SECTION 2

PROJECT BACKGROUND AND NEED

2. PROJECT BACKGROUND AND NEED

This section explains how the Interstate Reliability Project was developed as part of the NEEWS projects so that the electric supply system in Southern New England (SNE)[1], particularly in Connecticut, Rhode Island, and south-central Massachusetts, would comply with national and regional reliability standards and criteria. The section first identifies the applicable reliability standards and reviews how they evolved as the North American electric supply system was developed, then summarizes the initial development of this project and the overall NEEWS projects, and finally describes the need for the Interstate Reliability Project and how that need has evolved while the project has been in the development stage.

2.1 THE SYSTEM PLANNING PROCESS AND RELIABILITY CRITERIA

Maintaining continuity of service to customers has been a primary objective of electric utilities in North America since their very beginning. As electric supply systems have grown and become more complex, more interconnected, and increasingly critical to human welfare and a healthy economy, standards for assuring continuity of service have become mandatory and more stringent, requiring the use of increasingly sophisticated analytical tools. Today engineers using detailed and highly sophisticated and accurate computer models are able to evaluate the reliability of the existing interconnected transmission system and to plan modifications or additions needed to comply with those standards by simulating the performance of the system, as well as with proposed potential improvements to it. The following sections review the development of reliability planning standards and their current application.

2.1.1 A Brief History of Electric Reliability Planning

During the first half of the 20th Century, individual power systems each developed and applied their own planning criteria. By mid-century, however, with the dramatic growth of synchronous interconnections

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[1] For electric transmission purposes, SNE encompasses Connecticut, Massachusetts, and Rhode Island.

and the increasing use of the electric transmission system to move power over longer distances, utilities began to coordinate their planning activities.

When the Northeast Blackout of 1965 occurred, it was obvious that a more closely coordinated strategy was necessary. Shortly after the blackout, the electric utilities involved formed the Northeast Power Coordinating Council (NPCC) to promote and improve the reliability of the interconnected bulk power system in northeastern North American, including the six New England states, New York State, and the Canadian provinces of Ontario, Québec, New Brunswick, and Nova Scotia. The U.S. systems of the NPCC also formed two new power pools: the New England Power Pool, which eventually became the Independent System Operator – New England (ISO-NE), and the New York Power Pool, which evolved into the New York Independent System Operator (NYISO). Other utilities across North America also formed similar regional reliability councils, which together eventually encompassed most of the continent.

Each regional reliability council established its own reliability criteria. Each also developed procedures for assessing conformance. With time, individual electric utilities and power pools often developed their own more detailed and stringent planning and operating procedures to ensure the reliability of their portions of the interconnected bulk-power electric system; however, those procedures had to continue to be compliant with the broader regional criteria requirements.

In 1968, the U.S. regional reliability councils formed the National Electric Reliability Council (NERC) to coordinate their activities nationally and developed voluntary reliability guidelines for their collective systems. NERC has evolved over the years. In 1981, its name was changed to the North American Electric Reliability Council, to reflect the addition of Canadian members. But the most dramatic changes occurred in the wake of the August 14, 2003 Midwest/Middle Atlantic blackout. The Energy Policy Act of 2005 (EPAct) directed the Federal Energy Regulatory Commission (FERC) to establish an Electric

Reliability Organization (ERO), whose major role would be to develop and enforce mandatory reliability standards for planning and operations. After a period of study, FERC designated NERC as the ERO, and its name was changed to the North American Electric Reliability Corporation, Inc.

2.1.2 Modern Reliability Standards and Criteria

The NERC standards today are subject to approval by FERC and are much more specific than they were in the past, and compliance is mandatory under federal law. Violations are punishable by fines as high as $1 million per day per violation. Regional reliability councils may have their own criteria,[2] but these must conform to all NERC requirements – planning, system design and operations. Similarly, an Independent System Operator (ISO) and individual electric systems may also have their own criteria and procedures, but they all must conform to both NERC standards and the regional criteria. Thus, in conducting planning studies, all transmission owners in New England are required to comply with NERC standards, NPCC criteria, and ISO-NE planning procedures. Copies of these standards and criteria, and procedures, as well as the *Northeast Utilities Transmission Planning Guideline*, are included in Volume 5.

2.1.3 Simulating Contingencies

A key element of the reliability standards is the consideration of “contingency” events wherein generation and/or transmission facilities are assumed to suddenly and unexpectedly trip out of service. Such contingency events could be caused by weather; by generator, transmission line, or substation equipment failures; by contingencies on other transmission systems connected to the New England transmission system; or by some combination of these factors.

NERC, NPCC, and ISO-NE standards, criteria and procedures specify the contingencies that must be considered in planning studies. The NPCC criteria and ISO-NE procedures must be consistent with all

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[2] Although “standards” and “criteria” may be synonymous in many cases, in electric reliability planning, “standards” are correctly used to refer to the mandatory NERC standards, and “criteria” to the rules adopted by subordinate reliability organizations, which must be consistent with the NERC standards.

NERC standards. This means that NPCC criteria may be more stringent, but must as a minimum conform to the NERC standards. Likewise, ISO-NE procedures may be even more stringent, but must as a minimum conform to the NPCC criteria and NERC standards. In general, contingencies (i.e. outages of system elements) are studied to insure that, should one of the specified contingency events occur, the remainder of the system would survive without a transmission element overload, an unacceptably low voltage condition, instability, cascading outages, system separation, or loss of firm customer load.

When a generating unit or a transmission line suddenly and unexpectedly trips out of service, power flows increase instantaneously on the transmission lines that remain in-service. (This is in accordance with the laws of physics as applied to electric power systems.) Thus, an area's transmission system must be designed not only to transmit and/or import power required to offset anticipated generation deficits with all transmission facilities in service, but also must be capable of transmitting or importing power reliably following specific contingencies as required by the mandatory national standards and regional criteria. Otherwise, post-contingency power flows could exceed emergency transmission element ratings and/or result in low voltage conditions on portions of the electric system below prescribed limits.

Because each transmission line must be able to carry the additional current that would instantaneously flow in the event of the sudden loss of a generating unit, transmission line, or other system element, normal power flows on transmission lines will typically be well below the thermal ratings of the line.

Contingencies, as specified by NERC, NPCC, and ISO-NE standards and criteria, are usually characterized as loss of a single system element – that is, a generator, transmission line, bus section, etc. Sometimes, however, a single contingency can result in the loss of two transmission elements, such as where two electric circuits share a common set of towers, forming a "double-circuit tower" (DCT) transmission line. Both of these types of events are referred to as "N-1" contingency events. Another type of contingency involves the occurrence of two separate and unrelated outages within a short period of time (30 minutes per NPCC criteria and ISO-NE procedures). These are referred to as "N-1-1" events. When such a contingency event is simulated, reliability standards and criteria require an assumption that there will be sufficient time between contingency events for the system operator to implement specific "manual system adjustments" to the system before the second contingency event occurs.

Thus, the applicable standards and criteria require that in a planning study, after performing each of the required N-1 contingency analyses with all transmission facilities assumed to be initially in service, planning engineers test the ability of the system to be operated reliably with a key facility out of service. To do this, they apply a contingency; measure and document system performance prior to readjusting or reconfiguring the system (with "manual system adjustments"); then apply a second (unrelated) contingency; and then study the electric system's response. The criteria governing planning studies for the New England control area provide that, to make the system ready for the next contingency, only those manual adjustments that can be implemented within 30 minutes may be considered. These include adjusting the output of generation units, activating "quick start" generating reserves, and changing phase angle regulator taps.

To evaluate compliance with applicable reliability standards, the specified contingencies are simulated on computer models developed to represent the power grid with expected future modifications and additions, operating with projected future loads. If the simulations show that currents on a transmission element will exceed its thermal ratings (a thermal overload), or that system voltages cannot be maintained within acceptable limits following one or more of the contingencies (a voltage violation), appropriate solutions must be developed and implemented in order to maintain the reliability of the electric grid.

The specific contingencies prescribed by the NERC standards for power-flow analyses do more than demonstrate how the power grid would perform should the specific events being modeled occur. These simulations also represent stresses that could result from multiple other potential events, some of which may not even be foreseeable at present. That is, the objective of the simulations is not just to assure that the system will withstand the specific contingencies defined by the standards, under the specific conditions modeled, but to document that the system will be strong and robust enough to survive a wide range of potential events that could impose comparable stresses.

2.1.4 Generation Dispatches in Power-Flow Simulations

In accordance with the reliability criteria and procedures of NPCC and ISO-NE, the regional transmission power grid must be designed for reliable operation during stressed system conditions. Stressed conditions are simulated, in part, by developing generation dispatches. First, a base case that reflects the planners' expectation of likely resource availability in the study period is constructed. Resources may be assumed to be unavailable in the base case based on operating experience, announced retirement, or other reasons. Then, to simulate critical system conditions, at least the largest and most critical generating unit or station in an area is assumed to be unavailable. The planners may also determine that, in light of the size of the area under study or other considerations, additional units should be assumed to be unavailable. Such considerations include reducing dependence on specific local generation, and recognizing that units may be out of service for any one of a number of reasons, such as economics, equipment failure, loss of fuel supply or maintenance. Further, heightened environmental restrictions on fossil-fueled generating stations could affect continuous operation of generating units or result in the closure of one or more units at a generating station.

