ISO new england

2005

Regional System Plan

ISO New England ● **Regional System Plan 2005**

Approved by the ISO New England Board of Directors

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Preface

ISO New England Inc. (the ISO) is pleased to present its *Regional System Plan 2005* (RSP05). The report is a comprehensive summary of all aspects of electric system planning for 2005 to 2014 necessary for the reliable and efficient operation of the New England power system. The ISO is submitting RSP05 in compliance with its Federal Energy Regulatory Commission (FERC)-approved tariff, *Electric Tariff No. 3, ISO New England Inc. Transmission, Markets, and Services Tariff* (Part II, Section 48) (Transmission Tariff).

In terms of the system's future electricity supply, RSP05 identifies the desired amount of additional capacity required to assure a reliable supply of electricity in New England, when and where the capacity will be needed, and the types of generating resources that can provide this capacity. It also recommends needed transmission improvements. The report provides a comprehensive assessment of the system under a wide variety of generation and load scenarios. By applying the system's operating requirements, the ISO has determined the desired characteristics of necessary resources, such as fuel sources. RSP05 discusses the need for critical additions to the infrastructure in virtually every portion of the system.

While planning identifies the needed physical resources of the system, the electricity markets are intended to provide economic incentives for market participants to develop the required resource and transmission improvements and other investments. These improvements and investments may include a combination of generating units, merchant transmission facilities, distributed resources, and demand-reduction programs. This approach benefits the entire New England region in that the improvements ensure the long-term reliability and market efficiency of the system.

RSP05 also identifies new study initiatives to further address long-term reliability and summarizes improvements made to the interregional planning processes, which have become increasingly important after the August 14, 2003, blackout.

ISO New England appreciates the valuable comments received from all stakeholders as part of the open stakeholder process and gratefully acknowledges the many individuals who contributed to RSP05. We welcome comments on this report and seek ongoing input on further studies.

Executive Summary

ISO New England has completed its 2005 Regional System Plan (RSP05) for New England's electric power system and presents the results in this report. This Executive Summary highlights the major results of the 10-year plan and summarizes the ISO's conclusions and recommendations for the future development of the bulk power system.

RSP05 identifies system improvements needed over the next 10 years and provides information on what infrastructure improvements are needed and when and where they are needed to meet the system's peak demands in conformance with planning criteria. Plans for the region's future electricity infrastructure must account for the uncertainty of assumptions over the next 10 years in terms of load growth, fuel prices, new technology, market changes, environmental requirements, and other relevant events. As with previous planning reports, formerly called Regional Transmission Expansion Plans (RTEPs), RSP05 provides technical information and data on various scenarios and identifies the requirements for maintaining, improving, and ensuring the reliability of the system in the short term. The plan also assists in linking physical system needs to wholesale market mechanisms aimed at attracting market solutions (generation, demand response, etc.) to mitigate these needs. RSP05 thus is a broader plan of the region's electricity system needs than the previous RTEP reports.

RSP05 resource adequacy studies are consistent with previous RTEP findings that indicated the need for significant new generation or demand-side resources in New England in the 2008 to 2010 timeframe. Key findings of RSP05 are as follows:

- RSP05 identifies 272 transmission projects required for the reliability of the New England system. Previous RTEP reports emphasized the major 345 kV projects. RSP05 reinforces the need for the major 345 kV projects and places greater emphasis on the need for transmission projects throughout the system, particularly within load pockets.[1]
- Under high-demand conditions, New England will more likely be forced to operate under emergency conditions as soon as 2006 due to resource limitations in the Connecticut (CT), Southwest Connecticut (SWCT), and Norwalk/Stamford Subareas (NOR).[2]
- From a systemwide perspective, installed capacity (IC) projections show that additional resources are needed to meet systemwide demand as early as 2008 but no later than 2010.

[1] Load pockets are areas of the system where the transmission capability is not adequate to import capacity from other parts of the system, and load must rely on local generation.

[2] To conduct resource planning reliability studies within New England, the region is modeled as 13 subareas and three neighboring control areas. In addition to SWCT, NOR, and CT, these subareas include northeastern Maine (BHE); western and central Maine/Saco Valley, New Hampshire (ME); southeastern Maine (SME); northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine (NH); Vermont/southwestern New Hampshire (VT); Greater Boston, including the North Shore (BOSTON); central Massachusetts/northeastern Massachusetts (CMA/NEMA); western Massachusetts (WMA); southeastern Massachusetts/Newport, Rhode Island (SEMA); and Rhode Island bordering Massachusetts (RI). Greater Connecticut includes the CT, SWCT, and NOR Subareas. Greater Southwest Connecticut is comprised of the SWCT and NOR Subareas. The three neighboring control areas are New York, Hydro-Québec, and the Maritimes.

- Analysis of operating reserves shows the immediate need for approximately 1,100 megawatts (MW) of incremental quick-start resources or units with competitive energy prices in BOSTON and Greater Connecticut, especially in Greater Southwest Connecticut.[3] Adding 530 MW (of the 1,070 MW) in Greater Connecticut will meet this area's capacity needs and also serve to meet systemwide needs.

- The region must convert 400 MW of gas-fired generation to dual-fuel capability (i.e., having the flexibility and storage capacity to use oil as well as gas) by winter 2006/2007 and increase that capability by 250 MW per year through winter 2008/2009 and 500 MW more in winter 2009/2010.

Introduction to ISO New England

ISO New England is a not-for-profit corporation created in 1997. It 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 February 2005, the ISO began operating as a Regional Transmission Organization (RTO). The ISO is submitting RSP05 in compliance with its Federal Energy Regulatory Commission (FERC)-approved tariff, *Electric Tariff No. 3, ISO New England Inc. Transmission, Markets, and Service Tariff*.[4] In addition to complying with federal regulations, the ISO works closely with state regulators and stakeholders, including participants in the marketplace, to carry out each of its functions.

The six-state New England electric power system serves 14 million people living in a 68,000 square-mile area. The system is fully integrated, using all regional generating resources across state boundaries. Over 350 generating units produce electricity, representing approximately 31,000 MW of generating capacity, connected to approximately 8,000 miles of high-voltage transmission lines. Most of these lines are fairly short and networked as a grid, resulting in close interrelationships of electrical performance in all corners of the system. Twelve transmission ties interconnect New England with neighboring electricity systems in the United States and Canada, including New York, New Brunswick, and Québec; these lines carry power into or out of New England depending on system needs.

Approach to Planning

RSP05 is a comprehensive assessment of the needs for producing and transmitting power in New England. Studies conducted for RSP05 projected energy use and load growth and analyzed the adequacy of installed and operable capacity in New England in terms of the amount and types of resources needed and when and where they will be needed to ensure the reliability of the system. It examined the need for additional dual-fuel capability and where such additions are needed. The ISO also simulated future air emissions from the region's generators and compiled information related to a potential regional carbon dioxide (CO_2) emission cap and other environmental regulations. Additionally, studies were conducted with the transmission owners to evaluate transmission system improvements needed for satisfying reliability requirements throughout New England. These studies identify major transmission upgrades as well as other required improvements. The ISO also examined system conditions to identify transmission improvements for enhancing market efficiency.

[3] Quick-start capacity is typically comprised of pumped storage and conventional hydro units, combustion turbines, many load-response (i.e., load-reduction) program resources, and internal combustion units that can start up and be at full load in less than 30 minutes. These units provide greater operating flexibility in daily operations and in emergency situations than base-load generators, which are available at all times to serve load, or generators that are available to serve intermediate load levels. In daily operations, quick-start resources can help replenish the capacity lost due to a sudden and unexpected loss of a generating unit or transmission facility. Under severe peak-load conditions, quick-start units can help avoid the need to implement involuntary load shedding by providing either energy or operating reserves.

[4] See <http://www.iso-ne.com/regulatory/tariff/index.html>.

As part of the RSP05 effort, the ISO consulted with stakeholders about numerous topics, including analysis of data trends, possible future developments, and options related to the region's short- and long-term electricity supply. The ISO met with the Planning Advisory Committee (PAC) eight times in 2005 to fully review RSP05 assumptions and study results. The PAC consists of participants in the electricity markets, transmission owners, representatives from government agencies, and consultants. The transmission projects are the result of an ongoing planning process among the ISO and New England transmission owners. This open stakeholder process has provided benefits to regional planning in terms of study priority, scope, and quality.

The ISO also fully participates with its neighboring electric power system control areas as well as interregional planning bodies, including the Northeast Power Coordinating Council (NPCC) and the North American Electric Reliability Council (NERC), to ensure the reliability and security of the wide-scale electric power system.[5] The ISO complies with all the NERC planning criteria and procedures (as well as all internal planning procedures) to enhance resource adequacy and transmission performance and to better coordinate the development of the interconnected power system in the Northeast.[6]

During 2004, the ISO signed the Northeast Planning Protocol, an agreement among ISO New England, the New York ISO (NYISO), and PJM Interconnection that commits the ISO and these transmission providers to cooperate in interregional planning studies.[7] The neighboring Canadian provinces participate on a limited basis to share data and exchange information. This overall cooperation is needed to improve the overall reliable and efficient operation of the electric power system in the northeastern United States and these provinces and to minimize interregional reliability problems. The protocol specifically aims to resolve interregional planning issues and identify the impacts that proposed generating units and transmission projects could have on neighboring systems. Additionally, the ISO participates in planning studies to ensure that contingencies in New England will not adversely affect neighboring systems.

Collectively, the results of the RSP05 studies, data gathering, and interregional coordinated study efforts provide the ISO with the information it needs to create system plans that market participants can use to develop market solutions or transmission improvements to meet system needs. The studies conducted are summarized below.

Projected Energy Use and Load-Growth Studies

To estimate demand, the ISO conducted energy and load-growth studies that forecasted energy and peak loads for 2005 to 2014. These forecasts considered data on historical demand, economic and demographic factors, weather, and projected reductions in energy use and peak loads based on conservation efforts and peak-load management (C&LM) programs. The analyses use data on "50/50" and "90/10" peak loads in New England. A 50/50 peak load has a 50% chance of being exceeded due to weather conditions, while a 90/10 peak load has a 10% chance of being exceeded due to weather conditions.[8]

[5] NPCC defines control areas as electric systems bounded by interconnection metering and telemetry that can control generation to maintain a net interchange schedule with other control areas and contribute to the frequency regulation of the interconnection. For further information, see <http://www.npcc.org/default.asp>. Also see <http://www.nerc.com/>.

[6] For more information on the ISO's planning procedures, see <http://www.iso-ne.com/rules_proceds/isone_plan/index.html>.

[7] PJM is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.

[8] In the past 10 years, New England has exceeded the 90/10 peak load forecast under hot and humid weather conditions four times.

Resource Adequacy Studies

ISO New England relies on several types of studies to identify the resources required to meet future system reliability needs. The two frequently used studies are the installed capacity analysis and the operable capacity (OC) analysis. The IC analysis uses a well-established probabilistic method for determining the resources needed to meet a loss-of-load-expectation (LOLE) criterion that prevents the system from disconnecting firm load for a range of possible load levels and resource availabilities. The operable capacity analysis uses a deterministic method for identifying the amount of capacity needed to be operable to meet a specified peak load level including operating reserves. The OC analysis methodology is very similar to the approach system operators use to identify the resources needed on a daily basis to meet the expected peak-load conditions. Thus, installed capacity studies identify bulk power system reliability issues related to the adequacy of system resources, and operable capacity analyses identify reliability issues related to system security.[9]

Installed Capacity Analysis

When planning the generation system, ISO New England conducts an installed capacity analysis to identify an IC Requirement, or the adequacy of New England system resources and the amount of resources needed to meet an NPCC and ISO New England LOLE criterion.[10] To meet this criterion, the ISO must plan and install adequate resources for the New England bulk power system so that the probability of disconnecting firm customers due to resource deficiency will be no more than 1 day in 10 years.

The LOLE criterion has been used to determine New England's IC Requirement since 1971 when the New England Power Pool (NEPOOL) was charged to conduct regional planning.[11] This calculation assumes that no transmission constraints exist within New England so that all generating resources in the region are available to all loads. Other critical assumptions are as follows:

- The load forecast is modeled as a probability distribution of the weekday peak loads that accounts for the effects of weather uncertainty.
- The availability of resources is modeled based on the probability of forced outages.
- The transmission system can be operated reliably when systemwide operating reserves have been fully depleted.
- No generating units will be added or removed from the system during the assessment period.
- To meet emergency needs throughout the assessment period, New England can rely on 2,000 MW of uncontracted or otherwise unscheduled capacity (called tie benefits) from New York, Québec, and the Maritimes to meet needs.

[9] Reliability adequacy is a measure of the reliability of the bulk power system to meet demand and the sufficiency of the system's generating resources. Reliability security is a measure of the reliability of the bulk power system in terms of its ability to withstand disturbances arising within the system.

[10] Additional information on NPCC planning criteria can be found at: <http://www.npcc.org/criteria.asp>.

[11] NEPOOL was formed in 1971 by the region's private and municipal utilities to foster cooperation and coordination among the utilities in the six-state region and ensure a dependable supply of electricity. Today, NEPOOL members are ISO New England stakeholders and market participants. Over the next 18 months, the New England system stakeholders will review the methodology that calculates the IC Requirement.

- All ISO New England emergency actions per Operating Procedure No. 4, *Actions during a Capacity Deficiency* (OP 4), will be fully available during a capacity deficiency.[12]

Using this methodology and these assumptions result in identifying the minimum amount of capacity needed to meet the LOLE criterion. This is because these assumptions do not take into account the following risks, which, if present, would increase the IC Requirement:

- The New England transmission system may not be able to simultaneously transfer to load the full output from all of New England's generators. For example, Greater Connecticut is transmission limited, and power cannot always reliably or securely flow from a generator within that area to the load there. Also, the Maine–New Hampshire interface limits the receipt of generation output from Maine, including transfers from New Brunswick into New England.

- As shown by operating experience, transmission security (first- and second-contingency protection for thermal overloads, voltage collapse, and generator instability) cannot be maintained when New England-wide operating reserves do not meet the requirements stated in ISO New England Operating Procedure No. 8, *Operating Reserve and Automatic Generation Control* (OP 8).[13, 14]

- The ability of neighboring systems to supply emergency power may well diminish, as neighboring regions experience load growth that exceeds generation additions, and the reserve supplies in these regions decrease. The future ability to simultaneously import a total of 2,000 MW of uncontracted emergency assistance from Hydro-Québec, the Maritimes, and New York is uncertain. By 2008, New York is projected to run short of the installed capacity its criteria require. Ontario is also projected to be short of capacity resources within five years and will be facing additional governmental plans to phase out 6,500 MW of coal plants and acquire replacement resources within the same period. Since New England currently relies on 2,000 MW of tie benefits from other control areas, the projected resource adequacy of the surrounding NPCC systems is of great importance to New England. The projected capacity situation for the neighboring NPCC control areas coupled with transmission limitations shows that New England should not heavily rely on neighboring systems for capacity during periods of peak load, especially during the latter part of the planning period.

- While over 1,700 MW of New England generating capacity has been retired since 1999, RSP05 assumes no additional generators will retire during the 10-year planning period.

[12] Under OP 4 conditions, the system operator must take special steps to prevent curtailment of firm customer load. These actions include reducing operating reserves, reducing voltages, importing emergency power, activating emergency demand response to make capacity available, and taking other emergency measures while still maintaining transmission system reliability. See <http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html>.

[13] The first contingency is the loss of the first facility that has the largest impact on system reliability. The second contingency is the loss of the next facility, which would then have the largest impact on the system.

[14] For more information on OP 8, see <http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html>.

Operable Capacity Analysis

IC Requirement analyses do not identify the amount of resources that must be operational to meet a defined load level plus the requirements for operating reserves. Thus, to assess the ISO's operational risks and identify the amount of generating resources that must be operational to meet expected load and operating-reserve requirements, as well as the sensitivity of day-to-day system reliability and security to these risks at some point in the future, RSP05 complements the IC Requirement analysis with an operable capacity analysis. This is a deterministic analysis that reviews the ability of the bulk power system to serve load using a specific scenario. This approach compares the expected peak loads plus the requirements for reserve capacity to the amount of operable capacity the system is expected to have available during these peak loads. An adequate operable capacity margin maintains sufficient capacity resources to serve the native load and meet NERC and NPCC operating criteria (for operating reserves and transmission security) for the peak hour of each year, while recognizing the physical nature of the transmission system and the amount of capacity historically unavailable due to random forced outages on that peak day.[15] The operable capacity analysis considers both the 50/50 and 90/10 peak-load levels.

Fuel Diversity and Other Issues

RSP05 discusses the short- and long-term issues of fuel diversity. The short-term issues relate to a large portion of the gas-fired generating units lacking either firm gas contracts or dual-fuel capability to mitigate possible shortages of natural gas during periods of extreme winter weather. The longer-term issues relate to the ever-increasing reliance on natural gas in New England and neighboring regions and the need for more supply-side fuel diversity. The report discusses New England's winter capacity mix of fuels. It also summarizes a probabilistic study that investigated the physical risks related to winter gas-fired capacity and the amounts of dual-fuel conversions that could mitigate those risks. The report provides recommendations for encouraging dual-fuel capability and new energy resources.

RSP05 contains environmental information that can assist market participants in determining the types, amounts, and locations of resources they might find attractive for development. This includes analysis of future air emissions, the status of Renewable Portfolio Standards (RPS), and discussions of distributed resources including demand-response resources.[16] The report also presents the status of proposed generating projects in the ISO Interconnection Study Queue.

Transmission Studies

RSP05 summarizes the status of a number of transmission planning studies that aim to identify needed transmission facilities. Two studies that have a significant impact on RSP05 results have focused on reliability issues in southern New England and the interface constraints for the Connecticut and Southwest Connecticut imports.

[15] Additional information on NERC and NPCC planning criteria can be found at: <http://www.nerc.com/~filez/criteria-guides.html> and <http://www.npcc.org/criteria.asp>, respectively.

[16] State-mandated Renewable Portfolio Standards generally require competitive retail providers to supply a certain percentage of electricity from various renewable sources and technologies. Distributed resources are a growing form of smaller-sized on-site resources that involve load-reduction technologies or on-site generators. Distributed resources are typically located at or near load centers and are generally installed and owned by commercial or industrial facilities. A facility's use of these resources helps maintain the reliability of its electric supply during grid emergencies. Distributed resources may be installed to serve all or part of a facility's electric load and to provide thermal energy to enhance the economics of its overall energy supply. The ISO's demand-response programs are examples of distributed-resource measures. These programs provide financial incentives to customers that make their distributed-resource capacity available during OP 4 conditions or when wholesale prices are high. Demand response is when customers reduce load based on reliability needs or price signals.

Consistent with transmission reliability requirements, the ISO continues to study the southern New England region to identify and resolve its reliability issues. An overall goal of the study is to formulate a solution that better integrates load-serving and generating facilities within Massachusetts, Rhode Island, and Connecticut, thereby enhancing the grid's ability to move power between east and west and vice versa. The study report is scheduled to be completed by the end of 2005, and the project plan is scheduled for ISO approval by July 2006. The current in-service date for this project is December 2011.

The ISO has determined that the interface limits for the Connecticut and Southwest Connecticut imports have increased over the RTEP04 limits by 100 MW and 300 MW, respectively. This increase results from system improvements that relieved many voltage constraints in those areas. The new higher limits are primarily based on thermal limits, which will be addressed by subsequent projects. While operating practices have validated these study results, the ISO and the NEPOOL Reliability Committee will review the procedures and supporting documentation for establishing interface limits.[17]

RSP05 Findings

RSP05 generated data on future energy use and load growth, installed and operable capacity, and transmission needs. The results of the projected energy use and load-growth analyses conducted in January 2005 indicated that the use of energy in New England is projected to grow by 14% from 2005 to 2014. New Hampshire and Connecticut are projected to be the highest growth states. Greater efforts at conservation could reduce the energy-use growth rate throughout New England.

The summer 50/50 peak load in New England is expected to grow by about 15%, from 26,355 MW in 2005 to 30,180 MW in 2014. The summer 90/10 peak loads also are expected to grow about 15%, from 27,985 MW in 2005 to 32,050 MW in 2014. These projections include about 1,600 MW of peak reduction from ongoing utility-sponsored conservation programs. Due to several economic factors, the RSP05 summer-peak load forecasted for 2014 is about 1,000 MW higher than the RTEP04 peak load forecast for 2013. The preliminary peak load of July 19, 2005, was 26,749 MW, establishing a new all-time system peak for New England 5.5% higher than the previous all-time peak established in 2002. Eight days later on July 27, the system reached another all-time peak of 26,921 MW. This peak load would have been even higher by approximately 200 MW had demand-response measures not been activated in Connecticut under OP 4.

The long-run peak load forecasts in RSP05 assumed a constant load factor, which has been found to be inconsistent with historical data and short-term forecasts and has contributed to the under-forecasting of summer-peak loads. The ISO is in the process of improving its peak-forecast methodology by extending its declining summer-peak load factor over the entire forecast period.

Table ES.1 shows projected resource needs in New England in terms of the amount and types of generating resources needed and where and when these resources will be needed. The table also relates the system needs identified in RSP05 to solutions and requirements. The following sections summarize the findings presented in the table.

[17] For information on the NEPOOL Reliability Committee, see <http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/index.html>.

Table ES.1
Summary of RSP05 System Needs, Solutions, and Requirements
Based on RSP05 Assumptions and Analyses

System Needs	Solutions	Specific Requirements
Meet load-pocket requirements	Add resources to satisfy reliability needs (preferably quick-start resources)	For Greater Connecticut: Operable Capacity: - Need 30 MW by 2006 (90/10 load) - Need 670 MW by 2009 (90/10 load)
Meet systemwide operable capacity forecast requirements	Meet systemwide needs by adding quick-start resources that satisfy load-pocket needs	- Need 160 MW by 2008 (50/50 load) - Need 1,900 MW by 2008 (90/10 load)
Provide operating reserves	Add incremental quick-start resources or units with energy prices competitive with resources external to the load pockets	For Greater Connecticut: - Need 530 MW by 2006 *The preferred location for adding quick-start resources for meeting the needs of Greater Connecticut is Greater SWCT because this area needs 350 MW by 2009* - Need 500 MW in BOSTON by 2006
Meet systemwide 1-day-in-10-year LOLE criterion	Meet systemwide needs by meeting load-pocket needs	- Need 170 MW systemwide by 2010
Reliably operate system when gas is not available	Achieve greater fuel diversity by adding incremental dual-fuel conversions in southern New England, predominantly BOSTON	- Need 400 MW by winter 2006/2007 - Need an additional 250 MW every winter through 2008/2009 - Need an additional 500 MW in winter 2009/2010

Need for Capacity and Operating Reserves in Load Pockets

Among specific subregions, Greater Connecticut has the most significant resource need in New England, coupled with transmission constraints that limit the import of electricity into the state. If additional resources are not added soon, or the transmission lines currently being developed are not completed in a timely manner, these constraints create a significant risk that system operations will be required to shed load or to disconnect firm customers during periods of extremely hot weather and when generating units are less available than expected.

RSP05 results indicate that Greater Connecticut is also short of quick-start generating capacity that provides economical operating-reserve coverage under high-load conditions. Because of this shortage, intermediate units not economic in the energy market must be put on-line (for which the load-serving entities would incur operating-reserve costs) to provide the 30-minute response needed to maintain reliability upon loss of a critical generator or transmission line.[18]

Greater Connecticut currently needs an additional 530 MW of resources that can provide 30-minute response to meet its operating-reserve and second-contingency coverage. Ideally, a majority of these quick-start resources

[18] Operating-reserve costs are payments to generators for operating when it is more expensive for them to do so than the price-setting generator in the energy markets.

would locate in Greater Southwest Connecticut, which would need approximately 350 MW of this type of resource. These resources are needed with the addition of Phase 2 of the Southwest Connecticut Reliability Project, due to be in service in late 2009 and required to reliably serve load in Greater Southwest Connecticut.

BOSTON, another subarea of New England's power system, needs 500 MW of quick-start resources now to reduce out-of-merit commitment of uneconomic generation and provide operating reserves for contingency coverage under high-load conditions. Adding quick-start resources in BOSTON also would serve New England's overall resource adequacy needs and help reduce some of the operating-reserve costs in Boston. Adding quick-start units in the southern part of the New England system would provide for operating flexibility and improve the reliability of operation at critical load centers. As noted below, it is desirable for the units to have dual-fuel capability.

Systemwide Capacity Needs

By 2010, New England will require about 170 MW of capacity to meet the NPCC and ISO New England 1-day-in-10-year LOLE criterion. This calculation assumes no additional units will retire or deactivate by 2010 and load-growth and other assumptions remain appropriate. These results indicate total resource capacity barely meets the reliability requirement today and, as load grows, the need for operation under OP 4 will become more commonplace during high-demand hours.

During times of extreme peak demand, the use of additional capacity over the amount committed to firm contracts or OP 4 actions during emergency conditions may be needed. The fragile state of the transmission system and the lack of sufficient 30-minute-response resources in Connecticut make it especially vulnerable to the risk of unreliable operation or, in extreme conditions, load shedding. Quick-start resources and added diversity in generating-unit types are needed to reduce the operational risks identified.

Based on the results of the operable capacity analysis, by 2008, New England must acquire or rely on OP 4 actions to gain an additional 160 MW and 1,900 MW to meet the 50/50 and 90/10 peak-load forecasts, respectively.

Taken together, the results of the installed and operable capacity analyses demonstrate that New England will likely face an increased risk of operating with less capacity than needed by 2008. The results also show that the region will not have sufficient capacity to meet the IC Requirement in the 2008 to 2010 timeframe, depending on load growth, weather conditions, generator performance and attrition, and the conditions in specific load pockets, such as Connecticut. Because the timeframe for building new generation resources is about two to four years, the analysis highlights the urgent need for new generating resources in New England.

Need for Fuel Diversity

ISO's operating experience and RSP05 highlight a high level of vulnerability to increases in gas and oil prices and the potential for fuel disruptions in that gas and oil fuel plants provide almost two-thirds of the system's capacity. RSP05 identifies that to mitigate the impacts of possible natural gas shortages on system reliability during the winter, the region must convert approximately 400 MW of gas-fired generation to dual-fuel capability by winter 2006/2007, increasing the amount by 250 MW per year through 2008/2009 and by 500 MW for 2009/2010. Alternatively, gas-fired units could contract for firm supply, recognizing that scheduling flexibility may not be available for quick-start units. Study results indicate that converting gas-fired generation in southern New England, particularly in the BOSTON Subarea, to dual-fuel operation would help mitigate reliability concerns. These concerns are associated with a natural gas shortage that could occur during a winter cold snap and a resulting regional gas shortage. Additional dual-fuel capability, an additional firming of contracts, and/or an increase in the natural gas delivery system infrastructure-including new liquid natural gas (LNG) terminals-will be needed to support load growth in the future if gas continues to be a preferred fuel for new generation.

Since approximately 50% of New England's generating capacity is capable of being fueled with natural gas, and gas actually fuels 40% of the region's electrical energy generation, the region must focus on developing greater fuel diversity for its electricity supply for the long term. The fuel-diversity analysis clarified that adding resources, including nuclear-powered capacity, coal units, or renewable resources, will improve reliability in New England. RSP05 determined that energy conservation and peak-load management programs could contribute to decreasing New England's need for capacity in the short term and improve the fuel-diversity situation. The region also has the increased potential for using distributed resources to meet New England's growing demand for electricity.

An increasing energy use and rising natural gas prices relative to oil prices will tend to increase generating plant production by oil units, resulting in higher total air emissions in New England over the 10-year period. Conservation efforts and renewable resources will reduce emissions and encourage greater fuel diversity.

Needed Transmission Projects

RSP05 identifies 272 transmission projects required throughout New England to meet planning criteria. These upgrades are required to reliably serve load and to reduce the need to commit generating units for operating reserves, voltage support, and relief of other transmission constraints. These 272 projects are estimated to cost about $3.0 billion. Two-thirds of this cost is related to the following six major 345 kV projects.

- NSTAR 345 kV Reliability Project
- Southwest Connecticut Reliability Project Phase 1
- Northwest Vermont Reliability Project
- Northeast Reliability Interconnect (NRI) Project
- Southwest Connecticut Reliability Project Phase 2
- Southern New England Reinforcement Project

The load/generation pockets discussed in RSP05 include Middletown (CT); Norwalk-Stamford (CT); Southwest Connecticut; Springfield (MA); Boston; Wachusetts (MA); and the North Shore (MA). Additional studies are required to finalize many of the 272 projects, such as those required for increasing the northern New England transmission-transfer capability and improving the voltage performance of Downtown Boston.

Most of the transmission projects identified during the RSP process are reliability upgrades for ensuring the region continues to satisfy national and regional reliability standards while continuing to operate in an economical manner. Many of these upgrades will provide the additional benefit of enhancing the efficient operation of the region's power markets, as they will allow access to generating resources external to the load pockets, the repowering or interconnection of generating facilities, and the movement of power to where it is needed.

Infrastructure Achievements

This is the fifth year of ISO's leadership on the RTEP/RSP process for the region, and much progress has been made over the past years in planned transmission projects and market enhancements. Since the inception of the RTEP/RSP planning process in 2001, significant system improvements and modifications have been identified, seventy-five projects have been placed in service totaling $217 million in construction costs, and many others are well on their way toward completion. As of September 2005, the ISO had close to 500 MW enrolled in all of its demand-response programs implemented as part of Standard Market Design (SMD).[19] An audit in August 2004 of the demand-response programs showed these resources to be substantially capable when called upon to reduce load.

Transmission Upgrades

Because Connecticut and Southwest Connecticut are considered critical areas in terms of service reliability, shorter-term system improvements have been implemented in these areas. Coupled with reactive improvements to the distribution system, several completed reliability projects in Connecticut have enhanced both system reliability and market efficiency. Highlights of these projects are as follows:

- Elimination of a Long Mountain stuck-breaker contingency that led to the loss of three 345 kV lines
- Installation of the Glenbrook static compensator (STATCOM) to improve voltage performance in Southwest Connecticut
- Installation of two dynamic Voltage Ampere Reactive (DVAR) systems to improve voltage performance in Southwest Connecticut
- Installation of capacitor banks at strategic locations in Connecticut to further support steady-state voltage conditions
- Replacement of circuit breakers across Connecticut to increase short-circuit interrupt duty

ISO studies show that these improvements have reinforced the reliability of the Connecticut transmission system in advance of completing the major 345 kV reinforcement projects taking place in New England (see below). Earlier improvements have increased transfer limits into Southwest Connecticut by 300 MW, from 1,700 MW to 2,000 MW. More recent transfer-limit improvements have increased transfer limits into Southwest Connecticut by another 300 MW (up to 2,300 MW) and Connecticut's ability to import power by 100 MW up to 2,300 MW. These improvements help bring lower-cost energy into each area when available and mitigate the need for out-of-merit commitments for system reliability support. However, these projects have not eliminated the need for major additional system improvements.

Similarly, the NEMA upgrades, placed in service in the 2002 to 2003 timeframe, improved reliability to the northeastern Massachusetts/Boston load pocket while increasing transfer limits by 300 MW. The recent installation of a reactor in Cambridge helps improve VAR control in the Cambridge/Boston area during periods of lighter load. Significant progress has been made over the past year in siting and constructing five of the six major 345 kV projects the RTEP/RSP process has identified as critical for supporting a reliable power supply in New England into the foreseeable future, as summarized below:

- **NSTAR 345 kV Reliability Project**—increases the transfer limits into the Greater Boston area. The Massachusetts Energy Facilities Siting Board permitted the project in January 2005, and NSTAR has commenced construction. The projected in-service date is June 2006 for the first two cable circuits.

[19] ISO New England implemented Standard Market Design on March 1, 2003. SMD is an energy market structure that incorporates locational marginal pricing, day-ahead and real-time energy markets, and risk-management tools to hedge against the adverse impacts of having to pay higher locational-marginal prices (LMPs) when transmission congestion occurs.

The third cable is scheduled for service before summer 2008. The first two cables will increase the import capability by 900 MW and the third cable by another 200 MW.

- **Northeast Reliability Interconnect Project**—adds a new 345 kV tie line between New England and New Brunswick to improve the transfer capability between the two regions by 300 MW and improve system performance in northern Maine. The Maine Public Utilities Commission permitted the project in July 2005. The projected in-service date for this project is December 2007.

- **Southwest Connecticut Reliability Project Phase 1**—improves the transfer of power and system performance in Southwest Connecticut as the first stage of the major Northeast Utilities/United Illuminating Company (NU/UI) 345 kV project. The project is currently under construction with a projected in-service date of December 2006. Phase 1 will increase the import capability by 275 MW.

- **Southwest Connecticut Reliability Project Phase 2**—improves the transfer of power and system performance in Southwest Connecticut as the second stage of the major NU/UI 345 kV project. The Connecticut Siting Council (CSC) permitted the project in April 2005, and the project is currently in the final design and analysis stage. Its projected in-service date is December 2009. Phase 2 will increase the import capability by 825 MW.

- **Northwest Vermont Reliability Project**—improves the Vermont Electric Power Company's (VELCO) 345 kV and 115 kV transmission system for the major load center in northwestern Vermont. The Vermont Public Service Board permitted the project in January 2005 and, as part of that approval, ordered several project modifications. VELCO has commenced construction, is preparing the final design, and is analyzing project modifications. The projected in-service dates for individual stages of the project range from May 2006 through October 2007.

In addition to the Connecticut, NEMA/Boston, and major 345 kV line projects, a number of other significant system improvements are being made. The North Shore/Ward Hill (MA) Substation is currently being upgraded to work in conjunction with the NSTAR 345 kV project. Two of three 115 kV line upgrades from Ward Hill Substation have been completed, and an autotransformer is being added. Other improvements were made to increase the reliability to the Cape Cod load pocket, including the addition of an autotransformer, a new line, and a capacitor bank. The Central Massachusetts Project, which will unload the Sandy Pond Substation transformers, and the Auburn Project, which will upgrade a number of stations and lines in the Auburn-DuPont-Bridgewater area, also are under construction.

To increase the SEMA/RI export capability, improvements were made to select breakers at West Walpole, West Medway, Millbury, and Sherman Road. To increase the ability to move power within the Norwalk-Stamford and SWCT load pockets, two lines from Glenbrook Substation were reconductored, and 115 kV cables in the Bridgeport area and the Baird-Congress 115 kV lines were upgraded. Autotransformers were added at Scobie Substation in New Hampshire and at West Rutland Substation in Vermont.

Other projects nearing construction or recently begun include the following:

- **Southwest Rhode Island**—will increase both reliability and inter-area transfer capability between Rhode Island and Connecticut.

- **Y-138**—will increase both reliability and increase the transfer capability between Maine and New Hampshire by 100 MW.

