the difficulty of locating failed segments underwater.

To eliminate this N-1-1 reliability problem, a new circuit from the Cadwell Switching Station to Clinton Substation will provide a third power source to ensure that a reliable supply to downtown Springfield load is maintained under all design criteria contingencies. A third 115-kV supply to the Clinton Substation can also provide a flow-through path for power to move into and through the Springfield area. This new circuit will also reduce power flows on other surrounding transmission circuits and so extend their reliable service lives before enhancements are necessary in the future."

Petition to Construct, pages 2-27-2-28 (December 21, 2007).

4.2.3 The NU Reconsideration of Costs and Local Standards in the Interest of Regional Cost-Effectiveness and Regional Reliability

As a fundamental part of the ISO-NE Review Process, NU re-considered two issues: (1) the prospect of achieving significant cost-reductions while trading-off only modest reductions in reliability; and (2) the return to the more common regional interpretation of applicable reliability standards which allows for the temporary loss of load under second contingency events where the loss-of-load effects are restricted to local sub-areas and have no area-wide consequences.

NU re-considered the two issues through a progression of stages, summarized as follows:

1. At the January 31, 2008 conference with ISO-NE, NU proposed a variety of cost-reduction modifications to the SCP, including the elimination of the second new cable circuit from East Springfield to Breckwood; dropping the spare vaults planned for the new Clinton to East

[59] The remainder and bulk of the Clinton load would be lost for the period required to make repairs to one or the other existing cable circuit.

Springfield circuit; retaining straight-bus configurations at the Clinton and Breckwood Substations; and adjusting escalation and contingency factors.

2. Replacing the new Clinton to East Springfield cable with a new third cable between Clinton and the closer West Springfield Substation was considered.
3. Replacing the new Clinton to East Springfield cable with a new replacement cable between Breckwood and the West Springfield Substation was considered.
4. Eliminating the new Clinton to East Springfield cable without a new replacement cable between Breckwood and the West Springfield Substation, but with a Special Protection System on the existing Breckwood and the West Springfield cable was considered.
5. Eliminating all new cable construction and re-configuring the existing cable through-path from East Springfield to Breckwood to West Springfield to a set of radial supply cables by adding "in-line" breakers on each cable at the Breckwood Substation and opening the Breckwood bus[60].
6. The elimination of the proposed new Cadwell Switching Station was also reviewed.

With the elimination of the SCP, a very significant cost reduction will be achieved in the aggregate cost of the Springfield Solution (inclusive of the cables which were considered a part of the Springfield Solution from the early planning stages). See: Section 3.9, above.

4.3 A BALANCED REGIONAL AND LOCAL SOLUTION MEETING ATTACHMENT K REQUIREMENTS FOR THE MOST COST-EFFECTIVE AND RELIABLE SOLUTION

Along with the elimination of the SCP described in Section 4.2.3, above, NU conducted the "bottom-up" re-assessment of all other aspects of the GSRP described in Section 3, above. In the latter respect, at the request of ISO-NE, NU also addressed specific questions such as the choice between the northern and the southern route (Section 3.7, above); the choice to interconnect Stony Brook at the Fairmont Switching Station or to pursue one of the 115-kV overhead alternative upgrades (Section 3.4, above); the inclusion or the exclusion of the 345/115-kV connection at the Agawam Substation (Section 3.6, above); and the re-building of the Fairmont Switching Station or not (Section 3.8, above).

As a result of both the foregoing review and the re-consideration processes, the preferred Springfield Solution has the following components:

[60] As an independent project, NU intends to separate and re-build the double circuit towers carrying circuits #1412 and #1311 from West Springfield Substation to Agawam Substation.

Item A	Build a new 345-kV line from Ludlow Substation to Agawam Substation (MA Only)
Item B	Build a new 345-kV line from Agawam Substation to North Bloomfield Substation (MA Only)
Item C	Build a new 345-kV line from Agawam Substation to North Bloomfield Substation (CT Only)
Item D	Rebuild the 1782 line from Agawam to South Agawam Junction
Item E	Place 1781 circuit on the Agawam to North Bloomfield 345/115-kV double circuit structures
Item F	Reconfigure the existing 115-kV system (1768/1836/1821)
Item G	Rebuild 115-kV circuit 1314 from Chicopee Substation Chicopee to Agawam Substation Agawam
Item H	Rebuild 115-kV circuit 1602 from E. Springfield Jct to Chicopee Substation
Item I	Break Three-Terminal Circuits 1254/1723 into Two-Terminal Circuits creating a total of four (4) circuits (1601-1604)
Item J	Build single-circuit monopole 115-kV circuit 1601 from E. Springfield Jct to Piper Substation
Item K	Build single-circuit monopole 115-kV circuit 1230 from Piper Substation to Agawam Substation
Item L	Rebuild circuit 1481
Item M	Rebuild circuit 1845 on new monopoles
Item N	Bundle the conductors for the existing circuits 1481/1552/1426 into higher capacity portions of circuits 1552/1426
Item O	Rebuild circuits 1426 and 1552 from Orchard Tap to Orchard Substation on new monopoles
Item P	Ludlow 19S 345/115-kV Substation Changes
Item Q	Agawam 16C 345/115-kV Substation Additions
Item R	North Bloomfield 345-kV GIS and a second 345/115-kV autotransformer
Item S	Fairmont (Greenfield breaker-and-a-half switching station)
Item T	[Intentionally Deleted]
Item U	W. Springfield to Agawam Circuit 1311 second high speed protection group
Item V	W. Springfield to Agawam Circuit 1412 second high speed protection group
Item W	Ludlow to Shawinigan Circuit 1845 second high speed protection group
Item X	Fairmont to Shawinigan Circuit 1604 second high speed protection group
Item Y	Split Breckwood Substation bus, add breakers and load transfer
Item Z	Fairmont, bay with line from Shawinigan requires 4000 amp breakers(230-kV class)
Item AA	Shawinigan, 2 X 4000-amp breakers(230-kV class) required between lines
Item GG	Rebuild/reconductor the Woodland to Pleasant 1371 line
Item HH	Upgrade the Pleasant to Blandford 1421 line to the full 556-kcmil ACSR conductor rating
Item II	Upgrade the Blandford to Granville Junction portion of line 1512 to the full 556-kcmil ACSR conductor rating
Item JJ	Separate and Rebuild West Springfield to Agawam double-circuit line 1311/1412

Note: (1) The "blue coded" entries above are independent projects and will be subject to separate siting and other approvals. (2) The Manchester to Meekville Line Separation (defined above in Section 2.2.10) in Connecticut will be added to the above scope.

This preferred Springfield Solution is, in the view of NU, the most cost-effective and reliable regional solution to the Springfield area transmission needs.

5.0 CONVERSION TO LOCAL RADIAL SUPPLY CABLES IN THE CITY OF SPRINGFIELD: SATISFYING RELIABILITY STANDARDS

5.1 MANAGEMENT OF THE SPRINGFIELD SYSTEM DURING CONSTRUCTION OF THE SPRINGFIELD SOLUTION

The typical construction approach along the North[61] Route consists of (1) constructing the double circuit 345-kV/115-kV poles; (2) energizing the 345-kV circuit at 115-kV and the 115-kV circuit on the double circuit pole; (3) demolishing the existing transmission lines; and (4) constructing the single circuit 115-kV poles[62].

During the rebuilding of the 115-kV circuits, there is an increased chance that contingencies would overload the East Springfield to Breckwood and Breckwood to West Springfield 115-kV underground cable circuits if they continue to operate as they do today, as a “through-path” for power flow from the Ludlow to Agawam Substations. It will, therefore, be necessary first to complete the rebuilding and separation of the Agawam to West Springfield overhead 115-kV circuits #1311 and #1412, and to install a line-end circuit breaker on each 115-kV underground cable circuit at the Breckwood Substation. The completion of these changes establishes an operating mode whereby part of the Breckwood Substation load is served radically from the East Springfield Substation by the existing East Springfield to Breckwood 115-kV underground cable circuit #1322. The remaining Breckwood Substation load is served radially from the existing West Springfield Substation by the West Springfield to Breckwood 115-kV underground cable circuit #1433.

In this radial operating mode, the through-flow path is interrupted, thus preventing cable-circuit overloads. Protective relaying and circuit breakers at the Breckwood Substation can be programmed quickly to isolate one or the other 115-kV underground cable circuit if it experiences a failure, and then

[61] The 115-kV re-construction along the Ludlow – East Springfield Junction – South Agawam transmission corridor occurs whether the North or the South route is chosen. Except for the sequential construction described below, the construction along the North route and construction along the South route will generally require an equal number and duration of outages. The South route has a limited performance advantage during the construction period due to the ability to construct the 345-kV transmission line prior to re-building the 115-kV lines, thus providing a stronger system and eliminating contingencies during the construction period for the 115-kV lines. To implement this South route advantage, however, the total construction duration would be extended to account for constructing the 345-kV lines and 115-kV lines in series rather than in parallel. The extension of the total construction duration will add significant costs to the project, thus nullifying the performance advantage.