Thus, in a September 15, 2010 decision, the Connecticut Department of Public Utility Control (DPUC)[3] estimated that due to a combination of likely new emission rate limits and market conditions, 2,446 megawatts (MW) of oil-fired steam generation, including 1,504 MW in Connecticut, could be forced to

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[3] Effective July 1, 2011, the DPUC was consolidated with the former CTDEP as the Connecticut Department of Energy and Environmental Protection (CT DEEP). The agency is now referred to as the Public Utilities Regulatory Authority, within CT DEEP. In this document, references to the DPUC pertain to materials published by that agency prior to the July 1, 2011 consolidation.

retire by 2017.[4] Moreover, the DPUC noted that there is substantial uncertainty around these estimates, and that under certain foreseeable market conditions, retirements could exceed 4,000 MW. Recently, the owners of the 745-MW Salem Harbor Station in Salem, Massachusetts confirmed that all of the plant's units would be retired in 2014, notwithstanding requests from ISO-NE that two of the units continue to be operated for reliability reasons. ISO-NE determined that the probability that the 620-MW Vermont Yankee nuclear power station will be retired as early as 2012 is so significant that it was assumed to be retired in the "base case" power-flow simulations in ISO-NE's recent studies for the Interstate Reliability Project.

Unplanned outages of generating units are common in the electric industry. For example, in 1996 three nuclear-powered generators at Millstone Station (in Waterford, Connecticut) were shut down by order of the Nuclear Regulatory Commission, a loss of more than 2,600 MW of generating resources in Connecticut. These units remained out of service through 1997, 1998, and into 1999, and only two of the three Millstone units eventually returned to service. When ISO-NE set a record for peak winter load on January 21, 2003, eight generating units in Southwest Connecticut (SWCT), with a total capacity of approximately 1,038 MW, were unavailable due to problems associated with the extremely cold weather. Similarly, on June 30, 2008, Milford Power Units 1 and 2 tripped off line during a three-day-long forced outage of Millstone Unit 2, making about 1,470 MW of Connecticut-based generation unavailable for over 12 hours on a summer day. The Millstone Unit 2 (882 MW) was lost from service from July 3 to July 27, 2010 – nearly an entire summer month. And on four separate occasions in the last two years, two generators in the Boston area, with an aggregate capacity of 1,368 MW, were simultaneously lost from service. Most recently, on July 22, 2011, when the second highest New England historic peak load was reached, more than 1,400 MW of generation was unexpectedly unavailable due to forced outages and reductions.

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[4] DPUC Docket 10-02-07, DPUC Review of the Integrated Resource Plan, Sept. 15, 2010, at 4.

In general, modeling existing generators as out-of-service in planning studies is not conducted simply to assure that the system will be able to do without those generators in specific system conditions. This technique also tests the performance of the system under stresses that it may be required to withstand, whether from the unavailability of those specific generators or for other reasons. Generating units assumed to be unavailable or otherwise out-of-service should not be confused with the loss of a generating unit as a contingency, as described earlier. The former is a base case assumption – the system as represented before any contingency is applied. The latter is one of the many contingencies specified by the NERC, NPCC, and ISO-NE standards, criteria and procedures, which the pre-contingency system must be able to withstand without experiencing a transmission line or substation element overload, a low voltage condition, instability, cascading outages, system separation, or loss of firm customer load.

2.2 THE NEW ENGLAND BULK-POWER SUPPLY SYSTEM

The North American power systems are divided into four large synchronous interconnections or "grids." The largest of these, the Eastern Interconnection, stretches from the Canadian Maritimes to Florida, and from the Atlantic Ocean roughly to eastern Montana, Wyoming, Colorado, and New Mexico.

The New England bulk-power electric system is part of the Eastern Interconnection, and serves 14 million people living in a 68,000 square-mile area. There are more than 300 New England electric generating units, which are capable of producing a total of approximately 32,000 MW of electricity; most of these generating units are connected to approximately 8,000 miles of high-voltage transmission lines. Thirteen transmission tie lines interconnect New England with neighboring electric systems in New York and the Canadian provinces of New Brunswick and Québec. In addition to these power-supply resources and transmission interconnections, New England depends upon significant demand-reducing resources. As of the summer 2011, approximately 2,035 MW of demand-reducing resources, including "behind the meter" generators, were registered as part of the ISO-NE Forward Capacity Market. Customers in these programs agree to reduce load quickly to enhance system reliability.

FERC has designated all of New England as a single operating control area, and has designated ISO-NE as the independent system operator for the region. As such, ISO-NE is responsible for operating New England's bulk-power generation and transmission system, overseeing and administering the region's wholesale electricity markets, and managing the regional bulk-power system planning process.

In 1971, the New England Power Pool was formed to coordinate planning and operation of the New England power grid. The New England power grid now integrates resources with the transmission system to serve all regional load, regardless of state boundaries. Most of the transmission lines are relatively short and networked as a tightly integrated grid. Therefore, the electrical performance of one part of the system may affect other areas of the system.

The New England region reached a new record summer peak load of 28,130 MW on August 2, 2006, due to the extreme temperatures and humidity throughout the region. In accordance with ISO-NE operating procedures, demand-response programs were activated, and this action reduced the peak demand for electric power by approximately 640 MW. In the absence of these programs, the peak load would have been 28,770 MW. Although this peak load level has not been exceeded since 2006, it has been approached. Notwithstanding the current economic downturn, the 2010 summer peak load, reached on July 6, 2010, was 27,100 MW. On July 22, 2011, load peaked at 27,702 MW – the second highest peak ever recorded in New England. This load was net of 643 MW of real time demand resources that were dispatched by ISO-NE.

Normal dispatch, considering economics, generation availability, and transactions with neighboring systems, can result in multiple intra-New England power transfers of varying direction, magnitude, and duration. The development of about 9,500 MW of new generation in New England since 1999, without commensurate transmission system upgrades, has resulted in situations where surplus generation in one subarea may not be deliverable to other subareas and may not be operable with other generation in the sub-area or region.

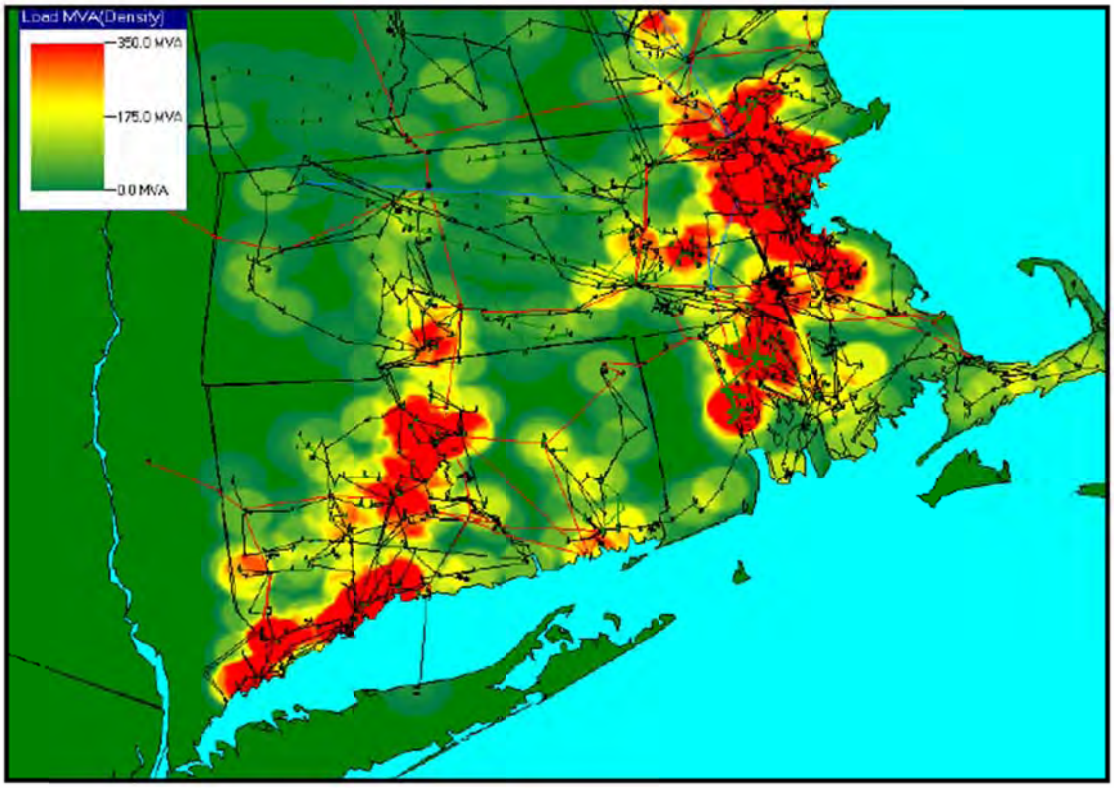
Generation in New England is not dispatched based on utility service areas or political jurisdictions. Rather, New England in its entirety is dispatched on a “single-system” basis. Transmission constraints can however constrain the optimal generation dispatch. Such constraints on the dispatch of generation can result in higher overall costs under normal conditions, and in reliability problems under contingent conditions.