- **Monadnock**—will eliminate thermal and voltage problems and increase reliability by creating stronger ties between central Massachusetts, southeastern Vermont, and southwestern New Hampshire.
- **Vermont Northern Loop**—will increase the reliability of the line by looping it through the area instead of feeding it radially.
- **Haddam Substation**—will connect a 345/115 kV autotransformer into the 115 kV system in south-central Connecticut.
- **Killingly Substation**—will install a 345/115 kV autotransformer in Connecticut into a 115 kV system, increasing the transfer limit into Connecticut.

New Initiatives

RSP05 identifies several new ISO initiatives and tasks to improve its planning process and assure the future reliability of service to the region's load:

- Develop a *Horizon Year Study* to provide longer-term direction for New England's transmission development.
- Review the load-forecast methodology to improve its quality.
- Conduct a comprehensive review of all the methodologies, criteria, and assumptions used to calculate the Installed Capacity Requirements for the system and load pockets. The review will take about 18 months to complete, with any revisions incorporated in the calculation used to generate the IC Requirements for Power Year 2007–2008.
- Initiate a long-term program to improve the monitoring and control of the grid. This effort will assess the data-communication and substation monitoring and control equipment presently installed on the grid and the effectiveness of the methods and facilities system operators use to respond to contingencies, including load shedding.
- Identify and address those issues that obstruct the market from providing, in response to price signals, the resources needed to reliably operate the power grid. These measures will reduce the commitments made to generating resources operating out of economic merit order to satisfy power system criteria. One area of focus for this project will be to identify key upgrades to the power system infrastructure that would reduce or eliminate the need to commit out-of-market generation to control voltage.
- Investigate the pricing rules and operating procedures to ensure that they are consistent with each other and that barriers do not exist for properly pricing or efficiently using resources.
- Evaluate and apply advanced technology solutions to maximize the thermal use of existing rights-of-way and improve voltage performance. These solutions include the use of new conductor technologies and innovative voltage-control devices.
- Conduct interregional transmission planning. Implementation of the Northeast Planning Protocol and continued participation in NPCC activities will improve coordination with neighboring control areas.

- Review the long-term viability of each Special Protective Scheme (SPS) used on the New England bulk power system to optimize transfer capability.

Recommendations for New England

The following are the ISO's recommendations to assure, through market incentives where appropriate, a reliable and more robust electricity supply system is implemented in New England over the next 10 years:

- **Complete Transmission Projects**—Improve the New England infrastructure and maintain power system reliability in New England over the next 10 years by supporting the timely completion of ongoing transmission improvements identified in RSP05. The report currently contains 272 projects, which will continue to be modified on an ongoing basis as new improvements are identified and projects are completed or eliminated from the listing.

- **Develop Resources**—Increase systemwide resources by at least 160 MW in the 2008 to 2010 timeframe. Add 670 MW in the Greater Connecticut load pocket by 2009 to satisfy reliability needs. Increase quick-start resources by 530 MW in Greater Connecticut now and by 500 MW in BOSTON to improve operating flexibility and efficiency. Greater Southwest Connecticut also needs 350 MW of quick-start resources by 2009, but if added by 2006, it can help satisfy Greater Connecticut's reliability needs. These needs are not mutually exclusive. The addition of quick-start resources in Greater Connecticut or BOSTON will satisfy system requirements. Additions to quick-start resources in Greater Connecticut will satisfy load-pocket needs as well as system needs.

- **Enhance Fuel Diversity**—Develop mechanisms to attract an improved diversity of fuel types for the New England fleet of supply resources. This should include clean coal technologies and additional nuclear resources. In addition, investigate the impact that alternative resources, such as wind and distributed generation (DG), will have on the operation and long-term security of the power system.

- **Improve Firmness or Flexibility of Gas Resources**—Firm up gas-supply arrangements for at least 400 MW or convert 400 MW to dual-fuel operations in southern New England by 2006 to 2007. This will provide for reliable operation of the system during periods of high demand when natural gas may be unavailable for electricity generation. Increase the arrangements or conversions by 250 MW per year through 2008/2009 and by another 500 MW by 2009/2010.

- **Develop Gas Supplies**—Develop new gas supplies and delivery capacity, including LNG facilities, to meet increased demand in New England.

- **Increase Demand Response**—Increase the penetration of demand response as part of the overall supply to assure reliability and ensure its operability.

- **Improve Operational Control**—Initiate a long-term program to improve the monitoring and control of the grid, to prepare for the upcoming period in New England when capacity will become more constrained and to respond to recommendations of the August 2003 Blackout Task Force.[20] This will allow the ISO and the local control centers to better monitor the grid and more accurately initiate load shedding at a substation feeder level.

[20] Natural Resources Canada and U.S. Department of Energy, *The August 14 2003 Blackout One Year Later: Actions Taken in the United States and Canada to Reduce Blackout Risk*. Report to the U.S.-Canada Power System Outage Task Force. August 13, 2004.

Part I **Introduction**

This introduction provides background information on the New England electric power system as a basis for understanding the results presented in RSP05 and its findings and recommendations. Section 1 presents an overview of the electric power system, the concept of electric power system control areas, and the control areas interconnected to New England. It also introduces the subareas used to model the region as part of the planning studies conducted for this report. This section then presents an overview of current generation capacity, current transmission capacity, and special transmission issues.

Section 2 presents an overview of RSP05 system planning. It summarizes the planning criteria with which the ISO must comply and the types of analyses conducted to forecast future load levels and resource adequacy needs, determine desirable locations and operating characteristics for future resources, and assess the transmission system. This section also discusses the rationale for conducting the various types of studies, the key assumptions under which the studies are conducted, and several study methodologies.

Section 1

System Overview

Created in 1997, the ISO is a not-for-profit corporation responsible for three main functions:

- The reliable day-to-day operation of New England's bulk power generation and transmission system
- Oversight and administration of the region's wholesale electricity markets
- Management of a comprehensive regional bulk power system planning process

On February 1, 2005, the ISO began operation as a Regional Transmission Organization, assuming broader authority over the day-to-day operation of the region's transmission system and possessing greater independence to better manage the region's electric power system and competitive wholesale electricity markets. The ISO works closely with regulators and stakeholders, including participants in the marketplace, to carry out its functions.

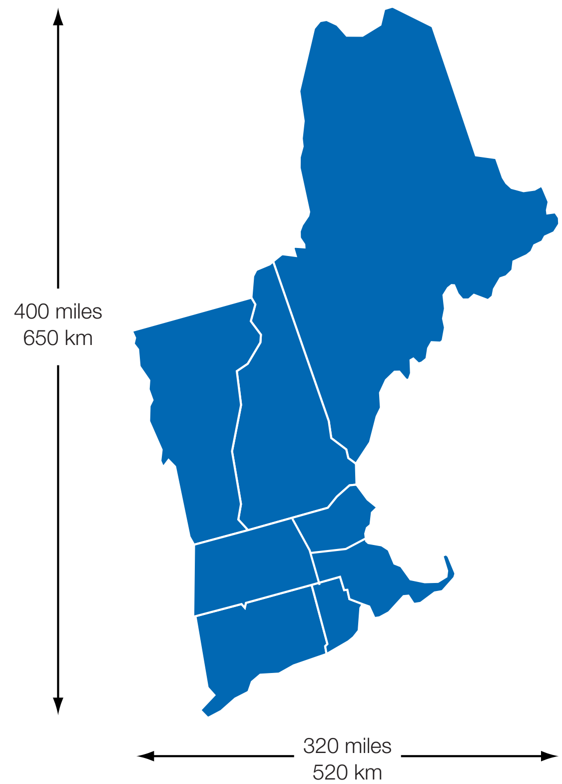
Section 1 of RSP05 provides an introduction to New England's electric power system. It summarizes the features of the electricity grid and trends in the demand for electricity. It also briefly describes the capacity of the system for generating electricity, by fuel type, and how the generation is distributed in New England. An overview of the transmission of electricity in New England is provided as well, which includes information on the system's infrastructure lines with dominant power flows, ties with neighboring regions, and major performance issues.

1.1 Overview of the Electric Power System

The electric power system in New England is a fully integrated system that uses all regional generating resources to serve all regional load independent of state boundaries. Most of the transmission lines are short and networked as a grid, so that electrical performance in one part of the system affects all corners of the system. As shown in Figure 1.1, the New England regional electric power system serves 14 million people living in a 68,000 square-mile area. Over 350 generating units produce electricity, representing approximately 31,000 MW of total generating capacity, most connected to approximately 8,000 miles of high-voltage transmission lines. New England is connected to its neighbors, New Brunswick, New York, and Québec, by 12 interconnections. As of summer 2005, almost 500 MW of demand can be reduced as part of ISO's Demand Response Programs, in which customers reduce load based on reliability needs or price signals (see Section 6.1.2). This quantity does not include other customer-based demand-response programs.

New England's power grid and its central dispatch system were created by the New England Power Pool (NEPOOL).[21] NEPOOL was formed in 1971 by the region's private and municipal utilities to foster cooperation and coordination among the utilities in the six-state region and ensure a dependable supply of electricity. Today, NEPOOL members serve as ISO New England stakeholders and market participants.

[21] For more information on NEPOOL participants, see <http://www.iso-ne.com/committees/nepool_part/index.html#top>.



- 6.5 million electricity customers; population 14 million
- 350+ generators and power plants
- 8,000+ miles of high-voltage transmission lines
- 12 interconnections with systems in New York and Canada
- 31,000+ megawatts of total supply
  (includes 500+ megawatts of demand response)
- Approximate peak demand: 27,121 megawatts on July 27, 2005
  (includes approximately 200 megawatts of demand response)
- 260+ participants in marketplace
- $7.25 billion total energy market value;
  $1.9 billion transacted in spot market

Figure 1.1 **Key facts on New England's electric power system and wholesale electricity market.**

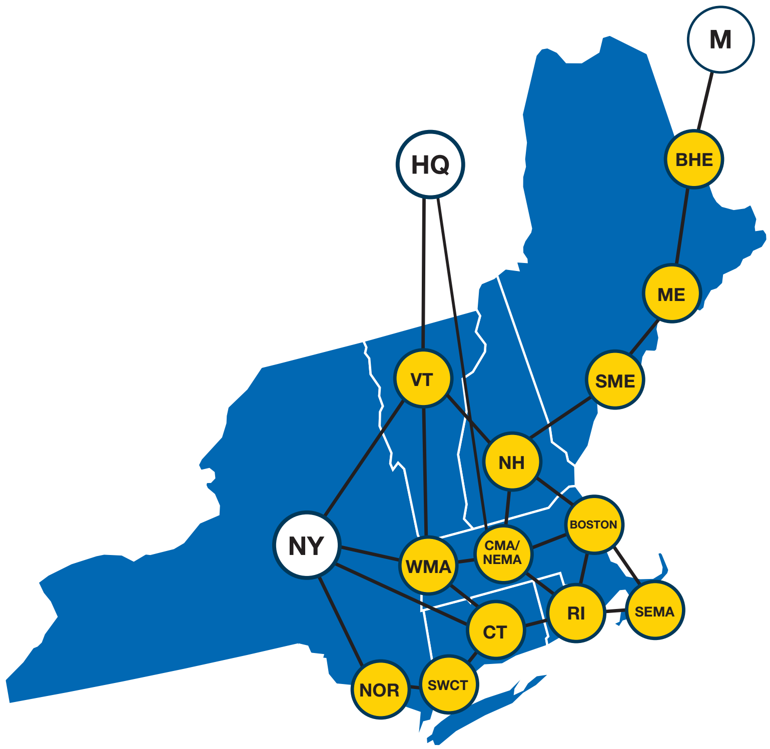
1.2 Control Areas and Subareas

To effectively plan and operate the generation, transmission, and distribution of electricity within New England, as well as the interactions that take place with its neighboring regions, New England is both part of a larger region and is divided into subregions, as described below. The Northeast Power Coordinating Council is an international organization to which ISO New England belongs.[22] NPCC was formed after the 1965 Northeast Blackout to promote the reliability of the interconnected power systems within northeastern North America. The NPCC consists of five control areas, defined as electric power systems bounded by interconnection metering and telemetry that can control generation to maintain a net interchange schedule with other control areas and contribute to regulating the frequency of the interconnection. The NPCC control areas are as follows:

- New England Control Area
- New York Control Area
- Hydro-Québec Control Area
- Maritimes Control Area
- Ontario Control Area

[22] See <http://www.npcc.org/default.asp>. NPCC is one of 10 regional reliability councils in the United States, Canada, and portions of Mexico that form the North American Electric Reliability Council.

Within New England, 13 subsets of the New England electric power system, called subareas, have been established to assist in modeling and planning electricity resources. These subareas reflect a simplified model of major transmission bottlenecks of the system, which are physical limitations of the flow of power that evolve over time due the variety of system changes that take place. Figure 1.2 is a simplified model of the system that shows the ISO subareas and three external control used in some of the RSP05 analyses, such as resource adequacy studies (see Section 4) and environmental emission studies (Appendix A). More detailed models are used for other types of analyses, including transmission planning studies (Part III), and for the real-time operation of the system. Some RSP studies investigate conditions in "Greater Connecticut," which combines the NOR, SWCT, and CT Subareas, and "Greater Southwest Connecticut," which is comprised of the NOR and SWCT Subareas.



Subarea Designation	Region or State
BHE	Northeastern Maine
ME	Western and Central Maine/ Saco Valley, New Hampshire
SME	Southeastern Maine
NH	Northern, eastern and central New Hampshire/eastern Vermont, southwestern Maine
VT	Vermont/southwestern New Hampshire
BOSTON	Greater Boston, including the North Shore
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts

Subarea or Control Area Designation	Region or State
WMA	Western Massachusetts
SEMA	Southeastern Massachusetts/ Newport, Rhode Island
RI	Rhode Island/bordering MA
CT	Northern and eastern Connecticut
SWCT	Southwestern Connecticut
NOR	Norwalk/Stamford, Connecticut
M, NY, and HQ	Maritimes, New York, and Hydro-Québec external control areas

Figure 1.2 **RSP05 geographic scope of the New England electric power system.**

1.3 Trends in System Demand

The New England power system is a summer-peaking system, meaning the highest demand for power during the year occurs in the summer season. The system's "50/50" peak demand projected for 2005 is 26,355 MW, while the "90/10" peak demand projected for 2005 is 27,895 MW.[23]

In the past 10 years, New England has experienced 90/10 peak loads under hot and humid weather conditions four times. On July 19, 2005, the region exceeded its August 2002 peak of 25,348 MW by 5.5% by reaching a peak demand of 26,749 MW, consistent with "80/20" weather conditions of about 92.9ºF. Eight days later on July 27, 2005, the regional demand peaked yet again, when the all-time demand reached 26,921 MW, under "55/45" weather conditions. This peak load would have been even higher by approximately 200 MW had demand-response measures not been activated in Connecticut under ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency*, to supply the required operating reserve, balance supply and demand, and help maintain system reliability.[24] The summer peak has increased by 20% over the last 10 years and is expected to continue to grow 14.5% over the next 10 years.

The winter-peak demand projected for 2005/2006 is 22,830 MW under 50/50 weather conditions, or 23,740 MW under more severe 90/10 weather conditions. An all-time winter record demand of 22,817 MW was set on January 15, 2004.

Both summer and winter peaks are expected to grow at an annual compound rate of approximately 1.52% per year from 2005 to 2104. The system peak demands forecasted for 2005 to 2014 reflect the estimated energy reductions that would result from utility-sponsored demand-side management (DSM) energy conservation and efficiency programs. These reductions are forecasted to range from approximately 1,500 MW to 1,600 MW during this period.

Figure 1.3 illustrates the concentration of load in the New England system. The largest concentrations of load are in the region's urban centers, Greater Boston, Southwest Connecticut, and the mid-Connecticut River Valley. Smaller load centers appear near smaller cities throughout New England, such as Providence, Rhode Island; Burlington, Vermont; and Portland, Maine.

[23] "50/50" peak loads refer to loads that have a 50% chance of being exceeded due to weather conditions expected to occur at an average New England temperature of 90.4ºF. The "90/10" peak loads refer to loads that have a 10% chance of being exceeded due to weather conditions, expected to occur at an average New England temperature of 94.2ºF.

[24] See <http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html>.

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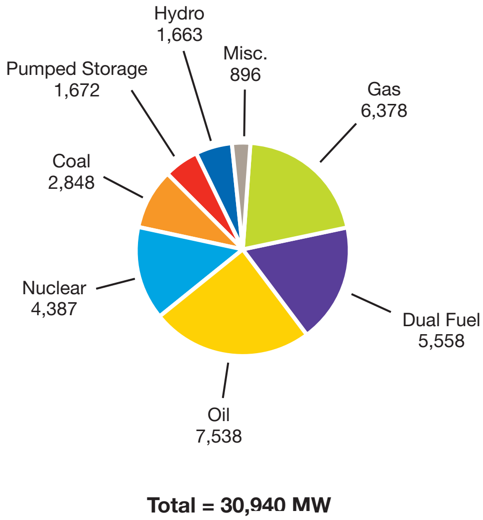
Figure 1.3 **Load concentrations in New England.**

1.4 Current Generation Resources

Figure 1.4 shows the installed capacity in New England by primary fuel type as of summer 2005. The figure includes capacity from generators that generate anywhere from 5 MW to about 1,200 MW.[25] In New England, approximately 72% of the installed capacity is fueled by fossil fuels. Approximately 39% of the capacity is fueled by natural gas, with about 47% of those gas units having dual-fuel capability (i.e., the flexibility and storage capacity to use oil as well as gas). About 24% of the installed capacity is oil-fired, and 9% is coal-fired.[26] Nuclear energy fuels approximately 14% of total New England installed capacity, while hydro capacity, including pumped storage, contributes about 11%. The remaining 3% of installed capacity is fueled by renewable resources, including biomass, refuse, and wind.

[25] Figure 1.4 also includes units called "settlement-only" generators. Settlement-only units generate less than 5 MW and are entitled to receive an installed capacity credit (ICAP credit) as part of the ICAP electricity market, but they are not centrally dispatched by the ISO control room and are not monitored in real time. See Section 6 for more information on the electricity markets.

[26] Based on the NEPOOL report, *2005–2014 Forecast Report of Capacity, Energy, Loads, and Transmission (2004 CELT Report)*, April 1, 2005.



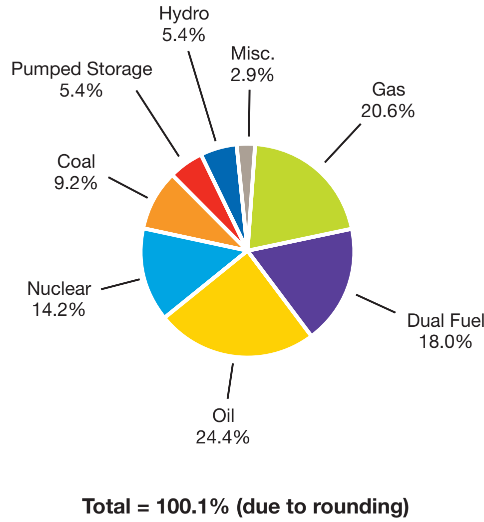


Figure 1.4 **New England installed capacity by primary fuel type, summer 2005 (MW and percent).**

Note: Units in the "Miscellaneous category include those fueled by biomass, refuse, and wind. Dual-fuel capacity is based on units with gas as the primary fuel; 11.5% of the total units have oil as the primary fuel with gas as the alternative fuel.

Table 1.1 indicates the number of New England generating units by fuel type and installation dates. As shown in the table, much of New England's current capacity was installed during the 20-year period from 1971 to 1990, and 39% of that capacity was oil-fired. Coal units make up 45% of the total capacity of the units that went into service between 1951 and 1970. In contrast, 97% of the generation installed since 1991 consists of units with natural gas as the primary fuel.

Table 1.1
Number of Generating Units in New England by Fuel Type and In-Service Dates, Summer 2005[a]

Fuel Type	In-Service Date prior to 1950		In-Service Date 1951–1970		In-Service Date 1971–1990		In-Service Date 1991 and after		Total	
	# of Units	MW	# of Units	MW	# of Units	MW	# of Units	MW	MW	Percent
Gas	0	0	0	0	0	0	24	6,378	6,378	20.6
Dual fuel[b]	3	63	4	354	9	336	27	4,805	5,558	18.0
Oil [c]	7	26	63	2,486	32	4,966	7	60	7,538	24.4
Nuclear	0	0	0	0	5	4,387	0	0	4,387	14.2
Coal	0	0	14	2,592	2	256	0	0	2,848	9.2
Pumped storage	1	29	0	0	3	1,643	0	0	1,672	5.4
Hydro	65	877	8	316	156	411	49	58	1,663	5.4
Miscellaneous[d]	0	0	0	0	31	656	33	240	896	2.9
Totals[e]	**76**	**996**	**89**	**5,748**	**238**	**12,655**	**140**	**11,540**	**30,940**	**100.0**
Percent of Total MW		**3.2%**		**18.6%**		**41.2%**		**37.6%**		

[a] Units in this table represent generator assets that may be power plants or individual units that make up power plants.

[b] Dual-fuel capacity is based on units with gas as the primary fuel; 11.5% of the units have oil as the primary fuel and gas as alternative fuel.

[c] For the oil units, 11.5% use oil as the primary fuel and gas as an alternative fuel.

[d] Miscellaneous units include those fueled by wood, refuse, wind, and other renewable sources.

[e] Totals include settlement-only units.

Figure 1.5 shows New England energy generation by fuel type for 2004, in megawatt hours (MWh) and percent. About 40% of energy was produced by gas-only and dual-fuel units. Roughly 58% of energy generated in 2004 was from fossil-fueled units. About 40% of energy was produced by gas-fired and dual-fuel units. Nuclear generation contributed approximately 27% of total generation, while energy provided from hydro and miscellaneous resources was approximately 11%. Net-energy interchange with neighboring control areas accounted for approximately 4% of total energy requirements.

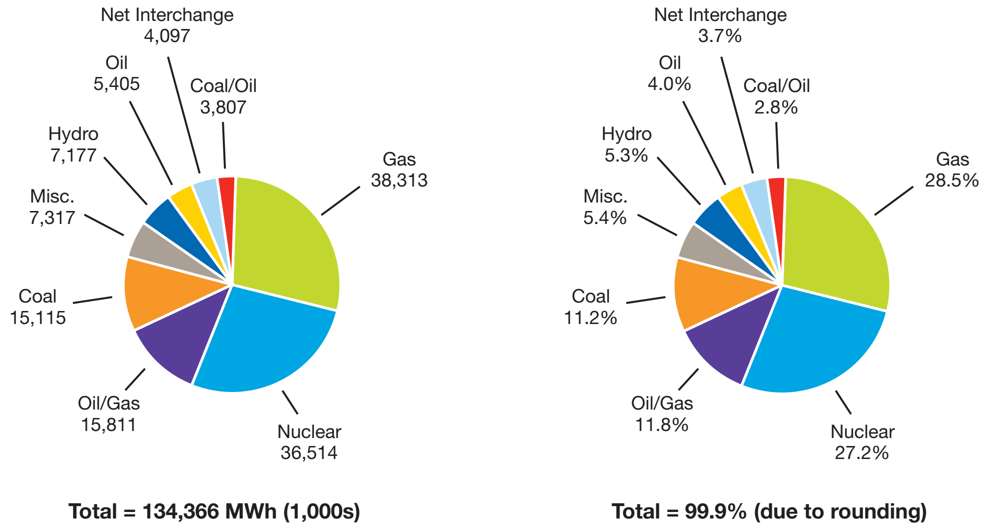


Figure 1.5 **New England annual source of energy for 2004 (1,000 MWh and percent).**
Note: Units in the "Miscellaneous" category include those fueled by biomass, refuse, and wind.

Of the 30,940 MW of total generation in the New England system, 3,200 MW is comprised of quick-start capacity that includes pumped storage and conventional hydro, combustion turbines, and internal combustion units. Quick-start resources provide greater operating flexibility than base-load or intermediate generation and can start up and be at full load in less than 10 minutes. In daily operations, quick-start resources replenish the capacity and energy lost due to a sudden and unexpected loss of a generating unit or transmission facility, both within and outside of a load pocket.[27] Quick-start units provide important operating flexibility in transmission-constrained areas; they can reduce the payments made to generators that provide reserve capacity and would otherwise need to run in that area. Many quick-start resources provide other functions, including those needed during emergency conditions. One such function is the ability to provide "black start" (i.e., the ability to start up quickly after a system blackout and without grid support).

Figure 1.6 shows the distribution of generation resources throughout New England. Most of the generation is concentrated along the coastal areas.[28] Hydroelectric plants provide a relatively larger proportion of the northern generation than the southern generation. The figure shows the Hydro-Québec Phase II and Highgate HVdc ties, as well as the New Brunswick tie (see below).

[27] Load pockets are subareas of the system where the transmission capability is periodically not adequate to import capacity from other parts of the system, and load must rely on local generation.

[28] Copies of the 2005 maps and diagrams of the New England transmission network can be obtained by contacting ISO Customer Service at (413) 540-4220.

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at (413) 540-4220.

Figure 1.6 **Distribution of generation resources throughout New England.**

Summaries of generating capacity by subarea, state, and Standard Market Design zone are shown in Table 1.2.[29] Appendix B lists the New England generation units by subarea and generator additions from 1999 through summer 2005.

Table 1.2
Generating Capacity by Subarea, State, and SMD Zone[a]

RSP Subarea	State	SMD Load Zone	Summer (MW) Capacity Rating	Summer (MW) Percent of Subarea	Summer (MW) Percent of State	Winter (MW) Capacity Rating	Winter (MW) Percent of Subarea	Winter (MW) Percent of State
BHE			**851**			**939**		
	ME	ME	851	100	26	939	100	27
ME			**912**			**1,004**		
	ME	ME	912	100	28	1,004	100	29
SME			**1,505**			**1,562**		
	ME	ME	1,505	100	46	1,562	100	45
NH			**3,991**			**4,187**		
	NH	NH	3,964	99	98	4,161	99	98
	VT	VT	9	0	1	9	0	1
	MA	WCMA	17	0	0	18	0	0
VT			**910**			**983**		
	NH	NH	91	10	2	92	9	2
	VT	VT	817	90	99	890	90	99
	VT	WCMA	1	0	0	2	0	0
BOSTON			**3,595**			**4,005**		
	MA	WCMA	11	0	0	15	0	0
	MA	NEMA	3,585	100	30	3,990	100	30
CMA/NEMA			**119**			**122**		
	MA	WCMA	119	100	1	122	100	1
WMA			**3,719**			**3,988**		
	MA	WCMA	3,719	100	31	3,988	100	30
SEMA			**3,362**			**3,623**		
	RI	RI	245	7	8	280	8	8
	MA	SEMA	3,117	93	26	3,343	92	25
RI			**5,198**			**5,813**		
	CT	CT	726	14	10	833	14	10
	RI	RI	2,902	56	92	3,182	55	92
	MA	SEMA	1,570	30	13	1,798	31	14
CT			**4,401**			**4,509**		
	CT	CT	4,401	100	59	4,509	100	56
SWCT			**1,924**			**2,171**		
	CT	CT	1,924	100	26	2,171	100	27
NOR			**455**			**481**		
	CT	CT	455	100	6	481	100	6

[a] Sum may not add due to rounding.

[29] ISO New England implemented Standard Market Design on March 1, 2003. SMD is an energy market structure that incorporates locational marginal pricing, day-ahead and real-time energy markets that produce separate financial settlements, and risk-management tools to hedge against the adverse impacts of having to pay higher locational marginal prices when transmission congestion occurs.

1.5 Current Transmission System

The New England transmission system includes nearly all of the networked electric power systems in New England.[30] It serves a diverse region that contains rural to dense urban areas and integrates a widely dispersed and diverse set of generating resources to serve customer loads. The geographic distribution of New England's peak load in summer and winter is approximately 20% in the north (Maine, New Hampshire, and Vermont), and 80% in the south (Massachusetts, Connecticut, and Rhode Island). Although the northern area is larger geographically than the southern area, the larger southern load reflects greater development and the concentration of population in urban areas.

Normal dispatch, considering economics, generation availability, and transactions with neighboring systems, results 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 has resulted in situations where surplus generation in one subarea may not be deliverable to other subareas and is not always available simultaneously with other generation in the region as a whole.

The New England transmission system is a complex grid that is mostly comprised of 115 kV-, 230 kV-, and 345 kV-rated lines. Transmission lines in the north are generally longer and fewer in number than those in the south. The increased transmission density in the south reflects larger load and power-supply concentrations. Three 345 kV lines provide the major transmission links between eastern and western New England.

New England is located in the northeastern corner of the U.S./Canada "Eastern Interconnection," where only three synchronous ties rated 230 kV and above exist between New England and New York. These ties include two 345 kV ties and one 230 kV tie. Additional ties between New England and New York include one 138 kV tie, three 115 kV ties, one 69 kV tie, and one 330 MW high-voltage direct-current (HVdc) tie.

Currently, the Maritime provinces (New Brunswick, Nova Scotia, and Price Edward Island) are connected to New England synchronously to the rest of the Eastern Interconnection through a single 345 kV tie, although a second 345 kV tie is planned (see Section 8.1.1). The New England system also has two HVdc interconnections with Québec—a 225 MW back-to-back converter at Highgate in northern Vermont and a +/- 450 kV HVdc line. The terminal configurations of the latter allow nonsimultaneous operation of either a 690 MW connection at Comerford, in northern New Hampshire, or a 2,000 MW connection at Sandy Pond, in eastern Massachusetts.

Figure 1.7 shows typical summer-peak transmission flows on a simplified representation of the network.

[30] Maine Public Service Co. and Eastern Maine Electric Co-op, both located in northeastern Maine, are not part of the New England Control Area. See <http://www.nmisa.com/>.

This graphic has been redacted

and may be accessed

by calling ISO New England

Customer Service

at (413) 540-4220.

Figure 1.7 **Typical summer-peak transmission flows in New England.**

The location and operation of existing and new generation has resulted in heavy stresses on northern and eastern New England transmission facilities. These situations have created a number of complex system stability concerns that vary with changes in system conditions.

The nature of the New England transmission system also has led to a number of voltage-performance issues that can create the potential for voltage collapse, a condition where low voltages cascade and result in widespread loss of load. These performance issues include the following:

- Transmission lines that connect distant resources, which can cause voltage drops
- Few transformers that connect the 345 kV and 115 kV systems
- Heavy transmission system flows near the physical system's capability

Numerous transmission interfaces have been defined within New England and between New England and its neighbors. A transmission interface is composed of one or more transmission facilities with capability to transfer a specific amount of power between or through various areas before a transmission limit is reached. Typical limits are line ratings or substation equipment ratings or voltage or stability limits. A transmission interface can create a bottleneck in the system if it reaches the limit of the total amount of power it can transfer from one direction to the other.

The critical contingency and limiting transmission facility, which restricts the power transfer through a given interface, may not necessarily be part of the interface; it may be electrically in series with or parallel to it. The most limiting transmission facility and critical contingency, which limits the interface transfer, may vary with system conditions. Maintaining transfers within interface limits can require restricting the operation of generating resources or adjusting imports or exports with neighboring systems.

In the real-time operating environment, transmission interface operating limits change constantly; both the potential for restriction and the precise level of the interface-transfer limit are affected by a number of variables, including the following:

- Load level
- Generation availability and dispatch
- Operation of pumped storage (pump versus generate)
- Imports or exports with neighboring systems
- Seasonal differences in transmission facility ratings

For determining interface-transfer limits, the ISO must evaluate a large range of potential system conditions.

Section 2

Overview of System Planning

Generation, demand, and transmission must all be considered when planning the New England electricity system. With the continued growth in the electricity load projected for the region and with several major portions of New England, including Greater Connecticut, Greater Southwest Connecticut, Boston, and Vermont facing serious reliability issues, proper planning is required to identify needed system improvements and maintain long-term system reliability.

The critical inputs to the planning process are load forecasts, projections of generation and distributed resources that reduce load, and an assessment of the performance of the overall system, including the transmission system that moves power to where it is needed.[31] Also vital to the planning process is to account for new supply and demand-side resources including the necessary lead times for permitting and construction. RSP05 studies account for these and other factors including load growth and conditions; weather; facility outages; potential resource retirements, deactivations, and delistings; and the addition of generating units and demand-response resources, with due consideration of the system's economic performance and impact on systemwide air emissions.[32] It also considers capacity benefits related to the ties with the neighboring systems in New York and Canada. As is evident in RSP05, electrical problems and solutions can—and in many cases do—cross state and operating-company boundaries.

As the Regional Transmission Organization, ISO New England leads the annual planning effort through an open stakeholder process. With input from the Planning Advisory Committee (comprised of electricity market participants, representatives from governmental entities, and consultants), the NEPOOL Reliability Committee, and other stakeholders, and technical assistance from the transmission owners, the ISO analyzes and plans for the reliability and adequacy of the New England bulk power system as an integrated whole.[33] This ensures that modifications made to one part of the system, including newly interconnected generating units, will not have an adverse impact on another part of the system. The PAC and the Reliability Committee have reviewed RSP05's scope of work, study assumptions, and results. Eight stakeholder meetings were held with the PAC from January to October 2005, and the ISO has modified the assumptions and analyses based on comments received.

Section 2 provides an overview of the ISO's planning process for assuring the reliability and adequacy of the New England power system. This section summarizes the planning criteria, the systemwide and subarea studies conducted for RSP05, and the rationale for conducting both probabilistic and deterministic studies as they relate to risk assessment. It also discusses study methodologies used. Studies that assessed the transmission system are discussed as well.

[31] Distributed resources are a growing form of smaller-sized on-site resources that involve load-reduction technologies or on-site generators. Distributed resources are typically located at or near load centers and generally installed and owned by a commercial or industrial facility. A facility's use of these resources helps maintain the reliability of its electric supply during grid emergencies. Distributed resources may be installed to serve all or part of a facility's electric load and to provide thermal energy to enhance the economics of its overall energy supply. The ISO's demand-response programs are examples of distributed-resource measures.

[32] Retirement is the permanent removal from service of a facility, which cannot return to service without major refurbishment and/or relicensing. Deactivation is the "mothballing" of a facility, such that with some minor reconditioning, it could be brought back into service in a relatively short time. Delisting is a more temporary removal of a facility from service for various reasons, usually related to maintenance. These facilities could be brought back on-line relatively easily.

[33] For more information on the NEPOOL Reliability Committee, see <http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/index.html>.

2.1 Planning Criteria

The North American Electric Reliability Council, the Northeast Power Coordinating Council, and the ISO all require RSP05 studies to be consistent with their planning criteria and procedures.[34] These criteria and procedures include prescriptive guidelines for resource adequacy and transmission performance necessary for ensuring a reliable electric power system design.