[62] For the use of the South route, the typical construction approach along the Ludlow – East Springfield Junction – South Agawam 115-kV transmission corridor is identical to the construction approach for the North corridor with the exception of step (1), which requires the construction of double circuit 115-kV/115-kV poles rather than the double circuit 345-kV/115-kV poles.

temporarily to pick up the interrupted load from the other radial 115-kV source. The interrupted load would thus experience only a momentary loss of service[63].

The reason why circuits #1311 and #1412 must be separated is that both circuits share common support structures and the single contingency outage of circuits #1311 and #1412 would isolate all the West Springfield and Clinton Substation distribution loads, and a portion of the Breckwood Substation load, leaving this load connected only to the West Springfield generation source. Unless the connected loads of the West Springfield and Clinton Substations, and that portion of the Breckwood load radially served from West Springfield Substation, match the total power output of the West Springfield Generating Station, violent power swings will occur. This would result in potential damage to a wide variety of customer and utility equipment and loss of all customer load served from these substations. This is not an acceptable contingency outcome, and it can be avoided by physically separating the #1311 and #1412 circuits.

5.2 RELIABILITY OF THE SPRINGFIELD AREA SYSTEM WITH RADIAL SUPPLY CABLES AFTER THE SPRINGFIELD SOLUTION IS CONSTRUCTED

As described in the preceding section, the operation of Breckwood Substation with two radial 115-kV underground cable-circuit supplies can be accomplished reliably during the Springfield Solution construction period, when one or more Springfield area overhead 115-kV circuits may need to be removed from service. After the Springfield Solution is completed, this mode of system operation will meet all national and regional reliability standards.

There will be two operating differences between the Springfield Solution and the much more costly alternative approach (the higher capacity underground 115-kV cable circuit from the East Springfield Substation to the Clinton Substation, the two higher capacity underground 115-kV cable circuits from the East Springfield Substation to the Breckwood Substation and the higher capacity underground 115-kV cable circuit from the Breckwood Substation to the West Springfield Substation). With the Springfield Solution, a momentary interruption to some of the Breckwood Substation load will occur if one cable circuit trips out of service for an unplanned failure. Also, with both the Clinton and Breckwood Substations remaining supplied by two 115-kV cable circuits rather than three, an N-1-1 contingency

[63] In addition, the existing operating mode could also be used as a through-flow path during conditions when a system contingency would not overload either cable circuit, or with a temporary special protection system in place which would quickly open the through-flow path at Breckwood Substation in the event of such a contingency. This through-flow operating mode would avoid the momentary interruption associated with the radial operating mode in the event that one of the two cable circuits trips out of service.

involving the two supply cables to either substation will drop 70% or more of that substation's load until one of the two cable circuits can be restored to service. This temporary loss of local load is consistent with local and regional reliability standards. See: Sections 4.2.2 and 4.2.3, above. While the existing 115-kV underground cable circuits have experienced very high reliability, the West Springfield to Clinton HPFF underground cables are now 42 years old and the East Springfield to Breckwood and Breckwood to West Springfield HPFF underground cables are 54 years old. None of these cables can be expected to last indefinitely. An inexpensive distribution load-transfer solution is not available. As a result, replacement upgrades to the existing Springfield underground cable circuits may need to be re-considered at a future date. This replacement may be done, however, without altering the currently planned radial re-design of the cable system in the City of Springfield.

6.0 SCHEDULE AND NEXT STEPS

NU anticipates that the Springfield Solution will be presented to the PAC, along with comparable presentations for the Interstate Reliability Project and the Rhode Island Reliability Project, at the May PAC meeting tentatively scheduled for May 19, 2008. NGrid and NU will both make presentations as to their respective parts of the subject NEEWS components.

During the month of May, associated studies will be submitted to the Transmission Task Force and the Stability Task Force, seeking their respective recommendations that the projects will have no adverse impact. It is anticipated that upon receipt of the necessary recommendations, a Proposed Plan Application (PPA) will be prepared on a consolidated basis for the NEEWS projects and submitted to the Reliability Committee for Section I.3.9 approval. A PPA submittal in June, 2008 is the goal of NU.

APPENDIX A

THE HISTORY OF THE SNETR STUDIES AND THE SCOPE OF NEEWS

A.1 Introduction: The Southern New England Transmission Reliability (SNETR) Study and the New England East-West Solution (NEEWS) Project

The Springfield Solution Report, to which this appendix is attached, will define, describe and evaluate the components of the "*Springfield Solution*". As explained in Section 1, the Springfield Solution contains more, and in some cases, fewer, components than those identified earlier with (i) the Southern New England Transmission Reliability (SNETR) component for Springfield, known as the Greater Springfield Reliability Project (GSRP), and (ii) the GSRP elements which formed the Springfield 115-kV Advanced Projects. As a threshold matter, this appendix must establish the context from which both the prior labels and the present solution emerged. The Springfield Solution must be seen and understood as a part of a ten-year transmission planning effort which combined a comprehensive regional transmission study with a comprehensive four-component regional transmission solution. That study has been referred to as the Southern New England Transmission Reliability study. The proposed regional solution has been referred to as the New England East – West Solution (NEEWS). The background and description of the SNETR study and the NEEWS project follow in this Appendix A.

At the conclusion of this Appendix A in Section A.5, the critical relationship between the Springfield Solution and the other NEEWS components is addressed. An appreciation of both the connection and the disconnection among the NEEWS parts is a necessary foundation for this Springfield Solution Report.

A.2 Brief History of the SNETR Study and the NEEWS Projects[64]

The NEEWS project emerged from a coordinated series of studies of the deficiencies in the Southern New England (SNE) electric supply system, which began in 2004, and were collectively called the SNETR study. Both the SNETR study and the NEEWS project were developed by the Independent System Operator – New England (ISO-NE), and by the planning staffs of Northeast Utilities Service Company (NUSCO) and National Grid USA (NGRID), with the assistance of outside consultants. Under the leadership of ISO-NE, the planning teams undertook a study of improvements that would be needed to address SNE transmission system problems expected to arise through 2016, assuming the completion of other regional projects already underway and projected peak-load growth. Initially, these studies

[64] The history of the SNETR study and the NEEWS project can be traced through each of the regional system plans from 2003 and following. See: Regional Transmission Expansion Plan 2003 (RTEP03) at page 31; RTEP04 at page 70; Regional System Plan 2005 (RSP05) at pages 89-90; RSP06 at pages 92-93; and RSP07 at pages 87-90.

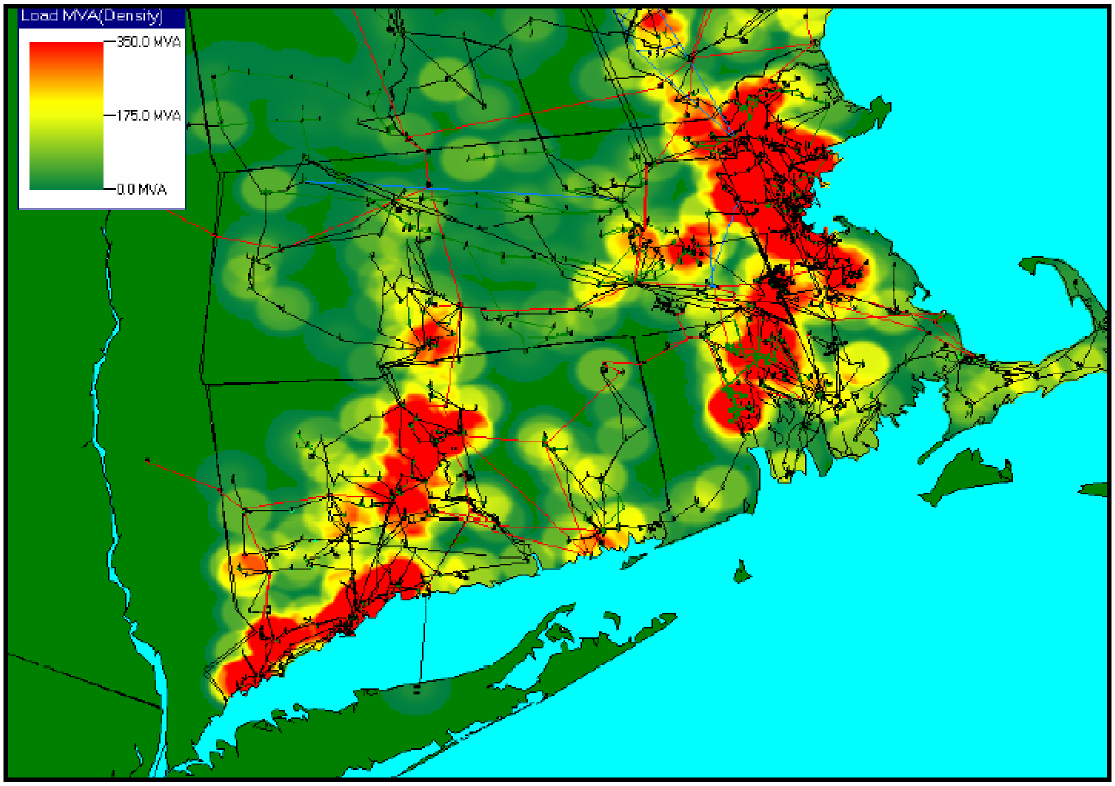
considered limitations on east-west power transfers across Southern New England and transfers between Connecticut and southeast Massachusetts and Rhode Island. These limitations had been identified as interdependent (that is, as affecting one another) in ISO-NE's 2003 Regional Transmission Expansion Plan (RTEP03). In the course of studying these interstate transfer limitations, the ISO-NE planning team determined that previously identified reliability problems in Greater Springfield and Rhode Island were not simply local issues, but also affected interstate transfer capabilities. In addition, the planners identified constraints in transferring power generated in – or imported into – eastern Connecticut across central Connecticut to the concentrated load in southwestern Connecticut (SWCT). A more detailed summary of the SNE problems follows below. A comprehensive plan to address all of these interrelated problems was then developed, at first under the working group name of the Southern New England Transmission Reliability Plan, and later under the more descriptive project umbrella name of NEEWS. The end result of these processes was the identification of four components of the NEEWS plan, described below, along with other system improvements to address local reliability issues.