2.3 BULK-POWER SUPPLY IN SOUTHERN NEW ENGLAND

The SNE area accounts for approximately 80% of the total New England load. Customer load in SNE exceeds available local generation capacity. Accordingly, power is routinely transmitted to SNE from generators in Northern New England and Canada.

As shown in Figure 2-1, the SNE load is concentrated in Boston and its suburbs, central Massachusetts, and Springfield, Massachusetts; Rhode Island; Hartford, Connecticut, and Southwest Connecticut. Such areas of load concentration are called “load pockets” if some portion of customer load demand must be met by local generation resources because the transmission system is not adequate to reliably import all the power needed to meet customer load requirements from other parts of the transmission system. Connecticut as a whole is a “load pocket.”

Figure 2-1: Southern New England Load Concentrations



Source: ISO 2008 Needs Report.

The 345-kV transmission network in SNE is the area of particular interest for this Application. Figure 2-2 illustrates this 345-kV transmission network, as it will be constituted with the completion of two of the NEEWS projects that are now under construction (i.e., the Greater Springfield Reliability Project [GSRP][5] and the Rhode Island Reliability Project [RIRP]).

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[5] GSRP was reviewed and approved by the Council under Docket No. 370.

Figure 2-2: Southern New England 345-kV System, Geographic Overview

Notes:
[1] 345-kV lines, substations, and switching stations are shown in red.
[2] Generating stations are shown in yellow.

2.3.1 Transmission Interfaces

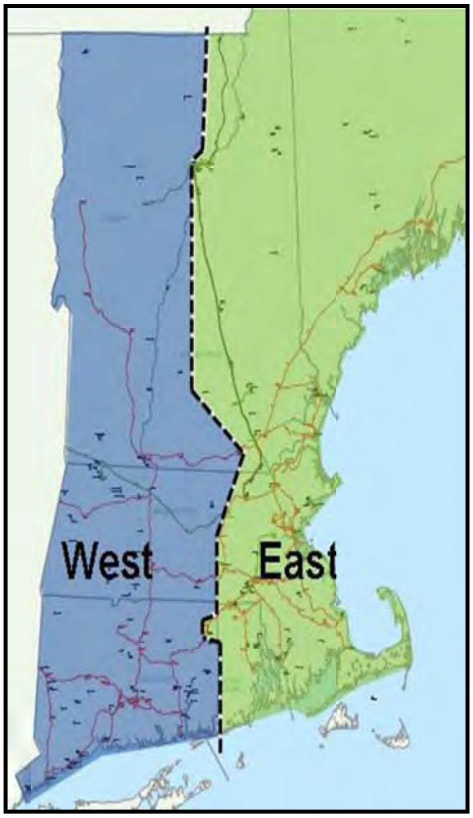
"Interfaces" are sets of designated transmission facilities that can be used to reliably transfer power, within defined limits, from one area to another. They can be visualized as "boundaries" between areas of the system – all transmission lines that cross such a boundary are by definition part of that interface. The transfer capability across an interface depends on the power flows that all of the transmission elements crossing the interface can carry without violating prescribed limits of system stability, current carrying capability, or permissible ranges of voltage. Transfer capabilities are expressed in terms of the power flow that the transmission elements can safely carry under normal conditions, and that which they can carry under defined contingency conditions. Since system conditions, such as load and the amount and location of available generation, can vary significantly from day-to-day and sometimes from hour-to-hour, transfer capabilities across an interface are properly expressed as a range of values. These transfer limit values will always be much lower than the sum of the individual current carrying capacities of each of the transmission elements that make up the interface. This is because the system must be planned to withstand the potential contingent loss of any of the elements of the interface, and for the overlapping loss of a second element within 30 minutes of the first contingency event. When such contingent events occur, the power flowing on the element lost from service automatically redistributes onto the remaining elements of the system.

Interface transfer limits are important tools for transmission planning studies. ISO-NE establishes transfer limit levels for each New England interface for use in planning studies. The limits are expressed as a range, since they will vary with system conditions. Transfer limits are published annually in FERC Form 715, and are considered the “applicable” limits for use in planning studies. However, when the object of the studies is to define and, if necessary, improve interface transfer capability, a different approach is used. Rather, the actual transfer capabilities that result from modeled system conditions are determined, and if the existing transfer capability is insufficient to comply with reliability requirements, then system improvements are designed to increase transfer capability.

2.3.2 The New England East – West Interface

Electrically, New England consists of two large operating areas, divided by the New England East –West Interface. In its traditional configuration, this interface roughly corresponds to the boundaries of the service areas of major electric utilities, and divides New England approximately in half, separating the load centers of the Southeast Massachusetts Area (SEMA)/Boston area and Connecticut. The interface follows the Connecticut – Rhode Island border (except for a jog around the Lake Road Generating Station in northeast Connecticut), then passes through Massachusetts, just west of the Millbury, Massachusetts hub, proceeds northeast into New Hampshire, west of the major generating facilities in southern New Hampshire, and then extends north through New Hampshire and Vermont, westerly of the high-voltage direct current (HVDC) line from Québec and its terminal facilities. The location of this interface is illustrated in Figure 2-3.

Figure 2-3: Approximate Boundary of New England East – West Interface



Three 345-kV transmission lines currently cross this interface. In addition, there are two 230-kV transmission lines, and a few underlying 115-kV facilities. Most of the 230-kV and 115-kV facilities extend for long distances, have relatively low thermal capacity, and do not add significantly to the transfer capability of the interface.

In the mid-1980s and early 1990s, monitoring the New England East-West Interface was important in day-to-day operations because of constraints in moving significant amounts of power from generating stations located in the west (including four nuclear generating units in Connecticut) to Boston and its suburbs in the east. At that time, Connecticut was a net exporter of power.

However, in the late 1990s, following the influx of new generation in the east and the long-term loss of four Connecticut nuclear generating units, this interface became severely constrained in the opposite direction, from east to west, as Connecticut became a large net importer of power. Following this period, only two of the Millstone generating units (units 2 and 3) returned to service in the late 1990s. Both Connecticut Yankee and Millstone Unit 1 were retired. Since then, approximately 2,000 MW of new generating capacity has been built or committed pursuant to ISO-NE's Forward Capacity Auction process in locations to the west of the interface, mostly in Connecticut. However, the addition of these new resources will not eliminate the constraints of the interface. To the contrary, as recent studies by ISO-NE (discussed later in this section) have demonstrated, under existing and anticipated future conditions, power flows across the interface may be constrained in both directions, so that power generated to the west of the interface and needed in the east – or vice versa – cannot be delivered under conditions for which the system must be planned.

As explained in Section 2.5.2, the New England East-West Interface is constrained under some system conditions. The Lake Road Switching Station (Connecticut) to Sherman Road Switching Station (Rhode Island) to West Medway Substation (Massachusetts) 345-kV lines are required to do the double duty of serving as a transportation corridor between eastern and Western New England (and between Connecticut and Rhode Island and Rhode Island and southeast Massachusetts), while simultaneously moving the power from four generating stations with an aggregate summer capacity of approximately 2,000 MW. These generators were constructed in recent years, following the restructuring of the electric power industry. As a result, system operators today protect against contingent overloads on the New England

East-West, Connecticut-Rhode Island and Rhode Island-SEMA interfaces by shifting the point along the Lake Road – Sherman Road – West Medway corridor where power flow is monitored, depending on whether power is flowing toward Connecticut or toward Massachusetts. Thus, the interface boundary shifts according to power-flow direction.

2.4 DEVELOPMENT OF THE INTERSTATE RELIABILITY PROJECT

The Project proposed in this Application is the product of more than six years of planning studies. The phases of these studies, and the results of each of them, are explained in the following sections.

2.4.1 The Southern New England Transmission Reliability Studies and the NEEWS Plan (2004-2008)

The existing 345-kV transmission line on the ROWs between CL&P's Card Street Substation in Lebanon, Connecticut and the Rhode Island border was constructed in the early 1970s and was looped into the Lake Road Switching Station and Killingly Substation when those facilities were constructed in 2002 and 2006, respectively. Prior to constructing that line, CL&P had acquired a ROW that was generally 300 feet wide because it then anticipated a future need to accommodate additional lines. In 2004, Northeast Utilities Service Company (NUSCO)[6] began planning and routing studies for a possible second 345-kV line from the Card Street Substation to National Grid's Millbury Switching Station in Millbury, Massachusetts, with a potential connection to National Grid's Sherman Road Switching Station in Burrillville, Rhode Island, and with a connection to the Lake Road Switching Station in Killingly, Connecticut. Also in 2004, ISO-NE, in conjunction with NUSCO and National Grid planners (collectively, the "Working Group") together with outside consultants, embarked on a coordinated series of studies of the deficiencies in the SNE electric supply system. These studies were collectively called the Southern New England Transmission Reliability (SNETR) study.