2.2 Planning Process

As illustrated in Figure 2.1, planning is an ongoing cyclical effort, and RSP05 is part of a continuum of past Regional Transmission Expansion Plans.[35] The process is continually affected by the results of load forecasts, changing fuel costs, new generation that has come on-line and generation that has gone off-line, new transmission projects, varying levels in demand-side response, firm purchases and sales, and new federal and state regulations, such as the Energy Policy Act of 2005.[36] RSP studies also evolve through the many PAC reviews that take place during the year. The studies supporting the RSP often do not follow the calendar year, which results in capturing and presenting mere snapshots of the studies in the planning reports.

RSP05 is broader in scope than the RTEP reports. For both RTEP and RSP reports, the ISO analyzed the system's capability to reliably serve load over a 10-year period, the need for new resources, and transmission improvements. RSP05 provides additional information on the types of resources needed over the planning period.

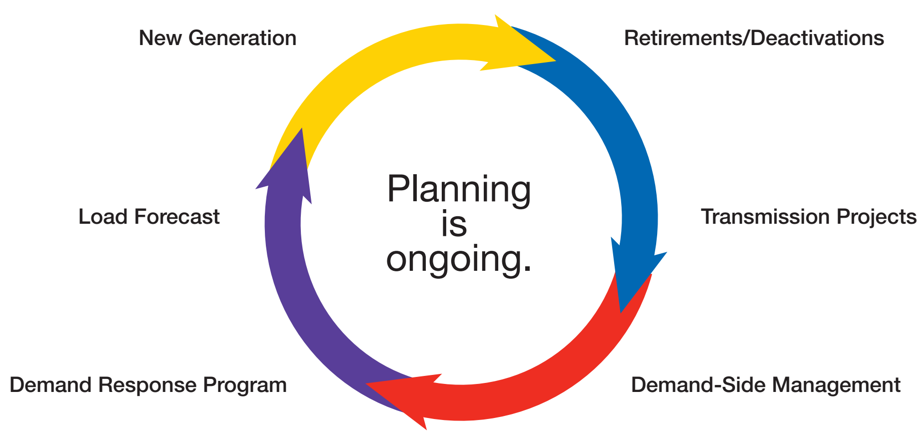


Figure 2.1 **RSP planning process.**

[34] See <http://www.nerc.com/>; <http://www.npcc.org/>; and <http://www.iso-ne.com/rules_proceds/isone_plan/index.html>.

[35] RTEP reports can be found in the ISO New England archives at: <http://www.iso-ne.com/trans/rsp/2005/index.html>.

[36] See <http://thomas.loc.gov/cgi-bin/bdquery/z?d109:h.r.00006:>.

2.3 Planning Studies

During the RSP planning process, the ISO analyzes the reliability and adequacy of the tightly integrated New England power system as a single entity. The ISO conducts a wide variety of analyses and system simulations under various conditions to capture all system changes, examine corresponding impacts, and obtain a comprehensive assessment of system performance. While each study has individual merit and a specific purpose, each one by itself does not provide the overall picture of the New England system. Thus, the ISO also reviews the results of all studies from an integrated perspective.

In some RSP analyses, the ISO uses a simplified model of the transmission system and the system's subareas (as shown in Figure 1.2). The simplified model accommodates certain simulations of projected system performance and captures potential limitations in the transmission system. The results of these analyses reflect approximate transfer capabilities *between* subareas, but do not capture system constraints *within* a subarea. Thus, they are considered "best-case" results suitable for resource-reliability assessments, but they do not substitute for detailed transmission analyses that more accurately capture system performance within and between the RSP subareas.

The modeling of the electric power system of New England and its subareas depends on a variety of assumptions regarding the in-service dates for new units, generation availabilities, fuel costs, timing of transmission upgrades, load forecasts, and transactions with neighboring control areas. A major part of the annual RSP process is to update the modeling assumptions used to reflect changed circumstances.

2.3.1 Determining the Amount of Resources Needed

The ability of generation to serve load, or resource adequacy, may be influenced by several factors, including generator outage rates, lack of fuel diversity, distribution of load throughout a region, penetration of demand-response programs that use conservation measures and distributed generation, and transmission constraints. The ISO conducted several complementary analyses to determine resource adequacy. One analysis is a probabilistic installed capacity analysis, which uses advanced mathematical techniques to determine the probability of disconnecting load under a range of conditions, such as varying load levels and generator outages. The second type of analysis is an operable capacity analysis. This type of analysis is deterministic and considers specific scenarios to determine operable capacity margins.

2.3.1.1 Installed Capacity Analysis—Methodology and Assumptions

The installed capacity analysis identifies bulk power system reliability issues related to the adequacy of system resources.[37] This measure of resource adequacy determines how much capacity load-serving entities must provide during the capacity auction.[38] The result of the installed capacity analysis is an Installed Capacity Requirement (formerly called the Objective Capacity Requirement) based on a criterion for loss-of-load expectation. A LOLE applies the probability of generator forced outages and load levels to calculate the amount of loss, or disconnection, that can be expected of the system during weekday peak-demand periods under various weather conditions and a range of resource availabilities. Although some of the LOLE analyses use a limited model of the transmission system and operational constraints, they are extremely important because they identify the amount of

[37] Reliability adequacy is a measure of the reliability of the bulk power system to meet demand and the sufficiency of the system's generating resources.

[38] For information on the capacity auction, see <http://www.iso-ne.com/markets/othrmkts_data/inst_cap/icap/index.html>.

resources needed to meet the established resource planning reliability criterion. ISO New England uses the NPCC resource planning reliability criterion, as described in A-2, *Basic Criteria for Design and Operation of Interconnected Power Systems*, that requires a power system to have enough installed capacity so that firm customer loads are not disconnected more than 1 day in 10 years (or 0.1 day per year).[39] The LOLE criterion has been used to determine New England's IC Requirement since 1971 when the New England Power Pool was charged to conduct regional planning.[40] This calculation assumes that no transmission constraints exist within New England so that all generating resources in the region are available to all loads. Other critical assumptions are as follows:

- The load forecast is modeled as a probability distribution of the weekday peak loads that accounts for the effects of weather uncertainty.
- The availability of resources is modeled based on the probability of forced outages.
- The transmission system can be operated reliably when systemwide operating reserves have been fully depleted.
- No generating units will be added or removed from the system during the assessment period.
- To meet emergency needs throughout the assessment period, New England can rely on 2,000 MW of uncontracted or otherwise unscheduled capacity (called tie benefits) from New York, Québec, and the Maritimes to meet needs.
- All ISO New England emergency actions per Operating Procedure No. 4, *Actions during a Capacity Deficiency* (OP 4), will be fully available during a capacity deficiency.[41]

Using this methodology and these assumptions result in identifying the minimum amount of capacity needed to meet the LOLE criterion. This is because these assumptions do not take into account the following risks, which, if present, would increase the IC Requirement:

- The New England transmission system may not be able to simultaneously transfer to load the full output from all of New England's generators. For example, Greater Connecticut is transmission limited, and power cannot always reliably or securely flow from a generator within that area to load there. Also, the Maine–New Hampshire interface limits the receipt of generation output from Maine, including transfers from New Brunswick into New England.
- As shown by operating experience, transmission security (first- and second-contingency protection for thermal overloads, voltage collapse, and generator instability) cannot be maintained when New England-wide operating reserves do not meet the requirements stated in ISO New England Operating Procedure No. 8, *Operating Reserve and Automatic Generation Control*, (OP 8).[42, 43]

[39] See <http://www.npcc.org/criteria.asp>.

[40] Over the next 18 months, the New England system stakeholders will review the methodology that calculates the IC Requirement.

[41] Under OP 4 conditions, the system operator must take special steps to prevent curtailment of firm customer load. These actions include reducing operating reserves, reducing voltages, importing emergency power, activating emergency demand response to make capacity available, and taking other emergency measures while still maintaining transmission system reliability. See <http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html>.

[42] The first contingency is the loss of the first facility that has the largest impact on system reliability. The second contingency is the loss of the next facility, which would then have the largest impact on the system.

[43] For more information on OP 8, see <http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html>.

- The ability of neighboring systems to supply emergency power may well diminish, as neighboring regions experience load growth that exceeds generation additions, and the reserve supplies in these regions decrease. The future ability to simultaneously import a total of 2,000 MW of uncontracted emergency assistance from Hydro-Québec, the Maritimes, and New York is uncertain. By 2008, New York is projected to run short of the installed capacity its criteria require. Ontario is also projected to be short of capacity resources within five years and will be facing additional governmental plans to phase out 6,500 MW of coal-fired generating units. Since New England currently relies on 2,000 MW of tie benefits from other control areas, the projected resource adequacy of the surrounding NPCC systems is of great importance to New England. The projected capacity situation for the neighboring NPCC control areas coupled with transmission limitations shows that New England should not heavily rely on neighboring system for capacity during periods of peak load, especially during the latter part of the planning period.

- While over 1,700 MW of New England generating capacity has been retired since 1999, RSP05 assumes no additional generators will retire during the 10-year planning period.

2.3.1.2 Operable Capacity Analysis—Methodology and Assumptions

IC Requirement analyses do not identify the amount of resources that must be operational to meet a defined load level plus the requirements for operating reserves. Thus, to assess the ISO's operational risks, as well as the sensitivity of day-to-day system reliability and security to future risks, the ISO complements the IC Requirement analysis with a deterministic operable capacity analysis. This analysis reviews the ability of the bulk power system to serve load using a specific scenario. It compares the expected peak loads plus the requirements for reserve capacity to the amount of operable capacity the system is expected to have available during these peak loads. The operable capacity analysis methodology is very similar to the approach system operators use to identify the resources needed on a daily basis to meet the expected peak-load conditions and identify reliability issues related to system security.[44]

Operable capacity analyses compare the 50/50 or 90/10 forecast peak loads plus reserve capacity required (typically 1,700 MW) to the amount of capacity the system is expected to have, considering resource availability (e.g., forced outages) and transmission constraints.[45] The reduced amount of capacity compared to the peak load plus the amount of operating reserves determines the available operable capacity margin, which becomes the resulting estimate for the "available surplus" (deficiency).

The total available surplus or deficiency for each load pocket and year under review is calculated as follows:

Available Surplus or Deficiency =
[(Capacity - Unavailable Capacity + Imports) - (Load + Required Operating Reserves)]

A negative operable capacity margin indicates a shortage of operable resources for maintaining the system's operating standards; the area's resources are inadequate to meet its load plus required operating reserves, and some combination of new resources and transmission improvements are needed. Under these conditions, the system operator must take special supply and demand actions, as defined in OP 4. A projected negative margin greater than the expected supply and demand relief obtainable from OP 4 actions indicates additional measures are needed, such as to purchase power from neighboring regions, to avoid disconnecting firm customer loads.

[44] Reliability security is a measure of the reliability of the bulk power system in terms of its ability to withstand disturbances arising within the system.

[45] The 1,700 MW amount represents 1.5 times the largest generating unit in the system.

A positive operable capacity margin indicates more capacity is available than the absolute minimum required to fully satisfy load and requirements for operating reserves. An adequate operable capacity margin is one that maintains sufficient capacity resources to serve the native load and maintain NERC and NPCC operating criteria (for operating reserves and transmission security) for the peak hour of each year, recognizing the physical nature of the transmission system and the amount of capacity not available historically due to random forced outages on that peak day.

2.3.1.3 Review of Approach to Determining Resource Adequacy

To address the compatibility and use of the probabilistic and deterministic approaches conducted to calculate resource adequacy, the ISO and its stakeholders are in the process of comparing these two types of analyses. A part of this process is to investigate how these approaches assess the system in term of its requirements for installed capacity in New England. Because the future ability to simultaneously obtain approximately 2,000 MW of uncontracted and unscheduled emergency assistance from Hydro-Québec, the Maritimes, and New York remains uncertain as load grows and reserve supplies decrease in those regions, the ISO and its stakeholders will carefully review the IC Requirement. This review will investigate the maximum amount of tie-reliability benefits New England could obtain from neighboring systems and the amount it should rely on to meet its 1-day-in-10-year LOLE criterion. This review will occur over the next 18 months and is targeted for completion in late 2006. Additional information can be found in PAC meeting materials.[46] (Also see Section 11.3.)

2.3.2 Analyzing Resource Location, Operating Characteristics, and Other Issues

Several analyses provide information on the desired location and operating characteristics of generating resources needed to supply load. In addition, RSP05 discusses other issues, including increased diversity of the New England mix of fuels, projections of electrical generation air emissions, and state requirements for using renewable sources of energy.

2.3.2.1 Fuel Diversity

Interruptions in fuel supply can create capacity and energy deficiencies. In Section 5.1.2, RSP05 summarizes lessons learned from the period of extremely cold weather in January 2004 when both gas and electricity demand peaked simultaneously.[47] It also describes the efforts by ISO New England and the natural gas industry to prepare for future cold snaps by increasing fuel flexibility. To better understand the natural gas industry, RSP05 summarizes analyses of the availability of and need for natural gas supply, storage, and transport (see Section 5.2.1). This report also summarizes reliability risks of fuel shortages by calculating the LOLE for various natural gas fuel-shortage scenarios and determines the amounts of dual or alternate fuels required to ensure reliable service to load. A longer-range look at fuel diversity is also provided.

[46] Refer to: <http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html> for information on the PAC.

[47] For additional information on January 2004 Cold Snap events, see <http://www.iso-ne.com/committees/comm_wkgrps/inactive/cold_snap_tf/index-p1.html#top>.

2.3.2.2 Air Emissions and Renewable Resource Issues

Appendix A of this report includes the results of simulations of regional air emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) attributed to the production of electricity over the next 10 years. A sensitivity analysis of fuel-price assumptions also was conducted. In addition, Appendix A presents information on a potential CO_2 emissions cap and the impacts it could have on electric power generators during the 10-year planning period. Other topics discussed include the role of distributed resources and the requirements for meeting Renewable Portfolio Standards. These are state-mandated requirements for competitive retail electricity providers to supply energy from renewable resources.

2.3.3 Conducting Transmission Studies

Transmission studies are necessary to ensure system reliability can be maintained in conformance with NERC, NPCC, and ISO criteria, procedures, and guidelines. These studies are also conducted to evaluate the performance of economic, elective, and merchant transmission upgrades. ISO New England uses a comprehensive model of the power system for conducting transmission studies that incorporates data on all generators, transmission facilities, and loads. The simulations address physical issues, such as thermal loading, minimum voltage, voltage regulation, transient stability, dynamic oscillations, harmonics, and short-circuit interrupting capability.

2.3.4 Conducting Interregional and Regional Planning Activities

The ISO must fully coordinate system assessments and planned improvements with its neighboring control areas. In addition, major new planning initiatives are needed within New England. RSP05 discusses both types of activities.

2.4 Additional Studies and Information

The following reports provide additional information on the New England system:

- *2005 CELT Report*—Statistics of capacity, energy, load, and transmission, available at: <http://www.iso-ne.com/trans/celt/report/index.html>

- *2005 Load Forecast*—Peak and energy load forecasts and supporting documentation, available at: <http://www.iso-ne.com/trans/celt/fsct_detail/index.html>

- *Draft 2005 Resource Adequacy Analysis*—Resource adequacy report issued to the Power Supply Planning Committee for review and comment. This report does not reflect the latest comments received from the PAC on RSP05. Available at: <http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2005/aug182005/Draft_ResAdqcy_Aug10.pdf>

- Transmission planning studies—Transmission planning and tariff reports, which can be accessed by calling ISO New England customer service (413-540-4220)

- ISO New England Project Listing Update—List of ISO-approved transmission system improvements, available at: <http://www.iso-ne.com/trans/rsp/2005/july05_update_final_redacted_072105.ppt>

Part II **Planning for Adequate Supply**

Part II provides a comprehensive discussion of planning for an adequate and reliable supply of electricity in New England during the next 10 years. In addition to providing essential information for managing the electric power system, assessing the adequacy of future generating resources supports the functioning of the wholesale electricity market so that it can attract the needed infrastructure improvements.

Section 3 presents historical data on energy use and the forecasts for peak demand in the New England Control Area and its subareas along with information on how the forecasts were generated. Section 4 provides information on the adequacy of systemwide and local-area resources in New England based on installed capacity and operable capacity analyses. The results of several analyses are provided that identify the amount of generating resources and capacity needed in New England and alternative perspectives on where and when the capacity will be needed. The issues surrounding the need to increase fuel diversity in New England are discussed in Section 5.

Section 6 discusses proposed electricity markets, which aim to provide participants with the financial incentives necessary for proposing new generation or demand-response resources to meet identified system needs.

Section 3

Peak Load and Energy Growth

This section summarizes New England's historical data and forecasts for energy use and peak loads and the process followed to generate the forecasts. This section also presents regional and subarea data and an analysis of historical peak-forecast errors. The key findings of these studies and a discussion of and how the forecasts have changed since last year are also presented.

Two ISO New England Web sites, as follows, contain more detailed information on short-run and long-run forecast methodologies, models, and inputs; weather normalization; ISO, state, and subarea energy and peak-load forecasts; and subarea allocation:

- <http://www.iso-ne.com/trans/celt/fsct_detail/index.html>

- <http://www.iso-ne.com/trans/celt/report/index.html>

3.1 System Energy and Peak-Demand Summary

The ISO load-forecast process creates energy and peak-load forecasts for the ISO New England Control Area and the New England states. These forecasts integrate the historical demand for each state, economic and weather data, and the impacts of utility-sponsored conservation and peak-load management programs on the forecasts.

Table 3.1 summarizes the ISO's forecast for the New England Control Area. The table shows the states' net energy for load and peak loads. Net energy for load is the net generation output within a control area, accounting for energy imports from other areas and subtracting energy exports to others. It includes system losses but excludes energy required the operate pumped storage plants. Peak loads are shown with a 50% chance of being exceeded (the 50/50 "Reference" case, expected at a temperature of 90.4ºF) and a 10% chance of being exceeded (the 90/10 "High" case, expected at a temperature of 94.2ºF). The table also shows the compound annual growth rate (CAGR) for each season from 2005 to 2014, calculated as follows:

$$\text{Percent CAGR} = \left\{ \left[\left(\frac{\text{Peak in 2014}}{\text{Peak in 2005}} \right)^{\left(\frac{1}{2014 - 2005} \right)} -1 \right] \text{x100} \right\}$$

Table 3.1
Energy and Peak-Load Forecast Summary for the ISO New England Control Area and States, Net Energy for Load (GWh)

Area	Net Energy for Load (GWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50		90/10		CAGR	50/50		90/10		CAGR
	2005	2014	CAGR	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**
CT	34,620	40,500	1.8	7,125	8,305	7,580	8,835	1.7	6,025	6,990	6,285	7,290	1.7
ME	12,140	13,790	1.4	1,975	2,255	2,060	2,355	1.5	1,960	2,220	2,010	2,270	1.4
MA	60,590	67,430	1.2	12,110	13,660	12,845	14,485	1.3	10,340	11,600	10,780	12,080	1.3
NH	11,840	13,990	1.9	2,300	2,720	2,490	2,950	1.9	2,040	2,400	2,125	2,500	1.8
RI	8,525	9,760	1.5	1,805	2,075	1,920	2,205	1.6	1,435	1,660	1,490	1,720	1.6
VT	6,375	7,035	1.1	1,045	1,175	1,100	1,235	1.3	1,030	1,150	1,060	1,180	1.2

3.2 Energy Use and Peak-Use Forecasts

The ISO New England Control Area's short-run energy forecast (for 2005 and 2006) is based on a quarterly model that regresses the amount of energy used per household on: 1) real income per household; 2) real average residential electricity prices from the U.S. Department of Energy (DOE), Energy Information Administration (EIA); and, 3) heating and cooling degree days.[48, 49] The total amount of energy used in New England is obtained by multiplying the existing number of households by the forecasted amount of energy used per household. The state long-run energy forecasts (2005–2014) are based on an annual version of the ISO New England Control Area model.

The ISO New England Control Area and state short-run seasonal-peak forecasts (2005, 2006) are based on a model that regresses weekday daily peak loads (1992–2004) on the following variables:

- Temperature and humidity (for summer) or temperature (for winter) at the time of the daily peak
- Cooling-load index (for summer) or heating-load index (for winter) that captures the change in peak-load response to weather over time based on annual studies of daily peak loads and weather conditions by season
- Base-load index that captures the change in peak-load response to energy and therefore economic and demographic factors based on the above annual studies

Forecasts of typical daily peak loads by week are developed using data for the weather experienced during each week over the last 35 years and the model's weather coefficients.

[48] For information on EIA average residential electricity prices, see <http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/sales_tabs.html>.

[49] A heating degree day is an indication of fuel consumption, which can be provided for each degree the daily mean temperature is below 65°F. A cooling degree day is used to estimate energy requirements and indicates fuel consumption for air conditioning or refrigeration. Cooling degree days are provided for each degree the daily mean temperature and humidity index is above the baseline of 65. For additional information, see the glossary of the Climate Prediction Center, National Weather Service, National Oceanic & Atmospheric Administration, available at: <http://www.cpc.noaa.gov/products/outreach/glossary.shtml#DD>.

The ISO New England Control Area and state long-run seasonal-peak forecasts (2007–2014) are based on applying the load factor (i.e., a peak-to-energy ratio of the average hourly energy use to the maximum hourly energy use expressed as a percent) from the last short-run forecast year to the long-run energy forecasts.

The forecasted energy use and peak loads for the ISO New England Control Area grow at approximately the same rate as historical trends, as shown in Figure 3.1 and Figure 3.2. Weather-normal energy and peaks are developed based on the weather conditions expected to occur at the time of the peaks.

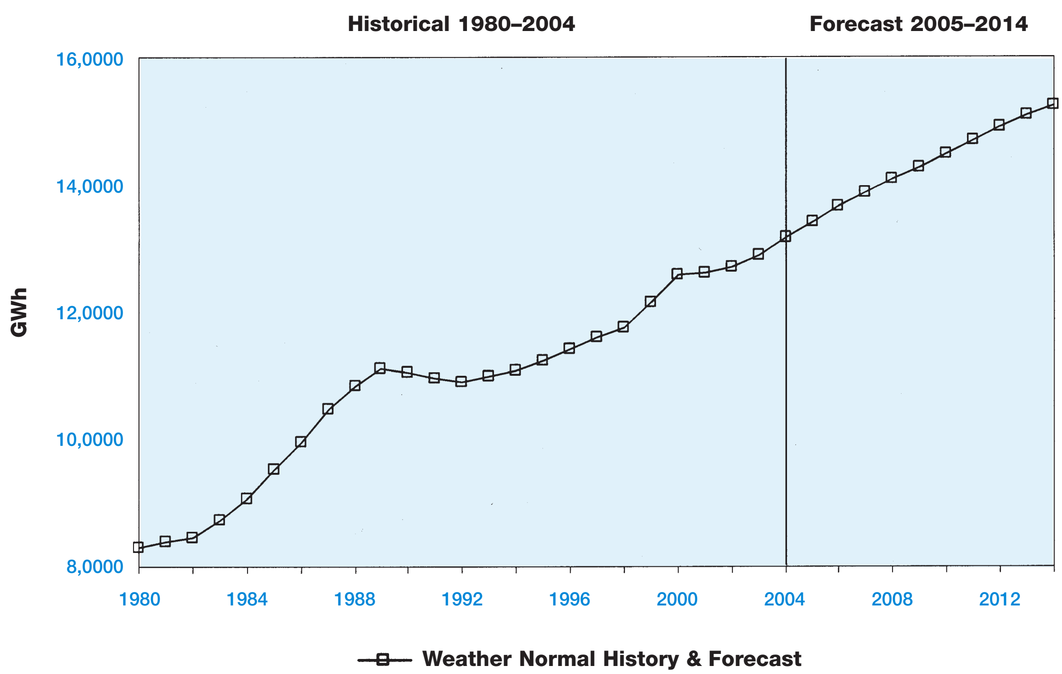


Figure 3.1 **ISO New England Control Area energy use (GWh).**

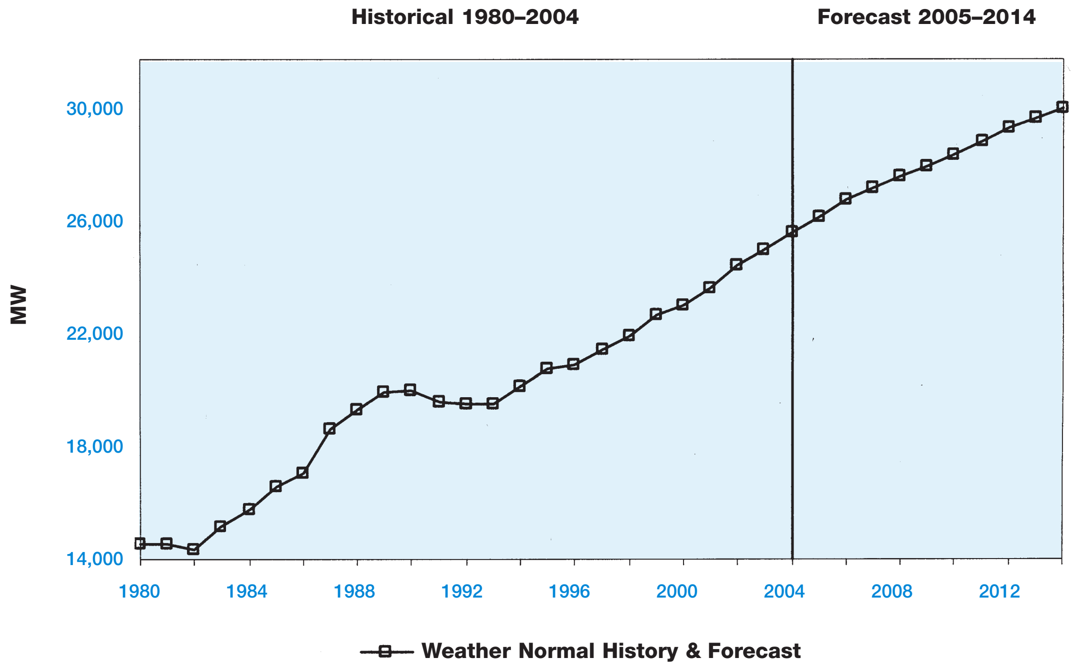


Figure 3.2 **ISO New England Control Area peak loads (MW).**

3.3 Energy and Economic/Demographic Factors

The ISO New England and state forecasts for energy use are based on a total energy concept—the sum of residential, commercial, and industrial energy used. The primary factors applied to determine energy use, which serve as proxies for overall economic and demographic conditions, include average income per household and total number of households. The specific determinants are listed below and summarized in Table 3.2; Figure 3.3 demonstrates these relationships with actual historical data from 1980 to 2004 and forecast data:

- Strong income-per-household growth in the 1980s drove energy use per household and growth in energy use.
- Falling income per household during the recession of the early 1990s depressed energy use per household and growth in energy use.
- Flat income per household and the resulting flat energy use per household in the mid-1990s were offset by household growth, resulting in moderate growth of energy use.
- Strong income-per-household growth drove energy use in the late 1990s and early 2000s.
- Continuing but slower growth in income per household and number of households underlie the energy forecast.

Table 3.2
Historical and Projected Growth Rates of Energy Use and Economic/Demographic Factors

Factor	1980	2004	CAGR	2005	2014	CAGR
Net energy for load (GWh)	82,927	131,750	1.9	134,085	152,505	1.4
Households (thousands)	4,374	5,535	1.0	5,583	5,974	0.8
Energy per household (MWh)	18.959	23.803	0.9	24.018	25.530	0.7
Income per household (thousands; 1996 $)	57.501	84.374	1.7	85.565	93.676	1.1

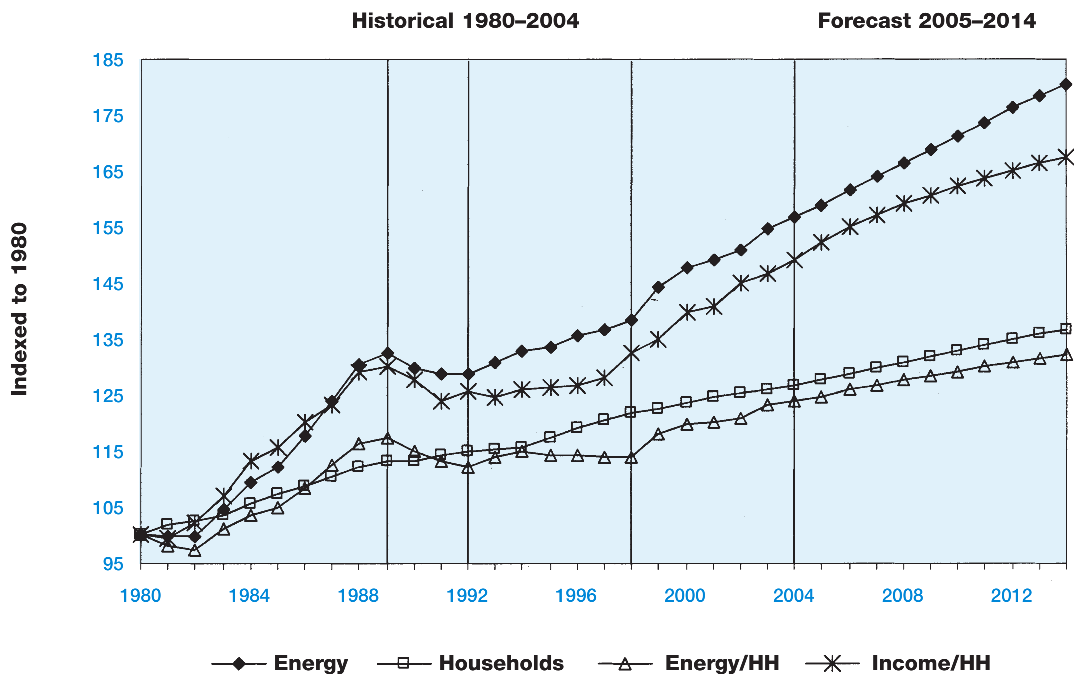


Figure 3.3 **New England energy and economic/demographic factors.**

3.4 Economic and Demographic Forecast Summary

Continued growth is forecasted for the New England economy, as detailed in Table 3.3 and Figure 3.4, but at a generally slower pace than in the last 25 years. Employment and the number of households tend to grow at the same rate, but household growth is more stable through expansions and recessions. Population growth continues to lag household and employment growth. New England continues to have slower economic growth than the rest of the United States, as seen in Figure 3.5. The figure shows that New England's share of the major economic and demographic factors compared to the United States as a whole is still declining.

Table 3.3
New England Economic and Demographic Forecast Summary

Factor	1980	2004	CAGR	2005	2014	CAGR
Net energy for load (GWh)	82,927	131,750	1.9	134,085	152,505	1.4
Population (thousands)	12,378	14,287	0.6	14,353	14,776	0.3
Households (thousands)	4,374	5,535	1.0	5,583	5,974	0.8
Employment (thousands)	5,479	6,853	0.9	6,978	7,576	0.9
Real Income (millions, 1996 $)	251,509	467,008	2.6	477,712	559,623	1.8
Real gross state product (GSP) (millions; 2000 $)	271,296	587,502	3.3	610,374	798,466	3.0

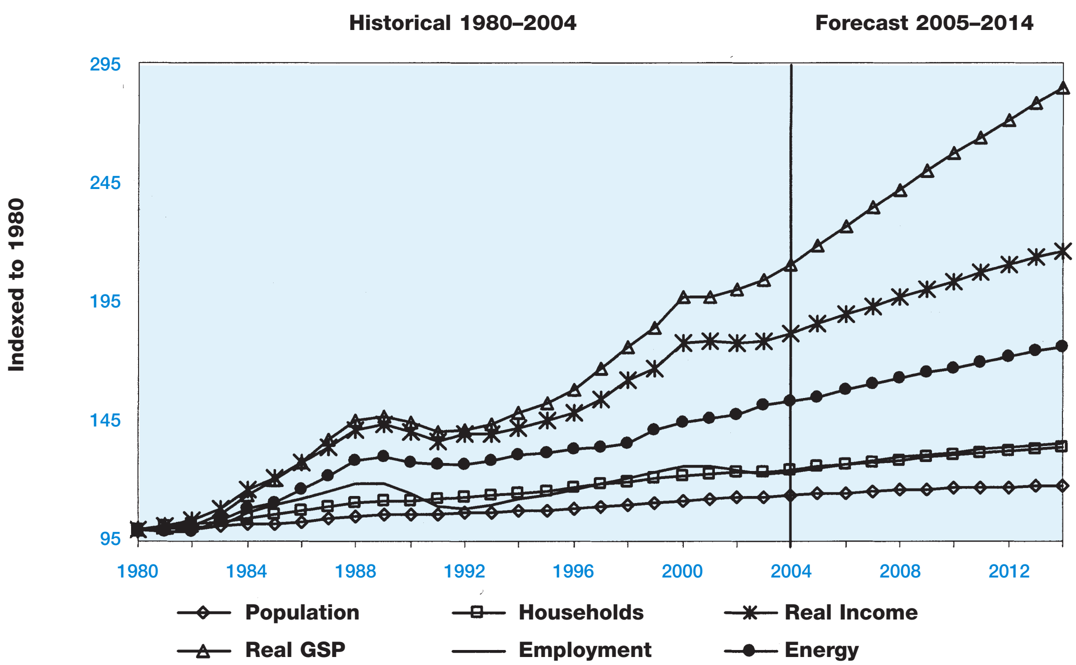


Figure 3.4 **New England economic and demographic factors.**

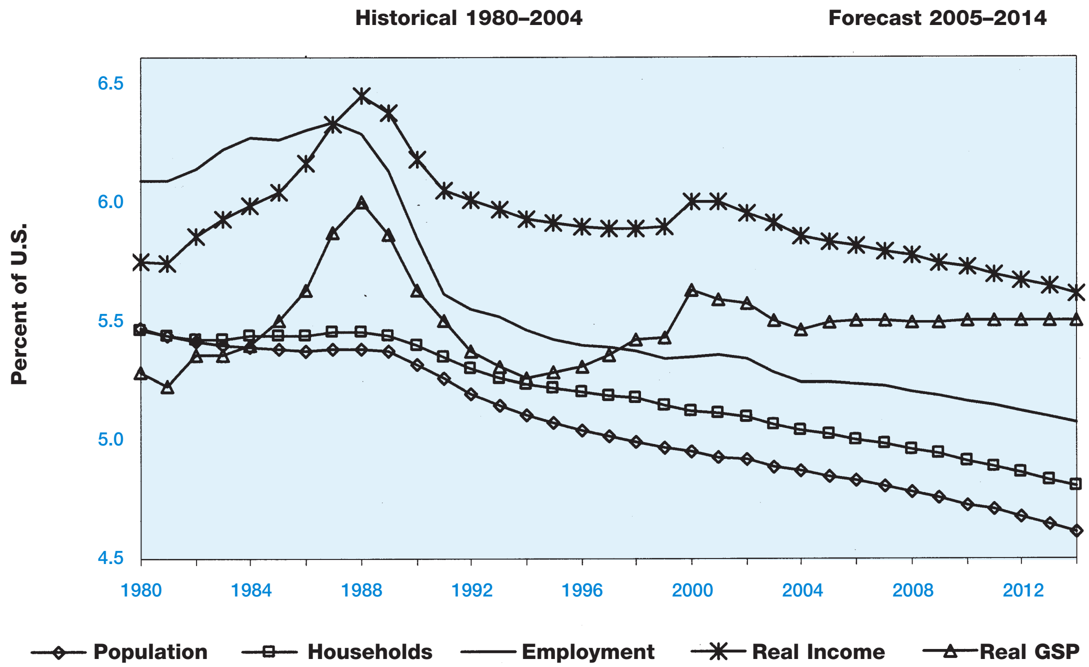


Figure 3.5 **New England economic and demographic factors as a percent of United States.**

3.5 Subarea Energy Use

Much of the RSP05 reliability analysis depends on forecasts for energy use and peak loads in the subareas. The projected loads provide important market information to stakeholders and are detailed on the ISO Web site.[50] The RSP subarea energy-use and peak forecasts are summarized in Table 3.4. Table 3.5 shows the RSP subarea loads in relation to the New England states and SMD energy market zones, with which many stakeholders are familiar.