A.3 Summary of the SNETR Study

The SNETR study was finalized in January, 2008 by ISO-NE in the *Southern New England Transmission Reliability Report 1: Needs Analysis (January, 2008).* In Section 1 of this Needs Analysis (pages 1-3), ISO-NE described the SNE region where these problems have materialized as follows:

> ### "1.1 Southern New England
>
> The map shown in Figure 1-1 depicts the load density for the geographic area of southern New England, namely Massachusetts, Rhode Island, and Connecticut. As shown in this figure, a substantial number of significant load pockets exist—Boston and its suburbs, central Massachusetts, Springfield, Rhode Island, Hartford/central Connecticut, and Southwest Connecticut. The load pockets of Springfield, Rhode Island, Hartford/central Connecticut, and Connecticut as a whole are primary areas of concern in this study with respect to the ability of the existing transmission and generation systems to reliably serve projected load requirements in these areas.

"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 the region's supply resources with load centers. The major southern New England generation resources, as well as the supply provided via ties from northern New England, Hydro-Québec, 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 SNE area has experienced significant load growth, numerous resource changes, and changes in inter-area transfers.

The east–west transmission interface facilities divide New England roughly in half. Vermont, southwestern New Hampshire, western Massachusetts, and Connecticut are located to the west of this interface; while 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 transmission lines. A few underlying 115 kV facilities are also part of the interface; however, most run long distances, have relatively low thermal capacity, and do not add significantly to the transfer capability. In the early 1990s, this interface was important to monitor in day-to-day operations because of constraints in moving power from the significant generation in the west to Boston and its suburbs in the east. Following the influx of new generation in the east in the late 1990s, this interface now becomes constrained in the opposite direction, from east to west.

Supplying southern New England with electricity involves a number of complex and interrelated performance concerns. Connecticut’s potential 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 strain the existing 345 kV network. These challenges are compounded further by transmission constraints in the Springfield and Rhode Island areas under contingency conditions. The following transmission transfer capabilities are all interrelated:

- 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 interface
- Connecticut import
- Connecticut East–West interface
- Southwest Connecticut (SWCT) import

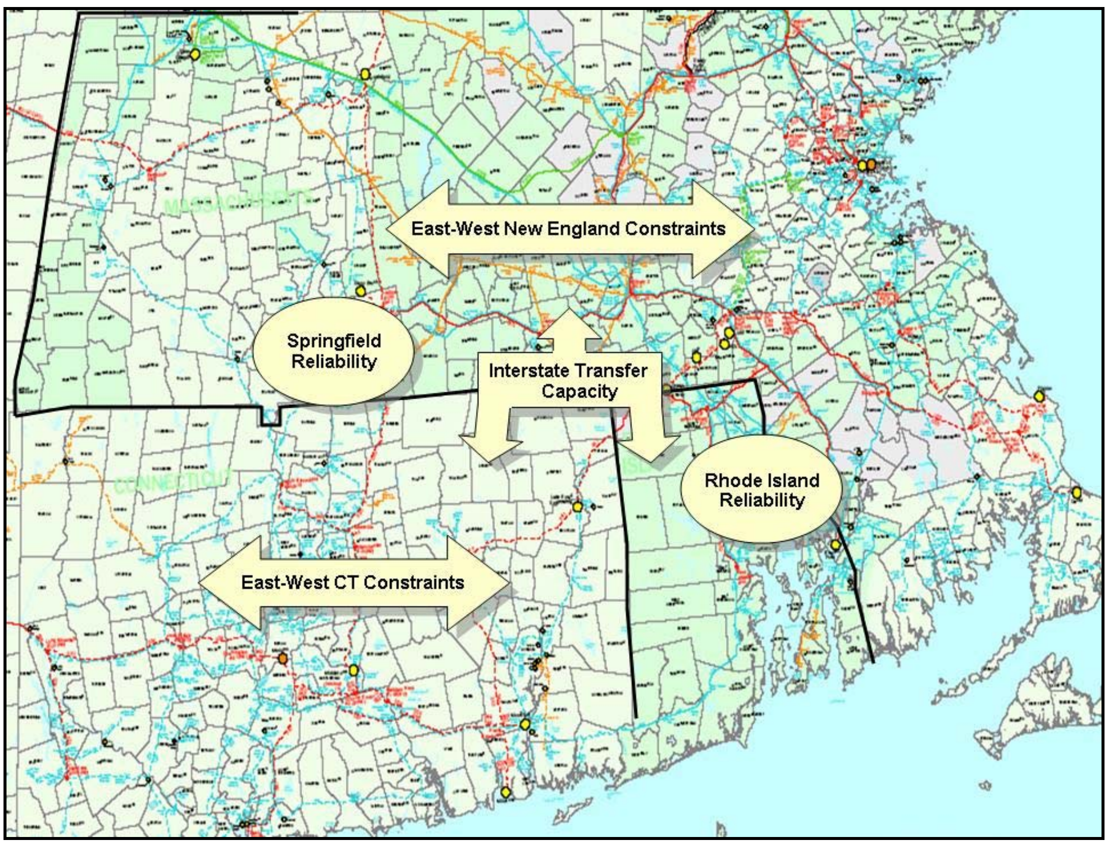
Transfers through these paths can contribute to heavy loadings on the same key transmission facilities.

These relationships exist for both thermal and stability limits. Studies have identified the relationship 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 as a result of line reclosing also have become an issue in the SNE area. These behaviors illustrate the interdependent nature of the SNE 345 kV network. Recent analyses have quantified an additional interdependence between the ability to import power into Connecticut and the ability to supply load in the Springfield area. Springfield’s reliability issues must be studied within the context of the overall southern New England analysis to not 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 existing transmission system does not allow for delivering 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. The Springfield and Rhode Island areas have additional transmission reliability concerns, both thermal limitations and voltage violations, which lead to a set of interrelated concerns with respect to the reliability of transmission service across southern New England (see Figure 1-2)."

Needs Analysis, pages 1-3.

"Figure 1-2: Southern New England subareas and constraints."



The problems illustrated in Figure 1-2 are described in the Needs Analysis as follows:

"Statements of Need

Analyses performed for the 10-year period (from 2007 to 2016) showed that on the basis of ISO planning procedures, the SNE transmission system over the 10-year study period has five major reliability concerns and a number of system deficiencies in transmission security, specifically area transmission requirements and transfer capabilities. These deficiencies form the justification for the needed transmission system improvements.

Reliability Concerns

The reliability concerns are as follows and are depicted in [Figure 1-2, above].

- **East–West New England Constraints:** Regional east–west power flows could be limited during summer peak periods across the SNE region as a result of thermal and voltage violations on area transmission facilities under contingency conditions.
- **Springfield Reliability:** The Springfield, Massachusetts, area could be exposed to significant thermal overloads and voltage problems under numerous contingencies at or near summer peak-load periods. The severity of these problems would increase as the transmission system attempts to move power into Connecticut from the rest of New England.
- **Interstate Transfer Capacity:** Transmission transfer capability into Connecticut and into Rhode Island during summer peak periods could be inadequate under existing generator availabilities for criteria contingency conditions.
- **East–West Connecticut Constraints:** East-to-west power flows in Connecticut could stress the existing system under "line-out," or N-1-1, contingency conditions (i.e., conditions under which a transmission element is unavailable and a single power system element is lost) during system peaks.
- **Rhode Island Reliability**: The system depends heavily on limited transmission lines or autotransformers to serve its peak-load needs, which could result in thermal overloads and voltage problems during contingency conditions.