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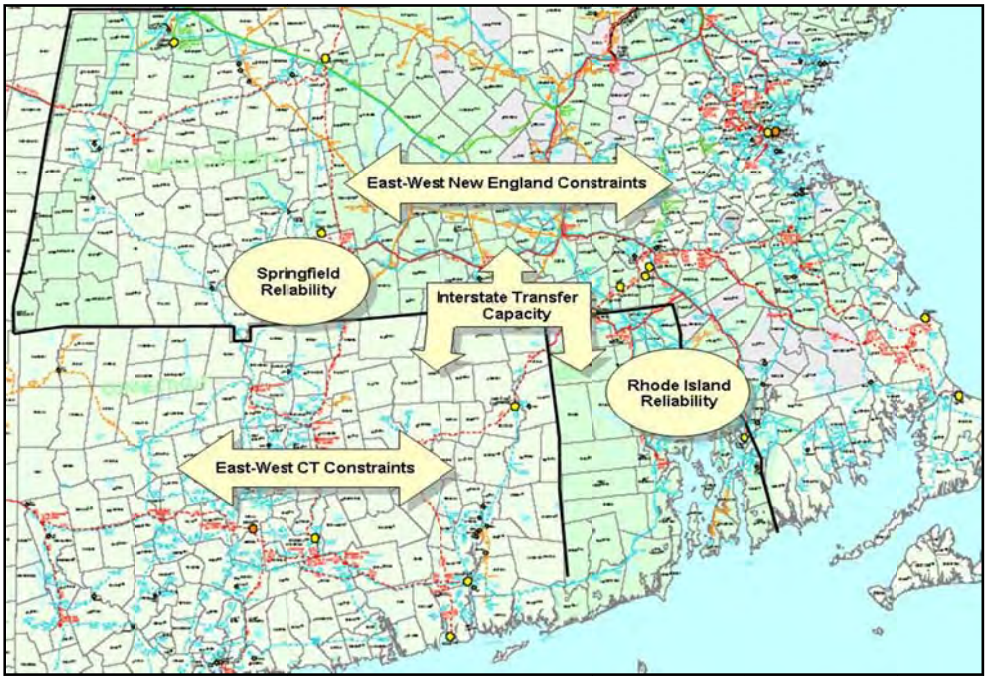
[6] CL&P is a wholly-owned subsidiary of NU, as is NUSCO. NUSCO provides services to CL&P, including transmission planning, design, and permitting work.

When the SNETR study was undertaken, the Southwest Connecticut and National Grid transmission system improvements previously described were planned or under construction, and were expected to be in-service by 2009. The SNETR study therefore assumed the completion of these projects, and sought to identify additional improvements that would be required to assure compliance with mandatory reliability standards by addressing problems expected to arise at least through 2016. Initially, these studies considered limitations on east-west power transfers across SNE, and transfers between Connecticut and southeast Massachusetts and Rhode Island – limitations that are addressed in large part by the proposed Project. These limitations were first identified as interdependent (that is, as affecting one another) in ISO-NE's 2003 Regional Transmission Expansion Plan (RTEP03).

In the course of these studies, the SNETR Working Group determined that other, previously identified reliability problems in Greater Springfield and Rhode Island were not simply local issues, but were also affected by interstate transfer capabilities. In addition, the planners discovered constraints in transferring power generated in (or imported into) eastern Connecticut across central Connecticut to the concentrated load in Southwest Connecticut. The cluster of reliability problems identified by the SNETR study is illustrated in Figure 2-4.

Figure 2-4: Southern New England Subareas and Constraints



As finally developed, the SNETR study addressed all of these interrelated problems and recommended transmission solutions. The transmission projects that emerged from this planning process were collectively referred to as the NEEWS Plan.

The four principal projects that comprise the NEEWS Plan are described below:

- The **Interstate Reliability Project**, which is the subject of this Application.
- The **Greater Springfield Reliability Project** (GSRP) 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 27 miles of overhead line ROW in Massachusetts; and related substation and switching station improvements in Massachusetts and Connecticut. This project was approved by the Council and by the Massachusetts Energy Facilities Siting Board in 2010, is currently under construction, and is planned to be in service in December 2013. In the proceeding in which it approved the GSRP, the Council also approved a separate but related **Manchester to Meekville Junction Project**, which strengthens the Connecticut 345-kV system by constructing transmission improvements along 2.7 miles of ROW in Manchester, Connecticut.

- The **Rhode Island Reliability Project** (RIRP), as proposed by National Grid, includes the construction of a new 345-kV line along 21 miles of existing overhead line ROW, extending from its West Farnum Substation in North Smithfield, Rhode Island to its Kent County Substation in Warwick, Rhode Island. It also includes a number of related improvements to existing 115-kV and 345-kV facilities. This project was approved by the Rhode Island Energy Facility Siting Board in 2010, and is expected to be in service in the fourth quarter of 2012.

- The **Central Connecticut Reliability Project** (CCRP), would have included the construction of a new 345-kV line along 38 miles of existing overhead line ROW, extending from CL&P's North Bloomfield Substation in the Town of Bloomfield to its Frost Bridge Substation in the Town of Watertown, together with related improvements to existing 345-kV and 115-kV facilities are also included. This project is currently under review by ISO-NE as part of the Greater Hartford / Central Connecticut (GHCC) study, which is examining both the problems that would be addressed by CCRP and other potential problems.

The following summarizes the electric transmission system deficiencies identified by the SNETR studies, and how they were addressed by the original NEEWS Plan:

- **Rhode Island Reliability**. Transmission system reliability and dependence on local generation were the major concerns for the Rhode Island system. System modeling demonstrated that a number of overload and voltage violations could occur on the Rhode Island transmission facilities following contingency conditions. These problems were caused by several contributing factors, both independently and in combination, including: high load growth (especially in southwestern Rhode Island and its coastal communities), generating unit unavailability, and transmission outages (planned or unplanned). It was determined that the addition of the new 345-kV line from West Farnum Substation to Kent County Substation and other associated improvements would both greatly improve the reliability of the state's transmission system and reduce dependence on local generation. New 345-kV lines from Millbury Switching Station to West Farnum Substation, and from West Farnum Substation to Lake Road Switching Station, would serve a dual role of both improving Rhode Island reliability and providing an essential component of the new 345-kV Interstate Reliability Project, as discussed herein.

- **Greater Springfield Reliability.** The GSRP addresses overloads and voltage violations on the existing Greater Springfield 115-kV system by improvements to that system and the construction of a new 345-kV line, substation modifications, and new switching stations. Together with the existing 345-kV line between the North Bloomfield, Barbour Hill, Ludlow and Manchester Substations, the new North Bloomfield – Agawam – Ludlow 345-kV line will complete a 345-kV "loop" through north-central Connecticut and western Massachusetts. This new high-capacity loop will relieve congestion on the 115-kV system that currently serves the Springfield area and will support interstate power transfers between the North Bloomfield, Barbour Hill and Ludlow Substations. At the same time, the new line will increase the power-transfer capability between Connecticut and western Massachusetts. The completed high-capacity electrical loop will serve a function analogous to that of a multi-lane circumferential highway constructed around an urban area where previously all highways had terminated at the edges of the city, requiring that traffic traverse congested city streets to gain access to the next section of highway.

- **Regional East–West Power Flows.** Regional power flows across New England were found to be limited due to the potential overloading of existing 345-kV lines that traverse Connecticut, Massachusetts and Rhode Island from east to west, and by potential voltage violations at substations served by those lines.

- **Connecticut Import Limitations.** Power transfers into Connecticut were found to be limited, such that they could eventually result in the inability to serve load under many contingencies that the system must withstand in order to comply with national and regional reliability standards and criteria. The Working Group determined that construction of additional 345-kV ties to Rhode Island and Massachusetts would greatly improve the system's ability to serve the load by providing additional paths on which power may flow in the event of a planned or unplanned loss of a system element, such as a transmission line or generating unit, and thus significantly increase power transfer capabilities into Connecticut.

- **Connecticut East-West Transfers.** Load in Connecticut is heavily concentrated in SWCT, whereas Connecticut's generation resources are concentrated in the eastern part of the state. The SNETR studies recognized that completion of a 345-kV loop serving SWCT in 2008 would enable power to move freely through SWCT, and that the construction of the Interstate Reliability Project and the GSRP would enable the import of sufficient power to provide reliable service to the entire state, including SWCT. However, the increased power flows across central Connecticut to serve the growing load were projected to result in overloads on existing transmission lines under contingency conditions. This "bottleneck" between eastern Connecticut and western Connecticut would be eliminated by the addition of another 345-kV connection between these areas. The 345-kV connection provides a less constricted path for power generated in eastern Connecticut and/or imported from generation resources central/eastern Massachusetts and Rhode Island to flow into western Connecticut thus reducing the amount of power that must presently flow through the lower capacity Hartford/Springfield 115-kV transmission system.

The Working Group's analysis and conclusions are summarized in two reports. The first of these reports is entitled *Southern New England Transmission Reliability Report – Needs Analysis* (the *2008 Needs Analysis*). That report was first published in draft form for stakeholder comment on the ISO-NE website in 2006, and was issued in final form in January 2008. The *2008 Needs Analysis* describes the related problems in SNE, which the NEEWS projects have been planned to address. The second report is entitled *New England East-West Solutions (Formerly Southern New England Transmission Reliability) Report 2, Options Analysis* (*Options Analysis*). The *Options Analysis* was issued in its final form in April 2008. It describes five sets of transmission "Options" that the Working Group had determined could provide a solution for the problems identified in the *2008 Needs Analysis*. Copies of each of these reports were provided with CL&P’s 2008 Municipal Consultation Filing for the Project, and additional copies are provided in Volume 5.[7]

Each set of Options related to a transmission system component that would address at least one of the identified system deficiencies by itself, and would work together with other components to provide a coordinated resolution of region-wide issues. ISO-NE tasked NU and National Grid, as transmission owners (TOs), to develop a set of compatible preferred Options for each component of the NEEWS Plan by further analyzing the technical advantages and disadvantages of the options identified in the *Options Analysis*, and their comparative cost, constructability, and routing aspects, so that selections could be made on the basis of all pertinent information. That further analysis, as it pertains to the Project, is described in a third report, *“Solution Report for the Interstate Reliability Project”* dated August, 2008, a copy of which is also provided in Volume 5.