The RSP subareas cross both state and operating-company boundaries. Therefore, the RSP subarea loads, associated weather, and economic/demographic factors cannot directly be observed, which makes directly forecasting their loads extremely difficult. However, the state energy-use and peak forecasts can be disaggregated into the RSP subareas by using two types of data. One type is historical load data from operating companies, which respect state boundaries. The second type is from FERC Form No. 715, a transmission planning and evaluation report containing data on seasonal peaks, which transmission operating companies submit to the agency each spring.[51] This methodology preserves both the differences between operating company growth rates and the detailed bus relationships within operating companies. The 2005 Form No. 715 report includes base-case power-flow data, with a summer and winter-peak forecast by bus for a near-term (2005) and midterm (2009) year.

[50] See <http://www.iso-ne.com/trans/celt/fsct_detail/index.html>.

[51] For more information on FERC Form 715, see <http://www.ferc.gov/docs-filing/eforms/form-715/overview.asp>.

Table 3.4

ISO New England Regional System Plan Subarea Energy Use and Peak-Load Forecast Summary

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

Table 3.5
Loads for RSP Subareas, the New England States, and SMD Energy Zones

RSP Subarea	SMD Load Zone	State	2005 Summer Peak Load Forecast					
			50/50			90/10		
			MW	Percent of RSP Subarea	Percent of State Peak Load	MW	Percent of RSP Subarea	Percent of State Peak Load
BHE: Northeastern Maine			**360**			**380**		
	ME	ME	360	100.0	18.6	380	100.0	18.6
ME: Western and Central Maine/Saco Valley, NH			**1,045**			**1,090**		
	ME	ME	993	95.0	50.6	1,033	94.8	50.4
	NH	NH	52	5.0	2.3	57	5.2	2.3
SME: Southeastern Maine			**595**			**620**		
	ME	ME	595	100.0	29.5	620	100.0	29.6
NH: Northern, Eastern and Central NH/Eastern VT and ME			**1,860**			**2,010**		
	ME	ME	27	1.5	1.4	29	1.4	1.4
	NH	NH	1,761	94.7	76.4	1,905	94.8	76.6
	VT	VT	72	3.8	6.9	76	3.8	6.9
VT: Vermont and Southwestern NH			**1,220**			**1,295**		
	NH	NH	322	26.4	14.0	348	26.8	13.9
	VT	VT	898	73.6	86.0	947	73.2	85.9
BOSTON: Greater Boston including North Shore			**5,360**			**5,685**		
	NEMA/Boston	MA	5,280	98.5	43.6	5,601	98.5	43.6
	NH	NH	80	1.5	3.5	84	1.5	3.4
CMA/NEMA: Central and Merrimack Valley, MA			**1,705**			**1,815**		
	West/Central MA	MA	1,618	94.9	13.4	1,721	94.8	13.4
	NH	NH	87	5.1	3.8	94	5.2	3.8
WMA: Western Massachusetts			**2,015**			**2,140**		
	Connecticut	CT	67	3.3	0.9	72	3.3	0.9
	West/Central MA	MA	1,873	93	15.4	1,989	93.0	15.5
	VT	VT	75	3.7	7.1	79	3.7	7.2
SEMA: Southeastern Massachusetts and Newport, RI			**2,750**			**2,915**		
	South East MA	MA	2,608	94.8	21.5	2,764	94.8	21.5
	RI	RI	142	5.2	7.9	151	5.2	7.9
RI: Rhode Island and Bordering Massachusetts			**2,390**			**2,540**		
	South East MA	MA	729	30.5	6.0	773	30.4	6.0
	RI	RI	1,661	69.5	92.1	1,767	69.6	92.1
CT: Northern and Eastern Connecticut			**3,515**			**3,740**		
	Connecticut	CT	3,515	100.0	49.3	3,740	100.0	49.3
SWCT: Southwestern Connecticut			**2,290**			**2,440**		
	Connecticut	CT	2,290	100.0	32.2	2,440	100.0	32.2
NOR: Norwalk/Stamford Connecticut			**1,250**			**1,330**		
	Conecticut	CT	1,250	100.0	17.6	1,330	100.0	17.6

3.6 Peak Error Analysis

An examination of the summer-peak forecast errors over the last 14 forecast cycles, as published in the CELT reports, shows that the forecast models generally under-forecast summer-peak loads.[52] The average error for the first-year forecast from each forecast cycle is just under 1%. However, the average forecast error grows over time to 2.3% for the third-year forecast and 4% for the fifth-year forecast. Figure 3.6 shows the historical forecast errors for each of the forecast cycles.

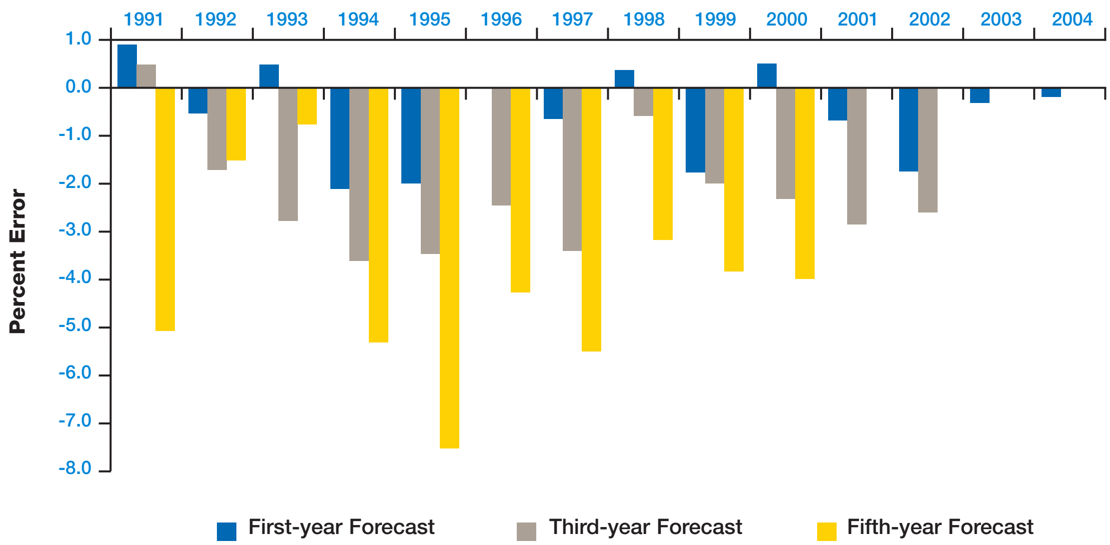


Figure 3.6 **ISO New England Regional summer-peak forecast error, 1991–2004.**

Note: Forecasts included in CELT reports, 1991–2004.

As shown in Figure 3.7, the long-run peak-forecast assumption of a constant load factor is not consistent with historical data and the short-term forecast, and it is one of the factors contributing to the under-forecasting detailed above. ISO New England is in the process of improving its methodology to extend the declining summer-peak load factor over the entire forecast period.

[52] See <http://www.iso-ne.com/trans/celt/report/index.html> for links to the 2000 to 2005 CELT Reports.

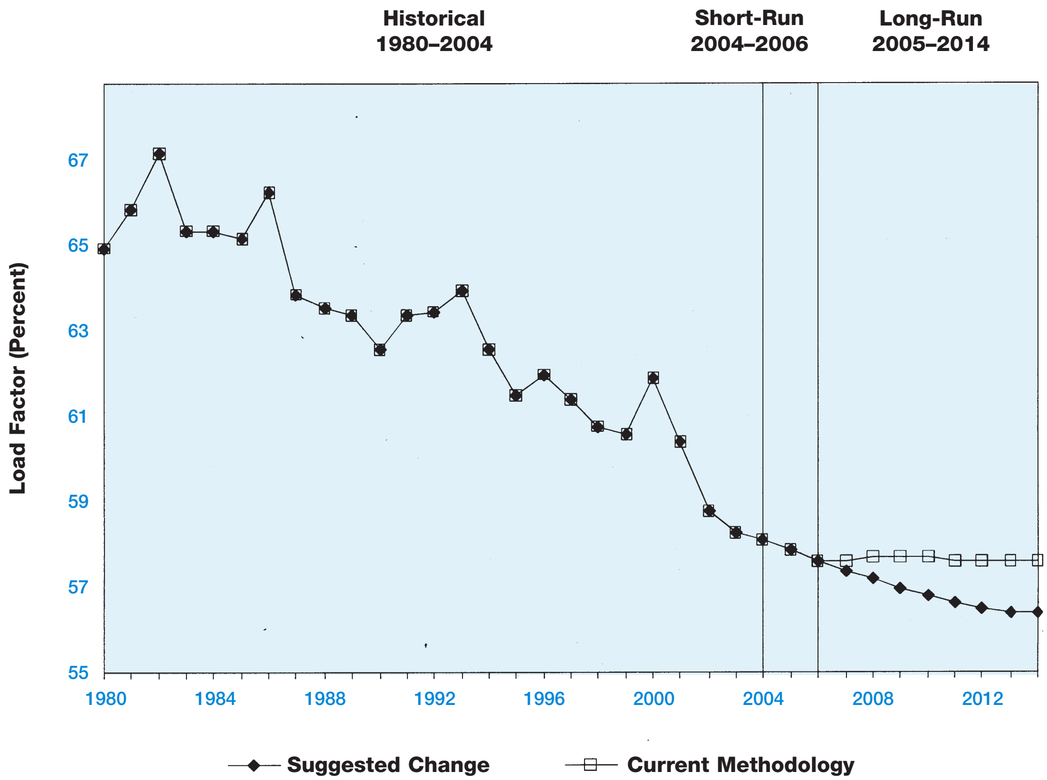


Figure 3.7 **ISO New England Control Area summer-peak load factors.**

3.7 Demand-Side Management (Conservation and Peak-Load Management)

The ISO New England Control Area and state long-run forecasts of energy use and peak loads are explicitly adjusted to reflect the reductions in energy use and peak loads from utility-sponsored C&LM programs. New England utility companies provide this data annually based on utility-initiated customer rebate and shared-savings programs for installing energy efficient appliances, lighting, and electrical machinery and for subsidized weatherization programs. Table 3.6 details these reductions.

Historical DSM energy savings are added into the historical energy data used to estimate the long-run energy models. The resulting energy forecast excludes the impacts of these utility-sponsored programs, but captures any naturally occurring conservation trends. The forecasted DSM energy reductions then are subtracted from the energy forecast. The load-factor methodology used to forecast the long-run seasonal peaks explicitly incorporates the DSM reductions in a similar manner.[53]

[53] For more information on the DSM forecasts, see <http://www.iso-ne.com/trans/celt/fsct_detail/index.html>.

Table 3.6
CELT05 and RSP05—Peak and Energy Reductions to the ISO New England Forecast Due to Utility-Sponsored Demand-Side Management Programs

Year	Summer Peak (MW)	Winter Peak (MW)	Energy (GWh)
2004	1,507	1,415	7,590
2005	1,552	1,465	7,909
2006	1,603	1,478	8,078
2007	1,656	1,502	8,319
2008	1,690	1,504	8,413
2009	1,696	1,494	8,453
2010	1,655	1,460	8,332
2011	1,564	1,396	8,179
2012	1,494	1,265	7,973
2013	1,504	1,269	7,983
2014	1,513	1,277	7,989

3.8 Changes from RTEP04

Each forecast cycle updates the historical energy-use and peak data by including resettlement adjustments and an additional year of data. The cycle also includes the most recent economic and demographic forecast.[54] The combination of these two updates resulted in slightly higher rates in energy use and peak growth compared to data published in RTEP04, yielding a 1,000 MW increase in the summer peak by 2014 (700 MW increase in the winter peak). To verify these results, ISO New England obtained two alternative economic and demographic forecasts and ran the forecasting models with both sets of alternative assumptions.[55] The resulting forecasts bracketed the standard forecast—one increased the 2014 summer peak by 1,400 MW, the other by 700 MW—thereby supporting the standard ISO forecast. The ISO will continue to assess and strive to improve the forecasting process.

3.9 Key Findings

The key findings of the peak-load forecasts are as follows:

- The overall deviation of the forecast from actual peak-load values is within 1% for the one-year forecasts. The overall deviation grows to 4% for the fifth-year forecast. ISO New England will continue to review the forecast methodology to improve the forecast results.

- The ISO New England Control Area summer peak is expected to grow at 2.3% per year in the short run and only 1.5% in the long run.

[54] See <http://www.economy.com/default.asp>.

[55] See <http://www.globalinsight.com/ProductsServices/ProductDetail403.htm> and <http://neepecon.org/>.

Section 4

Resource Adequacy Analyses

Ensuring the adequacy of New England's electric power system requires planning at the systemwide level as well as the subarea level. For both systemwide and subarea planning, the ISO conducted probabilistic and deterministic resource adequacy analyses.

The ISO conducts systemwide probabilistic planning by generating incremental LOLE analyses (see Section 2.3.1.1) that examine regional data for the New England system and the tie benefits and transmission-interface limits New England has with its neighboring regions. The results of these examinations show potential unacceptable load interruptions in smaller areas due to resource inadequacy. The ISO conducts systemwide operable capacity analyses (see Section 2.3.1.2) to estimate available surplus capacity or a capacity deficiency.

The ISO performs subarea probabilistic analyses to determine the impacts subarea loads and resource changes have on the incremental analyses. The subarea deterministic analyses calculate the required amount of operable capacity and reserves for load pockets. The load-pocket capacity margins also indicate areas where transmission improvements should be considered.

Section 4 discusses ISO's specific approach to conducting the RSP05 resource adequacy studies and summarizes the major findings of these studies.

4.1 New England Systemwide Analyses

For RSP05, the ISO conducted a systemwide analysis of Installed Capacity Requirements and a systemwide operable capacity analysis. The findings of the IC studies indicate New England needs approximately 170 MW of additional resources before summer 2010 to meet the New England reliability criterion to avoid disconnecting firm load more than 1 day in 10 years. These results assume the tie-reliability benefits are at the current FERC-ordered level of 2,000 MW. The results of the deterministic operable capacity analysis show that under the same conditions of 2,000 MW of emergency tie purchases and with no additional resources, starting in 2009, New England will be short of resources to meet the forecasted 90/10 peak and provide operating-reserve coverage.

4.1.1 Systemwide Installed Capacity Requirement Analysis

This section describes the ISO's approach for conducting the RSP05 systemwide analysis of IC Requirements and discusses the study results.

4.1.1.1 Approach

The model used for conducting the systemwide IC Requirement calculations for New England does not consider the New England transmission system and other operational constraints. The computation does account for the load and capacity relief obtainable from operating procedures, including the load-response programs and emergency assistance assumed to be available from neighboring systems. These emergency tie-reliability benefits account for both the transmission-transfer capability constraint of the tie lines, as well as the capacity that may be available from neighboring systems at the time of need in New England. The IC Requirement analysis modeled all external ties including the Hydro-Québec Phase II Interconnection and external firm purchases and sales, as reported in the *2005 CELT Report*. These and other assumptions used for the studies were fully discussed with the PAC and are consistent with the *2005 CELT Report* and those used in the 2005/2006 IC calculations.

For years that showed a capacity shortfall, the ISO conducted studies to determine the amount of generating resources that must be added to the system. As a modeling expedient, generator proxy units were added to the system. These units served to keep the LOLE at or better than the system criterion of not disconnecting firm load more than 0.1 day per year and provided an approximation of the possible amount of generating resources needed to meet this criterion. Each proxy unit had an assumed capacity of 172.5 MW with a 10% EFORd (equivalent forced-outage rate demand) and five weeks of maintenance per year. The actual amount of resources needed to comply with the LOLE criterion would vary depending on the type of resources installed to fill the need.

Recognizing the high level of uncertainty regarding the future load and capacity of neighboring systems and the amount of tie-reliability benefits they might be able to provide to meet ISO New England's reliability criterion, the ISO conducted IC Requirement analyses that simulated tie-reliability benefits of 0 MW, 1,000 MW, and 2,000 MW. These results provide an indication of the uncertainty as to when New England needs additional resources and the amount of resources needed to meet the resource planning reliability criterion under different assumptions for tie-reliability benefits.

The studies modeled known firm capacity contracts with neighboring systems. The Southwest Connecticut Emergency Capability Resources were modeled as OP 4 resources consistent with current operating practice. The studies assumed the contract for these resources would be extended through 2008.

4.1.1.2 Findings

The results of the systemwide analysis of Installed Capacity Requirements are summarized in Figure 4.1 and Table 4.1. Using the current approved levels of tie-reliability benefits of 2,000 MW, New England would need additional capacity or demand-response resources starting with one proxy unit (approximately 170 MW) in 2010 and increasing annually to approximately 2,100 MW by 2014 to meet the 1-day-in-10-year LOLE criterion. Similarly, assuming 1,000 MW of tie-reliability benefits, New England would need approximately 700 MW of additional capacity or demand-response resources starting in 2009, and increasing annually to approximately 3,300 MW by 2014. If no tie benefits were assumed to meet the resource planning reliability criterion, New England would need one proxy unit (approximately 170 MW) of additional capacity or demand-response resources as early as 2006. This need would increase annually to a total of approximately 4,300 MW by 2014. The additional amount of needed resources would be exacerbated by unit retirements, higher load growth, lower unit availability, transmission constraints, and a variety of other factors.

In this IC analysis, to capture the impact of various amounts of tie-reliability benefits on future resource needs, the Hydro-Québec Installed Capacity Credit (HQICC) was assumed to be zero. The decrease in summer installed capacity resources shown in Figure 4.1 reflects the termination of the SWCT Request for Proposal (RFP) resources after summer 2008.

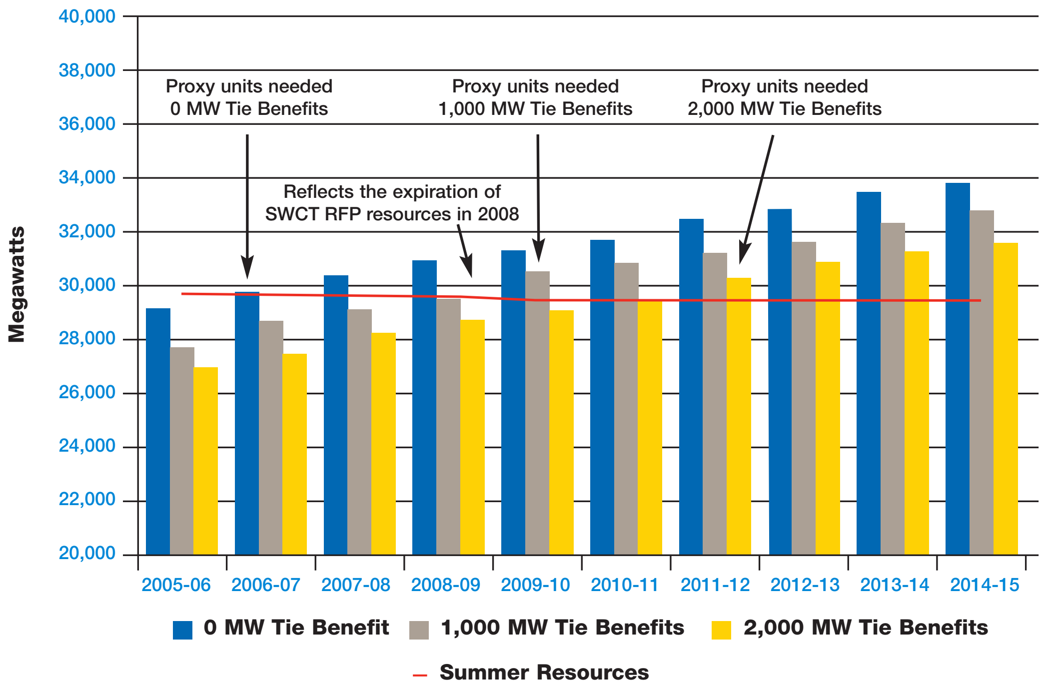


Figure 4.1 **New England installed capacity projection assuming different amounts of tie benefits (MW).**

Notes: The bars represent the June IC Requirement for each power year under the three tie-benefit assumptions as noted in the legend. The horizontal line across the bars represents the total capacity eligible to claim the installed capacity credit assumed in the calculation. Proxy units are needed when the IC Requirement is greater than the available summer resources, which include the total of the New England installed capacity, firm-capacity purchases, and demand-response resources eligible for the credit. This is consistent with the current definition of the IC Requirement.

Table 4.1
Cumulative Capacity Needed in New England to Meet 1-Day-in-10-Year LOLE (MW)

Year	0 MW Tie Benefits	1,000 MW Tie Benefits	2,000 MW Tie Benefits
2005	0.0	0.0	0.0
2006	172.5	0.0	0.0
2007	690.0	0.0	0.0
2008	1,035.0	0.0	0.0
2009	1,897.5	690.0	0.0
2010	2,415.0	1,207.5	172.5
2011	2,932.5	1,897.5	690.0
2012	3,450.0	2,415.0	1,380.0
2013	3,967.5	2,760.0	1,725.0
2014	4,312.5	3,277.5	2,070.0

Further details on the LOLE analysis methodology, assumptions, and results can be found in the materials presented to the PAC.[56] In summary, the IC analysis shows that for the range of tie benefits examined, New England needs a minimum of 2,100 MW of capacity by 2014, or, in the more extreme case of no tie benefits, a maximum of 4,300 MW of new resources by the same year.

4.1.2 Systemwide Operable Capacity Analysis

This section discusses the methodology used to conduct the systemwide operable capacity analysis as well as the results of this analysis.

4.1.2.1 Approach

For RSP05, the ISO conducted an operable capacity analysis for 2006 to 2014. As discussed in Section 2.3.1.2, the operable capacity analysis used 50/50 and 90/10 peak loads and assumed 1,700 MW of operating reserves. Based on historical observations, the study assumed 2,100 MW of capacity would not be available at times of peak load, but that all New England delisted resources would be available as New England resources.

4.1.2.2 Findings

Figure 4.2 and Table 4.2 show the results of the systemwide operable capacity analysis. Based on these results, New England could experience a negative operable capacity margin of approximately 160 MW as early as summer 2008, if the loads associated with the 50/50 forecast were to materialize. This negative operable capacity margin would grow to 2,600 MW by summer 2014 if no additional resources were added to the system. Similarly, Figure 4.2 and Table 4.3 show that New England could experience a negative operable capacity margin of approximately 1,070 MW as early as summer 2006 if: 1) the 90/10 peak loads associated with hot and humid weather (94°F and above) were to occur; 2) the assumed amount of generation outages were to materialize; and 3) no new resources were added. Without the addition of new resources and as load grows and reaches approximately 4,470 MW by 2014, this negative operable capacity margin will get progressively larger.

[56] See <http://www.iso-ne.com/committees/comm_wkgrps/othr/pac/mtrls/index.html>.

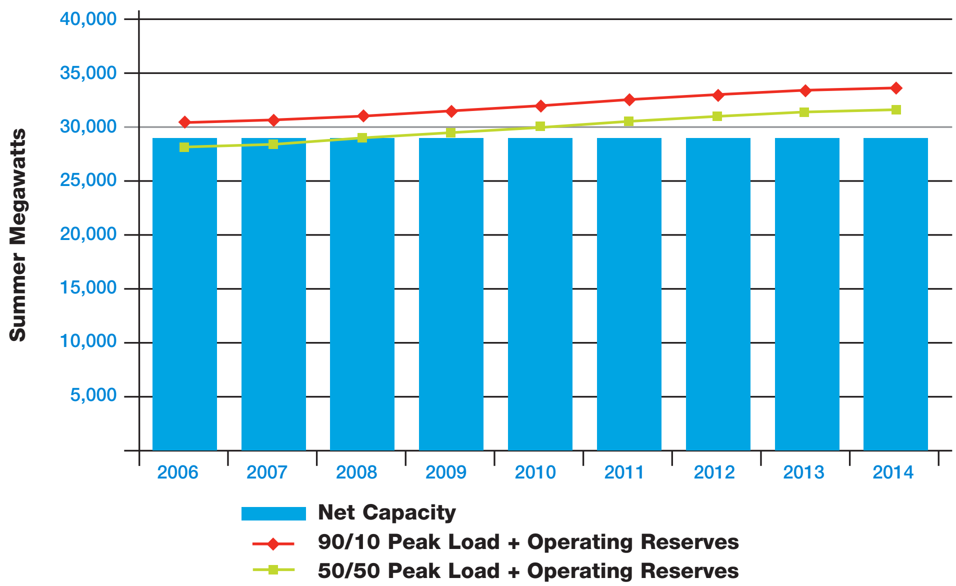


Figure 4.2 **Projected New England capacity situation, summer 2006–2014, using 50/50 and 90/10 loads (MW).**

Table 4.2
Projected New England Capacity, Summer 2006–2014, Using 50/50 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
Load (50/50) forecast	26,970	27,350	27,750	28,145	28,565	29,050	29,500	29,845	30,180
Operating reserves	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Total Capacity Requirement	**28,670**	**29,050**	**29,450**	**29,845**	**30,265**	**30,750**	**31,200**	**31,545**	**31,880**
Total overall capacity	31,393	31,393	31,393	31,393	31,386	31,386	31,386	31,386	31,386
Assumed unavailable capacity	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Total Net Capacity	**29,293**	**29,293**	**29,293**	**29,293**	**29,286**	**29,286**	**29,286**	**29,286**	**29,286**
Available Surplus (Deficiency)	**623**	**243**	**(157)**	**(552)**	**(979)**	**(1,464)**	**(1,914)**	**(2,259)**	**(2,594)**

Table 4.3
Projected New England Capacity Situation, Summer 2006–2014, Using 90/10 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
Load (90/10) forecast	28,660	29,070	29,495	29,910	30,350	30,860	31,330	31,700	32,050
Operating reserves	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Total Capacity Requirement	**30,360**	**30,770**	**31,195**	**31,610**	**32,050**	**32,560**	**33,030**	**33,400**	**33,750**
Capacity	31,393	31,393	31,393	31,393	31,386	31,386	31,386	31,386	31,386
Assumed unavailable capacity	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100	2,100
Total Net Capacity	**29,293**	**29,293**	**29,293**	**29,293**	**29,286**	**29,286**	**29,286**	**29,286**	**29,286**
Available Surplus (Deficiency)	**(1,067)**	**(1,477)**	**(1,902)**	**(2,317)**	**(2,764)**	**(3,274)**	**(3,744)**	**(4,114)**	**(4,464)**

The results above do not reflect generating unit additions, retirements, or deactivations that could occur during the planning period.

4.1.3 Observations

The probabilistic IC Requirement analysis shows (in Table 4.1) that New England will need approximately 170 MW of additional resources before summer 2010 to meet the New England resource planning reliability criterion to avoid disconnecting firm load more than 1 day in 10 years. These results assumed the tie-reliability benefits were at the current level of 2,000 MW. Similarly, the amount of total new resources needed will increase to approximately 2,100 MW by 2014.

Additional resources will be required in New England sooner than 2010 under several circumstances. One such situation would be if tie-reliability benefits used to meet the 1-day-in-10-year LOLE criterion were reduced, either physically or as a result of a FERC decision. The results of the systemwide analysis show the specific years and magnitude of resource needs associated with the 0 MW and 1,000 MW tie-reliability benefit scenarios. In summary, 170 MW to 4,300 MW will be needed through 2014, a time when the ability to obtain uncontracted emergency assistance from neighboring systems will become increasingly uncertain due to load growth and the decrease in reserve supplies in those areas.

Based on the deterministic systemwide operable capacity analysis, New England will need approximately 1,070 MW of load and capacity relief from OP 4 actions to meet the projected 90/10 loads in 2006.

The ISO should plan for a system with resources adequate to meet the load and operating-reserve requirements and rely on operating procedures as a contingency resource to mitigate unexpected events. To identify when additional resources will physically be required within New England to meet operating needs, the ISO assumed an additional 2,000 MW of external firm capacity could be purchased. Adding 2,000 MW of resources to the deficiency shown in Table 4.3 illustrates that, starting in 2009, New England will be 317 MW short of resources to meet the forecast 90/10 peak and provide operating-reserve coverage. Using the same external purchase assumption of 2,000 MW, Table 4.2 shows the region will need 259 MW of additional resources in 2013 to meet the forecast 50/50 peak and provide operating-reserve coverage. Since less than 2,000 MW of assistance will likely be available from neighboring systems, the need for operable capacity resources internal to New England will be required earlier than the 2009 through 2013 timeframe for the 90/10 and 50/50 load levels, respectively.

Short-term measures could be used to mitigate the risk of lower-than-expected emergency assistance available from the neighboring control areas and to minimize the possibility of having to disconnect firm load. These actions include making firm purchases from neighboring systems and using resources acquired through a special Request for Proposal (similar to the RFP for Southwest Connecticut Emergency Capability; see Section 8.2.3). In the longer term, market incentives would encourage the development of resources.

4.2 Subarea and Load-Pocket Analyses

For RSP05, the ISO analyzed the resource adequacy of subareas and load pockets using both probabilistic and deterministic approaches. The probabilistic analysis focused on the impact of subarea load and resource change on pool LOLE (incremental LOLE analysis). The incremental LOLE analysis calculated system LOLE reflecting static transmission-interface limits. The results of this analysis show the likelihood of unacceptable load interruptions in smaller areas. An LOLE in excess of 0.1 day per year is an unacceptable risk that could be the result of a subarea's having insufficient resource capacity and/or there being insufficient transmission capability between subareas.

The deterministic analyses show the required amount of operable capacity and reserves for selected major load pockets, including Greater Southwest Connecticut, Greater Connecticut, and the BOSTON Subarea. The resulting load-pocket operable capacity margins indicate the adequacy or inadequacy of transmission in these load pockets.

4.2.1 Modeling Transmission-Interface Limits

When modeling internal static transmission-interface limits, New England is modeled by 13 interconnected RSP subareas. The models use transmission-interface operating limits to identify the impacts transmission constraints have on the system LOLE and operable capacity margins associated with various resource-adequacy concerns, such as generator forced outages, retirements, or load increases in load pockets.

Transmission-interface operating limits change constantly in the real-time operating environment. The most limiting transmission facility and critical contingency, which limits the interface transfer, changes depending on unit dispatch, load level, and load distribution. For the subarea LOLE and operable capacity analyses, however, the interface limits between RSP subareas were modeled as constant or static for each transmission system configuration considered. The interfaces used in the analyses represent potentially limiting areas of the New England transmission system, which may become constrained under a variety of system conditions. The interface limits reflect the most restrictive of the thermal, voltage, and stability limits under reasonable assumptions for stressed system conditions.

Table 4.4 shows the transmission-transportation interface limits modeled in RSP05 analyses involving the 13 subareas. The values are based on ISO studies that reflect recent and future system improvements, coordinated voltage dispatch, and operating experience. Figure 4.3 illustrates the New England and neighboring system topologies and the major transmission interfaces modeled in these subarea analyses.

Table 4.4
Transmission-Interface Limits Used in Studies Modeling Subareas[(a)]

Interfaces	Interface Limit Assumptions for Studies (MW)	Basis for Interace Limits		
		Explanation	Relevant Study or Descriptive Information	Availability
New Brunswick–New England	700 2007: 1,000	Stability	New Brunswick–New England Tie Study	Public—Contact ISO New England
Maine–New Hampshire	1,400 2007: 1,500	Stability	2000 Maine Operating Study New Brunswick–New England Tie Study Y-138	Confidential—Strategic information
Orrington South Export	2005: 1,050 2007: 1,200	Thermal (summer)	Bucksport System Impact Study	Public—Contact Central Maine Power
			Northeast Reliability Interconnection Project	Bangor Hydro Electric
Surowiec South	2005: 1,150 2007: 1,250	Stability	2000 Maine Operating Study Y-138	Confidential—Strategic information
North–South	2,700	Thermal (summer)	Typical operating study result	
HQ–NE (Highgate)	210	HVdc equipment design limit and voltage	N/A	N/A
HQ–NE (Phase II)	1,500	External voltage constraints that occur in the PJM and NYISO areas	Historical operating practice	
BOSTON Import	2005: 3,600 2006: 4,500 2008: 4,700	Thermal (summer)	BOSTON Import Area 2004–2008 Review	Public—ISO New England Web site, Transmission Section studies
SE Mass Export	No limit	Stability	SEMA/RI Export Enhancement Feasibility Study	
(1) SE Mass/RI Export (2) East–West (3) Connecticut Import (4) Connecticut Import	(1) 3,000 (2) 2,400 (3) 2,300 2011: (4) 3,300	Simultaneous Stability/ Thermal Thermal Assumed	SEMA/RI Export SEMA/RI Export Enhancment Feasibility Study TBD	
Connecticut Export	2,030	Thermal (summer)	Export Limit—NU Haddam Neck System Impact Study	Confidential—Strategic information
Southwest Connecticut Import[(a)]	2005: 2,300 2007: 2,575 2010: 3,400	Thermal Thermal Thermal	ISO New England Studies	Public—ISO New England Web site, Transmission Section studies
Norwalk/Stamford	2005: 1,100 2007: 1,300 2010: 1,650	Thermal (summer)	ISO New England Studies	
New York–New England (w/o Cross Sound Cable)	Summer—1,255/925 Winter—1,475/1,475	Thermal	NYISO Summer 2003 Operating Study NYISO Winter 2002–03 Operating Study	Public—NYISO Web site
Cross Sound Cable	330 NENY/300 NYNE	HVdc equipment design limit	Cross Sound Cable System Impact Study	Public—Contact TransÉnergie US

[(a)] The procedure and studies supporting the static transmission interface limits are subject to review by the NEPOOL Reliability Committee.