Transmission Security Concerns

The analysis identified the following transmission security concerns related to meeting transfer capability and area transmission requirements:

Transfer Capability Concerns

- Power-transfer capabilities in the Connecticut area 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 conditions of generator unavailability and the loss of a single power system element (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 3,600 MW for N-1 conditions and 2,400 MW for N-1-1 conditions will be needed by 2016.
- Connecticut currently has internal elements that can limit transfers from neighboring New England states under certain system conditions. 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 overloads transmission facilities located within Connecticut that eventually tie into the new Middletown–Norwalk facilities.
- Under line-out (N-1-1) conditions and certain dispatch scenarios, the 345 kV transmission system in the southeastern Massachusetts and Rhode Island areas currently cannot support the requirements of southeast Massachusetts–Rhode Island, New England east–west, and the Connecticut power transfers following a contingency. These interfaces all have simultaneous and interrelated power-transfer limits.
- Rhode Island and Springfield have insufficient import capability to meet their load margins through 2016.
- 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 because of either an unplanned or a planned outage. As a result, numerous overloads occur in the 2009 simulations. These overloads are exacerbated when Connecticut transfers increase.

Concerns about Area Transmission Requirements

- In the Springfield area, local double-circuit tower (DCT) outages, stuck-breaker outages, and single-element outages currently can result in severe thermal overloads and low-voltage conditions.
- The severity, number, and location of the Springfield overloads and low-voltage conditions highly depend on the area's generation dispatch. Additional load growth and unit outages in the Springfield area would significantly aggravate these problems. As a result, network constraints in the Springfield area limit the system's present ability to serve local load under contingency conditions.
- Thermal and voltage violations can occur on the existing Rhode Island transmission system, dependent on unit availability and transmission outages (planned or unplanned). Relatively high load growth in the southwestern area and the coastal communities in recent years have increased the possible occurrence of criteria violations.
- The capabilities of the underlying Rhode Island 115 kV system currently are insufficient to handle the power requirements within the state following the loss of 345 kV transmission facilities, both lines and autotransformers, under certain system conditions. 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."

Needs Analysis, Executive Summary, pages iii-v.

A.4 Summary of the NEEWS Project

The reliability concerns depicted in Figure 1-2, in the Needs Analysis, above, are addressed by a combination of four separate NEEWS projects, each of which provides needed reliability improvements in its own right, but all of which are designed to work together to provide unconstrained and reliable transmission of electric power within and across New England under both normal conditions and following contingency events such as the unplanned outage of one or more transmission lines or generating plants. In general terms, the four NEEWS projects are:

- The Springfield Solution is the subject of this Springfield Solution Report. The Springfield Solution will be described in detail in this report and, without limitation, includes: the construction of new 345-kV lines along approximately 35 miles of overhead line ROW (23 miles in Massachusetts and 12 miles in Connecticut); the construction, reconstruction and upgrade of

115-kV lines along approximately 26 miles of existing overhead line ROW in Massachusetts; the separation of 345-kV/115-kV lines between Manchester Substation and Meekville Junction, South Windsor, Connecticut; and related substation improvements in both Massachusetts and Connecticut.

- The Interstate Reliability Project, which, as currently under consideration, would consist of a new 345-kV line from NGRID's Millbury Substation in Massachusetts to its West Farnum Substation in North Smithfield, Rhode Island, and a new 345-kV line west from there to CL&P's Lake Road Substation in Killingly, Connecticut, and to CL&P's Card Street Substation in Lebanon, Connecticut. Overall, the project would involve approximately 77 miles of new 345-kV lines, including approximately 16 miles in Massachusetts, 23 miles in Rhode Island, and 38 miles in Connecticut, together with related improvements to existing 345-kV and 115-kV facilities.
- The Central Connecticut Reliability Project, which, as currently under consideration, would consist of a new 345-kV line from CL&P's North Bloomfield Substation to its Frost Bridge Substation in Watertown, a distance of approximately 38 miles, together with related improvements to existing 345-kV and 115-kV facilities.
- The Rhode Island Reliability Project, which, as proposed by NGRID, would consist of an approximately 23-mile 345-kV line between its West Farnum Substation in North Smithfield, Rhode Island and its Kent County Substation in Warwick, Rhode Island, together with related improvements to existing 115-kV and 345-kV facilities.

A.5 The Springfield Solution and NEEWS: An Independent Project Designed on an Integrated and Interdependent Basis with the Other NEEWS Components

As a foundation to this Springfield Solution Report, it is necessary to appreciate the critical relationship between the Springfield Solution and the other NEEWS components. An appreciation of both the connection and the disconnection among the NEEWS parts is needed.

The relationship among the parts may appear complex, complicated by the common origins and integrated planning of all four NEEWS components. However, this degree of integration should not mask the element of independence associated with the need for each component. Each NEEWS component is needed to meet an independent sub-regional need and would be designed in some fashion to address that sub-regional need even if no other component were constructed. In short, each NEEWS component provides needed reliability improvements in its own right, but all NEEWS components are being designed to work together to provide unconstrained and reliable transmission of electric power within and across Southern New England. Each NEEWS component is independent, but all are interdependent as explain below.

No modification to the transmission system can have a significant adverse impact on other parts of the system. As a result, no modification can be designed in a vacuum. Each modification must be tested in advance to see how its addition affects the operation of the remaining system. As a fundamental part of any system modification, each NEEWS project is selected from the alternative options to make all chosen options consistent, and not in conflict, with the other[65]. In addition, with the NEEWS projects, each addresses related regional problems. As a direct result of a coordinated approach to related regional problems, each is selected to complement the others in resolving all related problems.

As a result, NEEWS components are interdependent in two senses – by design, they work consistently and not adversely, one with the others, and they work to complement each other in solving related problems. In this latter regard, the benefits of the NEEWS projects are interdependent provided that the components of NEEWS are constructed.

Being interdependent does not mean each component has lost its independence as a needed part of the transmission system. Being interdependent does not mean that each has no benefit apart from the others. If the other components are not built, each component is still needed and itself solves a specific sub-regional need which must be solved whatever the fate of the other components.

The common origins of the NEEWS components and the integrated nature of the coordinated planning among ISO-NE, NUSCO and NGRID may cause the independence of each NEEWS component to become lost from sight, from time to time or at any given moment. This is, however, not the only administrative complication. The SNETR studies were designed and executed on a fully integrated basis, so that the administrative "baskets" in which the smaller project components were placed often had more to do with geographic or planning convenience, and less to do with their technical connection to the sub-regional need being addressed. For example, all of the Connecticut 115-kV projects were grouped with the Interstate Reliability Project components as a matter of convenience, simply because the same planner was responsible for all of them.

[65] In fact, it is presently anticipated that all four NEEWS projects may apply for and receive Reliability Committee technical approvals at the same time in a common application. In fact, this common approach simply uses common sense to meet the requirements of Section I.3.9 of the ISO-NE Open Access Transmission Tariff (OATT) in the most efficient manner. Modifications to the transmission system of a Transmission Owner may not have a "significant adverse impact on the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant." Since each NEEWS component was designed to meet this basic requirement, both as to each other and as to their respective impacts on the existing transmission system, establishing these facts all at once, when the state of the existing system can be assumed to be the same relative to each NEEWS addition, is the most efficient and sensible way to meet the OATT requirements.

However, at this stage, as each of the Transmission Owners begins to assemble the various NEEWS components into separate projects to prepare individual Solution Reports and to pursue project- and state-specific siting and other approvals, each separate project must stand on its own in meeting a distinct need. Each separate project must include all elements required to provide its claimed system performance as both a separate project, and as a component of the total NEEWS plan. Each separate project must exclude elements required to meet needs which are independent of its specific NEEWS need. In this Springfield Solution Report, the Springfield Solution will be framed in this fashion. The Springfield Solution Report will start with the listing of the smaller project components formerly associated with both (i) the SNETR component for Springfield, known as the Greater Springfield Reliability Project (GSRP), and (ii) the GSRP elements which formed the Springfield 115-kV Advanced Projects (which in most cases were considered a subset of the GSRP). The Springfield Solution Report will drop smaller project components which have independent needs and add a smaller project component in Connecticut[66] after reviewing both its relationship to the Springfield area need and the other Connecticut alternatives over which it was selected.

[66] See: Section 2.2.11 for a discussion of the Manchester-Meekville line separation.

APPENDIX B

Chapter 7, ISO-NE Options Analysis (including Appendix A, Table A-4)

"7.0 Springfield Component Options

As discussed in Section 2, the Springfield, Massachusetts, area has significant transmission reliability concerns, including thermal overloads and voltage problems under numerous contingency scenarios. The severity of these problems increases as the system attempts to move power into Connecticut from the rest of New England. 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.

A wide range of transmission reinforcement options were considered to alleviate thermal and voltage problems in the Springfield area. These options included extensive 115 kV reinforcements, additional 345/115 kV transformers, new 345 kV lines, new bulk power sources, and phase shifters. Some of the reinforcement options investigated did not fully meet the area reliability requirements or were not considered to be effective long-term solutions. Other options were not sufficiently compatible with the overall SNE transmission reinforcement plans.

The working group determined that three 345 kV expansion options would fully meet the reliability requirements of the Springfield area and be consistent with the long-term expansion plans for southern New England. Each of the 345 kV options has a number of 115 kV variations, resulting in 12 distinct options. A complete listing of the upgrades that are part of these 12 options can be found in Appendix A.