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[7] The version of each report that is provided has been redacted by ISO-NE, in accordance with federal Homeland Security regulations, to avoid the disclosure of information determined to be Confidential Energy Infrastructure Information (CEII). Unredacted reports will be provided to the Council and to qualified participants in the proceedings on this Application, pursuant to the Council’s rules that preserve the confidentiality of CEII.

2.4.2 Re-Evaluation of the NEEWS Projects, 2008-2010

ISO-NE is obliged by Section 4.2(a) of Attachment K to its FERC-approved Open Access Transmission Tariff to update its needs assessments as new resources materialize through the Forward Capacity Auction process. In accordance with this requirement, ISO-NE undertook needs reassessments for all four of the NEEWS components in 2008. The reassessment was undertaken before the start of siting hearings for the RIRP, which was the first component of the four NEEWS projects to proceed to siting. The needs reassessments for the RIRP and the GSRP were completed, presented to the ISO-NE Planning Advisory Committee (PAC)[8], and provided in support of the applications in both the RIRP and the GSRP state siting proceedings. As previously noted, both of these projects have received their siting approvals in 2010 and are now under construction.

The re-evaluations of the Interstate Reliability Project and the Central Connecticut Reliability Project were complex and required more time. The Interstate Reliability Project re-evaluation was not substantially completed until the summer of 2010, and was presented to the PAC in August and November of 2010. The CCRP re-evaluation is underway and has expanded into a more regional review including the greater Hartford area.

Since the original (2008) SNETR *Needs Analysis* was finalized in 2008, there have been significant developments affecting electric system supply and demand that could be expected to affect the need for the Interstate Reliability Project, and therefore required a reevaluation of that need. Approximately 2,000 MW of new generation resources have been built, or committed to be built, through ISO-NE’s Forward Capacity Auction process, in Connecticut and other areas west of the New England East-West Interface. (Refer to Figure 2-5).

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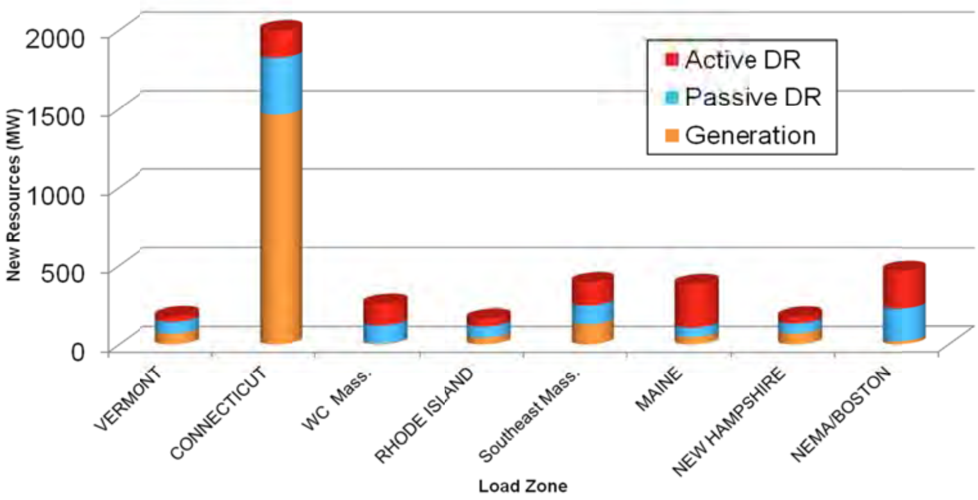
[8] The ISO-NE PAC is an advisory committee open to all parties interested in regional system planning activities in New England. ISO-NE is required by its FERC-approved tariff to conduct an open and transparent planning process. Pursuant to this requirement, ISO-NE presents to the PAC the scope of work, assumptions, and draft results for its annual Regional System Plan and for supporting studies, including Needs Assessments and Solution Studies, and considers the comments of the PAC members in developing its final plans and recommendations.

Figure 2-5: Resource Additions by Load Zone Since 2008 Needs Analysis[9]



Further, the *2008 Needs Analysis* had been based on 2005 vintage CELT[10] load forecasts and, largely because of the subsequent economic downturn, more recent load forecasts have been lower. However, the original Needs Assessment considered a load projected by ISO-NE's 2005 CELT forecast to occur in 2009, whereas the re-evaluation considered system conditions beginning in 2015 – as a practical matter the first full year in which the Interstate Reliability Project could be in-service in light of its deferral for further study. The 2010 load forecast for 2015 was actually higher than the 2005 vintage forecast for 2009 (30,000 MW) that initially showed the criteria violations identified in the *2008 Needs Analysis*. This relationship is shown in Figure 2-6.

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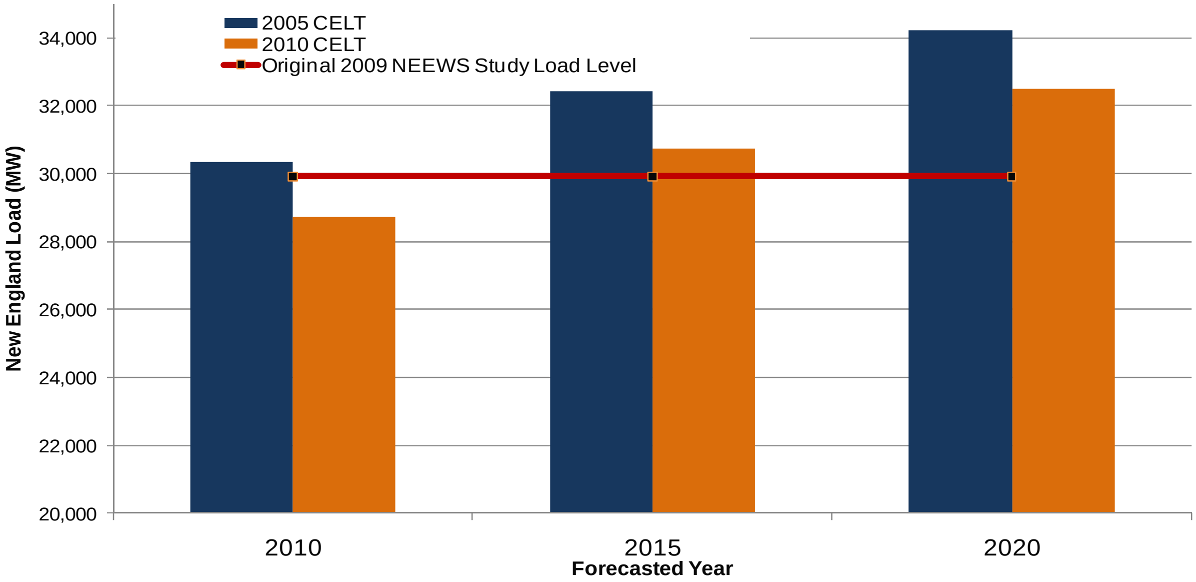
[9] DR stands for Demand Response, which is a temporary change in electricity consumption by a demand resource in response to market or reliability conditions. Passive Demand Resources (Passive DR) save energy (MWh) when on during peak hours and are not dispatchable. Active Demand Resources (Active DR) are designed to reduce peak loads (MW) and can reduce load based on real-time system conditions or ISO instructions. Generation is any electric generating or storage facility using any fuel, including nuclear materials, that furnishes electricity (but not including an emergency generating device). Figure 2-5 is extracted from the *2011 Needs Reanalysis.*

[10] ISO-NE publishes annually its Forecast Report of Capacity, Energy, Loads, and Transmission, known as the CELT Report.

Figure 2-6: Comparison of Original NEEWS Load Level to 2005 & 2010 CELT Forecasts



2.5 THE 2011 NEEDS RE-ANALYSIS

The detailed assumptions, analyses, and results of ISO-NE's re-study of the need for the Interstate Reliability Project are set forth in a report entitled: *New England East-West Solution (NEEWS): Interstate Reliability Project Component Updated Needs Assessment*, April 2011 (the *2011 Needs Re-analysis*). A copy of that report, redacted to avoid disclosure of CEII, is provided in Volume 5 of this Application. An unredacted copy will be provided to qualified parties and intervenors in the Council proceeding, pursuant to the Council's rules protecting the confidentiality of CEII.

The *2011 Needs Re-analysis* re-confirmed the existence of serious thermal and voltage violations in Connecticut, Massachusetts and Rhode Island starting as early as 2015. It also confirmed specifically a need for increased transfer capability into Connecticut.[11] However, the most striking results of the re-analysis concerned transfer capability across the New England East-West Interface. In addition to

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[11] As previously noted, the original need for the Interstate Reliability Project component of NEEWS was based, in large part, on a deficiency in the system's capability to move power from Eastern New England to Western New England and into Connecticut. While Connecticut's need for increased import capability has since been mitigated by the commitment of new local generation resources and load growth lower than expected, the *2011 Needs Re-analysis* concludes that a Connecticut load serving problem would still exist under N-1-1 conditions in 2015.

confirming the previously documented deficiency in the system's capability to move power across that interface from resources in the east to load in the west, it documented a new problem of insufficient transmission capability to move power from newly constructed generation resources in the west to load centers in the east.