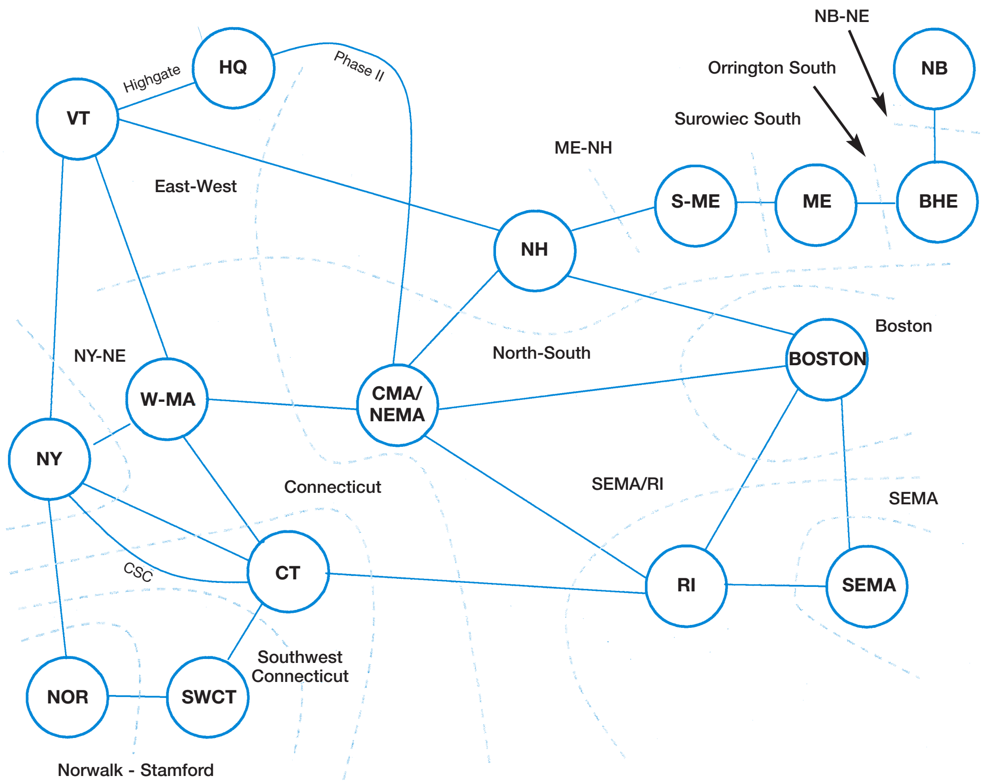


Figure 4.3 **Representation of New England subareas and transmission interfaces.**

The interface limits for the Connecticut import and the Southwest Connecticut import have increased over the RTEP04 limits by 100 MW and 300 MW, respectively. The RTEP04 voltage restrictions on these interfaces were relieved by recent transmission system improvements that include 115 kV circuit upgrades, the addition of the Glenbrook STATCOM and static capacitors, as well as reactive improvements to the distribution system. Updated ISO studies show that the Connecticut import and Southwest Connecticut import interfaces are now thermally limited at the RSP05-assumed values. These studies will be reviewed with the Reliability Committee.

The modeling of the BOSTON import limit has also changed from RTEP04. This change reflects the phased approach of the NSTAR 345 kV Project that will initially add two cable circuits to BOSTON by summer 2006, with a third circuit to be completed in 2008.

The transmission-interface limits are a critical part of RSP analyses, and the ISO updates them at least annually. The limits are subject to revisions as facilities go into service or the configuration of the system changes. A procedure for developing these interface limits is being reviewed through the stakeholder process.

4.2.2 Incremental LOLE Analysis

To identify the areas potentially at greatest risk due to long-term generator forced outages, unit retirements, or load-growth conditions higher than forecasted, the ISO used an incremental analysis that shows the change in system LOLE based on changes in subarea load. The analysis modeled the transmission-interface limits shown in Table 4.4 that prevent constrained load pockets from gaining access to needed capacity. The load in individual subareas was then increased or decreased to determine the impact on the systemwide LOLE. When compared with the single-bus LOLE model, the modeling of the transmission constraints shows a greater need for capacity as well as the location where the capacity is needed. This is because the transmission constraints prevent excess capacity from reaching areas where it is most needed.

4.2.2.1 Results for 2006

Figure 4.4 illustrates the results for the conditions associated with the 2006 expected system. These results include the completion of the first two cable circuits of the NSTAR 345 kV Transmission Reliability Project (discussed in more detail in Section 8.1.4). The figure shows that without changes to the expected system loads, New England is expected to be at an LOLE lower than 0.1 day per year in 2006. Using Figure 4.4, the amount by which load could be increased (or the amount by which generating capacity could be decreased) and still meet the planning reliability criterion can be identified by reading the megawatts on the *x*-axis that correspond to the 0.1 day-per-year system LOLE on the *y*-axis. As shown, the RSP05 subareas most sensitive to load/supply variations are NOR, SWCT, CT, and BOSTON because smaller load increases or generating-unit decreases in these areas have a greater impact on the system LOLE compared to other subareas. Another way to interpret the results is that these areas would benefit most from the development of new generating units, additional load response, and transmission upgrades.

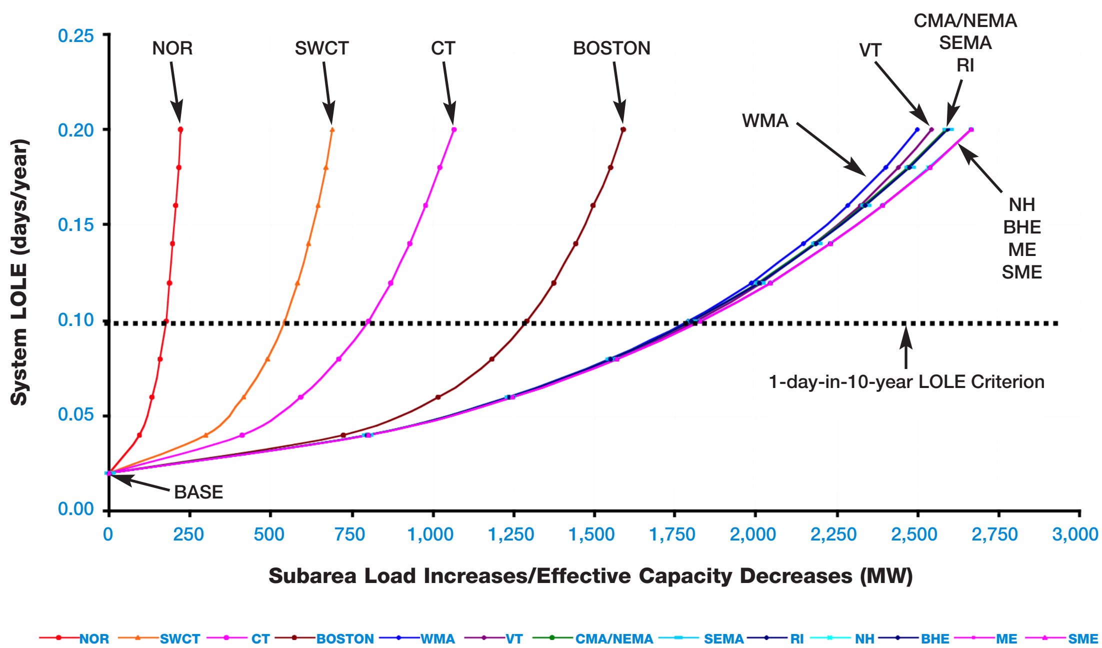


Figure 4.4 **System LOLE per change in MW of RSP subarea load—2006.**

4.2.2.2 Results for 2009

Figure 4.5 illustrates the results for the conditions associated with the 2009 expected system. These results show that New England is expected to have a level of resources slightly above the amount required to meet the 0.1 day-per-year LOLE.

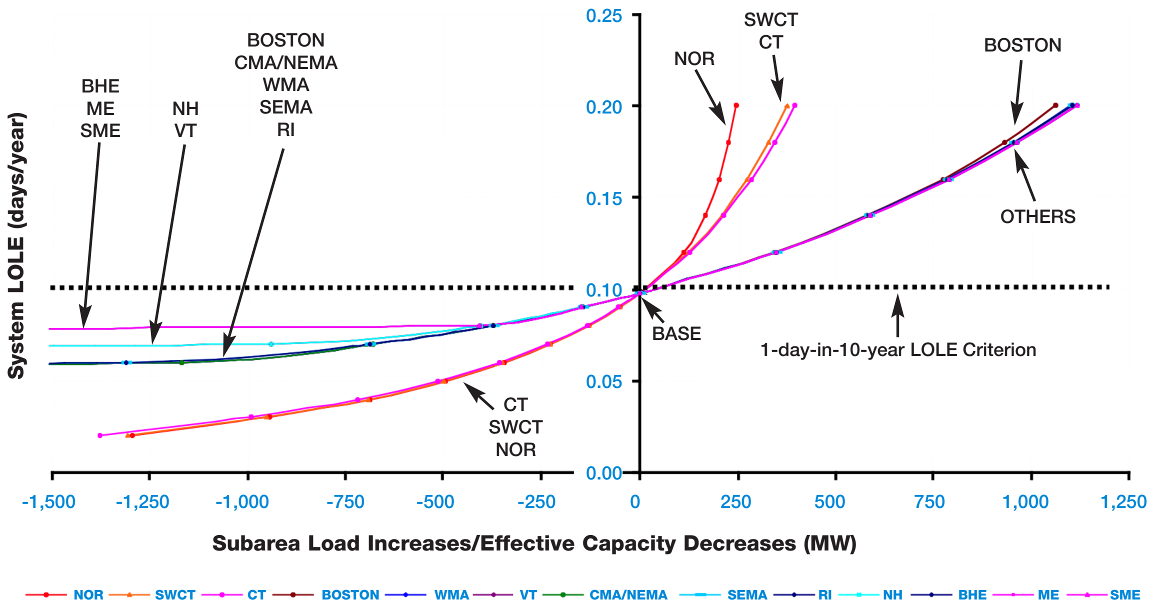


Figure 4.5 **System LOLE per change in MW of RSP subarea load—2009.**

4.2.2.3 Results for 2010

Figure 4.6 shows the results for 2010 when New England would be approximately 270 MW short of resources to meet the system LOLE criterion. As shown, the criterion can be met in two ways-by decreasing 270 MW of load or increasing 270 MW of effective resources in the Connecticut subareas. A less effective alternative is to reduce approximately 950 MW of load or add 950 MW of capacity in the subareas on the southern side of the North–South interface. Load reduction or resource addition in other New England subareas on the northern side of the North–South interface would not help meet the system LOLE criterion due to transmission-import constraints into the CT Subarea, which is in need of resources.

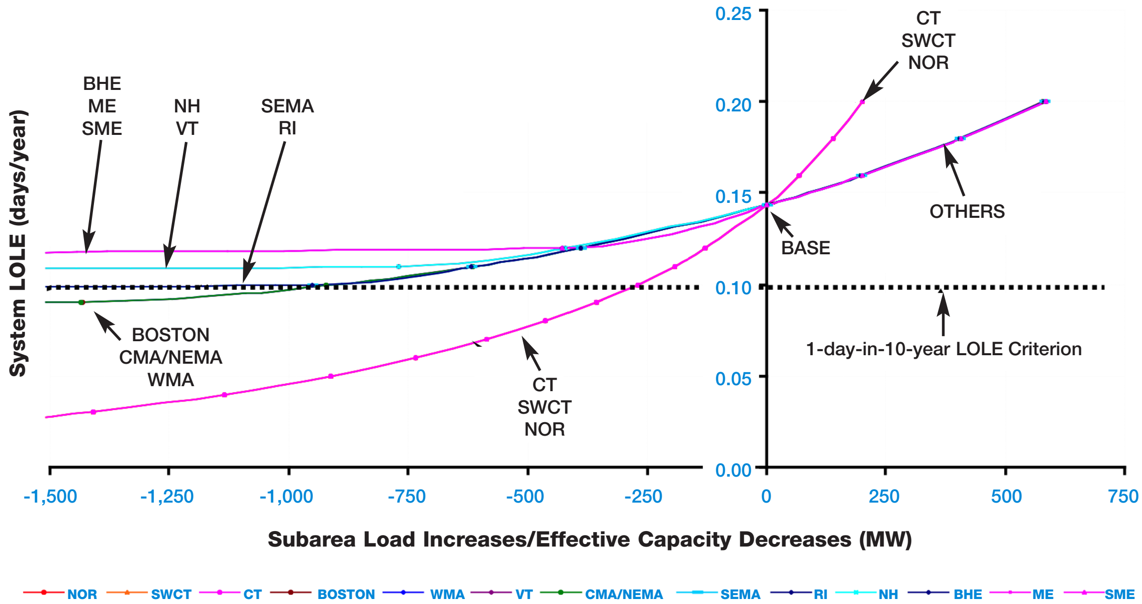


Figure 4.6 **System LOLE per change in MW of RSP subarea load—2010.**

4.2.2.4 Results for 2014

The ISO repeated the incremental LOLE analysis for the 2014 load level, assuming the major transmission projects would be completed for the BOSTON, SWCT, NOR, and CT load pockets. Figure 4.7 shows that NOR, SWCT, CT, BOSTON, CMA/NEMA, and WMA are most vulnerable to LOLE reliability risks. Adding new capacity in these subareas will not only provide the greatest reduction in LOLE for the system overall, it will greatly reduce the LOLE in these subareas, as well, as shown in the table. As shown, decreasing load or increasing capacity by approximately 1,900 MW in these subareas will bring the system LOLE from approximately 0.4 day per year to 0.1 day per year.

The figure also shows that meeting the 0.1 day-per-year LOLE would not be possible if all the needed generating resources were installed on the north side of the North–South interface or within the SEMA/RI Subarea. As shown, adding resources in Maine would contribute very little toward improving the New England system LOLE due to transmission constraints within Maine. A maximum of about 600 MW of resources could be added in Maine before the transmission constraint would limit their reliability contribution to system LOLE. The results also show that approximately 1,500 MW of resources could be added in the SEMA/RI Subarea before it reaches its transmission-export limit, which would limit the generating resources’ contribution toward improving the New England system LOLE to no lower than about 0.16 day per year.

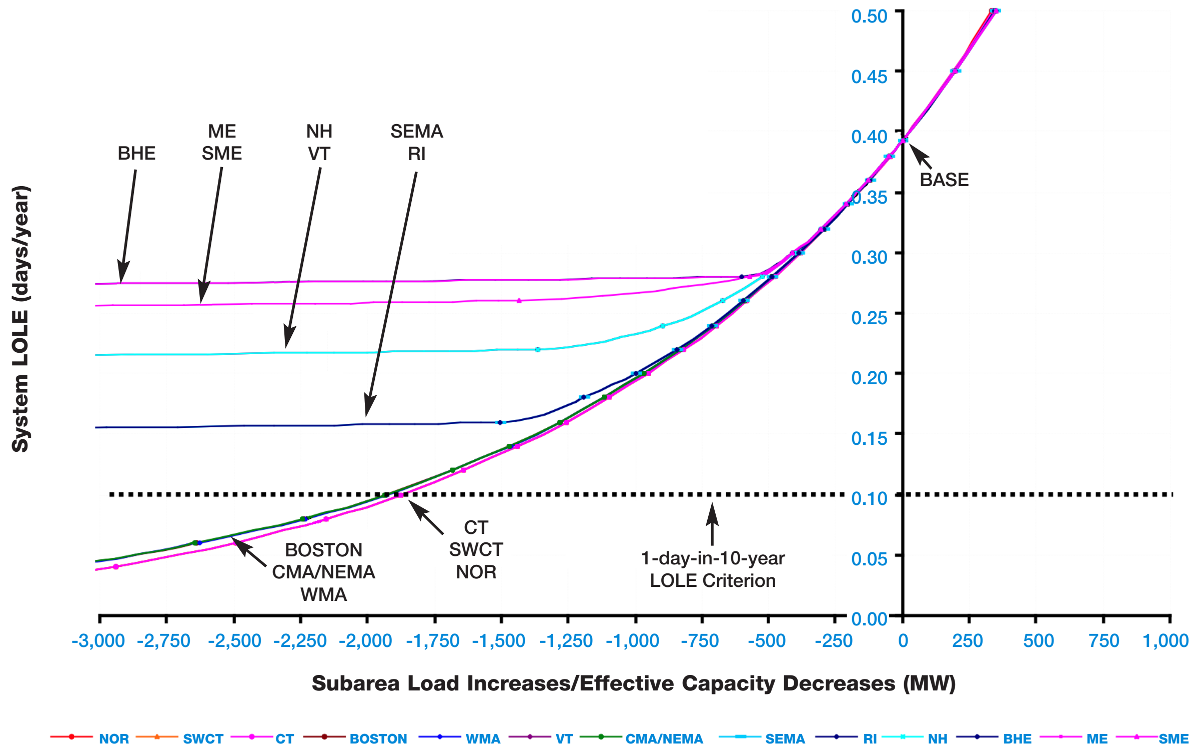


Figure 4.7 **System LOLE per change in MW of RSP subarea load—2014.**

4.2.2.5 Observations

The SWCT, NOR, and CT Subareas are most vulnerable to load increases, unit deactivations, or generator forced outages, including fuel-supply interruptions. Accordingly, reductions in demand through conservation or demand-response resources, as well as generator additions in the SWCT, NOR, and CT Subareas, would provide the most effective LOLE benefits.

4.2.3 Subarea Operable Capacity Analysis

The ISO conducted an operable capacity analysis to evaluate the resource adequacy of the Greater Southwest Connecticut, Greater Connecticut, and BOSTON load pockets. The analysis determined whether the operable capacity margin for each area is adequate to meet the area's operational needs over the study period (2006 to 2014). The ISO used both the 50/50 and 90/10 forecasts for each load pocket. The 50/50 results are provided for informational purposes and are consistent with the long-term scheduling of generating-unit maintenance outages. The use of the 90/10 load scenario is consistent with NPCC and ISO planning procedures, because the transmission capability in smaller regions or load pockets is typically more limited. These areas have fewer options for emergency actions, and they need to protect against situations that could cause cascading outages. The results of the load-pocket operable capacity analysis are summarized in the figures for each load pocket.

4.2.3.1 Greater Southwest Connecticut

Figure 4.8 and Table 4.5 show that Greater Southwest Connecticut could experience a negative operable capacity margin of approximately 30 MW by summer 2013, if the 50/50 peak-load forecast were to materialize, the expected level of forced outages were to occur, and the SWCT Reliability Project (see Section 8.1.5) were not yet in service. Without this transmission upgrade, the deficiency would grow to approximately 70 MW by summer 2014.

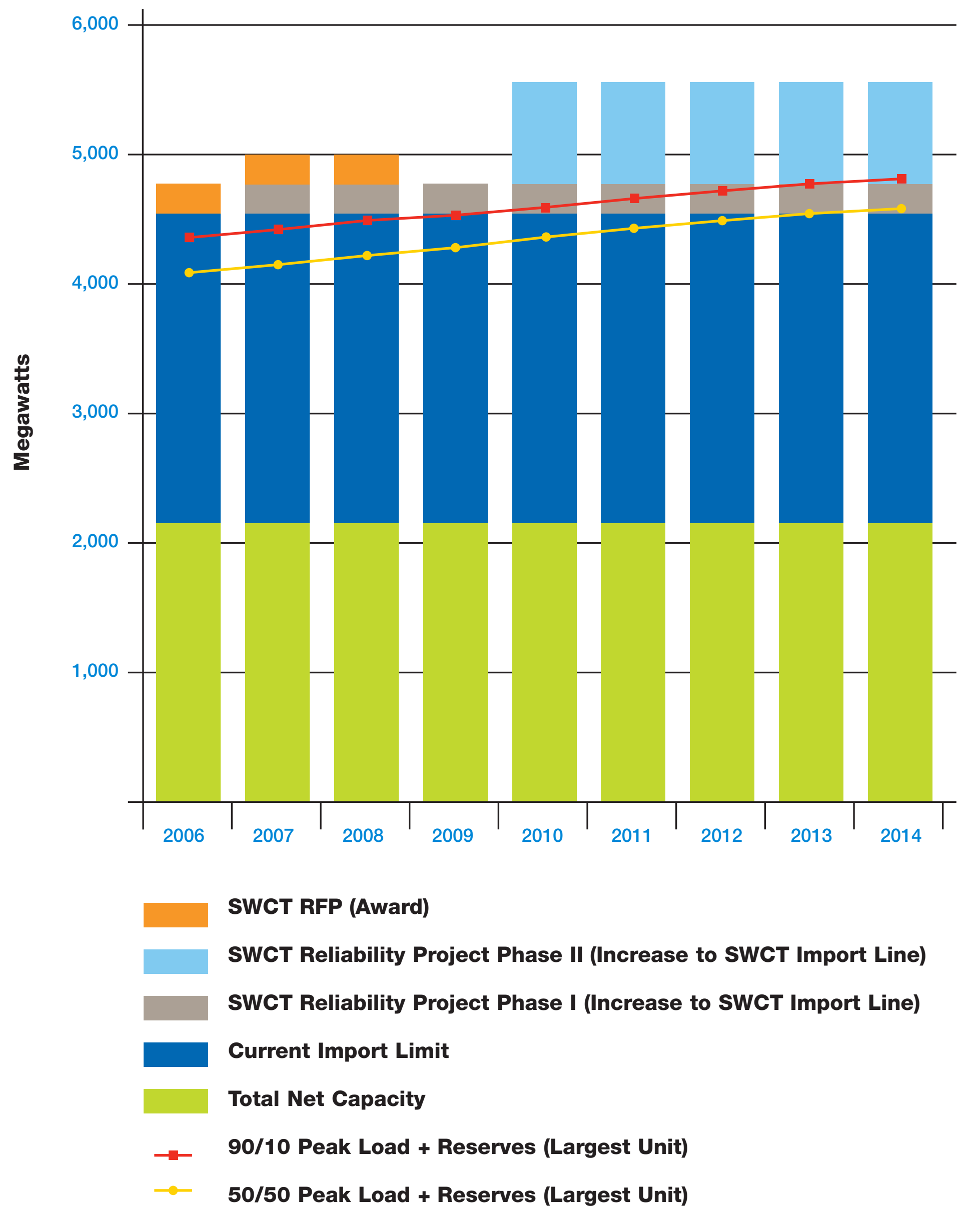


Figure 4.8 **Projected Greater Southwest Connecticut operable capacity margin, summer 2006–2014 (MW).**

Table 4.5
Projected Greater Southwest Connecticut Operable Capacity Margin, Summer 2006–2014, Using 50/50 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
CAPACITY									
Load (50/50 forecast)	3,620	3,665	3,725	3,780	3,850	3,915	3,980	4,020	4,060
Reserves (largest unit)	454	454	454	454	454	454	454	454	454
Total Capacity Requirement	**4,074**	**4,119**	**4,179**	**4,234**	**4,304**	**4,369**	**4,434**	**4,474**	**4,514**
Total overall capacity	2,379	2,379	2,379	2,379	2,379	2,379	2,379	2,379	2,379
Assumed unavailable capacity	232	232	232	232	232	232	232	232	232
Net capacity	2,147	2,147	2,147	2,147	2,147	2,147	2,147	2,147	2,147
Current import limit	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Total Available Resources	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**
CAPACITY SURPLUS/DEFICIENCY	**373**	**328**	**268**	**213**	**143**	**78**	**13**	**(27)**	**(67)**
ACTIONS TO ENHANCE CAPACITY									
Strengthening of System									
SWCT Reliability Project Phase I (Increase to SWCT import limit)	-	275	275	275	275	275	275	275	275
SWCT Reliability Project Phase II (Increase to SWCT import limit)	-	-	-	-	825	825	825	825	825
Emergency Actions									
SWCT RFP (Award)	250	256	256	-	-	-	-	-	-
TOTAL IDENTIFIED ACTIONS	**250**	**531**	**531**	**275**	**1,100**	**1,100**	**1,100**	**1,100**	**1,100**
SURPLUS/DEFICIENCY WITH TOTAL IDENTIFIED ACTIONS	**623**	**859**	**799**	**488**	**1,243**	**1,178**	**1,113**	**1,073**	**1,033**

If the Southwest Connecticut Reliability Project were delayed, under the 90/10 load forecast (see Table 4.6), Greater Southwest Connecticut could experience a negative operable capacity margin of approximately 30 MW as early as summer 2009; by 2014, the negative operable capacity margin could reach approximately 325 MW. With the proposed Southwest Reliability Project, Greater Southwest Connecticut will have enough resources over the planning period to meet its peak load and reserves required to sustain the loss of the largest unit, assuming adequate resources are available in New England to meet the reliability criterion. However, any changes in the capacity in that area (i.e., retirements or additions) could affect these results.

Table 4.6
Projected Greater Southwest Connecticut Operable Capacity Margin, Summer 2006–2014, Using 90/10 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
CAPACITY									
Load (90/10 forecast)	3,850	3,905	3,965	4,025	4,090	4,165	4,235	4,280	4,320
Reserves (largest unit)	454	454	454	454	454	454	454	454	454
Total Capacity Requirement	**4,304**	**4,359**	**4,419**	**4,479**	**4,544**	**4,619**	**4,689**	**4,734**	**4,774**
Total overall capacity	2,379	2,379	2,379	2,379	2,379	2,379	2,379	2,379	2,379
Assumed unavailable capacity	232	232	232	232	232	232	232	232	232
Net capacity	2,147	2,147	2,147	2,147	2,147	2,147	2,147	2,147	2,147
Current import limit	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Total Available Resources	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**	**4,447**
CAPACITY SURPLUS/DEFICIENCY	143	88	28	(32)	(97)	(172)	(242)	(287)	(327)
ACTIONS TO ENHANCE CAPACITY									
Strengthening of System									
SWCT Reliability Project Phase I (Increase to SWCT import limit)	-	275	275	275	275	275	275	275	275
SWCT Reliability Project Phase II (Increase to SWCT import limit)	-	-	-	-	825	825	825	825	825
Emergency Actions									
SWCT RFP (Award)	250	256	256	-	-	-	-	-	-
TOTAL IDENTIFIED ACTIONS	250	531	531	275	1,100	1,100	1,100	1,100	1,100
SURPLUS/DEFICIENCY WITH TOTAL IDENTIFIED ACTIONS	393	619	559	243	1,003	928	858	813	773

4.2.3.2 Greater Connecticut

As shown in Figure 4.9 and Table 4.7, Greater Connecticut could experience a negative operable capacity margin of approximately 180 MW as early as summer 2009, if the load associated with the 50/50 forecast were to materialize and the expected level of forced outages were to occur. This deficiency would grow to 828 MW by summer 2014, assuming no capacity were added to the system and the proposed Southern New England Reinforcement Project (see Section 8.1.6) were not completed.[57]

[57] This project, called SNERP, is a conceptual project being investigated as part of the Southern New England Transmission Reinforcement Analysis (SNETRA).

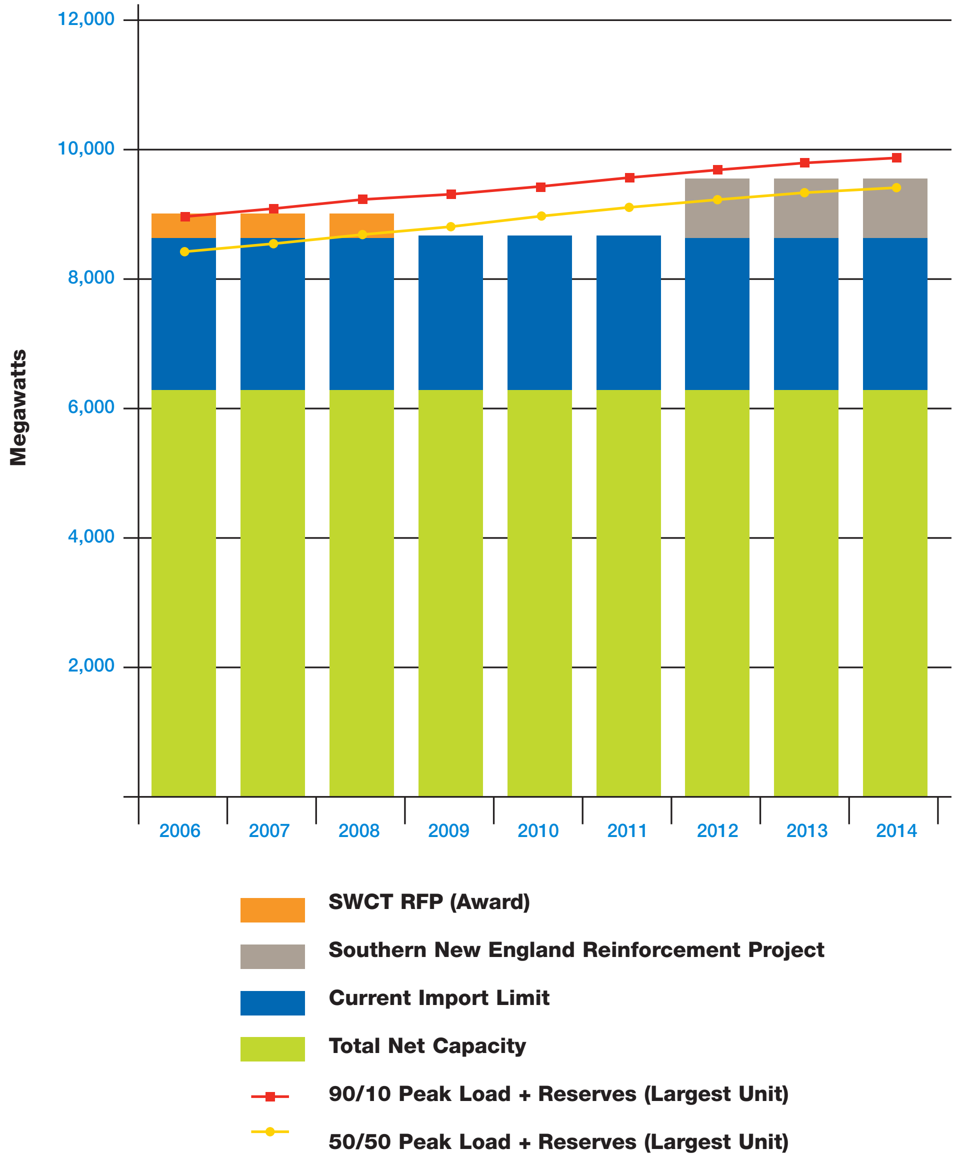


Figure 4.9 **Projected Greater Connecticut operable capacity margin, summer 2006–2014 (MW).**

Table 4.7
Projected Greater Connecticut Operable Capacity Margin, Summer 2006–2014 Using 50/50 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
CAPACITY									
Load (50/50 forecast)	7,220	7,320	7,450	7,575	7,725	7,875	8,030	8,125	8,225
Reserves (largest unit)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Total Capacity Requirement	**8,420**	**8,520**	**8,650**	**8,775**	**8,925**	**9,075**	**9,230**	**9,325**	**9,425**
Total overall capacity	6,779	6,779	6,779	6,779	6,779	6,779	6,779	6,779	6,779
Assumed unavailable capacity	483	483	483	483	483	483	483	483	483
Net capacity	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297
Current import limit	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Total Available Resources	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**
CAPACITY SURPLUS/DEFICIENCY	**177**	**77**	**(53)**	**(178)**	**(328)**	**(478)**	**(633)**	**(728)**	**(828)**
ACTIONS TO ENHANCE CAPACITY									
Strengthening of System (Increase to CT Import Limit)									
Southern New England Reinforcement Project	-	-	-	-	-	-	1,000	1,000	1,000
Emergency Actions									
SWCT RFP (Award)	250	256	256	-	-	-	-	-	-
TOTAL IDENTIFIED ACTIONS	**250**	**256**	**256**	**-**	**-**	**-**	**1,000**	**1,000**	**1,000**
SURPLUS/DEFICIENCY WITH TOTAL IDENTIFIED ACTIONS	**427**	**333**	**203**	**(178)**	**(328)**	**(478)**	**367**	**272**	**172**

Under the 90/10 peak-load forecast, Greater Connecticut could experience a negative operable capacity margin of 30 MW as early as summer 2006, and this deficiency would grow to approximately 670 MW in 2009 and to 1,350 MW by 2014, assuming no capacity were added or unit attritions were to take place (see Table 4.8). Of the alternatives being evaluated based on the Southern New England Transmission Reinforcement Analysis, a preferred solution could be implemented prior to summer 2012. Even with the assumed increase in the Connecticut import limit of approximately 1,000 MW expected from the project, Greater Connecticut would still be short of resources to meet operable capacity needs under the projected 90/10 loads. This suggests the Connecticut import limit warrants a higher increase, and Greater Connecticut warrants new capacity additions.

Table 4.8
Projected Greater Connecticut Operable Capacity Margin, Summer 2006–2014 Using 90/10 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
CAPACITY									
Load (90/10 forecast)	7,675	7,795	7,930	8,065	8,210	8,375	8,535	8,645	8,750
Reserves (largest unit)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Total Capacity Requirement	**8,875**	**8,995**	**9,130**	**9,265**	**9,410**	**9,575**	**9,735**	**9,845**	**9,950**
Total overall capacity	6,779	6,779	6,779	6,779	6,779	6,779	6,779	6,779	6,779
Assumed unavailable capacity	483	483	483	483	483	483	483	483	483
Net capacity	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297	6,297
Current import limit	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300	2,300
Total Available Resources	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**	**8,597**
CAPACITY SURPLUS/DEFICIENCY	**(278)**	**(398)**	**(533)**	**(668)**	**(813)**	**(978)**	**(1,138)**	**(1,248)**	**(1,353)**
ACTIONS TO ENHANCE CAPACITY									
Strengthening of System (Increase to CT Import Limit)									
Southern New England Reinforcement Project	-	-	-	-	-	-	1,000	1,000	1,000
Emergency Actions									
SWCT RFP (Award)	250	256	256	-	-	-	-	-	-
TOTAL IDENTIFIED ACTIONS	**250**	**256**	**256**	**-**	**-**	**-**	**1,000**	**1,000**	**1,000**
SURPLUS/DEFICIENCY WITH TOTAL IDENTIFIED ACTIONS	**(28)**	**(142)**	**(277)**	**(668)**	**(813)**	**(978)**	**(138)**	**(248)**	**(353)**

4.2.3.3 BOSTON

As shown in Figure 4.10, Table 4.9, and Table 4.10, under the assumed capacity resource and load situation, the BOSTON area has sufficient resources through summer 2014 to meet the expected 50/50 load level and the severe 90/10 peak load and reserve requirement to cover the loss of the largest unit. This scenario also assumes forced outages will be at an expected level, adequate resources will be available in New England to meet the reliability criterion, and no generating unit will retire in the BOSTON area. Given the prior request for over 1,100 MW of retirements in the BOSTON area, the operable capacity situation could be tighter. This situation is further complicated by additional operating constraints in the North Shore and Downtown Boston areas.