7.1 Description of the Springfield 345 kV Options

The Springfield area option expansion plans include three 345 kV transmission reinforcement options that are highly compatible with the overall southern New England bulk transmission reinforcement plans. These options are as follows:

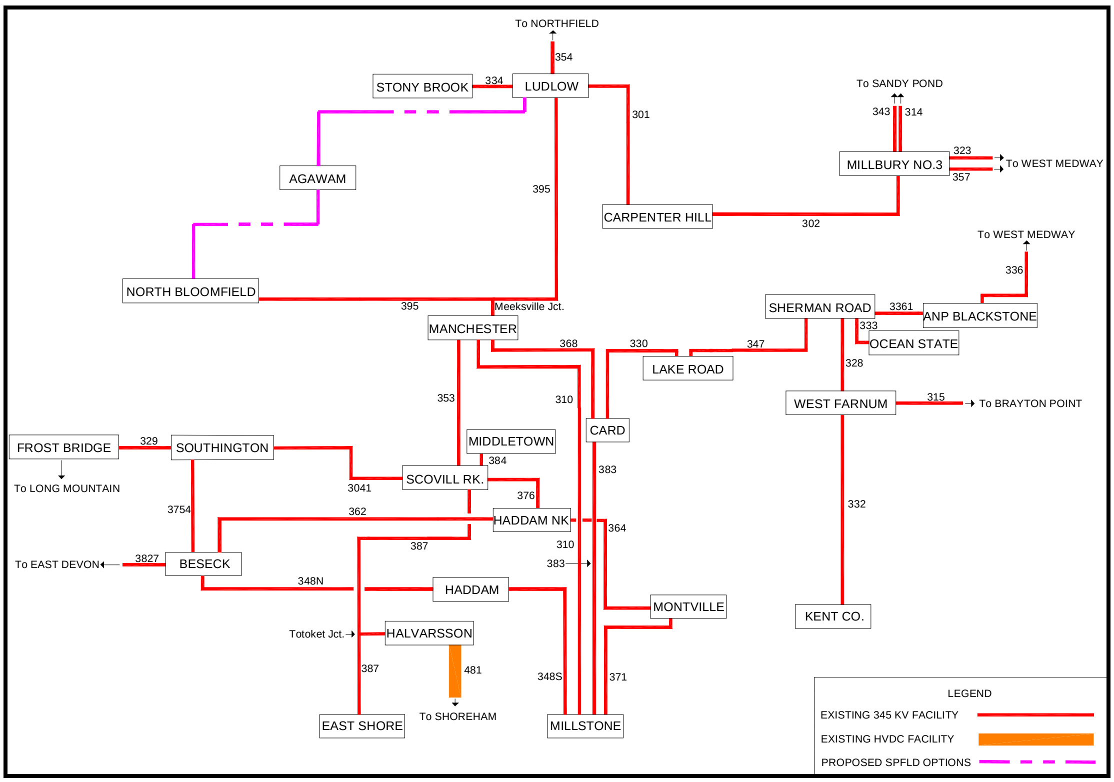
- A new 345 kV line from Ludlow to Agawam and from Agawam to North Bloomfield
- A new 345 kV line from Ludlow to North Bloomfield
- A new 345 kV line from Ludlow to Manchester

Each of the above options reinforces the electrical connection between western Massachusetts and Connecticut, which provides benefits to both the Springfield and Connecticut areas. These 345 kV options along with their associated 115 kV reinforcements all meet the required reliability standards.

7.1.1 Springfield Option A—345 kV Line from Ludlow to Agawam to North Bloomfield

This option consists of building new 345 kV lines from Ludlow to Agawam and Agawam to North Bloomfield with 345/115 kV transformation at Agawam. Springfield Option A provides another bulk transmission supply point for the Springfield area. The Springfield area requires other 115 kV transmission reinforcements to meet reliability requirements. Figure 7-1 is a 345 kV one-line diagram of Springfield Option A.

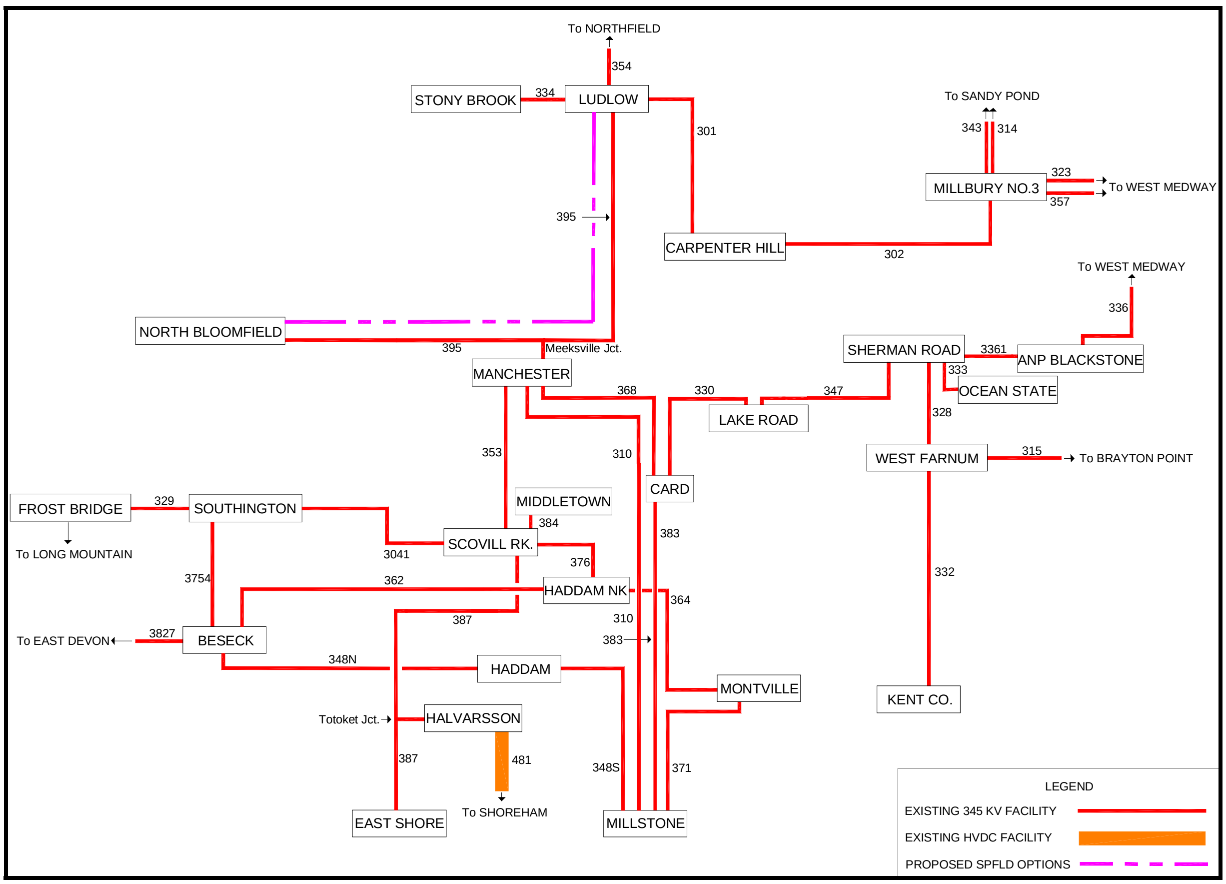
"Figure 7-1: Springfield Option A – 345 kV line from Ludlow to Agawam to North Bloomfield."



7.1.2 Springfield Option B—345 kV line from Ludlow to North Bloomfield

Springfield Option B includes building a new 345 kV line from Ludlow to North Bloomfield. It is primarily a backup to the existing 345 kV line 395, decreasing the amount of power being wheeled through the Springfield 115 kV system.[67] Springfield Option B requires phase shifters at North Bloomfield on the 115 kV ties between western Massachusetts and Connecticut to further restrain the power flow through the Springfield area. The Springfield area requires other 115 kV transmission reinforcements to meet reliability requirements. Figure 7-2 depicts the 345 kV portion of Springfield Option B.

"Figure 7-2: Springfield Option B—Ludlow to North Bloomfield 345 kV line."