2.5.1 Summary of Re-Analysis Testing

ISO-NE performed various power-flow simulations to model system conditions projected to exist in 2015 and 2020. The results of these studies showed that the Project is needed to maintain system reliability.

2.5.1.1 Power-Flow Modeling Assumptions

The assumptions built into the power-flow modeling are set forth in detail in the *2011 Needs Re-analysis*. In summary, all transmission projects with ISO-NE Proposed Plan Application approvals as of the June 2010 Regional System Plan Project listing were included in the base case. These projects included two NEEWS projects - the GSRP and the RIRP. They did not include the CCRP, which is being re-evaluated, or the Interstate Reliability Project, which was the subject of the study.

Both existing generation plants and new projects expected to be in-service during the study years, because they have accepted a Forward Capacity Market (FCM) Capacity Supply Obligation, were included in the study base case. However, the Vermont Yankee nuclear power station was not included because of the significant uncertainty concerning its continued operation after 2012. On the other hand, the 745-MW Salem Harbor Station, located on the north shore area of Massachusetts, was included in the base case, and modeled as out-of-service only in a sensitivity analysis. More recently, the owners of Salem Harbor have confirmed that it will be retired in 2014, and ISO-NE has directed the New England transmission owners not to include Salem Harbor in any reliability studies for any year after 2014. Active Demand Resources that have cleared the FCM were also modeled as capacity resources.

In accordance with ISO-NE planning procedures, the modeled load was based on the 90/10 weather forecast in ISO's 2010 CELT load forecast. These values were 31,810 MW for all of New England in 2015 and 33,555 MW in 2020, allocated among the New England states as shown in Table 2-1 below:

Table 2-1: 2010 90/10 CELT Load

State	2015 Load (MW)	2020 Load (MW)
Maine	2,275	2,400
New Hampshire	2,750	2,957
Vermont	1,138	1,205
Massachusetts	14,160	14,952
Rhode Island	2,098	2,208
Connecticut	8,112	8,486
Total*	**31,810**	**33,555**

*after adjustment for transmission losses

The modeled loads[12] were based on the 2010 CELT forecasted loads, but were adjusted downwards to reflect the effect of passive and active demand response measures. Finally, generator dispatch scenarios in each sub-area under study were constructed. In this set of studies, ISO-NE assumed the two largest generation resources in the study area to be out-of-service as part of the base case.

2.5.1.2 Power-Flow Modeling Results – Thermal Criteria and Voltage Violations

Numerous thermal criteria violations were found in New England for N-1 and N-1-1 contingency events. These violations occurred when the system attempted to deliver power from western New England to serve load in eastern New England, and when it attempted to move power from eastern New England to serve load in western New England. Overloads also occurred within Connecticut and Rhode Island. The detailed results are provided in the *2011 Needs Re-analysis*.

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[12] Since the *2011 Needs Re-analysis* was begun, the 2011 CELT report was published. The forecasted 2015 and 2020 loads in this report are higher than those predicted in the 2010 CELT report that were used in the analysis. Accordingly, the need for the Project is likely even more acute than the 2011 analysis recognized.

The power-flow modeling also showed voltage violations following N-1-1 contingency events in Eastern New England, Western New England, and Connecticut.

2.5.1.3 Delta P Testing

Delta P testing analyzes the torsional impact on the shafts of generating machines from contingencies. Higher stresses as a result of transmission line switching events may cause serious damage to generator shafts and machine equipment, which could result in a prolonged outage.[13] Delta P testing of the Lake Road Generator (Killingly, Connecticut) showed both delta P in excess of 0.5 per unit when the Connecticut import level was only 1,700 MW. These violations were exacerbated as the Connecticut import level was increased.

2.5.1.4 Transmission Transfer Capability Analysis

ISO-NE performed a transmission transfer capability analysis of each of the subareas in order to estimate when the transfer capability into each subarea is likely to become inadequate and the extent of such inadequacy. This analysis sums up the total resources available to an area (local generation plus demand response minus generation outages) and then subtracts the resource requirement of that area (area load minus imports). If there is a surplus (positive value) afterwards, then the import region has sufficient resources in a given year. If there is a deficit (negative value) afterwards, then the import region has insufficient resources in a given year. In order to perform this analysis, it is first necessary to establish an import limit for the subarea under study. This is done by using a computer program to model transfers across an interface, in both all-lines-in and line out conditions, until an element becomes overloaded.

As explained in detail in the *2011 Needs Re-analysis*, the results of the transfer capability analysis showed:

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[13] A delta P below 0.5 per unit of machine megavolt ampere (MVA) is considered acceptable.

- Transfer capability from western to eastern New England is already deficient in 2011 by 446 to 546 MW and this deficiency would grow to between 1,762 to 1,862 MW in 2020 without transmission improvements. With generation retirements (including Salem Harbor Station retirements) the need for additional eastern New England import capability would be even greater. A New Brunswick import of 1,000 MW could defer the need for additional west-to-east transfer capability, but only to between 2015 and 2016.

- A need for additional transfer capability from eastern to western New England can be reasonably forecasted to occur between 2017 and 2018. This need would be advanced if generation resources in western New England retire.

- A need for additional transmission transfer capability into Connecticut can be reasonably forecasted for between 2014 and 2015. This need would be advanced if generation resources in Connecticut retire.

2.5.2 Discussion of Transmission Deficiencies

New England has adequate quantities of generation and load-reducing resources to meet its electric needs under normal system conditions, and this situation can be expected to continue into the indefinite future, even with some retirements of existing generation. However, in many circumstances, the available generation would not be deliverable to all resource-deficient load centers. In particular, ISO-NE’s analyses have shown that, in the modeled system conditions, there is surplus generation on one side of the New England East-West Interface that cannot be delivered to the other side of the Interface when it is needed following certain contingency events. Such undeliverable generation is said to be “locked-in.”

ISO-NE presently disqualifies proposed new generators from participating in the FCM if they are to be interconnected to the electric grid in a location that would constrain delivery of their output. However, much of the existing New England fleet of generation was not sited to assure regional deliverability. Even when central station generation is optimally sited, transmission is needed to integrate it with load, and to balance generation and demand resources with customer load demand. This is particularly true because, under ISO-NE’s FCM rules, it will procure only such new capacity as it determines to be necessary to meet New England-wide capacity needs. The transmission system will therefore need to be capable of delivering generation to all New England loads in order to avoid load-serving problems.

Many of the problems documented by the ISO-NE analysis relate to the constrained transmission path along the Card Street – Lake Road – Sherman Road – West Medway corridor (CT-RI-MA), which crosses the New England East-West Interface, providing the only direct 345-kV tie between Connecticut and Rhode Island[14], and one of two 345-kV ties between Rhode Island and Massachusetts. This corridor extends from CL&P's Card Street Substation in Lebanon to the Lake Road Switching Station and Killingly Substation (both in Killingly), across the Connecticut/Rhode Island border to National Grid's Sherman Road Switching Station in Burrillville, Rhode Island, and from there to NSTAR's West Medway Substation in southeast Massachusetts.

Figure 2-2 (refer to page 2-12) illustrates the location of the Card Street – Lake Road – Sherman Road to West Medway corridor within the SNE 345-kV transmission system. Several modern and efficient gas-fired generators, most constructed since electric restructuring, are located along this corridor. These generators are listed in Table 2-2.

Table 2-2: Generation Resources Located along Card Street Substation to West Medway Substation Corridor

Generating Station	Aggregate Summer Capacity (MW)	Location	Year Placed in Service
Lake Road	745	Killingly, CT	2002
ANP Blackstone	444	Blackstone, MA	2001
NEA Bellingham	278	Bellingham, MA	1991
Ocean State	541	Burillville, RI	1990-1991
ANP Bellingham	473	Bellingham, MA	2002
Total	2481		

The generating stations listed in Table 2-2 may not all be dispatched at the same time because of a potential for overloading one or more of the lines making up the New England East-West Interface in the

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[14] In addition, southeastern Connecticut is also tied to southwest Rhode Island by a 115-kV line of very limited capability.

event of a contingency. For the same reason, ISO-NE has refused requests from generators to site an additional 430 MW of capacity along this corridor.

Transmission lines that cross an interface typically terminate at load-serving substations on each side of the interface and do not also interconnect multiple large generating stations in between those terminals. The Card Street – Lake Road – Sherman Road - West Medway 345-kV transmission line corridor is unusual in that it performs these dual purposes. It serves as a “super highway” transporting power from Connecticut resources to serve load in southeast Massachusetts (including the Boston area) and also transports power from southeast Massachusetts resources to Connecticut load centers. In addition, this “super highway” has several large “on ramps” between Card Street and West Medway Substations – the four large, highly efficient base load generating stations that connect to the 345-kV transmission network at various locations along the transmission corridor.

As a result, the New England East-West Interface must shift according to whether power is flowing on this transmission corridor into Connecticut or into southeastern Massachusetts. The aggregate flows on the New England East-West Interface must be maintained at levels where overloads will not result following the contingent loss of any of its elements.