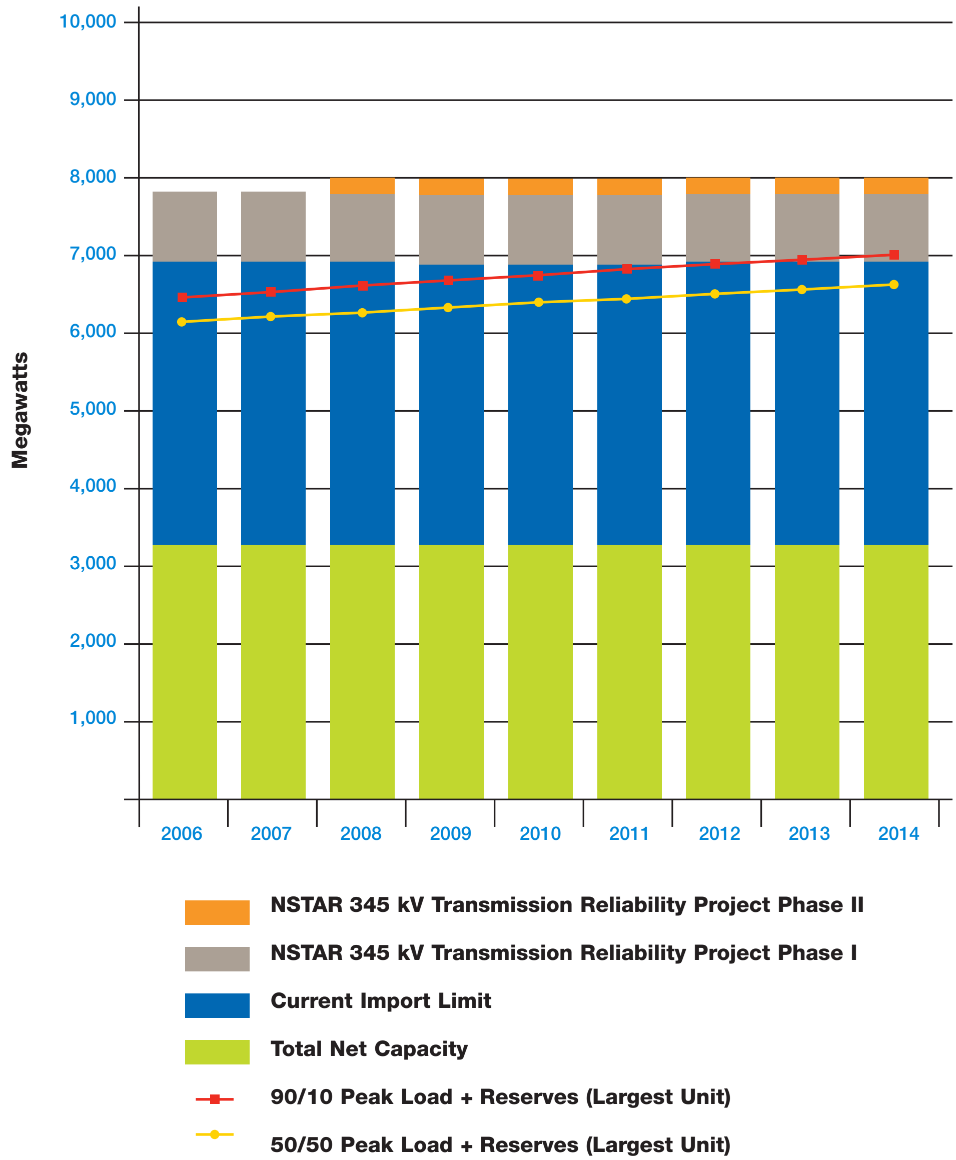


Figure 4.10 **Projected BOSTON operable capacity margin, summer 2006–2014 (MW).**

Table 4.9

Projected BOSTON Operable Capacity Margin, Summer 2006–2014 Using 50/50 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
CAPACITY									
Load (50/50 forecast)	5,470	5,530	5,580	5,635	5,695	5,780	5,840	5,890	5,940
Reserves (largest unit)	710	710	710	710	710	710	710	710	710
Total Capacity Requirement	**6,180**	**6,240**	**6,290**	**6,345**	**6,405**	**6,490**	**6,550**	**6,600**	**6,650**
Total overall capacity	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596
Assumed unavailable capacity	271	271	271	271	271	271	271	271	271
Net capacity	3,324	3,324	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Current import limit	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600
Total Available Resources	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**
CAPACITY SURPLUS/DEFICIENCY	**744**	**684**	**634**	**579**	**519**	**434**	**374**	**324**	**274**
ACTIONS TO ENHANCE CAPACITY									
Strengthening of System (Increase to BOSTON Import Limit)									
NSTAR 345 kV Transmission Reliability Project—Phase I	900	900	900	900	900	900	900	900	900
NSTAR 345 kV Transmission Reliability Project—Phase II	-	-	200	200	200	200	200	200	200
TOTAL IDENTIFIED ACTIONS	**900**	**900**	**1,100**	**1,100**	**1,100**	**1,100**	**1,100**	**1,100**	**1,100**
SURPLUS/DEFICIENCY WITH TOTAL IDENTIFIED ACTIONS	**1,644**	**1,584**	**1,734**	**1,679**	**1,619**	**1,534**	**1,474**	**1,424**	**1,374**

Table 4.10

Projected BOSTON Operable Capacity Margin, Summer 2006–2014, Using 90/10 Loads (MW)

Capacity Situation (Summer MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014
CAPACITY									
Load (90/10 forecast)	5,805	5,865	5,925	5,975	6,045	6,130	6,190	6,245	6,295
Reserves (largest unit)	710	710	710	710	710	710	710	710	710
Total Capacity Requirement	**6,515**	**6,575**	**6,635**	**6,685**	**6,755**	**6,840**	**6,900**	**6,955**	**7,005**
Total overall capacity	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596	3,596
Assumed unavailable capacity	271	271	271	271	271	271	271	271	271
Net capacity	3,324	3,324	3,324	3,324	3,324	3,324	3,324	3,324	3,324
Current import limit	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600
Total Available Resources	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**	**6,924**
CAPACITY SURPLUS/DEFICIENCY	**409**	**349**	**289**	**239**	**169**	**84**	**24**	**(31)**	**(81)**
ACTIONS TO ENHANCE CAPACITY									
Strengthening of System									
NSTAR 345 kV Transmission Reliability Project—Phase I	900	900	900	900	900	900	900	900	900
NSTAR 345 kV Transmission Reliability Project—Phase II	-	-	200	200	200	200	200	200	200
TOTAL IDENTIFIED ACTIONS	**900**	**900**	**1,100**	**1,100**	**1,100**	**1,100**	**1,100**	**1,100**	**1,100**
SURPLUS/DEFICIENCY WITH TOTAL IDENTIFIED ACTIONS	**1,309**	**1,249**	**1,389**	**1,339**	**1,269**	**1,184**	**1,124**	**1,069**	**1,019**

4.2.4 ISO Operating Requirements

In accordance with NERC, NPCC, and RTO criteria, the electric power system is operated and planned to withstand a set of contingencies that includes the possible loss of a transmission facility or generating unit. ISO New England Operating Procedure No. 19, Transmission Operations (OP 19), requires the power system to operate such that when any power system element (N-1) is lost, power flows remain within applicable emergency limits of the remaining power system elements.[58] This "N-1" limit may be a thermal, voltage, or stability limit of the transmission system.

OP 19 further stipulates that within 30 minutes of the loss of the first contingency element, the system must be able to return to a normal state that can withstand a second contingency (N-2). This "N-2" constraint is met by maintaining an operating reserve that can increase output when the first contingency occurs.

Operating reserves can take the form of spinning or nonspinning reserve. Spinning reserve is generation that is already on-line and can increase output. Nonspinning reserve is comprised of off-line quick-start resources that can be synchronized to the system and rapidly reach rated capability. Load-response resources also can qualify as quick-start resources, if their response rate meets the response-time requirements.

ISO System Operations conducts studies to identify the resources needed in transmission-constrained areas for the next day. The analysis takes into account the projected area peak load, the largest contingency in the area, the possible forced outage of resources, and expected transmission-import limits. Failing to have sufficient generation

[58] See <http://www.iso-ne.com/rules_proceds/operating/isone/op19/index.html>.

to meet N-1 or N-2 limits would present reliability risks and result in the need to initiate emergency procedures, including the possibility of disconnecting some firm load. Based on the results of the assessment, generating resources within the load pocket are committed to meet the following day's requirements set by the more severe N-2 limit.

The RSP05 operable capacity analysis determined the total amount of resources needed to protect against both N-1 and N-2 generation contingencies for Greater Southwest Connecticut, Greater Connecticut, and BOSTON. In addition to using the 90/10 forecast for operable capacity analysis of load pockets, consistent with NERC, NPCC, and ISO planning procedures, the analysis accounts for the need to respect the N-2 limit and thus identifies the total amount of resources required within a load pocket. The following sections discuss the types of resources required for operating reserves.

4.2.4.1 Operating-Reserve Requirements

The required operating reserves must compensate for the worst generation or transmission contingency. The amount and type of area generation needed for operating reserves depends on the reliability constraints of the system and the characteristics of the generating units. Secure and economical operation of the system includes a reserve requirement, which can be provided by spinning reserve, quick-start resources, or some combination of both. To provide spinning reserve, additional generation may need to be committed on-line and generators paid net commitment period compensation (NCPC) credits (formerly known as Operating Reserve Credits), an additional cost to load for load-serving entities (see Section 7.5). These costs can be mitigated by quick-start resources that provide nonsynchronized reserve on a systemwide or local-area basis. Quick-start units also offer operational flexibility and improve the reliability of critical load pockets.

Operating experience has demonstrated that many uneconomical units have been scheduled on-line for many hours at a time to provide the required operating reserves in the transmission-constrained areas of Greater Southwest Connecticut, Greater Connecticut, and BOSTON. This results in units operating out of merit in these areas at an increased cost to load.

Table 4.11 shows the typical operating-reserve requirements for Greater Southwest Connecticut, Greater Connecticut, and BOSTON when their transmission interfaces are at limit. The table also shows the existing amount of quick-start capability in each area. These levels tend to be close for the studied areas, but the amount of required reserves in Greater Southwest Connecticut increases with the addition of the transmission improvements of Phase 2 of the Southwest Connecticut Reliability Project. This occurs because the N-2 contingency loss of the new transmission facility is more severe than the loss of the largest generator within the load pocket.

As shown, the 435 MW of quick-start resources in the Greater Southwest Connecticut Subarea currently meets most of that area's requirement for operating reserves. However, another 365 MW of quick-start resources will be required to meet the increase in the operating-reserve requirement once Phase 2 of the Southwest Connecticut Reliability Project is in service, assumed to be December 2009. Currently, the Greater Connecticut Subarea has only 669 MW of quick-start resources; approximately 530 MW of additional quick-start resources are needed to meet the current 1,200 MW requirement for operating reserves. It would be best to install the quick-start resources in the Greater Southwest Connecticut Subarea, because doing so would meet the needs for quick-start resources anywhere in Connecticut.

The analysis for the BOSTON Subarea assumes improvements will be made to the Mystic plant and the simultaneous loss of Unit #8 and Unit #9 will not need to be covered. The BOSTON Subarea requires approximately 500 MW of additional quick-start resources to meet the operating-reserve requirements during the planning period, since it only has 211 MW of quick-start resources to meet operating-reserve requirements in the 750 MW range.

Table 4.11
Major New England Import Area Reserve Requirements (MW)

Area/Improvement	Effective Date	Existing Amount of Quick-Start Resources (MW)	Reserve Requirement (MW)
Greater Southwest CT		435[a]	
Existing	Current		450–650
SWCT Reliability Project Phase 1	12/2006		450–650
SWCT Reliability Project Phase 2	12/2006		800
Greater Connecticut		669[b]	
Existing	Current		1,200
Southern New England Reinforcement Project	12/2011		1,200
BOSTON		211	
NSTAR 345 kV Transmission Reliability Project Phase I	6/2006		710
NSTAR 345 kV Transmission Reliability Project Phast II	12/2007		750

[a] Does not include SWCT RFP resources
[b] Does not include SWCT RFP resources but does include other resources in Greater Southwest Connecticut

4.2.4.2 Summary of ISO Operating Requirements

The need for new generating capacity in Greater Connecticut, Greater Southwest Connecticut, or BOSTON can be met by adding either quick-start capacity or units with energy prices competitive with those resources external to each of these respective subareas. Either of these types of resources could alleviate the reliability and economic considerations. Adding quick-start units in either of these load pockets would provide much needed operating flexibility and operating reserves when the transmission interface is loaded near its N-1 limit. Alternatively, it would be desirable to add base-load resources that typically bid less than resources external to the load pockets, which reduces flows across the transmission interfaces into the areas. (The addition of expensive base-load resources with bids higher than external resources would result in yet heavier loading of the transmission interfaces into the areas.)

4.3 Summary of Resource Adequacy Analyses

The systemwide probabilistic LOLE analysis demonstrates that, by 2010, the New England system will lack the resources necessary to supply load as required by NPCC and ISO criteria, assuming 2,000 MW of tie-reliability benefits. Additional capacity resources will be needed even sooner if less emergency assistance is deemed available from the neighboring systems.

The deterministic operable capacity analysis for New England shows that under the 90/10 peak-load forecast, negative operable capacity margins will occur during the entire planning period. New England will need to rely on OP 4 actions to balance load and resources for maintaining system reliability without disconnecting load. While it may be assumed that 2,000 MW of emergency energy or capacity resources could be purchased from outside of New England when needed, the actual amount that will be available is uncertain. Results indicate that without additional capacity resources, New England will more frequently and heavily rely on external resources and OP 4 supply and demand relief. Retirements and higher forced outages of generating units would worsen the capacity situation.

Greater Connecticut is the most critical area of New England from a resource-adequacy perspective. The Greater Southwest Connecticut area as well as the Greater Connecticut area are and will remain the areas most at risk of experiencing loss of load for any increase in load or decrease in resources. While the Greater Southwest Connecticut's LOLE and resource adequacy will improve when the Southwest Connecticut Reliability Project comes in service, the 1,000 MW assumed transfer-limit increase, attributable to the proposed Southern New England Reinforcement Project, is not adequate to meet all the reliability needs of Greater Connecticut. A greater increase in transfer capability and additional resources are needed in Greater Connecticut to meet its long-term needs and to provide overall benefit to New England as a whole to meet load and established reliability criteria.

Based on the results of the systemwide probabilistic and deterministic analyses and subarea deterministic analysis, the ISO concludes that additional resources are needed by the 2009/2010 timeframe to meet the New England resource-adequacy criterion and minimize the risk of disconnecting firm load.

The operable capacity analysis shows that Greater Connecticut will need approximately 670 MW of additional resources in 2009 to meet the 90/10 peak forecast and provide for operating-reserve coverage. The addition of resources during the 2008 to 2009 period is essential for meeting the reliability needs of Greater Connecticut for the 2008 to 2012 timeframe. Adding those resources in 2009 and an amount equivalent to the annual regional load growth every year thereafter will assure regional reliability and resource adequacy. Since the Greater Connecticut subregion has the greatest risk of disconnecting firm customers to provide for the largest contingency-loss protection and to meet the system reliability criterion, resources installed in this state will create the most reliability benefits for New England and meet both Connecticut's and New England's resource needs.

The addition of quick-start resources for meeting Greater Connecticut's needs will be extremely beneficial for enhancing the reliability of operations. These resources can be used to meet Greater Connecticut's operating-reserve requirements. Adding nonquick-start resources also could benefit Greater Connecticut, if these resources were competitive in energy price with resources external to Greater Connecticut. If these resources were to continuously operate at full output, they could alleviate transmission-import constraints and enhance the import capability to provide operating-reserve coverage.

New England could decrease its capacity resource needs in the short term through conservation and load management, improved unit-availability performance, and purchases of firm capacity from neighboring regional control areas. For the long term, the development of generating and demand-response resources must increase.

Section 5

Need for Increased Fuel Diversity

This section discusses the short-term and long-term issues related to the diversity of fuels used to generate electricity in New England. The short-term issues relate to a large portion of the gas-fired generating units' lacking either firm gas contracts or dual-fuel capability. Having additional gas-fired generating units with either of these two "reliability-based" capabilities would dramatically assist the ISO in reliably operating the bulk power system during periods of extreme winter weather and/or abnormal conditions of the natural gas supply or delivery systems. The longer-term issues relate to the high and increasing reliance on natural gas for producing electric power in New England and neighboring regions, suggesting the need for greater electric power supply-side fuel diversity in the region.

The section addresses New England's winter capacity mix of fuels. It summarizes a probabilistic analysis that investigated the physical risks related to the winter gas-fired capacity and determined the amounts of dual-fuel conversions that could mitigate those risks. It also identifies concerns associated with the nonwinter gas supply. The section concludes with recommendations for encouraging dual-fuel capability and new energy resources for the longer term.

5.1 Near-Term Issues

In the near term, the availability of natural gas during periods of extremely cold weather must be addressed. The availability of natural gas during hot summer periods may also become a reliability issue depending on the number of new natural gas-fired generators that will be built within the NPCC area. The commercialization of large amounts of new gas-fired generation within NPCC without the corresponding enhancements to gas-side infrastructure will foster heated competition for the limited resources of the Northeast's natural gas supply and delivery systems. Some of the potential summer problems are discussed below.

5.1.1 Vulnerability to Natural Gas Interruptions

During periods of extreme cold, the demand for natural gas within the core gas market (for space heating and other uses) occurs coincidently with the demand for gas-fired electric power production. ISO New England had previously conducted studies of New England's interstate natural gas pipeline system. These studies showed that the pipeline capacity into and throughout the region is not sufficient to simultaneously satisfy the winter demand for gas by the local gas distribution companies (LDCs) and the burgeoning gas-fired electric power generation sector. Table 5.1 shows the natural gas demand by sector and the supply capability during the normal peak day for 2005 and 2012.

Table 5.1
New England's Natural Gas Demand and Supply Outlook for a Normal Peak Day (Bcf/day)[a]

Sector	2005	2012
	Demand	
Gas LDC	3.34	3.87
Electricity generators	0.96	1.19
Total Demand	**4.3**	**5.06**
	Supply	
Existing pipelines	3.51	3.51
Distrigas	0.72	0.72
Vaporization	1.22	1.28
Pipeline expansion	0.06	0.16
Total Supply	**5.44**	**5.67**

[a] The table is based on Table 3.3 and Table 3.4 from *Meeting New England's Future Natural Gas Demands: Nine Scenarios and their Impacts*, a report to the New England Governors by the Power Planning Committee of the New England Governors' Conference, March 1, 2005.

The development of the interstate gas pipeline infrastructure has not traditionally been based on serving a forecast of potential market need. Rather, it has been based solely on the expressed need by those parties willing to sign firm long-term contracts to support that infrastructure expansion. In New England, the gas LDCs have funded the majority of pipeline expansion and, therefore, hold the majority of the contract rights and entitlements of the pipeline capacity into and throughout the region.[59] Since gas-fired electric power generators hold firm gas-transportation contracts covering the (winter) peak-use period for only about 4,300 MW, the electric power sector faces a fuel-supply reliability risk during periods of extreme cold when natural gas experiences its regional peak demand.

5.1.2 A Cold Snap Proved the Point

This problem of coincident peak demand for gas materialized during January 14-16, 2004, when the demand for natural gas in New England hit an all-time peak record. Both the natural gas and electricity sectors experienced newly recorded peak demands for each product.[60] The ISO refers to this period as the "January 2004 Cold Snap." During this period, a large amount of electric power generation, primarily gas-fired generation, became unavailable due to a number of reasons, and the ISO needed to invoke emergency operating procedures to maintain the reliability of the power grid. Fortunately, both the natural gas and electricity sectors managed to serve the record peak demand without a loss of service to customers. However, the January 2004 Cold Snap was clearly a 'wake-up call' to the electric power sector with respect to ensuring system reliability during periods of extreme winter-peak demand.

Following the January 2004 Cold Snap, the ISO conducted a number of investigations, which were discussed in RTEP04. These investigations provided an understanding of the problems and recommended ways to avoid future occurrences of cold-weather reliability problems. These were the studies that revealed that of the 17,500 MW total capability of gas-capable units, only about 4,300 MW are under firm gas-transportation (pipeline) contracts linking

[59] Gas-fired power generators hold in aggregate approximately 0.8 billion cubic feet per day (Bcf/d) of firm transportation rights to natural gas trading hubs located outside New England. This can supply approximately 4,300 MW of capacity to generate electricity.

[60] On January 15, 2004, New England experienced its all-time winter-peak demand for electricity of 22,818 MW.

the units to the natural gas trading hubs located outside the region. However, many of these gas-fired units arbitraged their firm gas contracts for financial gain during the January 2004 Cold Snap when selling natural gas fuel was more lucrative than using the fuel to generate power for the electricity market. The studies found that the gas units were not available for the following reasons:

- Exercising of natural gas contractual rights
- Uneconomic conversion of natural gas into electricity[61]
- Very tight or illiquid gas spot-market (commodity and transportation) trading
- Overall weather-induced equipment failures

A key recommendation of these studies is for the ISO to encourage dual-fuel capability of these gas-only units. The studies identified that many gas-only units had air permits to burn limited amounts of oil during emergency periods. However, in some cases, these air permits were ambiguous about when these units could actually burn oil. Furthermore, many of these units had not installed the oil-storage or burner systems necessary to fire oil.[62]

5.1.3 Summer Reliability Concerns

Several factors are causing growing concerns about the reliability of gas generators during the summer months. The use of gas pipelines typically drops to around 50% during the summer months, which has enabled the gas-fired electric power generators to obtain spot-market gas supplies during the peak-load days for electricity. However, the pipeline capability to deliver this seasonal supply is becoming less reliable.

One factor is that the pipelines are facing increased maintenance requirements. The U.S. Department of Transportation (DOT), Office of Pipeline Safety (OPS), has implemented new Integrity Management Rules that essentially mandates increased inspection, testing, and maintenance of natural gas and oil pipelines.[63] The new mandate includes provisions for partial compliance by December 2007 and requires full compliance by December 2012. This will require a vast majority of interstate gas pipelines (and LDCs) to increase inspections of their mainline, network, and lateral systems. These inspections will decrease pipeline availability throughout the year and have a direct impact on fuel deliveries to end-use customers, including gas-fired power generators.

Another factor affecting the capability to deliver gas is the reduced time available for the pipeline companies to conduct maintenance based on the present diversity of the pipelines' customer base; winter demand emanates from the core gas sector, and summer demand emanates from the gas-fired power generation sector. While the summer season has historically been the off-season for New England's gas pipelines during which they performed their maintenance, the pipeline maintenance window has been shortened by New England's reliance on gas-fired power generation to satisfy the peak summer demand for electricity, which is at its highest rate.

[61] This type of conversion, called "negative spark spread" occurs when the wholesale price of electricity is less than the cost (fuel price times heat rate) to produce it.

[62] ISO New England's final report on the January 2004 Cold Snap can be found at: <http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/Cold%20Snap%20Report%20Final_CW.pdf>. Other reports related to this cold snap can be found at <http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/index.html>.

[63] For more information, refer to the Pipeline Integrity Management Program of the Department of Transportation, Office of Pipeline Safety at: <http://ops.dot.gov/init/init.htm>.

A key concern is that the ISO and gas-fired generators are not cognizant of pipeline and LDC maintenance activities, which may have an impact on or constrain fuel deliveries. To gauge the impact, if any, gas sector maintenance activities could have on the availability of gas-fired generation, the ISO has begun to review gas sector maintenance notifications published in the directory, *Planned Service Outages*, available on all regional interstate pipeline electronic bulletin boards. Advanced notification of these types of gas sector outages will help ensure the ISO has the supply-side resources available when and where needed to support system topology and serve load.

A third factor affecting the capability to deliver gas is reduced pipeline throughput and operational flexibility in the warmer summer months. This is primarily due to higher ground temperatures combined with the seasonal loss of compression (horsepower) due to ambient air conditions.[64] This reduction in compression capability during the summer, due to the seasonal impacts from hot weather and compounded by gas sector maintenance (i.e., compressor station outages), results in the loss of operational flexibility. The pipeline companies have traditionally used this flexibility to reliably serve quick-start generation, manage variable hourly swings, and satisfy the overall pressure and flow requirements of these new gas-fired power generation facilities.

Another reliability factor relates to quick-start generators that do not have firm-contract gas and cannot obtain "no-notice" service (i.e., when gas pipeline companies provide gas on short notice), if the generators are suddenly needed for a peak day or a contingency response or another unit experiences an unscheduled outage. Units with dual-fuel capability can alleviate this problem.

Given that natural gas pipelines build sufficient capacity to support firm customer requirements only, gas pipeline systems are inherently designed without "reserves" and/or "redundancy." The ISO has observed that under this type of design criteria, fuel supply to gas-fired electric power generators can be disrupted if critical elements of the natural gas infrastructure (i.e., compressor stations) experience forced outages. Planned or forced outages on the gas infrastructure can reduce overall system capacity to below design capacity or lead to the curtailment of non-firm services. During summer 2005, such forced outages reduced the availability of quick-start gas-fired generating units on the New England electricity grid.

Finally, during the next few years, approximately 9,000 MW of new gas-fired generators in neighboring control areas are expected to go into service.[65] The additional demand these gas units will create may cause increasing problems for gas supply and delivery for both New England and the neighboring areas unless new supply or infrastructure improvements are made. The next section includes further details of this problem.

[64] Higher ground temperatures cause thermal expansion of the gas itself, causing fewer Btus (heat content) to be transported within the same volume of gas. The pipeline then must transport a larger volume of gas to deliver an equivalent heat content of fuel.

[65] For more information on additions planned in New York, Ontario, Québec and Eastern Canada, see <http://www.iso-ne.com/pubs/spcl_rpts/2005/cld_snp_rpt/5_new_england_natural_gas_supply_assessment.pdf>.

5.2 Longer-Term Fuel Diversity Issues

ISO also has concerns about New England's long-term fuel diversity for electric power generation. Many generating units in New England are increasingly reliant on natural gas as their sole or principal fuel. As discussed, other areas compete with New England for the use of the same gas supply, storage, and delivery infrastructure. The need for greater supply-side fuel diversity is clearly apparent. This section presents the results of ISO-sponsored studies on the outlook for gas supplies and regional infrastructure and the potential impacts the expansion of natural gas demand within neighboring markets can have on New England. It also suggests the development of future generating resources in New England focus on energy sources other than gas to achieve a more balanced fuel supply portfolio.

5.2.1 Studies of the Future Outlook for Gas Supplies and Infrastructure

A number of studies conducted for ISO New England examined the outlook for natural gas supplies, infrastructure improvements, and contracting issues. Key findings from these studies are as follows:

- New England's historical and primary sources of natural gas supply now are projected to decline or remain flat. The potential production quantities obtainable from the new gas exploration areas of the Western Canadian Sedimentary Basin (WCSB) and the offshore eastern coast of Canada (Sable Island) are lower than originally anticipated.

- The demand for natural gas continues to grow both within the region and in Canada to serve newly planned gas-fired electric power generators. Over 9,000 MW of planned gas-fired power plants are considered likely to be built within New York, Ontario, and Québec combined.[66] These new facilities will be competing with New England's power generators for the same traditional gas supplies and delivery infrastructure.

- Upward price pressure and competition for natural gas supply and transportation will continue to be a problem during peak winter periods in New England. As a result of the high demand and tight supplies, the regional interstate gas pipelines do not currently support incremental no-notice services. This type of gas contracting could help quick-start electric power generators nominate fuel supply during peak-demand periods or when required for providing operating reserves for electricity.

- Under the current market structures for electricity and natural gas, the gas LDC sector has a competitive advantage over gas-fired electric power generators for purchasing natural gas products and services. This is primarily due to the ability of the gas LDCs to "pass-through" the costs to the rate base for recovery, whereas the gas-fired electric power generators operate in a very competitive market for wholesale electricity.

- New England's electric power generation sector should not anticipate the Portland Natural Gas Transmission System (PNGTS) or the Maritimes & Northeast Pipeline (M&N) to provide any major new supply in the near term, due to the continuing decline in production from the Sable Island supply basin that feeds those pipelines.[67]

[66] Based on a report by the Merrimack Energy Group, *New England Natural Gas Supply Assessment*, April 1, 2005. p. 70.

[67] PNGTS can be "backfed" by Sable Island gas (i.e., have gas injected into the line near the end of the pipeline). Its normal supply source is western Canadian gas delivered by TransCanada Gas Pipeline.

- New LNG import facilities will most likely be required to meet New England's incremental requirements for gas supply in the near term. However, siting concerns for the six proposed projects within New England suggest that the two LNG facilities proposed in the Canadian Maritimes will more likely be the first new import facilities built, which should increase supply to New England.

- Dependency on the global LNG production "chain" for new gas supply also has risks. Expanded liquefaction facilities are needed, but they are currently being developed in areas of political unrest. More LNG tankers have been ordered and are being built, but concerns exist over obtaining enough skilled maritime crews for safely operating this new fleet. Global (winter-period) competition for LNG supplies exists from the growing demand in other areas of the Northern Hemisphere (i.e., Europe and Asia), and any spare or spot market LNG may be sent to the highest bidder based on the economics of need. Also, imported LNG must travel farther than any domestic gas supply source, and delivery delays are always possible due to affects of weather.

- New LNG projects located along the pipeline routes already developed for Sable Island gas deliveries will benefit New England's electric power sector because the existing gas grid will be backfed from the Northeast. This backfeeding will create a great deal of residual gas pipeline capacity, which should increase the operational flexibility for the pipelines and possibly enable them to offer new products and services.

The findings of these gas studies generally raise a major concern regarding the future availability and sustainability of natural gas for electricity generation in New England, given the uncertainties associated with the future demand for northeastern United States and Canadian natural gas and the supply and delivery situation.

5.2.2 Impacts of Expanding Natural Gas Demand in Neighboring Markets

As discussed, the expanding natural gas demand in neighboring markets (i.e., NPCC areas) has an impact on long-term reliability in New England; over 9,000 MW of new gas-fired generation capacity are currently projected to be commercialized in New York, Ontario, and Québec by 2008.

A previous multi-regional gas study showed the majority of natural gas use within the NPCC region to be seasonal (winter peaking), with the core gas-market demand accounting for over 80% of the entire regional demand on a winter-peak day.[68] This study projected that natural gas transportation should be available during the nonwinter months, primarily due to the large amounts of residual pipeline capacity the core market is releasing (from their lower off-peak seasonal demand). It is this nonwinter slack pipeline capacity (released capacity) the gas-fired electricity generation sector has been using for the majority of their fuel deliveries.

Prior studies have also projected that natural gas delivery during the nonwinter months should not be a problem. However, these studies did not foresee or project the vast amount of new gas-fired generation currently being planned throughout the study region. In addition, the regional electric power sector still must compete with gas LDCs for pipeline capacity from the south and west, as they aggressively purchase commodity targeted for the (mandatory) refilling of their gas-storage reservoirs located in Pennsylvania, New York, and southern Ontario. Historically, gas producers have been able to satisfy this coincidental off-peak demand.

[68] In July 2003, ISO New England, NYISO, PJM, IMO, now Independent Electricity System Operator (IESO-Ontario), and NERC participated in a multi-regional gas study assessment entitled, *Multi-Regional Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to Serve the Electric Power Generation Sector*. This assessment was "Classified Confidential for Homeland Security" and, due to compliance with nondisclosure agreements (NDA) signed by participating parties, it was not released into public domain.

Recent concerns about flat or declining North American gas production combined with the projected increase in summer demand from the electric power sector will result in tight near-term gas supplies for the region. This tight-supply situation will exist until one or more newly proposed LNG import facilities become commercial, possibly within in the 2007 to 2008 timeframe and somewhere within the northeastern United States or eastern Canada.[69] The tight-supply situation could then change significantly, because access to new imported LNG would be equivalent to a large "in-region" gas supply source. These new LNG facilities would fill the supply void left by declining Sable Island gas production and may eventually use the existing pipeline infrastructure already built to access that Sable Island gas. This backfeeding of base-load natural gas into the northeastern regional gas grid, in turn, would dampen regional gas supply concerns and relieve the congestion in pipeline capacity from the south and west.

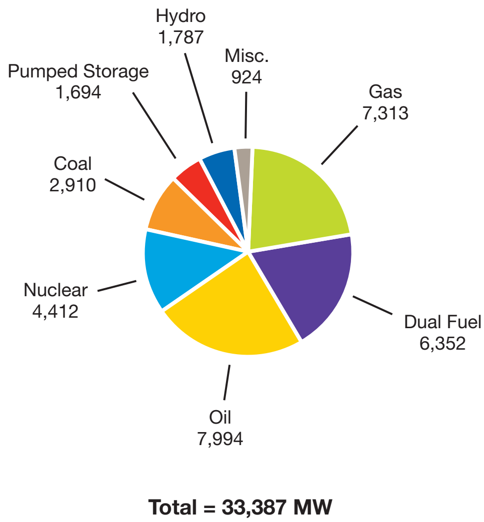
Competition for gas supply and transportation during the winter season will be a growing issue. New England already has experienced the January 2004 Cold Snap, with a regional natural gas infrastructure not designed or built to serve the coincidental winter demands from both the core gas market and the burgeoning electric power sector. LDCs still hold the majority of the contractual entitlements accessing regional storage and long-haul interstate pipeline transportation capacity.

For New England, the increasing use of natural gas within neighboring markets (both gas and electricity sectors) could have an impact on the native gas-fired generation fleet with respect to access to gas supply and the availability of transportation. Decreased competition for the limited infrastructure would occur if a corresponding amount of new natural gas infrastructure were built to satisfy those incremental electricity-sector demands. If the gas infrastructure were not built, competition would be greater, and an increased amount of electricity-sector demand would compete for existing (but limited) gas resources. Except for the (dwindling) Sable Island supply, New England is literally "at the end of the pipeline." Thus, any increase in upstream demand directly corresponds to a downstream shortfall (all factors being equal). Therefore, as gas-fired generation grows throughout the NPCC market area, additional winter-peak "cold-snap" events will likely increase within New England and possibly neighboring markets, unless a comparable amount of incremental gas infrastructure is built to serve this incremental electricity-sector demand for natural gas.

5.3 New England and Subarea Winter Capacity Mix

Figure 5.1 shows the existing capacity mix in New England expressed in winter ratings. As shown, capacity fired solely with natural gas accounts for 7,313 MW (winter ratings), or 21.9% of the total New England capacity. Approximately two-thirds of New England's supply portfolio depends on natural gas and oil for its primary fuel. These fuels have a high price volatility, and their availability is increasingly dependent on imports. This reliance on gas and oil places New England's electricity supply at risk. As discussed later in this chapter, the viable alternative energy sources in the region are limited, and the ISO believes New England should more aggressively pursue energy conservation, demand response, and the development of renewable resources. It also should investigate the potential to develop clean coal and eventually nuclear technologies to lessen its reliance on oil and natural gas and achieve a more balanced energy portfolio.