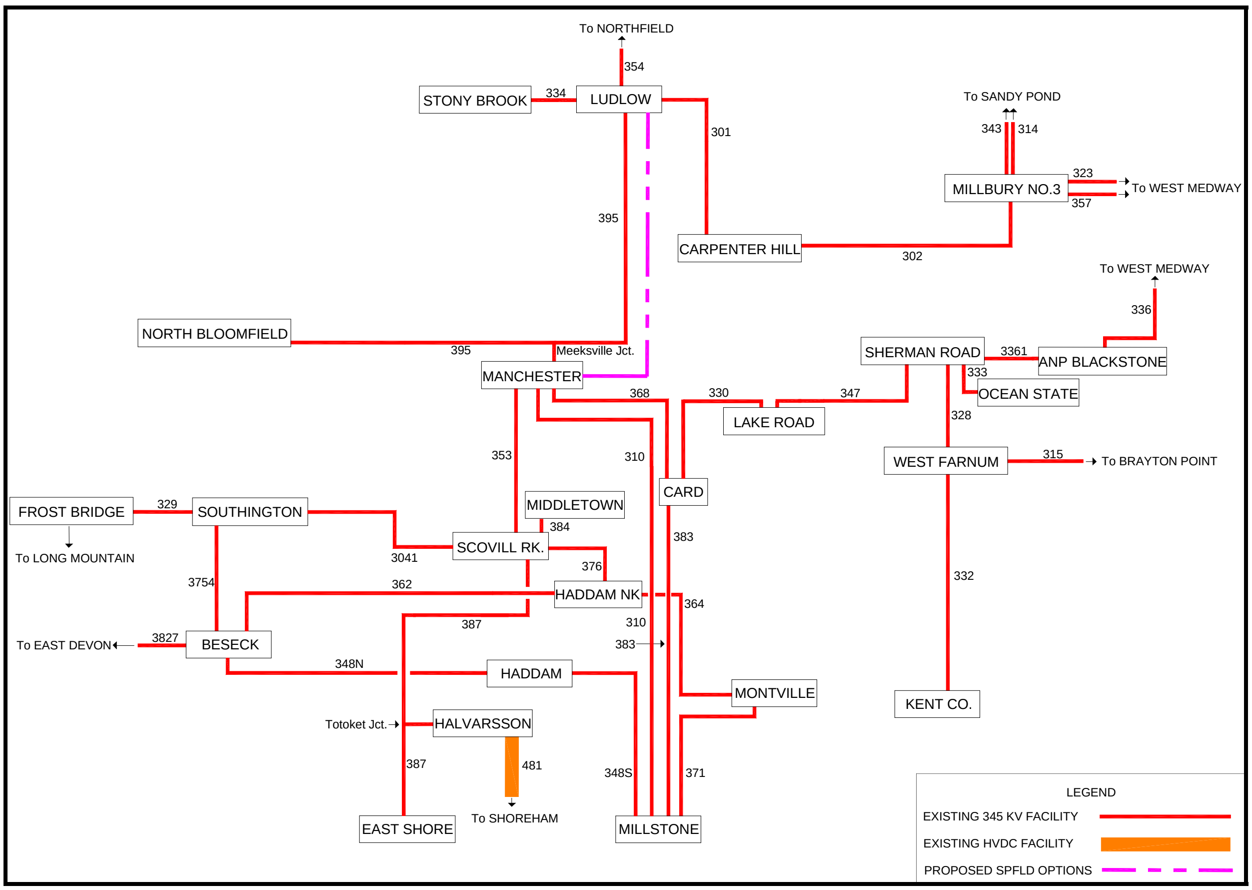
7.1.3 Springfield Option C—Ludlow to Manchester 345 kV Line

Springfield Option C consists of building a new 345 kV line from Ludlow to Manchester. It also primarily is a backup to the existing 345 kV line 395, decreasing the amount of power

[67] *Wheel through* refers to the transmission of power through an area to supply load in another area.

being wheeled through the Springfield area. Springfield Option C requires the installation of phase shifters at North Bloomfield on the 115 kV ties between western Massachusetts and Connecticut to further restrain the power flow through the Springfield area. The Springfield area requires other 115 kV transmission reinforcements to meet reliability requirements. Figure 7-3 depicts Springfield Option C.

"Figure 7-3: Springfield Option C—Ludlow to Manchester 345 kV line."



7.2 Comparison of Springfield Options

The three Springfield area 345 kV options (A, B, and C) and their various associated 115 kV reinforcement options were formulated into a total of 12 transmission reinforcement options. The following subsections discuss the features, benefits, and disadvantages of these options. Appendix A provides a complete list of reinforcements for each option.

The capital letter in each option name (A, B, or C) refers to the 345 kV solution that serves as the backbone of the option. The number and small letter following the capital letter signify the varying 115 kV improvements associated with each of the 345 kV options. Sequential numbers that appear to be missing were assigned to alternatives that were previously eliminated.

7.2.1 Springfield Option A Variations

Eight variations of Springfield Option A remained after the elimination process.

7.2.1.1 Springfield Option A Variation 3a

The major system improvements of this option, in addition to the new 345 kV lines from Ludlow to Agawam and Agawam to North Bloomfield, include three 345/115 kV autotransformers at Agawam, three 115 kV phase shifters in series with the Agawam autotransformers, and the replacement of both 115 kV cables from Breckwood to West Springfield and from Breckwood to East Springfield. This option also would separate the 115 kV ties between western Massachusetts and Connecticut in the South Agawam–North Bloomfield area.

The benefits of this option are as follows:

- Less 115 kV work would be required.
- Phase shifters would facilitate more power flow through the Agawam autotransformers, which would further limit power flow through the Springfield area system.
- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The new 345 kV source at Agawam would provide an alternate path for power to flow into the Springfield-area 115 kV system.
- The weak 115 kV western Massachusetts/Connecticut ties would be replaced with a stronger 345 kV tie.
- The North Bloomfield 2A substation would be more reliable.

One disadvantage of this option is the possibility that additional studies may need to be conducted periodically to optimize the phase-shifter settings.

7.2.1.2 Springfield Option A Variation 3b

This option is similar to the 3a variation except that it ties the Stonybrook 115 kV station into the Springfield 115 kV system. It also allows the output of the Stonybrook plant to be injected directly into the Springfield load pocket as opposed to passing it through the Ludlow 345 kV substation and down the autotransformers.

Variation 3b of Springfield Option A has the following additional benefits:

- The Stony Brook fast-start units would improve the area's nonspinning reserves.[68]
- The severity of extreme contingencies would be reduced or minimized because the Stony Brook–Fairmont lines are on a right-of-way separated from the other Springfield lines.

7.2.1.3 Springfield Option A Variation 6a

In addition to the new 345 kV lines from Ludlow to Agawam and Agawam to North Bloomfield, which is inherent to the Option A variations, this variation includes the following measures:

- Replacing the Breckwood–East Springfield 115 kV cable
- Adding a new 115 kV cable from East Springfield to Clinton
- Eliminating the three-terminal lines at East Springfield Junction (lines 1254 and 1723)
- Installing a breaker-and-one-half substation configuration at Fairmont
- Separating and rebuilding double-circuit lines from Ludlow to East Springfield
- Separating and rebuilding the double-circuit lines from East Springfield to Fairmont
- Separating the western Massachusetts/Connecticut 115 kV ties

No phase shifters would be installed with this variation, and one of the Agawam autotransformers would be replaced with a third autotransformer at Ludlow.

The benefits of this option are as follows:

[68] *Non-spinning* (non-synchronized) operating reserves are off-line, fast-start resources that can be electrically synchronized to the system and quickly reach rated capability. *Spinning* (synchronized) operating reserve is generation that already is on line, is synchronized to the system, and can increase output.

- The new 345 kV source at Agawam would provide an alternate path for power to flow into the Springfield-area 115 kV system.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The weak 115 kV western Massachusetts/Connecticut ties would be replaced with a stronger 345 kV tie.
- The North Bloomfield 2A substation would be more reliable.

One disadvantage of this option would be that the flexibility to restrain power flow through the Springfield area, which variable phase shifters provide, would not be available.

7.2.1.4 Springfield Option A Variation 6b

This option is similar to the 6a variation except that it ties the Stonybrook 115 kV station into the Springfield 115 kV system, as in the 3b variation (Section 7.2.1.2), instead of separating and rebuilding the double-circuit 115 kV lines from Ludlow to East Springfield to Fairmont.

This option has the following benefits:

- The new 345 kV source at Agawam would provide an alternate path for power to flow into the Springfield-area 115 kV system.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The weak 115 kV western Massachusetts/Connecticut ties would be replaced with a stronger 345 kV tie.
- The Stony Brook fast-start units would improve the area’s nonspinning reserves.
- The severity of extreme contingencies would be reduced or minimized because the lines from Stony Brook to Fairmont would be on a right-of-way separated from the other Springfield lines.
- The North Bloomfield 2A substation would be more reliable.

Similar to Option 6a, one disadvantage of Option 6b would be that the flexibility to restrain power flow through the Springfield area, which variable phase shifters provide, would not be available.

7.2.1.5 Springfield Option A Variation 6c

This option is similar to the 6b variation except that it installs a third 115 kV cable from West Springfield to Clinton and a new 115 kV line from Ludlow to Fairmont as opposed to tying the Stonybrook 115 kV station into the Springfield 115 kV system.

The benefits of the 6c variation of Springfield Option A are as follows:

- The new 345 kV source at Agawam would provide an alternate path for power to flow into the Springfield area 115 kV system.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The weak 115 kV western Massachusetts/Connecticut ties would be replaced with a stronger 345 kV tie.
- The North Bloomfield 2A substation would be more reliable.

Similar to 6a and 6b, one disadvantage of this option would be that the flexibility to restrain power flow through the Springfield area, which variable phase shifters provide, would not be available.

7.2.1.6 Springfield Option A Variations 8a, 8b, and 8c[69]

These options are very similar to the 6a, 6b, and 6c variations except that the third Ludlow 345/115 kV autotransformer and the Fairmont substation work is replaced with a 115 kV line from Stonybrook to Ludlow. Accordingly, the benefits and the disadvantage are similar also.

7.2.2 Springfield Option B Variations

Three variations of Springfield Option B remained after the elimination process.