System operators therefore must measure, in real time, the remaining capacity of each line that will be available in the event of a contingency. In order to maintain the margin necessary to accommodate the largest potential contingency, system operators must consider the generators along the Lake Road to West Medway corridor as being on the side of the interface from which power is being exported.

Thus, if power is flowing toward eastern Massachusetts, the flow will be measured just west of the West Medway Substation. On the other hand, if power is flowing into Connecticut, the power flow will be measured just west of the Lake Road Switching Station.

The power flow on the Lake Road – Sherman Road – West Medway 345-kV transmission line corridor is thus treated as part of the "transfer" across the Interface, and power flows on the remaining elements of the Interface are maintained at levels such that overloads will not result in the event the Lake Road – Sherman Road – West Medway transmission lines or any of the other elements that make up the Interface are suddenly lost. This practice has the effect of including greater Rhode Island resources with those on the west side of the New England East-West Interface when power flows toward eastern Massachusetts or greater Boston, and with those on the east side of the Interface when power flows toward Connecticut.

The concentration of resources along the Lake Road – Sherman Road – West Medway corridor also results in shifts of the Connecticut – Rhode Island and Rhode Island – Massachusetts interfaces. When the Lake Road plant was placed in-service in 2002, Connecticut was typically a net importer of power. Because imports into Connecticut are monitored just west of the Lake Road Switching Station, the Lake Road Generating Station is treated as electrically in Rhode Island. However, when Connecticut is exporting power to or through Rhode Island, the Lake Road Generating Station capacity is treated as being within Connecticut, so as to avoid overloading the Connecticut - Rhode Island interface. Similarly, when power is being exported to southeastern Massachusetts, the flow on the line between Sherman Road (in Rhode Island) and West Medway (in Massachusetts) is monitored just west of the West Medway Substation to avoid overloading this element of the New England East-West Interface the reliability of the entire Interface.

The shifting New England East-West Interface is illustrated in Figure 2-7 and Figure 2-8.

Figure 2-7: East – West Interface and Greater Rhode Island Corridor Limit Flows From the West and Greater Rhode Island to the East

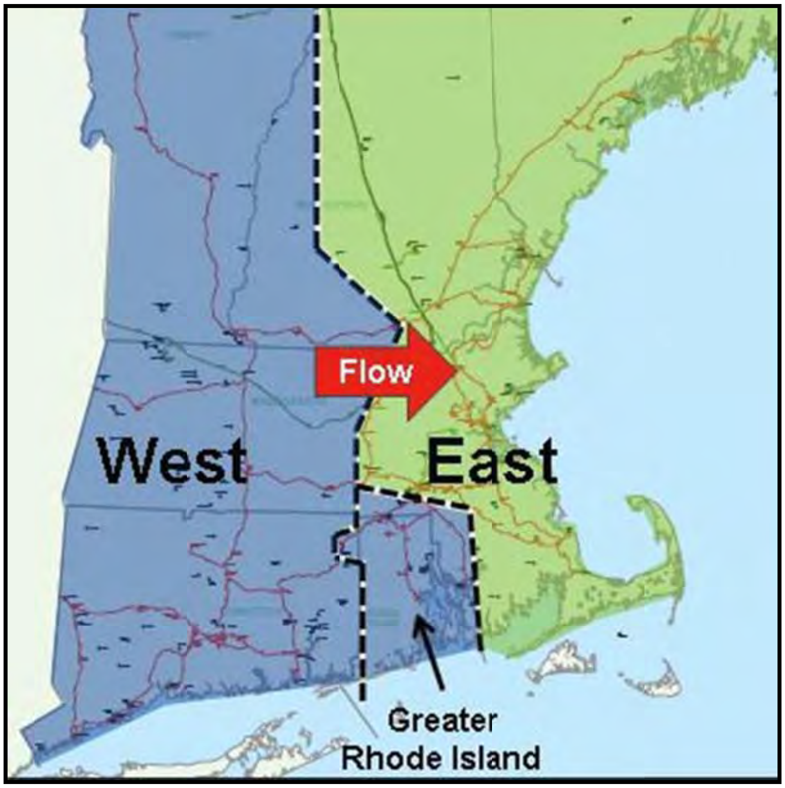
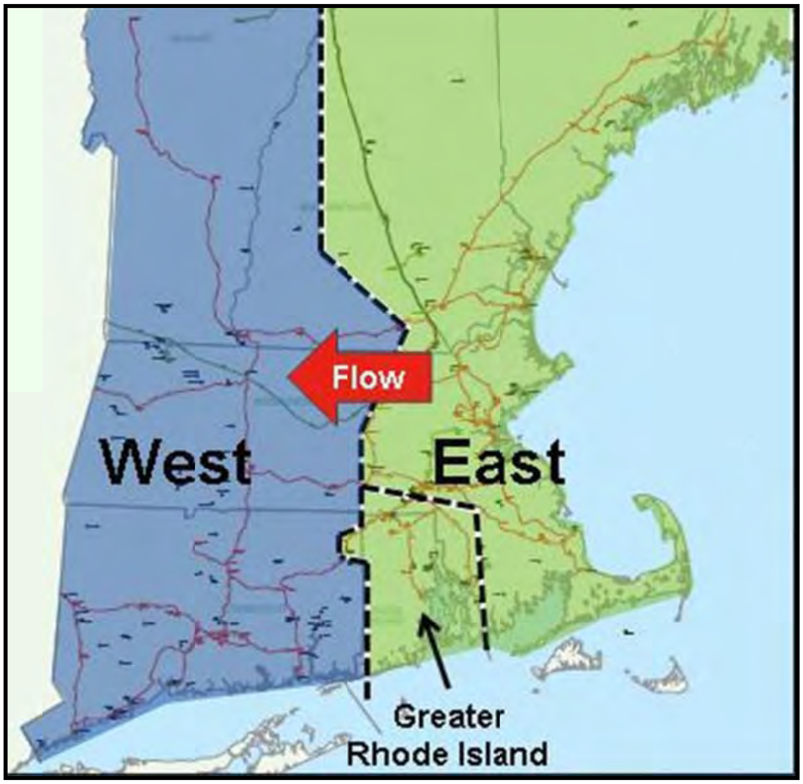


Figure 2-8: East – West Interface Limits Flows to the West From the East and Greater Rhode Island



The studies undertaken for the *2011 Needs Re-analysis* simulated these complex power flows and performance of the projected future New England bulk power network under contingency conditions, in accordance with NERC, NPCC and ISO-NE planning standards, criteria and procedures. The results or this modeling are summarized in Section 2.5.1 and are set forth in detail in the *2011 Needs Re-analysis*.

The *2011 Needs Re-analysis* demonstrated that, although the Interstate Reliability Project, as originally designed, would resolve most of the modeled criteria violations, it would not resolve the constraints of moving power from the west to the east across the New England East–West Interface. These constraints became apparent when the extensive new generation constructed or committed for construction on the west side of the interface was modeled in the course of the re-analysis.

2.6 THE UPDATED SOLUTION STUDY

After determining that the need for the Project had evolved to include new reliability problems of insufficient capability to use resources in the west to serve load in the east, ISO-NE undertook a further study to determine if any changes to the Project were necessary to serve this enhanced need; and to identify the optimal and most cost effective design for any such required changes. ISO-NE assigned responsibility for these studies to the previously formed Working Group of planners from ISO-NE, NUSCO, and National Grid. For the purpose of this study, the group was expanded to include representatives of NSTAR.

The expanded Working Group determined that changes and additions to the Project facilities in Rhode Island were required. No additions to the Connecticut portion of the Project were needed. In fact, a planned looping of the 345-kV Millstone to Manchester 310 Line to Card Street Substation over a 1-mile-long ROW segment in the Town of Lebanon, Connecticut and an associated expansion of the footprint of Card Street Substation were removed from the Interstate Reliability Project scope.[15]

The redesigned Interstate Reliability Project differs from the original Project mainly in that the Sherman Road Switching Station will be rebuilt and a reconductoring of the Rhode Island portion of the Killingly to Sherman Road 347 Line is replaced by a rebuild of the Sherman Road to West Farnum 328 Line. The revise proposed Project is illustrated in Figure 2-9.