[69] Regionally proposed LNG projects are in the range of 0.4 to 1.0 Bcf/day of capacity. This compares to New England's winter peak-day demand of 4.3 Bcf/day, of which 0.96 Bcf/day is due to gas-fired electric generators.



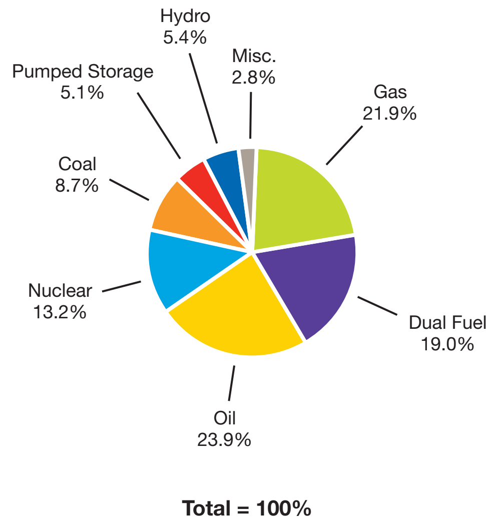


Figure 5.1 **New England installed capacity by primary fuel type assumed in RSP05, winter 2005/2006 (MW and percent).**

Note: "Miscellaneous" units include those fueled by biomass, refuse, and wind resources. "Dual-fuel capacity" is based on units with gas as the primary fuel.

Fuel diversity within transmission-constrained subareas is important to ensure the reliability of the system. Table 5.2 provides tabulations of the capacity mix by generation type for the RSP subareas in winter ratings.

Table 5.2
Subarea Capacity Mix by Generation Type (Winter MW)

Subarea	BHE	ME	SME	NH	BOSTON	SEMA	CMA/ NEMA	WMA	RI	CT	SWCT	NOR	VT
Generation Type[a]													
Gas	540	270	542	1	1,863	1,276	0	247	1,786	0	788	0	0
Dual fuel[b]	184	156	0	1,316	421	160	27	922	2,357	97	714	0	0
Oil	20	0	872	504	1,291	1,301	30	719	509	2,012	184	422	129
Nuclear	0	0	0	1,161	0	685	0	0	0	2,037	0	0	529
Coal	0	75	0	580	312	109	0	146	1,135	182	370	0	0
Pumped storage	0	0	0	0	0	0	0	1,665	0	0	29	0	0
Hydro	120	401	66	503	15	0	24	282	3	46	79	0	248
Miscellaneous[c]	75	103	82	123	102	91	41	7	23	135	7	59	77
Total	939	1,004	1,562	4,187	4,005	3,623	122	3,988	5,813	4,509	2,171	481	983

[a] Categories shown represent the total capacity by the primary fuel (or type, in the case of pumped storage).
[b] The "Dual-Fuel" category represents the dual-fuel capacity primarily fueled by natural gas as reported to the ISO by the generators.
[c] The "Miscellaneous" category includes biomass, refuse, and wind.

5.4 Probabilistic Analysis of Winter Gas-Fired Capacity Needs at Various Risk Levels and Locations

The ISO conducted a probabilistic analysis to identify the minimum amount of gas-only capacity that must be operable in New England to meet a range of risk levels under expected load and capacity assumptions and transmission interface limits. This analysis used a multi-area reliability simulation program to calculate the system LOLE. The analysis first identified the maximum amount of capacity attrition that could occur in New England and its subareas while continuing to maintain the specific LOLE reliability risk of 0.1 day per winter season. The result of this calculation was then compared to the existing gas-only capacity to obtain the estimated amount of gas-only capacity that must be available during a systemwide natural gas shortage. The availability can be achieved by using alternate fuels (therefore requiring the gas-only resource to convert to dual-fuel capability) or accessing gas through firm transportation contracts.

The study covered the winter periods of 2005/2006 through 2009/2010 and accounted for load growth and the transmission improvements over the next five years. Transmission constraints within New England that limit the transfer of power from source to load were also recognized. The analysis used the same load and capacity assumptions as the incremental LOLE analysis, except this study assumed no tie-reliability benefits during the winter months of the study. This approach reflected lower emergency assistance expected from neighboring systems during periods of extreme cold.

5.4.1 Study Results

For New England to meet a given system risk level during December through February, assuming a shortage of natural gas to the area, a minimum amount of gas-only capacity within certain New England load pockets must be operable, either by converting to dual-fuel capability or by contracting for firm gas transportation. The location of these operable gas-fueled resources can have a significant impact on New England system reliability. For example, the conversion of gas-only units in export-constrained areas to dual-fueled capability will most likely have a minimal impact on system reliability in New England. Thus, the ISO prefers facilities that convert gas-only resources to dual-fueled capability to be located on the importing side of a binding transmission constraint.

Table 5.3 summarizes the results of the Winter Gas-Fired Capacity Needs Analysis for 2006 to 2010. The results in the table identify the minimum amount and location of operable gas-only capacity needed to maintain system reliability assuming a shortage of natural gas during December through February.

Table 5.3
Minimum Amount of Gas-Only Capacity Needed to Meet the 0.1 Day/Winter Risk Level (MW)

Winter (Dec. to Feb.)	2005/2006	2006/2007	2007/2008	2008/2009	2009/2010
Total New England	≥1,148	≥392	≥641	≥892	≥1,385
Southern Subareas	≥1,148	≥392	≥641	≥892	≥1,385
BOSTON	≥1,148	≥297	≥146	≥186	≥226
Greater CT	≥0	≥0	≥0	≥0	≥29
Greater SWCT	≥0	≥0	≥0	≥0	≥29

Figure 5.2 depicts these same results graphically for 2009/2010. As shown, New England needs 1,385 MW of operable gas-only capacity during the winter period, all of which must be located in southern New England (i.e., the subareas south of North–South interface, defined as Southern Subareas for this study). Further, at least 29 MW must be in Greater SWCT, and 226 MW must be in BOSTON. The balance of the 1,130 MW can be located anywhere in the Southern Subareas

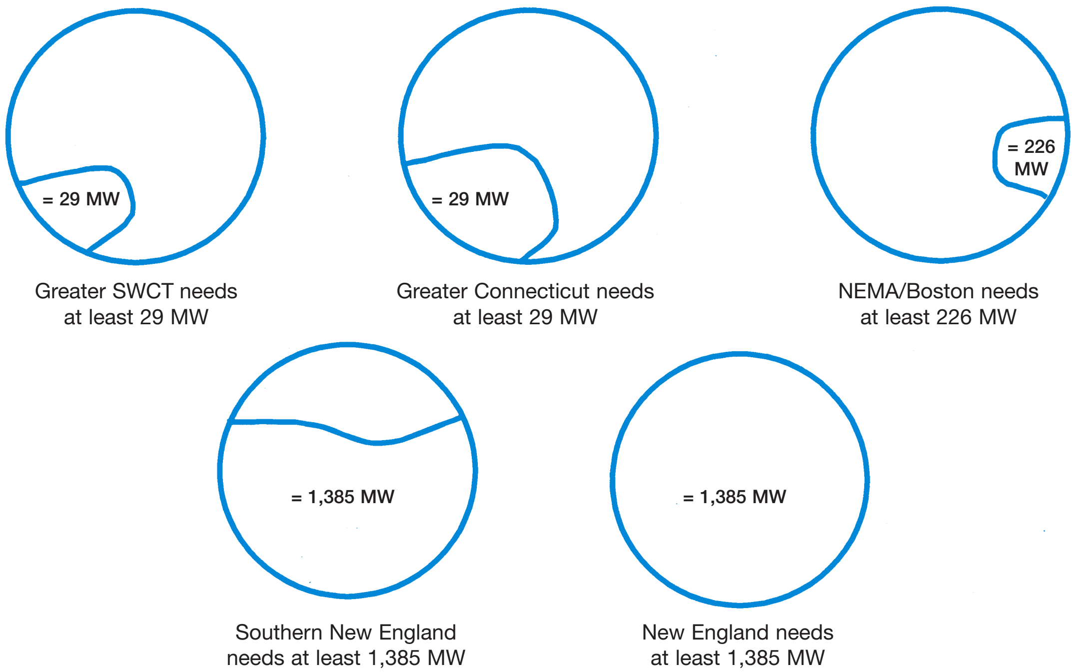


Figure 5.2 **Simultaneous solution—minimum gas-only capacity resources needed to be operational within New England to meet a systemwide 0.1 day/winter system risk level, winter 2009/2010.**

Figure 5.3 through Figure 5.7 graphically depict the minimum amount of gas-only capacity that must be available to meet various risk levels over the next five winter periods.[70] The figures specifically show the gas-only capacity that must be available in Greater Southwest Connecticut, Greater Connecticut, BOSTON, all areas south of the North–South interface, and all of New England. In each figure, the total New England need is the minimum amount of gas-only capacity that must be available through conversion to dual fuel or access to gas through firm transportation contracts. The subarea values illustrate where this minimum capacity must be located to meet the various risk indices.[71] In the figures, all minimum needs for gas-only availability must be met simultaneously to ensure the system can operate at the given risk level when a natural gas shortage occurs. As shown, the level of risk one is willing to take would affect the amount of capacity needed.

[70] The risk level shown is in days/winter, where winter covers the months of December through February.

[71] The values shown are the minimum values and represent an optimal solution.

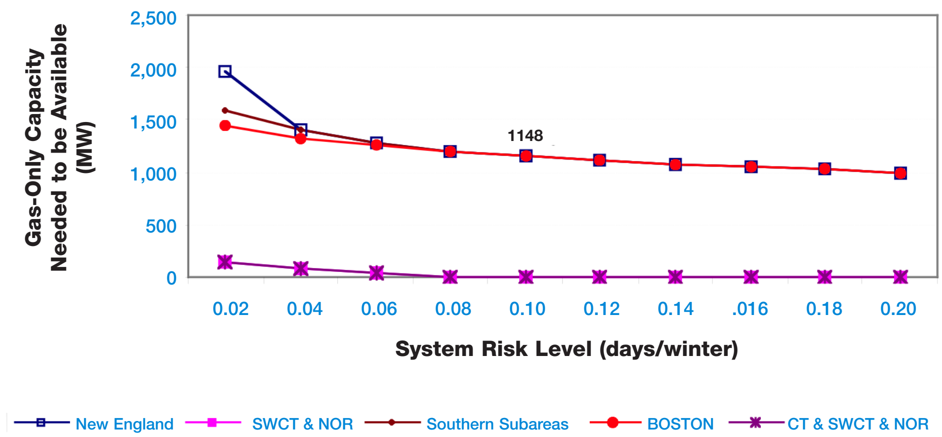


Figure 5.3 **Minimum amount of gas-only capacity to meet risk level, 2005/2006 (MW).**

For winter 2005/2006 (Figure 5.3), a minimum of 1,148 MW (winter ratings) of gas-only capacity must be available in southern New England to meet the system risk level of 0.1 day per winter. This level can be achieved by adding dual-fuel capability or by accessing gas through firm transportation contracts in BOSTON.

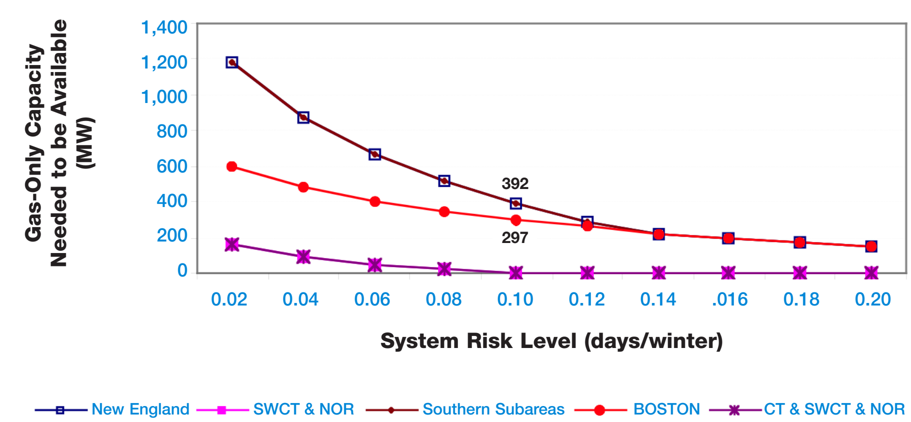


Figure 5.4 **Minimum amount of gas-only capacity to meet risk level, 2006/2007 (MW).**

For winter 2006/2007 (Figure 5.4), of the 392 MW minimum (winter ratings) of gas-only capacity that must be available within southern New England to meet the 0.1-day-per-winter system LOLE, 297 MW must be available in BOSTON; the remaining 95 MW can be available anywhere in southern New England.

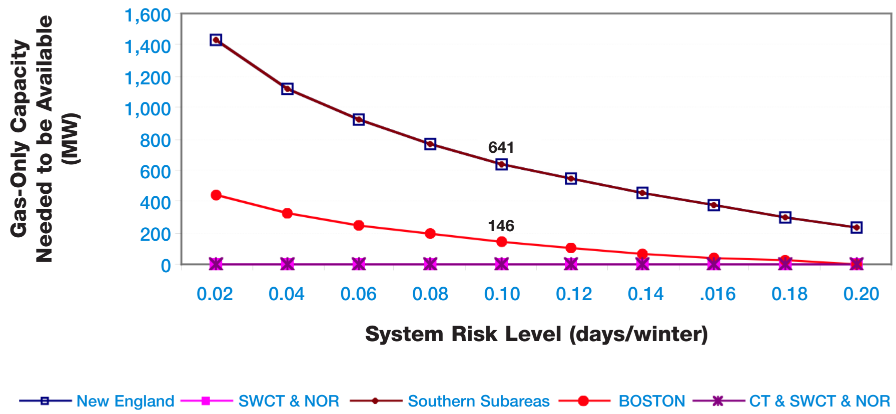


Figure 5.5 **Minimum amount of gas-only capacity to meet risk level, 2007/2008 (MW).**

For winter 2007/2008 (Figure 5.5), of the 641 MW minimum (winter ratings) of gas-only capacity needed to meet the 0.1-day-per-winter risk level, a minimum of 146 MW must be available in BOSTON. The balance of 495 MW to be converted can be available anywhere in southern New England.

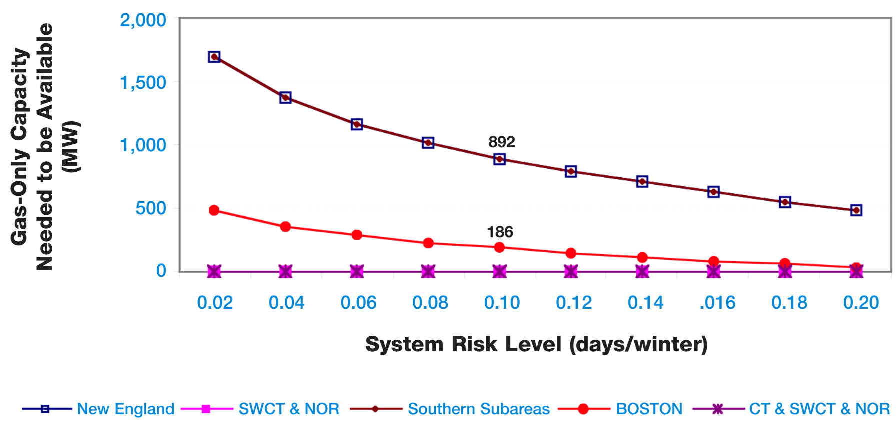


Figure 5.6 **Minimum amount of gas-only capacity to meet risk level, 2008/2009 (MW).**

For winter 2008/2009 (Figure 5.6), of the 892 MW minimum (winter ratings) of gas-only capacity that must be available within southern New England to meet the 0.1-day-per-winter risk level, 186 MW must be available in BOSTON. The balance of 706 MW can be available from any units in areas south of the North–South interface.

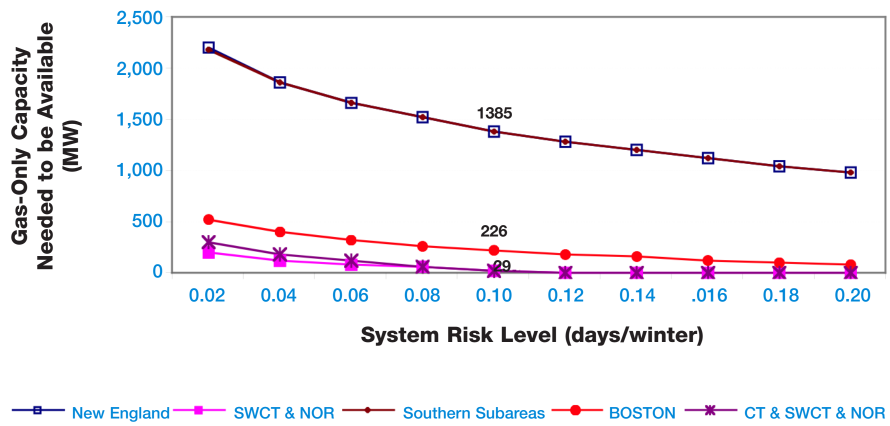


Figure 5.7 **Minimum amount of gas-only capacity to meet risk level, 2009/2010 (MW).**

For winter 2009/2010 (Figure 5.7), a minimum of 1,385 MW (winter ratings) of gas-only capacity must be available within New England to meet the system risk level. Of this amount, a minimum of 226 MW must be available in BOSTON, and 29 MW must be in SWCT. The remaining New England need of 1,130 MW must be from units in southern New England.

5.4.2 Observations

The following points can be made based on the results of the analysis presented above:

- For the next two winters, the availability of gas-only capacity in BOSTON would assure the winter adequacy of New England system resources.
- After the completion of the proposed transmission upgrades in the Boston area, the need for gas-only resource availability in BOSTON during the winter would decrease until 2008/2009 when load growth would place additional demand on resource availability.
- Firming up gas transportation is one way for gas-only resources to help assure system reliability. A second way is to convert the gas-only units to dual-fuel capability and secure the availability of the back-up fuel during the winter.
- While additional conversion to dual-fuel capability and/or additional firm gas contracts would be beneficial, a minimum threshold of 400 MW by winter 2006/2007 would reduce the risk of disconnecting firm customers due to the disruption of gas supplies. This amount would need to increase by approximately 250 MW per year to keep the winter risk level below 0.1 day per year through the winter 2008/2009. A total of about 1,400 MW would be required by 2009/2010.

5.5 Recommendations for Encouraging Dual-Fuel Capability and New Energy Resources

Regional progress in improving New England's dual-fuel capability and the ISO's recommendations for further enhancing this capability and encouraging the development of new energy resources are summarized below.

5.5.1 Progress Toward Enhancing Dual-Fuel Capability

Since the January 2004 Cold Snap, ISO New England, in cooperation with the natural gas industry, generator owners, and state regulators, has made progress toward increasing the dual-fuel capability of the region's gas-fired generators during extreme winter cold-snap periods.

First, ISO New England has developed a new operating procedure, Cold Weather Event Operations, which is Appendix H to ISO New England Market Rule 1 (Appendix H).[72] The procedure forecasts, notifies, and temporarily modifies the wholesale electricity market trading deadlines to minimize the risk of fuel-supply interruptions. This is accomplished through an early procurement of the natural gas commodity and timely "nomination" (securing) of transportation.

Second, ISO New England has created a Natural Gas Pipeline Contracts Database. This database identifies the contracts gas-fired generators have for firm gas-transportation from prominent natural gas trading hubs outside the region. This information clarifies which units should have fuel availability during periods of peak-gas demand, based on their contractual capability.

Third, ISO New England has worked with state air regulators to clarify existing air permits on two gas-fired facilities, with additional rules pending.[73] These revised air permits will allow these facilities to burn limited amounts of fuel oil under specific ISO New England declared emergencies (per Appendix H). Other improvements include weekly communications during the winter-peak period between ISO New England and the regional natural gas sector (operational look-ahead meetings) and continued employee training on gas/electricity operations and interdependencies.

Historical electricity system operation and recent legislation mandating increased pipeline inspection and maintenance is pushing both sectors to coordinate future maintenance requirements. Outage coordination is warranted among ISO New England, generation owners, transmission operators, gas pipelines, LDCs, and the regional liquefied natural gas (LNG) provider. Together, these steps should make the region better able to avert gas shortages that could degrade the reliability of the New England electric power system.

[72] See <http://www.iso-ne.com/regulatory/tariff/sect_3/Market_Rule_1_Appendix_H.doc>. This procedure was previously referred to as *Operating Procedure 20* (OP 20).

[73] The total winter rating of these two facilities equals 1,130 MW.

5.5.2 Actions Needed to Achieve Additional Dual-Fuel Capability

Three actions are needed for the gas-fired generation sector to achieve greater dual-fuel capability. The first action is to determine, by subarea, which gas-fired units are actually vulnerable to having their gas supply interrupted during the winter period due to their contractual arrangements. The second action is to analyze these risks and determine which gas-fired units could add dual-fuel capability. RSP05 has quantified the amount of gas-fired generation capacity needed to maintain various risk levels during a natural gas shortage.

The third action is for ISO Markets Development to create a market incentive for gas-fired units to invest in oil-storage and oil-burning capability in the critical subareas (see Section 6). Identifying these subareas would be based on combining the results of the first two actions. In addition to the locational capacity "availability" design the ISO proposed to improve the availability of units during shortage hours, possible market incentives are as follows:

- Revise the Forward Reserve Market (FRM) rules to promote greater incentives for delivering 10- or 30-minute operating reserves. Investigate the economic incentives for either contracting firm or no-notice gas delivery or installing and operating dual-fuel capability.

- Include operating features related to unit start and stop cycles and load-following capability. Tailor the Forward Reserve Market rules to align more with delivery of energy or reserves based on the true physical capability of units.

- Offer "option payments" for adequacy of backup fuel supplies.

The ISO will explore these and other options with stakeholders and recommend changes to the markets implemented by ISO New England, if appropriate.

5.5.3 Encouraging New Energy Resources

Based on the 2005 ISO New England energy forecast (see Section 3), the region's electricity consumption will increase by about 18,420,000 MWh by 2014. Given the need to diversify the region's mix of fuels to enhance regional reliability, the market will need to encourage other (non-gas) energy sources to serve this growth (see Appendix A).

The first resource option of choice is to encourage efficient conservation efforts throughout the region to minimize new electricity growth. Nonmarket incentives related to conservation and demand-response programs should contribute to this effort. Nonmarket incentives related to distributed generation and state requirements for Renewable Portfolio Standards should lead to the addition of new diversified resources in the region.

To provide a perspective of the amount of supply resources that might be needed, if wind generation were to provide all the energy to meet the 10-year increase in New England's energy demand, about 8,400 MW of new wind capacity would be needed. This assumes a typical capacity factor for wind of 25%. Alternatively, if this increase in energy were to come from a base-load plant (fossil or nuclear fueled), about 2,500 MW of new capacity would be needed by 2014. This assumes a typical capacity factor for base load plants of 85%. If the 2014 energy growth were served by current highly efficient gas-fired combined-cycle technology, approximately 130 billion cubic feet of additional natural gas would need to be procured annually.

Clean coal is the only other major fossil option to consider for increasing the region's fuel diversity. However, the state and federal air emission regulations are being tightened over the 10-year planning period, and the implementation of a proposed regional cap on CO_2 emissions from electric generators is possible resulting from the Regional Greenhouse Gas Initiative (RGGI) (see Appendix A). The RGGI proposal will likely affect the economics of coal plants more than the other fossil options because of coal's higher CO_2 emission rate. Any new fossil plant may be required to reduce or offset most or all of its carbon emissions. Current efforts to develop advanced nuclear plant designs may result in nuclear providing another potentially viable option near the end of the RSP05 10-year planning period. Clearly, non-CO_2 emitting options such as wind, solar, and nuclear will look favorable under a CO_2-constrained future.

Appendix A more fully discusses the implications of environmental considerations and distributed resources for developing future resources in New England. Appendix B provides information on the region's proposed generating projects currently listed in the ISO's Interconnection Study Queue.

Section 6

Adequate Resources through Markets

In previous sections, RSP05 has identified numerous needs of the New England power system involving transmission reliability, resource adequacy, resource flexibility, and fuel diversity. Further, RSP05 identifies specific infrastructure improvements that address transmission reliability issues. This section describes the key market mechanisms the ISO is developing to attract specific type of resources to the locations where they are most needed.

6.1 Needed Market Improvements for Meeting Resource Needs

RSP05 has identified the following major resource needs:

- New resources systemwide and in Greater Connecticut in the 2008 to 2010 timeframe
- An immediate need for quick-start resources in the constrained areas of BOSTON and Greater Connecticut and the need for these resources in Southwest Connecticut by 2009
- Dual-fuel capability or firm fuel supply or additional demand-response resources to assure the availability of sufficient resources to serve load if natural gas supplies are short due to severe winter weather

The energy markets have been workably competitive since their implementation, which has resulted in significant economic efficiencies. However, the wholesale market design remains incomplete and must be improved so that it sends the proper price signals to the marketplace for making the needed investments in existing and new resources to assure both short- and long-term reliability. For example, the wholesale energy market does not clear at the efficient price levels needed to sustain existing investment and promote new investment. The energy market does not clear at efficient levels because an offer cap on the energy market limits prices to about $1,000/MWh.[74] This offer cap is needed because the wholesale market lacks demand response, preventing demand from clearing the market when the demand for electricity approaches or exceeds supply. This makes the energy market vulnerable to the exercise of market power.

Improvements are needed in two market areas, the capacity markets and the Ancillary Services Markets (ASM), particularly the operating-reserves markets. The capacity market improvements are intended to send the proper price signals for meeting the long-term resource needs identified in RSP05. They are also intended to address the need for firm fuel supply or back-up fuel supply, such as oil. Improvements to the Ancillary Services Markets, known as ASM Phase II, are intended to send appropriate price signals to encourage existing and new resources to provide quick-start capacity in the constrained load-pocket areas identified in RSP05. ASM Phase II improvements may also help meet resource needs in that they will facilitate demand-side participation in the market and thereby increase the quantity of demand resources.

[74] Prices can exceed $1,000 due to congestion and losses.

6.1.1 Capacity Market Improvements—The Locational Installed Capacity Market

The capacity market supplements the energy market by replacing the price signals lost from the energy market caps. Another reason for the capacity market is based on the ISO's need to meet its regional IC Requirement and the 1-day-in-10-year reliability criterion to assure that capacity is always sufficient to meet demand. The capacity market helps send the proper price signals for assuring the system's installed capacity meets this standard. Since this requirement is imposed outside of the normally functioning energy market, however, the energy market alone cannot be expected to meet it.

Since the energy market alone is unable to efficiently price electricity during hours of peak use, ISO New England, with FERC approval, is developing improvements to the existing capacity market. These improvements include making the current regional capacity market locational to reflect the different values capacity has in various locations on the system.

On March 1, 2004, the ISO filed a locational installed capacity (LICAP) design with FERC that included a sloped demand curve to address the price volatility of installed capacity, a locational clearing process to appropriately price capacity on a locational basis, and a capacity transfer-rights mechanism to allow for nonuniform allocations of the ability to import capacity into or export it from a region. FERC approved the overarching design of the ISO's LICAP proposal (the use of a downward-sloped demand curve and pricing within constrained regions), but set certain issues for hearing, including the specific parameters of the demand curve, the method of calculating capacity transfer limits, and the allocation of capacity transfer rights. In addition, the commission directed the ISO to submit a further filing addressing the commission's proposal to create a separate, import-constrained installed capacity region for Southwest Connecticut.

On June 15, 2005, FERC's Administrative Law Judge issued an initial decision in the LICAP proceeding. While the judge's initial order accepted most of ISO New England's proposed LICAP design, she did not accept the ISO's "shortage-hour" concept, which would have required all resources to be available during times of scarcity to receive LICAP payment. On August 10, 2004, FERC issued an order delaying the implementation of LICAP until October 1, 2006. FERC's ultimate disposition of this case will affect the implementation of the capacity market. The ISO is prepared to implement the LICAP Market on October 1, 2006, if so ordered by FERC. The ISO also is committed to actively participate in the LICAP proceedings, as may be ordered further by FERC.

6.1.2 Ancillary Services Market Improvements—ASM Phase II

ASM Phase II is designed to build upon the current Forward Reserves Market by running separate auctions for the region's import-constrained subareas as well as for the remainder of the region. These locational auctions are intended to elicit the needed quick-start capability identified in RSP05 and to address the market inefficiencies identified in the ISO's *2004 Annual Markets Report and the Independent Market Monitoring Unit (Patton) Report*.[75] ASM Phase II also will enable dispatchable loads to participate directly in the real-time energy market, and it jointly minimizes the costs for energy and reserves in real-time.

[75] See <http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html> and <http://www.iso-ne.com/pubs/spcl_rpts/2005/immu/index.html#top>.

To meet the need for quick-start resources in constrained areas, the existing process to set Forward Reserves Market requirements and clear the FRM will be modified to add a locational component. This component will reflect the forecasted operational requirements for commitment and dispatch to meet the second-contingency requirements for defined areas (so-called “reserve zones”) of the power system. These requirements will be observed during both forward-market clearing and real-time dispatch.

The Forward Reserves Market will be modified to allow participants to submit “portfolio” bids (i.e., single bids from multiple resources) for evaluation and clearing in the market and to trade these obligations via bilateral arrangements. Participants will need to convert all obligations to physical resources by the bidding deadline for the day-ahead market. Finally, the forward market will be modified to allow qualifying demand resources to participate in the Forward Reserves Market.

The dispatch algorithm currently used in the energy market does not recognize the regional or locational reserve requirements to which the ISO must adhere when operating the system. If the energy dispatch alone does not provide sufficient reserves, system operators must manually dispatch the system to provide those reserves. Although such manual interventions are necessary at this time to preserve system reliability, the decisions made by the system operator are not transparent to market participants, and the resulting interventions may not be optimal (i.e., a less-expensive resource may have been available to provide reserves but was not selected).

To improve the efficiency of dispatch decisions to provide needed reserves and jointly optimize the dispatch of energy and reserves, the ASM project will include both regional and locational reserve constraints in the energy dispatch. An hourly clearing price for reserves will be created when an opportunity cost for providing reserves exists. This price will be paid to all those providing energy or resources on the system. When the system does not have enough reserves, shortage pricing will include the value of the foregone reserves in both the energy and reserve price. Quick-start resources, when economic for supplying energy or reserves or when needed to manage transmission constraints, will continue to be committed and dispatched by the real-time dispatch software.

Increased demand response can help meet both the resource and quick-start needs identified in RSP05. Once demand resources are integrated into real-time operations, it will have the potential to help balance load and generation and offer reserve services. Demand-response participation in the reserves market has the potential to improve the efficiency of this market by increasing the resources available to participate in the market, thus making it more competitive. Indeed, demand resources in the ISO’s Demand Response Programs have already demonstrated the ability to respond rapidly to ISO dispatcher instructions and provide reserves. These additional opportunities for demand response should increase the amount of demand response in the market. Accordingly, the software infrastructure needed to support the ability of demand-side resources to participate in the energy and the reserves markets will be implemented as part of the Ancillary Services Markets project.

6.2 Summary of Needs and Proposed Solutions

Table 6.1 shows projected resource and transmission needs in New England in terms of the amount and types of generating resources needed and where and when they will be needed. The table also links the system needs identified in RSP05 to preferred solutions to meet those needs and to the existing and proposed wholesale energy market features that will facilitate those solutions by providing appropriate incentives to the wholesale market place.

Table 6.1
Summary of RSP05 System Needs, Solutions, and Proposed Market Mechanisms Based on RSP05 Assumptions and Analyses

System Needs	Solutions	Proposed Market Mechanisms
Meet load-pocket requirements	Add quick-start resources to satisfy reliability needs. Operable capacity requirements for Greater Connecticut: - Need 30 MW by 2006 (90/10 load) - Need 670 MW by 2009 (90/10 load)	Improved capacity market and ancillary services including demand response
Meet systemwide forecast requirements	Add quick-start resources that satisfy load-pocket needs to satisfy system need. Systemwide operable capacity requirements: - Need 160 MW by 2008 (50/50 load) - Need 1,900 MW by 2008 (90/10 load)	Improved capacity market and ancillary services including demand response
Provide operating reserves	Add incremental quick-start resources or units with energy prices competitive with resources external to the load pockets. Requirements: - Need 530 MW in Greater Connecticut by 2006 *The preferred location for adding quick-start resources for meeting the needs of Greater Connecticut is Greater SWCT because this area needs 350 MW by 2009.* - Need 500 MW in BOSTON by 2006	Improved capacity market and ancillary services including demand response
Meet systemwide 1-day-in-10-year LOLE criterion	Meet systemwide needs by meeting load-pocket needs. Requirements: - Need 170 MW systemwide by 2010	Improved capacity market and ancillary services including demand response
Reliably operate system when gas is not available	Achieve greater fuel diversity by adding incremental dual-fuel conversions in southern New England, predominantly BOSTON. Requirements: - Need 400 MW by winter 2006/2007 - Need 250 MW more every winter through 2008/2009 - Need 500 MW more in winter 2009/2010	Improved capacity market and ancillary services including demand response May need additional market incentives or tariff provisions

Part III **Transmission**

The New England power system has been designed and planned over time as an integrated system of generation serving load through a transmission system. Today, with an aging infrastructure, load that continues to grow, changes in the primary flow patterns, and other concerns, the power system must be upgraded in the short- and long-terms to ensure its overall reliability.

Part III discusses the major issues associated with the transmission system in New England and the projects planned and underway to upgrade it. Section 7 provides background information on the transmission system and identified transmission system needs. Section 8 summarizes the status of the major transmission development efforts in the region, most of which have been identified in previous plans, and information on the system needs in load/generation pockets. The changes in the Transmission Project Update, compared to RTEP04, are presented in Section 9.

Appendix C includes a more thorough discussion of the need for transmission system upgrades. Appendix D provides a Web site link to the complete current ISO Transmission Project Listing.

Section 7

ISO New England Transmission System Needs

This section discusses some of the main problems associated with New England's transmission system that threaten the reliability of the system overall. The region must address these problems to accomplish the following major tasks:

- Solve so-called "pure" transmission problems related to voltage and dynamic instability in the system and upgrade equipment where existing equipment ratings are limiting flows on the system.
- Serve load pockets deficient because of load growth and/or limited sources of delivery. A local area may be excessively dependent on a single line, or the failure of one or a few local generators could jeopardize the reliability of a local area.
- In a broader sense, assure the reliability of the network, if alternative resources do not emerge when and where needed based on market incentives. Transmission remains the single essential improvement in this regard. Adding alternate resources may solve a problem in a specific area, but a transmission solution often solves a number of problems; hence, it typically is a more robust alternative.