7.2.2.1 Springfield Option B Variation 7a

69 This summary description of the “series 8” options appears to be in error. Language from the June 25, 2007 draft report is thought to be accurate and is re-produced here as follows: "These plan variations are similar to the 6a, 6b, and 6c variations except that lines 1254 & 1723 remain three-terminal lines at East Springfield Junction, Fairmont substation is not converted to a breaker-and-a-half arrangement, and a 115-kV line from Stony Brook to Ludlow (option 8b) is required. The benefits and the disadvantages are also similar."

In addition to adding the new 345 kV line from Ludlow to North Bloomfield, the major system improvements of this option include adding phase shifters at North Bloomfield on the western Massachusetts/Connecticut 115 kV tie lines, replacing the cable from Breckwood to East Springfield, adding a new cable from East Springfield to Clinton, eliminating the three-terminal lines at East Springfield Junction (lines 1254 and 1723), installing a breaker-and-one-half substation configuration at Fairmont, and separating and rebuilding the double-circuit lines that run from Ludlow to East Springfield and from East Springfield to Fairmont.

The benefits of the 7a variation of Springfield Option B are as follows:

- Phase shifters would help restrain the power flow through the Springfield-area 115 kV system.
- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The North Bloomfield 2A substation would be more reliable.

The disadvantages of this option are that another 345 kV connection into the Springfield load center would not be provided. Additionally, to avoid future problems and system upgrades, operating studies may need to be conducted periodically for properly adjusting the phase-shifter setting of the variable phase shifter.

7.2.2.2 Springfield Option B Variation 7b

This option is similar to the 7a variation except that it ties the Stonybrook 115 kV station into the Springfield 115 kV system, as in the 3b and 6b variations of Option A, instead of separating and rebuilding the double-circuit 115 kV lines that run from Ludlow to East Springfield to Fairmont. This option also adds a third 115 kV cable from West Springfield to Clinton.

The option has the following benefits:

- Phase shifters would help restrain the power flow through the Springfield area 115 kV system.

- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The Fairmont substation would be more reliable and better able to provide voltage support in to the surrounding area.
- The North Bloomfield 2A substation would be more reliable.
- The Stony Brook fast-start units would improve the area's nonspinning reserves.
- The severity of extreme contingencies would be reduced or minimized because the lines from Stony Brook to Fairmont would be on a right-of-way separated from the other Springfield lines.

The disadvantages of the 7b variation of Springfield Option B are the same as those for the 7a variation.

7.2.2.3 Springfield Option B Variation 7c

This option is similar to the 7b variation except that it installs a new 115 kV line from Ludlow to Fairmont as opposed to tying the Stonybrook 115 kV station into the Springfield 115 kV system.

The benefits of this variation of Springfield Option B are as follows:

- Phase shifters would help restrain the power flow through the Springfield-area 115 kV system.
- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The Fairmont substation would be more reliable and better able to provide voltage support to the surrounding area.
- The North Bloomfield 2A substation would be more reliable.

The disadvantages of this option are the same as for the 7a and 7b variations of Option B.

7.2.3 Springfield Option C Variation

Only variation 5b of Springfield Option C was deemed to be viable.

In addition to the new 345 kV line from Ludlow to Manchester, the major system improvements of this option include adding 115 kV phase shifters at North Bloomfield in series with each of the three western Massachusetts/Connecticut tie lines, replacing the 115 kV cable from Breckwood to East Springfield, and adding a new 115 kV cable from East Springfield to Clinton and a third 115 kV cable from West Springfield to Clinton. The three-terminal lines at East Springfield Junction (lines 1254 and 1723) would be eliminated, and a breaker-and-one-half substation configuration would be installed at Fairmont. This option ties the Stonybrook 115 kV station into the Springfield 115 kV system.

The benefits of this variation are as follows:

- The phase shifters would help restrain the power flow through the Springfield-area 115 kV system.
- The phase shift could be modified in the future to accommodate system configurations and conditions that are not presently foreseen.
- The Stony Brook fast-start units would improve the area’s nonspinning reserves.
- The severity of extreme contingencies would be reduced or minimized because the lines from Stony Brook to Fairmont would be on a right-of-way separated from the other Springfield lines.

The disadvantages of the 5b variation of Springfield Option C are that the Hartford area would require additional 115 kV reinforcements, including underground cable circuits; the North Bloomfield 2A substation would not be more reliable; and another 345 kV connection into the Springfield load center would not be provided. Additionally, to avoid future problems and system upgrades, operating studies may need to be conducted periodically for properly adjusting the phase-shifter setting of the variable phase shifter.

7.2.4 Input from Operations Personnel

The working group presented the details of the Springfield options to Operations personnel from ISO New England and CONVEX at a joint Planning Operations meeting. The operators, who were not presented with any information concerning cost, environmental, or routing impacts, preferred Option A, variation 6b (installing a Ludlow–Agawam–North Bloomfield 345 kV line and a 115 kV tie to the Stony Brook generating station with no phase shifters at either Agawam or North Bloomfield) for the following reasons:

- It relies less on the smaller-conductor 115 kV lines heading north out of North Bloomfield.
- The operation of phase-shifters would be burdensome (i.e., they would require daily adjustments) and add an unknown degree of operating complexity.
- It offers a 345 kV source to Agawam and provides an injection point more centrally located in the Springfield load pocket.
- It reduces reliance on the Ludlow autotransformers, which are roughly 40 years old and have a known design deficiency.
- Separating the Connecticut and Massachusetts 115 kV feeds at North Bloomfield is desired as a result of all the operating problems experienced with this through the years.
- A tie to Stony Brook allows power from Stony Brook to flow to the Springfield load center directly, even with the Ludlow substation out of service. (Currently, Stony Brook ties radially into Ludlow.)
- A tie to Stony Brook provides a redundant path for power flowing on the 345 kV to enter the Springfield 115 kV system.
- Currently, all power to the 115 kV system in this area comes through the Ludlow substation. The tie to Stony Brook will allow some power to flow directly to the 115 kV system from the generator, reducing reliance on the Ludlow autotransformers, which are roughly 40 years old and have a known design deficiency.
- Stony Brook autotransformers are single-phase banks, which can be replaced more quickly than three-phase banks at Ludlow providing greater reliability.

7.3 Springfield Component Conclusion

A wide range of transmission reinforcement options were considered to remedy problems in the Springfield area. The 12 options developed were selected for their ability to meet area reliability requirements. They all provide reliability and supply benefits to both Springfield and Connecticut and are compatible with the long-term expansion of the southern New England electric transmission system.

All the Springfield area reinforcement options include a new 345 kV connection between western Massachusetts and Connecticut as well as other associated 115 kV reinforcements to bring the Springfield area electric system into compliance with reliability standards. The main differences among these options are whether they provide another area bulk supply point, eliminate the weak western Massachusetts/Connecticut 115 kV ties, or use phase shifters to restrain power being wheeled through the area."

(Options Analysis, pages 41-52).

Options Analysis: Appendix A,

"Table A-4: Springfield Component Reinforcements"

	Springfield Option Designation											
Springfield Reinforcements	**3a**	**3b**	**5b**	**6a**	**6b**	**6c**	**7a**	**7b**	**7c**	**8a**	**8b**	**8c**
Associated 345 kV Option:	**A**	**A**	**C**	**A**	**A**	**A**	**B**	**B**	**B**	**A**	**A**	**A**
345 kV												
Build Ludlow–Agawam 345 kV circuit #1	X	X		X	X	X				X	X	X
Build Agawam–N. Bloomfield 345 kV circuit #1	X	X		X	X	X				X	X	X
Build Ludlow–Manchester 345 kV circuit #1			X									
Build Ludlow–North Bloomfield 345 kV circuit							X	X	X			
Transformers												
Install Agawam 345/115 kV transformer #1	X	X		X	X	X				X	X	X
Install Agawam 345/115 kV transformer #2	X	X		X	X	X				X	X	X
Install Agawam 115 kV phase shifters circuit #s 1–2 (in series with transformer)	X	X										
One spare 115 kV phase shifter	X	X	X				X	X	X			
Replace N. Bloomfield 345/115 kV transformer #1 (CT)	X	X		X	X	X	X	X	X	X	X	X
Install N. Bloomfield 345/115 kV transformer #2 (CT)	X	X		X	X	X	X	X	X	X	X	X
Install N. Bloomfield–S. Agawam phase shifters #s 1–2			X				X	X	X			
N. Bloomfield–Southwick phase shifter			X				X	X	X			
Reconnect Ludlow 345/115 kV transformer #1 into bay	X	X	X	X	X	X	X	X	X	X	X	X
Reconnect Ludlow 345/115 kV transformer #2 into bay	X	X	X	X	X	X	X	X	X	X	X	X