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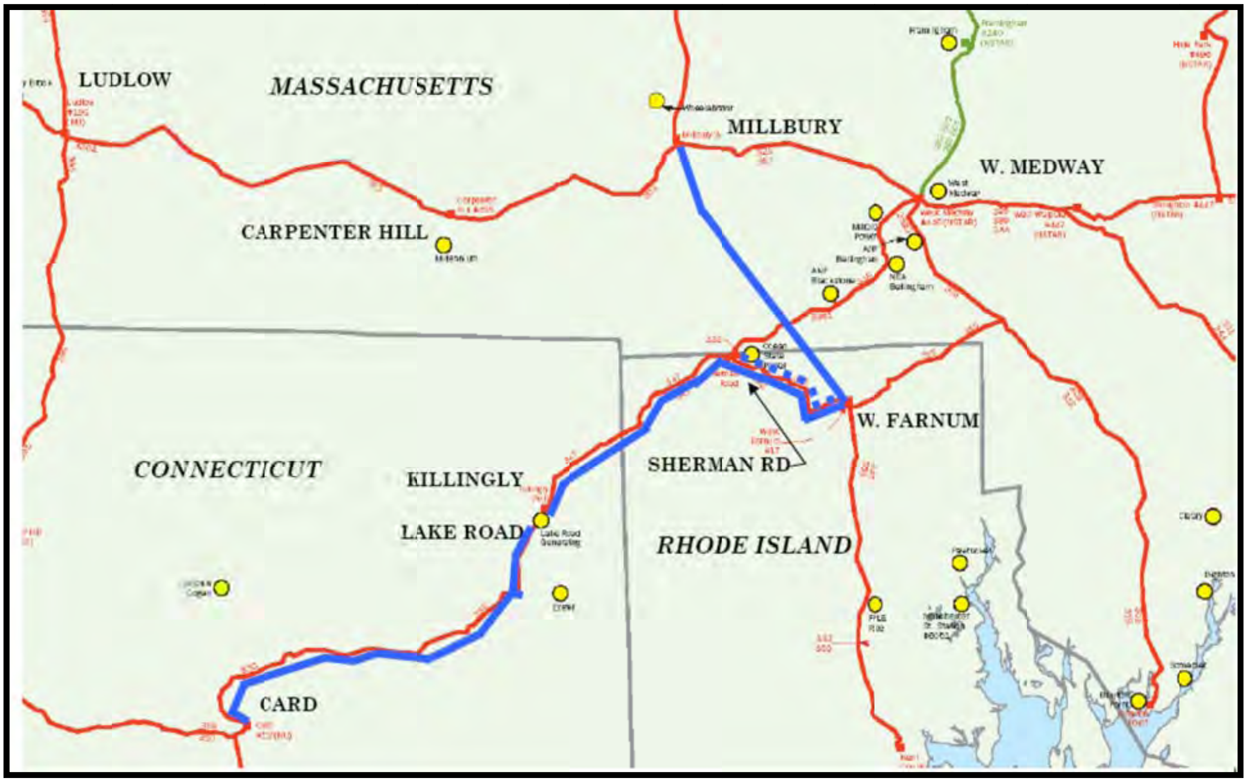
[15] This potential improvement is now being evaluated as part of the Greater Hartford / Central Connecticut study, and could be proposed again as an outcome of that study.

Figure 2-9: Proposed Interstate Reliability Project as Identified by Results of Updated Solution Study



🟥	Existing 345-kV Lines
🟦	New 345-kV line Millbury-West Farnum-Lake Road-Card Street
┅	Reconductor and rebuild 345-kV line from Sherman Road to West Farnum

Note: For readability, Figure 2-9 shows the proposed new lines slightly offset from existing lines. The new 345-kV lines would actually be aligned along and within existing CL&P and National Grid ROWs.

This supplemental analysis is described in Volume 1A, Section 13 of this Application. The results of the analysis were presented to the PAC on November 30, 2010, and are set forth in detail in an ISO-NE report entitled New England East-West Solution (NEEWS): *Interstate Reliability Project Component Updated Transmission Analysis Solution Study Report*, a redacted copy of which is provided as part of Volume 5 of this Application.

2.7 CONNECTICUT-SPECIFIC BENEFITS OF THE INTERSTATE RELIABILITY PROJECT

While the principal purpose of the Interstate Reliability Project is to better integrate the electric supply systems of the three Southern New England states for the benefit of the entire New England control area, it will also yield significant benefits specifically to Connecticut electric customers.

2.7.1 Improving Connecticut's Import Capability: Reliability Benefits

Of all the New England states, Connecticut is the least able to import power to supplement its internal supply resources. New Hampshire, Vermont, and Rhode Island have enough import capability to serve 100% of their peak load under N-1 contingency events. Massachusetts and Maine can import slightly less than 50% of their peak load. Connecticut, however, will only be able to import approximately 33% of its peak load even following the improvement in its import capability from completion of the GSRP.

Transfer capability limits are properly expressed as a range, because they will vary depending on system conditions such as load level, generation dispatch, system topology, and other regional transfer levels. The existing upper limit of the Connecticut Import interface transfer capability is approximately 2,500 MW. Following the completion of the GSRP, the upper limit of the Connecticut Import interface transfer capability is expected to increase by at least 100 MW, to 2,600 MW. The more significant impact of GSRP on the Connecticut Import Interface will be to significantly increase the lower end of the range, which is presently set at 300 MW, and to make transfers in the upper portion of the range more regularly available. CL&P expects that the Interstate Reliability Project will increase the upper limit of the Connecticut Import interface transfer capability by at least an additional 800 MW, to approximately 3,400 MW. The new transfer capability levels will be determined by ISO-NE with detailed and comprehensive studies.

As previously described, power-flow simulation studies show that Connecticut will require power imports to maintain reliability for N-1-1 contingencies in accordance with mandatory reliability standards and criteria. Moreover, this increased import capability will provide desirable flexibility to maintain reliability in light of potential changes in system conditions that could occur in short notice.

2.7.2 Environmental Benefits

In its 2010 review of the *Integrated Resource Plan*, submitted by the Connecticut Energy Advisory Board, the Department of Public Utility Control (DPUC)[16] observed that, because of potential changes in federal and state clean air regulations, it is plausible that 1,504 MW of Connecticut oil-fired steam capacity will retire, unless it can be exempted from the new regulations. Other capacity may remain, but will need to be upgraded. While industry participants expect most of these retirements to occur between 2013 and 2020 due to the anticipated timing of changes in the environmental regulations, the DPUC determined that the amount and timing of these retirements are uncertain. What is clear is that the implementation of the Interstate Reliability Project by 2015 will provide a capacity margin that will allow older, high emission plants that have become uneconomic to retire; it will also allow, if economic to do so, some of those retired generating units to be re-powered with cleaner burning fuels.

Similarly, recent government policy initiatives require access to low-emission and/or renewable energy sources. These include the Renewable Portfolio Standards (RPS) adopted by all of the New England states except Vermont. The Connecticut RPS require that, starting in 2007, escalating annual percentages of retail load must be served by each of three classes of renewable generation including, for instance, wind and solar energy. In its review of the 2010 *Integrated Resource Plan*, the DPUC concluded that "there is considerable uncertainly" as to whether Connecticut can meet renewable resource adequacy requirements after 2013.[17] If state policy continues to require that significant in-state energy needs be met with renewable resources, they will have to be imported from outside the state, likely from northern New England and Canada. While the Interstate Reliability Project will not by itself provide Connecticut with

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[16] As the result of 2011 legislation, the DPUC is now the Public Utilities Regulatory Authority (PURA)

[17] Docket No.10-02-07 DPUC Review of the 2010 Integrated Resource Plan, Sept. 15, 2010, p. 66.

direct access to such sources, it will serve as an essential link to the new regional transmission network necessary to do so.

2.7.3 Increasing Connecticut's Generation Resources

In addition to increasing Connecticut's Import Interface capability, the Project will increase the state's defined local generation. For import-constrained areas such as Connecticut, ISO-NE sets a Local Sourcing Requirement (LSR). The LSR is the minimum amount of generating capacity that must be electrically located within an import-constrained load zone to meet system-wide resource adequacy requirements.

The Lake Road Generating Station is physically located in Killingly, Connecticut, but because of the limitations of the existing transmission system, it presently cannot be counted toward the Connecticut local sourcing requirement. Construction of the Interstate Reliability Project, which will provide a second 345-kV path in and out of the Lake Road Switching Station, is expected to make the Lake Road Generating Station's three units eligible for consideration as local Connecticut resources.

2.8 CONCLUSION

The Interstate Reliability Project has been under study by regional planners for more than six years, during which time the evolving analyses have taken into account multiple changes in system conditions. The Project is needed to fully integrate generation with load throughout SNE by eliminating transmission constraints on the transfer of power from east to west and from west to east.

At the same time, the Project will resolve multiple remaining reliability issues within SNE and provide needed N-1-1 import capability to Connecticut. It will ensure that the approximately 2,000 MW of generation along the Card Street – Lake Road – Sherman Road – West Medway corridor, most of which is relatively new and efficient, can be called upon to reliably serve load in both western and eastern New England, as needed, over the long-term planning horizon. The bulk-power transmission system will be capable of carrying sufficient power to meet peak customer demands in the event one of the 345-kV transmission lines across the New England East-West Interface is lost suddenly, or other design contingencies occur.

The future in which the Project must be operated continues to hold many uncertainties. Significant generation retirements are highly probable, but their extent and timing is uncertain. Some generators that are not retired may be taken out of service for lengthy periods in order to be repowered to allow the use of more efficient and/or cleaner fuels. Power imports beyond those required for reliability are likely to be needed in order to meet renewable portfolio standards. The need to move greater amounts of power across the New England East-West Interface may continue to be predominantly from east to west, or it may change to be more from west to east. In either case, there will be system conditions requiring significant transfers in the opposite direction. All of these reliability concerns will be addressed by the Interstate Reliability Project. Accordingly, while recognizing these uncertainties, the DPUC included the Interstate Reliability Project in its 2010 Integrated Resource Plan[18]. Pursuant to Section 16a-13b(a) of the Connecticut General Statutes, CL&P is required to pursue siting approval for transmission upgrades specified in the plan.

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[18] Docket No.10-02-07 DPUC Review of the 2010 *Integrated Resource Plan*, Sept. 15, 2010, p. 18.

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