	Springfield Option Designation											
Springfield Reinforcements	**3a**	**3b**	**5b**	**6a**	**6b**	**6c**	**7a**	**7b**	**7c**	**8a**	**8b**	**8c**
Associated 345 kV Option:	**A**	**A**	**C**	**A**	**A**	**A**	**B**	**B**	**B**	**A**	**A**	**A**
Install Ludlow 345/ 115 kV transformer #3				X		X	X			X		X
115 kV												
Rebuild/reconductor Ludlow–Shawinigan				X						X		
Separate/rebuild E. Springfield–Orchard-Ludlow and E. Springfield–Ludlow				X			X			X		
Separate or rebuild W. Springfield–Agawam circuit #s 1 & 2	X	X										
Upgrade West Springfield–Agawam circuit #s 1 & 2				X		X				X		
Rebuild S. Agawam–Silver circuit #s 1 & 2 or add circuit # 3			X				X	X	X			
Rebuild Silver–Agawam circuit #s1 & 2 or add circuit # 3			X				X	X	X			
Replace Breckwood–W. Springfield cable circuit	X	X										
Replace Breckwood–E. Springfield cable circuit	X	X	X	X	X	X	X	X	X	X	X	X
Replace Breckwood reactors	X	X	X	X	X	X	X	X	X	X	X	X
Rebuild/reconductor Woodland–Pleasant line circuit #1	X		X	X	X	X	X	X	X	X	X	X
Rebuild Agawam–Piper Rd. circuit #1	X	X			X							
Install new Clinton–E. Springfield cable circuit			X	X	X	X	X	X	X	X	X	X
Clinton reactor			X	X	X	X	X	X	X	X	X	X
Install 3rd Clinton–West Springfield cable circuit			X			X		X	X			
Upgrade Ludlow–E. Springfield circuit #1						X						X
Build new Stony Brook–Ludlow 115 kV line		X									X	
Build new Stony Brook–Five Corners #s 1 & 2 115 lines		X	X		X			X			X	
Rebuild Five Corners–Fairmont #s 1 & 2 115 kV lines		X	X		X			X			X	
Build new Ludlow–Fairmont 115 kV Line						X			X			X
Disconnect CT/WMASS 115 kV ties	X	X		X	X	X				X	X	X

	Springfield Option Designation											
Springfield Reinforcements	**3a**	**3b**	**5b**	**6a**	**6b**	**6c**	**7a**	**7b**	**7c**	**8a**	**8b**	**8c**
Associated 345 kV Option:	**A**	**A**	**C**	**A**	**A**	**A**	**B**	**B**	**B**	**A**	**A**	**A**
115 kV												
Reconductor E. Springfield Jct. –Fairmont N.											X	
Separate/Rebuild 1254/1723	X									X		
Undo 3-terminal line 1254/1723 & rebuild lines from E. Sprgfld Jct. to Fairmont			X	X	X	X	X	X	X			
Separate/Rebuild (Fairmont–Shawinigan)/(Fairmont– E. Springfield)			X	X			X	X				
Reconductor E. Springfield Jct.–Shawinigan											X	X
Reconductor Fairmont–Shawinigan					X	X						
Upgrade E. Springfield Jct.–Chicopee											X	
Reconductor E. Springfield Jct. –Piper Rd	X	X									X	X
Reconductor Fairmont–Piper Rd					X	X						
Upgrade Fairmont S. –Holyoke 115			X		X	X					X	
Upgrade Pineshed–Fairmont N.												X
Upgrade Blandford–Granville Jct.	X	X	X	X	X	X	X	X	X	X	X	X
Upgrade Southwick–N. Bloomfield							X		X			
Upgrade Pleasant–Blandford			X	X	X	X	X			X	X	X
Create breaker-and-half substation at Fairmont			X	X	X	X	X	X	X			

APPENDIX C

Table C-1: Springfield Option Designation including November 28, 2007 PPA

Springfield Reinforcements	3a	3b	5b	6a	6b	PPA	6c	7a	7b	7C	8a	8b	8c
Associated 345 kV Option:	A	A	C	A	A	A	A	B	B	B	A	A	A
345 kV Transformers													
Install Agawam 345 / 115 kV Transformer #1	X	X		X	X	G	X				X	X	X
Install Agawam 345 / 115 kV Transformer #2	X	X		X	X	G	X				X	X	X
Install Agawam 115 kV Phase shifters ckt 1-2 (in series with transformer)	X	X											
One (1) spare 115 kV Phase shifter	X	X	X					X	X	X			
Replace N.Bloomfield 345 / 115 kV Transformer #1 (CT)	X	X		X	X	G	X	X	X	X	X	X	X
Install N.Bloomfield 345 / 115 kV Transformer #2 (CT)	X	X		X	X	G	X	X	X	X	X	X	X
Install N.Bloomfield - S.Agawam Phase Shifters 1-2			X					X	X	X			
N.Bloomfield - Southwick Phase Shifter			X					X	X	X			
Reconnect Ludlow 345/115 kV Transformer #1 into bay	X	X	X	X	X	G	X	X	X	X	X	X	X
Reconnect Ludlow 345/115 kV Transformer #2 into bay	X	X	X	X	X	G	X	X	X	X	X	X	X
Install Ludlow 345/ 115 kV Transformer #3				X			X	X			X		X
115 kV													
Rebuild / Reconductor Ludlow - Shawinigan				X		SN					X		
Separate / Rebuild E. Springfield-Ochard-Ludlow & E. Springfield-Ludlow				X		A		X			X		
Separate or Rebuild W. Springfield - Agawam ckt #1 & #2	X	X											
Separate or Rebuild W. Springfield - Agawam ckt #1 & #2	X	X											
Upgrade West Springfield - Agawam ckt #1 & 2				X		GN	X				X		
Rebuild S. Agawam - Silver ckt 1&2 or add ckt 3			X			ROW		X	X	X			
Rebuild Silver - Agawam ckt 1&2 **or** add ckt 3			X			ROW		X	X	X			
Replace Breckwood - W. Springfield cable circuit	X	X				G							
Replace Breckwood - E. Springfield cable circuit	X	X	X	X	X	C	X	X	X	X	X	X	X
Replace Breckwood reactors	X	X	X	X	X	C	X	X	X	X	X	X	X

Springfield Reinforcements	3a	3b	5b	6a	6b	PPA	6c	7a	7b	7C	8a	8b	8c
Associated 345 kV Option:	A	A	C	A	A	A	A	B	B	B	A	A	A
Rebuild / reconductor Woodland - Pleasant line ckt #1	X		X	X	X	G	X	X	X	X	X	X	X
Rebuild Agawam - Piper Rd. ckt #1	X	X			X	S							
Install new Clinton - E. Springfield cable circuit			X	X	X	C	X	X	X	X	X	X	X
Clinton reactor			X	X	X	C	X	X	X	X	X	X	X
Install 3rd Clinton - West Springfield cable circuit			X				X		X	X			
Upgrade Ludlow-E. Springfield circuit #1							X						X
Build new Stony Brook - Ludlow 115 kV line		X										X	
Build new Stony Brook - Five Corners 1 & 2 115 lines		X	X		X	G			X			X	
Rebuild Five Corners - Fairmont 1 & 2 115 kV lines		X	X		X	G			X			X	
Build new Ludlow - Fairmont 115 kV Line							X			X			X
Disconnect CT/WMASS 115 kV ties	X	X		X	X	G	X				X	X	X
Reconductor E. Springfield Jct. - Fairmont N.												X	
Separate / Rebuild 1254 / 1723	X										X		
Undo three-terminal line 1254/1723			X	X	X	S	X	X	X	X			
Separate / Rebuild (Fairmont - Shawinigan) / (Fairmont - E. Springfield)			X	X		SN		X	X				
Reconductor E. Springfield Jct - Shawinigan												X	X
Reconductor Fairmont - Shawinigan					X		X						
Upgrade E. Springfield Jct - Chicopee												X	
Reconductor E. Springfield Jct. - Piper Rd	X	X										X	X
Reconductor Fairmont - Piper Rd					X	S	X						
Reconductor Fairmont - Chicopee						SN							
Upgrade Fairmont S. - Holyoke 115			X		X	G	X					X	
Upgrade Pineshed - Fairmont N.													X
Upgrade Blandford - Granville Jct.	X	X	X	X	X	G	X	X	X	X	X	X	X
Upgrade Southwick - N. Bloomfield								X		X			
Upgrade Pleasant - Blandford			X	X	X	G	X	X			X	X	X
Create breaker-and-half			X	X	X	S	X	X	X	X			

Springfield Reinforcements	3a	3b	5b	6a	6b	PPA	6c	7a	7b	7C	8a	8b	8c
Associated 345 kV Option:	A	A	C	A	A	A	A	B	B	B	A	A	A
substation at Fairmont													
Rebuild Agawam - Chicopee						SN							
Clinton Ring Bus						C							
Breckwood Ring Bus						C							
Cadwell Substation						C							
2nd East Springfield - Breckwood cable						C							
C - Springfield Cables (draft 12.C)													
S - Springfield 115-kV as seen by TTF/STF Springfield Cables are part of this													
SN- Added to Springfield as result of Northern Route													
G- NEEWS GRSP as seen by TTF/STF													
GN- Added to NEEWS as result of Northern route													
A- added to Springfield 115 as a result of modified dispatch 7 as a request of ISO-NE, West Springfield #3 placed in-service													
ROW- added because of ROW constraints, worse for South route , 2-345													