7.1 Aging Infrastructure; Growing Load

The existing 345 kV transmission system was developed as the primary network to integrate generation mostly planned and installed before the 1990s to serve a peak load that has since been surpassed. Many facilities are from 60 years to 80 years old, and the generation interconnected to the 115 kV network particularly shows signs of age. Additionally, load has continued to grow, and a large amount of new generation has connected to the system at new previously undeveloped sites. These events have combined to produce a number of stresses on the overall transmission network, including an increasing number of reliability concerns in smaller areas served by relatively few older units. As a result, reliably operating and maintaining these areas is becoming increasingly difficult. In some cases, the addition of new generation has been beneficial, but in other cases, the loadings on the transmission system have become increasingly stressed.

7.2 Change in Predominant Directional Flow Patterns

The regional transmission systems have had predominant directional flow patterns (i.e., north to south, east to west), some of which have changed over time as new generators and transmission lines have been built. In Connecticut for example, the predominant flow pattern was west to east, but this pattern has reversed due to the large amount of new generation added in southwestern Massachusetts and Rhode Island coupled with load growth. The north to south flow still predominates, although it is constrained at the New Hampshire–Maine interface. Consequently, the ISO has identified a number of major transmission system reinforcements urgently needed to address current and future reliability concerns.

7.3 Voltage Levels

The 115 kV network provides an important regional power supply function in New England. The 115 kV facilities carry power provided by 345/115 kV transformation and 115 kV generation to numerous load-serving stations. The New England 115 kV transmission facilities have a wide range of individual capabilities, most reflecting their age, although many facilities have relatively low thermal capabilities. Many facilities originally constructed for 69 kV operation have since been upgraded to operate at 115 kV.

7.3.1 Reliability Concerns

Normal load growth requires the continual review of the aggregate capabilities of the 115 kV portions of the New England system and modification as necessary. Considerable efforts and progress have been made for assessing the adequacy of the transmission system and the need for proposed modifications. Reliability studies and progress in modifying the system are discussed throughout Appendix C and are illustrated by the project listing referenced in Appendix D. The studies have been ongoing to comprehensively assess all parts of the system and have prompted efforts to consider alternatives and pursue preferred solutions. The tables in this section illustrate the progress made to provide adequate regional transmission service.

7.3.2 Voltage Performance Improvement

Modifications may include such changes as replacing existing facilities, adding new facilities, or adding new 345/115 kV transformers to improve the balance of loadings on existing facilities. These changes account for the largest number of system modifications required to meet reliability standards, although the modifications tend to be much smaller in scope than the major projects.

Fixed capacitors sufficient to address voltage-performance issues have been installed in many instances. However, capacitors have limited applications because the amount of voltage support they provide decreases as the voltage decreases. Thus, capacitors provide less voltage support at the very time they are needed the most—as voltages become very low.

The system will increasingly require fast-response dynamic voltage-control devices to prevent pre-contingency excess voltage and allow post-contingency voltage recovery. These devices also provide continuous voltage support and improved voltage regulation. Some of the devices that provide dynamic and continuous voltage support are static compensators and static VAR compensators (SVCs). These devices use power electronics to adjust power and voltage output almost instantaneously.

Another emerging voltage-control technology yet to be employed in New England involves the installation of "clutch devices" on generators. These devices allow a synchronous generator (i.e., a typical type of generator connected to the network) to be disengaged from its prime mover—the motive force that drives the electric power generator, such as a water or steam turbine—and be operated as a voltage-regulating synchronous condenser.[76] Reactive compensation to improve voltage support has limitations, however. Many studies have identified locations where reactive compensation has already been maximized, such as in northwestern Vermont. These areas can be improved only by adding new transmission facilities.

[76] Generation owners interested in such opportunities should contact ISO New England to discuss potential locations for such conversions.

7.4 Access to Economical Generation and Fuel Sources

In addition to concerns for reliability, other reasons for improving the transmission system relate to cost savings and access to fuel. Transmission lines in the geographic locations that can increase the system's access to economical generating capacity and energy in neighboring areas can provide cost savings. Additional transmission can allow access to a wider variety of fuel sources and greater operational flexibility across a larger area. Alternative resources, such as distributed generation and demand-response resources, can also help meet an area's need.

7.5 Interactions between the Transmission System and the Energy Markets

When the marketplace alone does not develop the necessary resources to ensure system reliability, transmission enhancements are necessary. The increase in efficiency brought about by these enhancements in turn supports a robust market. When the resources and/or transmission improvements are not developed, the inherent inefficiencies and increasing reliability risks created result in out-of-merit commitments, which then produce operating-reserve charges.

Operating-reserve charges, known as second-contingency net commitment period compensation credits, are paid to generating units required for reliability within a particular reliability region on a particular day. NEMA/Boston and Connecticut are the only regions that have local second-contingency coverage, thus, in 2004, second-contingency NCPC credits were made in these areas only.[77]

Second-contingency commitments are a function of local reserve requirements and the availability of quick-start units to meet these requirements. Areas with local reserve requirements greater than available quick-start generation, and without sufficient in-merit generation (based on accepted and dispatched supply offers), require second-contingency commitments. Local contingencies determine local reserve requirements. These contingencies include the possibility of a transmission line or generator failure and load-shedding assumptions for the area, which transmission owners provide to the ISO. Limited transmission capacity into an area reduces the amount of reserves that can be supplied from outside the area, and this lack of supply increases local reserve requirements.

In addition to the second-contingency NCPC credits, several additional NCPC credits and tariff-based payments result from constraints on the transmission system in a specific area, as follows:

- First-Contingency (formerly called Economic) NCPC Credits—These charges are made to participants whose real-time load deviates from the day-ahead schedule. The credits are paid to eligible units that provide operating reserves the ISO has committed for ensuring pool reliability (e.g., to supply replacement reserves) and whose decommitment would pose a threat to that reliability. Units not flagged, or designated, for another type of NCPC credit receive these credits. Most first-contingency NCPC payments are made to generators committed to supply systemwide energy in peak hours that must stay on during later hours to satisfy minimum runtime requirements. While these generators may have been in-merit during peak hours, they become out-of-merit (more expensive) in later hours and thus receive NCPC payments. Costs associated with first-contingency NCPC credits are not incurred as part of the economic dispatch of the power system.

[77] See <http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html>.

- Voltage and Distribution Tariffs—Generators providing voltage and distribution service are compensated for shortfalls between their energy revenues and energy offers the same as generators receiving first- or second-contingency NCPC credits. Voltage payments are shared by all New England transmission owners based upon network load, while distribution charges are directly assigned to the transmission owner requesting a generator commitment. In 2004, daily out-of-merit costs in constrained areas were driven by reliability needs for transmission support, typically reactive power and second-contingency coverage.[78]

Reliability-based transmission system improvements can help mitigate or even eliminate NCPC and tariff payments thereby providing a more efficient operation over the long term. In some cases, the transmission improvements may not be sufficient, and new quick-response resources (i.e., generators or demand-response resources) may be needed as well.

Review of the historical loadings of major transmission boundary interfaces indicates an absence of significant transmission-constrained congestion, which is due in part to the out-of-merit commitments to protect for first and second contingency and the lack of appropriate shortage-hour pricing in the energy market.[79] This results in a decrease in congestion costs and an increase in so-called NCPC costs.[80] Based on these observations and the results of previous analysis of potential future congestion, significantly enhancing market efficiency through major transmission upgrades does not seem to be needed at this time. However, ISO New England will continue to examine ongoing and projected system conditions and remain vigilant in exploring future opportunities.

[78] Ibid.

[79] For the complete set of exhibits for all eight interfaces see "Historical LMP and Interface Flows" at: <http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2005/mar32005/index.html>.

[80] For more information, see <http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html> and <http://www.iso-ne.com/pubs/spcl_rpts/2005/immu/index.html#top>.

Section 8

Transmission Projects

Much progress has been made over the past few years regarding transmission projects. Seventy-five projects have been placed in service since RTEP01 totaling $217 million in construction costs. Five of the region's six major 345 kV projects are in various stages of development, with state siting approval either completed or underway. Section 8 provides an update on the progress of the current major transmission efforts in New England and describes the needed transmission improvements to load or generation pockets.

8.1 Major Transmission Projects

This section summarizes the main features of the six major transmission projects in New England. They are considered major in terms of their potential specifications, costs, and how they will improve the transmission system; most involve new 345 kV transmission lines. The projects are as follows:

- Northeast Reliability Interconnect Project
- Northern New England Transmission Transfer Capability Project
- Northwest Vermont Reliability Project
- NSTAR 345 kV Transmission Reliability Project
- SWCT Reliability Project, Phase 1 and Phase 2
- Southern New England Reinforcement Project

8.1.1 Northeast Reliability Interconnect Project

The Northeast Reliability Interconnect Project, also known as the Second New Brunswick Tie Project, is proceeding. It is comprised of a new 144-mile, 345 kV transmission line connecting Le Preau Substation in New Brunswick to Orrington Substation in northern Maine along with supporting equipment. It is designed to increase transfer capability from New Brunswick to New England by 300 MW.

The ISO reviewed and approved the proposed plan in early 2003. The stakeholder transmission cost review, which was completed in mid-2004, determined that the $90.4 million total U.S. cost of this project should be included in the regional transmission rate, which the ISO then approved. As is typical, the final actual cost of the constructed project may vary from the estimated cost and continues to be subject to review per the ISO tariff.

The project's application for a Certificate of Public Convenience and Necessity from the Maine Public Utility Commission (PUC) was approved in July 2005. The project is currently undergoing two other regulatory proceedings as follows:

- Application for an environmental permit from the Maine Department of Environmental Protection (DEP)

- Request for a Presidential Permit from the U.S. Department of Energy required for international tie lines

The planned in-service date for this project is the end of 2007.

8.1.2 Northern New England Transmission Transfer Capability Project

The ISO is conducting analyses to identify upgrades that will increase the transfer capabilities of the northern New England interfaces and reduce operational complexity by reducing the interdependencies of specific generators on the transfer capability. The Surowiec–South, Maine–New Hampshire, and northern New England Scobie and 394 interfaces are most notably affected by these analyses. The ISO has identified alternatives, as follows, to address these issues, either individually or in combination:

- **Closing the Y-138 line.** This project, actively being pursued to address central New Hampshire reliability needs, also will provide some limited increase to the Surowiec–South and Maine–New Hampshire voltage and thermal limitations. This project is currently estimated to cost $20 million. It is anticipated that the proposed project plan will be submitted for review in late 2005.

- **Adding a 500–600 MVAR static compensator to provide dynamic voltage control at the Deerfield 345 kV Substation.** This project would reduce the complexities and interdependencies of generators on the voltage limits of the Maine–New Hampshire interface and could also increase the Maine–New Hampshire and northern New England Scobie and 394 interface stability limitations. This potential alternative is currently estimated to cost $25 million.

- **Eliminating critical Buxton 345 kV contingencies resulting from the failure of key circuit breakers to operate.** This project would increase the steady-state and stability limitations of the Surowiec–South and Maine–New Hampshire interfaces. This potential alternative is currently estimated to cost $5 million.

- **Looping Section 391 into the Deerfield 345 kV Substation.** This project would reduce the complexities and interdependencies of the generators on the voltage limits of the Surowiec–South and Maine–New Hampshire interfaces. It could also increase the thermal and voltage limitations of the Surowiec–South and Maine–New Hampshire interfaces. This potential alternative is currently estimated to cost $4 million.

- **Upgrading 115 kV facilities near the southern Maine–New Hampshire border.** This could increase Maine–New Hampshire thermal transfer limits during peak load or shoulder-peak load periods. This potential alternative is estimated to cost approximately $4 million.

- **Adding capacitor banks in western Maine and at Maxcy's.** These additions could improve the Maine–New Hampshire voltage limits. This potential alternative is estimated to cost approximately $6 million.

The ISO must evaluate these alternatives to determine which one to implement for addressing southern New England's reliability needs. The system changes associated with closing the Y-138 line and addressing southern New Hampshire's needs will improve the interface capabilities of the area. Once the ISO evaluates the base reliability upgrades, it can evaluate the critical interface capabilities. It also can more fully assess the incremental needs and benefits of the various other alternatives and produce recommendations regarding the alternatives most beneficial to pursue. The ISO expects to complete these tasks in late 2005.

Eliminating constraints and improving technical performance on this transmission corridor will become increasingly important as the demand for capacity and resource diversity in the region increases in the very near future. While current system conditions might not suggest a need for a major system reinforcement, this may change in time. Analyses performed to assess future transmission adequacy may indicate further reliability needs within Maine and New Hampshire that, in aggregate with the region's needs or independently, may require additional and more significant transmission system reinforcements. These longer-term analyses will continue into 2006.

8.1.3 Northwest Vermont Reliability Project

The Northwest Vermont Reliability Project is designed to improve reliability of the northwestern area of Vermont. The project is particularly needed to cover outages in this area that could cause voltage collapse. The project consists of a new 36-mile, 345 kV line, a new 28-mile, 115 kV line, additional phase-angle regulating transformers (PARs), two dynamic voltage-control devices, and static compensation. Prior to 2005, the ISO and NEPOOL reviewed the proposed plan and completed the transmission-cost allocation (TCA) for the project, initially estimated to cost $156 million.

Two separate applications (Section 248) were filed with the Vermont Public Service Board (VPSB), one on May 23, 2003, for the Sandbar PAR, and a second one on June 5, 2003, for the balance of the project.[81] This was done to expedite the Sandbar work in light of the unexpected failure of the PAR at Plattsburgh, New York, on April 11, 2003 (35 months after a prior failure), which the Sandbar PAR is meant to replace. The VPSB approved the Sandbar PAR application, and construction was completed on this project in 2004. A modified version of the second application was approved in early 2005. VELCO is presently reviewing the modifications, which included, among other changes, modifications to the design of a portion of both the 345 kV line and the 115 kV line. The original scheduled in-service dates of 2005, 2006, and 2007 for the various phases of the project may not be achievable, and cost impacts could lead to an amended transmission-cost application.[82] Construction is now scheduled to begin in late 2005. If extreme weather conditions were to occur, combined with low generation availability and critical outages, local operator actions may be needed to maintain reliability.[83]

8.1.4 NSTAR 345 kV Transmission Reliability Project

The NSTAR 345 kV Project includes the construction of a Stoughton 345 kV station and the installation of three new underground 345 kV lines—two 17-mile cables to K Street Substation and one 11-mile cable to Hyde Park Substation. The project also includes adding new autotransformers at both Hyde Park and K Street Substations and shunt reactors at both Stoughton and K Street Substations. This $234 million project will be constructed in two stages with a final in-service date of late 2007.

[81] For information on Vermont Statute Section 248, see <http://publicservice.vermont.gov/Lamoille/248statute.htm>.

[82] See Vermont Public Service Board Docket No. 6860.

[83] The loss of Highgate would compromise the reliability of the service to northern Vermont.

This project brings a new source of 345 kV supply to the Boston area from the south to address the reliability problems that emerged due to changing load and generation patterns. In addition to improving the reliability of the Boston-area transmission system, it also will increase the Boston-import transfer capability by approximately 1,000 MW.

In July 2004, the ISO completed its review and approval of the proposed plan for this project. The Massachusetts Energy Facilities Siting Board issued its approval of this project to NSTAR in December 2004. Construction of Phase 1 of the project began in April 2005; it is scheduled for completion in June 2006.

8.1.5 Southwest Connecticut Reliability Project

As discussed in previous RTEP reports, the transmission system in SWCT must be upgraded to remove operating constraints on existing generation, allow new generation to be installed, and improve the import capability of the area. Studies of the Southwest Connecticut region have been ongoing for several years. As reported in RTEP02, the Southwest Connecticut Reliability Project was to include a number of system reinforcements and an overhead (OH) 345 kV loop connecting existing 345 kV facilities in Middletown and Bethel. RTEP03 reconfirmed the need for the project in its entirety, but also indicated the likely need for some modifications due to local requirements. Ongoing studies have focused on alternative routings, alternative technologies, and significant technical performance issues raised by replacing sections of overhead line with underground cable.

In July 2003, the Connecticut Siting Council approved a combination overhead/underground (UG) alternative for the 20-mile Phase 1 project from Bethel to Norwalk. This modification required the development of a cost-effective acceptable design that could demonstrate the system would experience no significant adverse effects. The NEPOOL Reliability Committee found a number of relatively minor modifications to be necessary; it recommended approval of the proposed plan with the modifications in February 2004.

In April 2005, the CSC approved the construction of the approximately 70-mile Middletown to Norwalk section of the project (proposed and approved to include approximately 24 miles of UG cable). The addition of considerable high-capacitance cable into a relatively weak corner of the New England grid created the possibility for switching events to cause sustained temporary over-voltage conditions (due to harmonic resonances) that could significantly damage equipment. After prolonged study, modifications were developed to mitigate the potentially harmful conditions and allow the project to continue. The modifications included changing the proposed cable technology and installing additional equipment and upgrades.

The current cost estimates for Phase 1 and Phase 2 of the SWCT Reliability Project are $357 million and $990 million, respectively. The ISO has reviewed and approved the proposed plan for Phase 1. Phase 1 substation construction is well underway, and work has begun on the 115 kV underground cable. Overall completion of the Phase 1 project still is scheduled for late 2006. Final supplementary studies to support the review of Phase 2's proposed plan began in the second quarter of 2005.

Areas within the Greater SWCT Subarea and NOR Subarea also face reliability problems due to inadequate 115 kV transmission. The preferred upgrades are a pair of new 115 kV lines from Norwalk to Glenbrook developed as part of the SWCT Reliability Project.

Studies are currently determining whether the construction of the Singer Substation and the reconnection of the Bridgeport Energy Center generator, elements of the Phase 2 project, can advance independently of Phase 1 tasks without the occurrence of any adverse system impacts. If so, this could somewhat mitigate area short-circuit current problems from hampering the interconnection of some generation in the area.

8.1.6 Southern New England Reliability Analysis

The ISO continues to study the southern New England region to identify and resolve reliability issues and to determine whether any interdependencies exist among these issues. An overall goal of the study is to formulate a solution that better integrates load-serving and generating facilities within Massachusetts, Rhode Island, and Connecticut, enhancing the grid's ability to move power from east to west and vice versa. Specific problems identified are as follows:

- The need for additional 345/115 kV-transformation capacity in Rhode Island
- Transmission constraints in Rhode Island, especially with transmission facilities out-of-service
- The inability of Rhode Island to access generation on the 345 kV system
- The criticality of the West Medway (MA) 345 kV station
- Forecasted capacity deficiencies in Connecticut
- Connecticut's limited import capability
- The limited effectiveness of the Lake Road plant to serve Connecticut load
- Connecticut's inadequate infrastructure to move power through the state
- The dependency of Connecticut import on Springfield–North Bloomfield capabilities
- Numerous contingency thermal overloads on the Springfield 115 kV system
- The dependency of the Springfield area on the Ludlow–Manchester–North Bloomfield 345 kV line

Ongoing studies are examining reinforcements for these key issues. The most practical alternatives to simultaneously improve the SEMA/RI, East–West, and Connecticut-import interface capabilities also appear to be 345 kV reinforcements. The studies to examine these alternatives are considering line loading, voltage, stability, and torsional-reclosing issues.

Different options for system reinforcement are being explored, based on available rights-of-way, space constraints at existing substations, and specific locations where area-supply reinforcements are needed. As is typical, an overriding goal of the analyses is to determine the minimum set of projects that could provide the maximum benefits or solutions to the problems uncovered. The analyses could find some problems to be totally independent of the major issues facing the Greater Southern New England system that would, therefore, require an independent project. However, the studies may also indicate many issues could be remedied through a common project or group of projects.

Not all of the alternatives first formulated are still being considered because they have been deemed to be impractical or infeasible or due to their failure to sufficiently improve the transfer capability into Connecticut. The alternatives (in whole or in part) still being considered are listed below:

- Sherman Road or West Farnum (RI)–Lake Road (CT)–Card (CT) 345 kV
- Sherman Road or West Farnum–Kent County (RI)–Montville (CT) 345 kV
- Brayton Point (RI)–Montville 345 kV
- Millbury (MA)–Carpenter Hill (western MA)–Manchester (CT) 345 kV
- Millbury–Carpenter Hill–Ludlow–Agawam (western MA)-North Bloomfield (CT) 345 kV

Similarly, the options considered for improving load service into Rhode Island and to best integrate the generation connected to the 345 kV network include the following projects in whole or in part:

- Millbury–Sherman Road–Lake Road (CT)–Card (CT) 345 kV
- Millbury–West Farnum–Lake Road–Card 345 kV
- Millbury–West Farnum–Kent County–Montville 345 kV
- Brayton Point–Manchester Street (RI)–Kent County–Montville 345 kV
- 345/115 kV autotransformers at 345 kV substations in Rhode Island

The report of the study work is scheduled to be completed by the end of 2005, leading to an ISO-approval of a project plan by July 2006. The projected in-service date for the final set of solutions is 2011.

8.2 Transmission Improvements to Load/Generation Pockets

Various areas of the system are highly dependent on imbedded generators operating to maintain reliability in smaller areas of the system. Reliability may be threatened when few generating units are available to provide system support, considering normal levels of unplanned or scheduled outages of generators or transmission facilities. These generators have been designated as daily second-contingency units, which may be needed on a regular basis to maintain the reliable operation of these smaller areas to avoid violating ISO New England operating criteria. This could mean maintaining voltage at the minimum levels or avoiding overloads per OP 19. This local-area dependency on generating units typically results in relatively high net compensation period costs associated with out-of-merit unit commitments.

The ISO is studying many of these areas. Transmission projects are being planned for some areas, while others already have projects under construction to mitigate dependency on the imbedded generating units. The sections that follow describe several of the smaller areas that have units for maintaining reliability and transmission projects for reducing the need to run these units.

8.2.1 Middletown Area

Four 115 kV lines and three generators connected to the 115 kV system—Middletown #2 (117 MW), Middletown #3 (236 MW), and Middletown #10 (17 MW)—supply the Middletown, Connecticut, area. Unit #10, 38 years old, is the newest of these units. Middletown #4 (400 MW) is connected to the 345 kV without transformation to the 115 kV system, so it does not support the local load in the area.

ISO Operations has flagged Middletown Units #2, #3, and #4 as daily second-contingency units that provide critical voltage support. These units help avoid low voltages that would result from single- or double-circuit outages in the area. Since suppliers have not offered the electricity market alternative resources in this area to relieve the operation of these units, the ISO has studied alternative transmission solutions. The most effective solution for providing for future load growth, reducing dependency on the operation of these Middletown units, and potentially allowing the future retirement of the units was found to be a new 345/115 kV autotransformer located at Haddam Substation along with other area improvements. The ISO has reviewed and approved the proposed plan for these projects, which are discussed in more detail in Appendix C.

8.2.2 Norwalk–Stamford Area

The Norwalk–Stamford, Connecticut, area has been highly dependent on area generation to maintain reliable operation for general operation and maintenance of the 115 kV system. This area is part of the Greater SWCT area. This generation is comprised of Norwalk Harbor Units #1 (162 MW), #2 (172 MW), and #10 (17), and Cos Cob Units #10, #11, and #12 (18 MW each). The two Norwalk Harbor units have been designated as daily second-contingency units for the current year.

The planned SWCT 345 kV Reliability Project Phase 1 will provide for load growth, reduce dependency on the operation of these local units, and may eventually allow the retirement of these units.

8.2.3 Southwest Connecticut Area

For the current year, the ISO has designated 14 units in the SWCT area, excluding the Norwalk–Stamford area, for daily second contingency. These units are Bridgeport Energy, Bridgeport Harbor #2 and #3, Devon #11 to #14, Milford #1 and #2, and Wallingford #1 to #5. These units must operate due to the limitations of the transmission system in SWCT. The capacity deficiency in this area and the weakness of the existing transmission system have been the basis for the SWCT Reliability Project, Phase 2, which will help reduce the dependency on these units. Emergency measures, such as those included in the SWCT RFP for Emergency Capability Resources, can provide some relief during emergency OP 4 conditions until the Phase 2 project is built, but these are only temporary measures.[84] Phase 2 (along with Phase 1) will also allow the interconnection of new generation in this area. Other transmission solutions were examined in the process of deciding on the current 345 kV project.

[84] Resources were selected for SWCT in response to the RFP issued by ISO, December 1, 2003.

8.2.4 Springfield Area

The Springfield area has two generators, West Springfield #3 and Berkshire Power, which have been designated as daily second contingency for the current year. Their operation is needed to support local reliability during peak hours for avoiding overloads in violation of OP 19. Electricity market suppliers have not proposed alternative resources in this area to relieve the operation of these units. Studies of alternative transmission solutions are underway for the Greater Springfield area. The ultimate solutions will provide for load growth and reduce dependency on the operation of these local units. They also may allow for the eventual retirement of the units.

8.2.5 Boston Area

The Boston area has several units designated as daily second contingency for the current year. New Boston #1 is needed for local reliability support for the Boston downtown area along with Mystic Units #7, #8, and #9. In the absence of any sufficient resource proposals from electricity market suppliers for this area, the NSTAR 345 kV Reliability Project has been developed to serve future load growth and improve the reliability of this area. When completed, the project will allow New Boston Unit #1 to retire.

A new 345 kV shunt reactor is being installed for late summer to early fall 2005 operation at North Cambridge to help reduce the high-voltage conditions that exist during the light-load period. The goal is to at least reduce, if not eliminate, the need to run local generation for reactive compensation during these periods. The costs associated with running the local generation for this purpose have become very high, highlighting a significant concern. The variable reactors being installed in 2006 as part of the NSTAR 345 kV Reliability Project should further improve light-load voltage control. In addition to continuing to examine further short-term improvements, in late 2005, the ISO plans to complete a long-term reactive study that is determining future VAR requirements for the Boston area. These studies assess the ability to adequately control voltages over a wide range of operating conditions.

8.2.6 North Shore

In the North Shore area, Salem Harbor Units #1 to #4 are designated as daily second-contingency units for the current year and support the reliable operation of this area to avoid violation of operating criteria. Adequate resource proposals from electricity market suppliers have not been forthcoming to solve this area's problem. The proposed North Shore Upgrades Project (the Ward Hill Substation) will relieve this area of its dependency on the Salem Harbor units for reliability. Additional longer-term modifications to this area are still under study.

8.3 Other Transmission Projects

Other projects nearing construction or recently started include the following:

- **Southwest Rhode Island**—involves reconductoring the Mystic–Wood River 115 kV transmission line to increase area reliability and improve inter-area transfer capability between Rhode Island and Connecticut by approximately 100 to 150 MW.

- **Y-138**—will improve inter-area transfer capability between Maine and New Hampshire by approximately 100 MW and increase central New Hampshire reliability.

- **Monadnock**—will create stronger ties between central Massachusetts, southeastern Vermont, and southwestern New Hampshire to eliminate thermal and voltage problems and increase reliability.
- **Vermont Northern Loop**—will loop the line through the area instead of feeding it radially to increase the reliability of the line.
- **Haddam Substation**—involves the installation of a 345/115 kV autotransformer in south-central Connecticut to allow the 345 kV network to supply a weak 115 kV system.
- **Killingly Substation**—involves the installation of a 345/115 kV autotransformer in eastern Connecticut to allow the 345 kV network to supply a weak 115 kV system.
- **Wachusett Substation**—will provide additional 345/115 kV autotransformers in central Massachusetts to strengthen supply to this region and reduce loading on other autotransformers.

Section 9

Transmission Projects Update

This section summarizes the changes to the Transmission Projects Update listing that have occurred since October 2004, the basis for RTEP04. The July 2005 Transmission Project Update contains 272 projects with the following project status:

- **In service:** projects placed in operation—none
- **Under construction:** projects that have received necessary approvals with a significant level of engineering or construction underway—62 projects
- **Planned:** projects that have received approval per the ISO's tariff, Section I.3.9 (if required), but may or may not have received transmission-cost allocation approval—37 projects
- **Proposed:** projects that have had a significant degree of analysis to show potential need, but have not yet received Section I.3.9 approval—109 projects
- **Concept:** projects with little or no available supporting analysis, but with significant information to suggest a pending need for future study work and a remedial project—64 projects
- **Cancelled:** projects that have been cancelled—none

These projects will add transmission capacity to serve load in growing urban regions, such as Boston and Southwest Connecticut, and in smaller urban areas throughout the region. Many of the projects will bring an area into compliance with ISO New England planning criteria, as summarized in ISO New England Planning Procedure No. 3, or maintain an area's compliance with the criteria.[85]

The investment cost estimate for the 272 projects in the region is about $3.0 billion for the next 10 years. The six major projects, as listed in Section 8, account for about two-thirds, or $2 billion, of the total cost (midrange estimate) for all the projects. State siting reviews have been completed for four of these projects—the Northwest Vermont Reliability Project, the NSTAR 345 kV Transmission Reliability Project, and the SWCT Reliability Project, Phases 1 and 2.

Table 9.1 shows the cost estimate changes in three of the six major projects since the October 2004 update. The increase in costs for these projects is $474.2 million. The total increase in cost for the projects in the "Other" category is $185.4 million. "New Projects" add $79.9 million, and 34 "TBD Projects" that had no estimates in October 2004 now have estimates totaling $197.1 million. The total cost increase for all these planned transmission grid improvements in the ISO New England region is $936.6 million (41%), compared to the October 2004 update.

[85] See <http://www.iso-ne.com/rules_proceds/isone_plan/index.html>.

Table 9.1
Cost Comparison of Reliability Projects October 2004 versus July 2005

Major 345 kV Projects	As of October 2004 Plan Update (in millions $)	As of July 2005 Plan Update (in millions $)	Change in Plan Estimate (in millions $)	Reasons for Change
Northwest Vermont Reliability Project	156.3	156.3	0	
Southwest Connecticut Reliability Project (Phase 1)	200.0	357.0	157.0	Re-evaluation of costs based on actual bids, one-year delay in in-service date, inflation, environmental mitigation, and higher exchange rates and copper prices (cables)
Southwest Connecticut Reliability Project (Phase 2)	690.0[a]	990.0	300.0	Re-evaluation of engineering cost estimates, two-year delay in in-service date, inflation, environmental mitigation, and higher exchange rates, copper prices (cables), and design and scope modifications resulting from CSC review
NSTAR 345 kV Transmission Reliability Project	217.0	234.2	17.2	Cable work related to New Boston
Southern New England Reinforcement Project	125.0	125.0[b]	0.0	
Northeast Reliability Interconnect Project	90.4	90.4	0.0	
Subtotal	**1,122.4**	**1,952.9**	**474.2**	
Other projects	824.2	1,009.6	185.4	Various
New projects	0.0	79.9	79.9	
TBD projects with cost estimates	0.0	197.1	197.1	First estimates reported for projects
Total	**2,302.9**	**3,239.5**	**936.6**	
Minus in-service projects	-143.3	-216.8		
(Aggregate estimate of active projects in the plan)	2,159.6	3,022.7		

[a] $690 million dollars included the estimated cost of the Glenbrook–Norwalk 115 kV cables. The estimated cost of these cables is treated separately, but as part of "Other Projects" in the July 2005 update.

[b] The cost estimate of this project will likely change to reflect its broadening scope as a more comprehensive reinforcement plan. The revised estimate will likely include some costs presently included as part of "Other Projects."

Since RTEP04, 36 new projects have been identified, which are summarized in Table 9.2. The four projects for new transmission lines are described in Table 9.3. The needs for these projects are identified in Table 9.4 and Table 9.5.

Table 9.2
New Transmission Projects since October 2004 Update[a]

Number of Projects	Type Project	Total # of Projects and RSP Subarea	Other
4	New 115 kV transmission lines	3 NH 1 BOSTON	
23	Transmission upgrades	5 CT 4 SEMA 1 RI 8 WMA 2 NH 2 CMA/NEMA 1 BOSTON	6 lines; 14 substation equipment; 2 345/115 kV transformers; 1 230/115 kV transformer
9	Substation upgrades	3 CT 1 BOSTON 1 WMA 2 RI 1 NH 1 CMA/NEMA	5 expansion of equipment upgrades; 4 new substations

[a] Projects may have some non-pool transmission facility (PTF) components (typically the transformer costs).

Table 9.3
New Transmission Lines and Corresponding Needs since October 2004 Update[a]

Project	RSP Subarea	Need
Install 115 kV line from Long Hill to South Milford	NH	Eliminate contingency overload
Install 115 kV line from Jackman to Peterborough	NH	Eliminate contingency overload
Install 115 kV line from Peterborough to Fitzwilliam	NH	Eliminate contingency overload
Build new 115 kV circuit from Kendall to Somerville	BOSTON	Eliminate contingency overload

[a] Projects may have some non-PTF components (typically the transformer costs).

Table 9.4

New Transmission System Upgrades and Corresponding Needs since October 2004 Update[a]

Project	RSP Subarea	Need
Upgrade bus work at Somerset 115 kV Substation	SEMA	Increase reliability to supply load growth
Install Tremont 115 kV bus-tie circuit breaker	SEMA	Eliminate contingency overloads and low voltages
Install new 115 kV circuit breaker at Sandwich Substation	SEMA	Minimize loss of load for loss of (122) 115 kV line
Install new 115 kV circuit breaker at Hatchville Substation	SEMA	Minimize loss of load for loss of (115) 115 kV line
Reconductor 69 kV Y25S line from Harriman to Deerfield #5	WMA	Eliminate line overload
Add 345/115 kV transformation in the Berkshire/Pittsfield area	WMA	Increase capacity to 155 kV system
Add 345/115 kV transformation in the Springfield area	WMA	Eliminate contingency overloads
Build new Springfield-area transmission circuits (OH or UG) in the area	WMA	Eliminate contingency overloads
Conduct additional uprating or rebuilding the existing 115 kV OH lines in the Springfield area	WMA	Eliminate contingency overloads
Add capacitors in Springfield-area substations	WMA	Maintain voltage
Install 115 kV capacitors at Montague Substation	WMA	Maintain voltage
Replace additional MA circuit breakers	WMA	Eliminate overstressed breakers
Add 345 kV regulating shunt reactor in Boston area	BOSTON	Improve voltage control for light-load conditions
Replace Tewksbury #22A GIS and protection/control equipment	BOSTON	Replace antiquated GIS equipment
Add Pratts Junction third 230/115 kV 150 MVA transformer	CMA/NEMA	Increase capacity to supply load
Upgrade 115 kV circuit breakers at W. Farnum Substation and add 4 new 115 kV breakers at Woonsocket Substation	RI	Increase reliability to supply load growth
Conduct Frybrook Substation breaker project	CT	Eliminate critical multi-element contingency
Reconfigure Frost Bridge corridor 115 kV lline	CT	Prevent voltage collapse in this corridor
Separate the 115 kV line from the Windsor Locks to Enfield line (1300)	CT	Eliminate double-circuit contingency
Add a 345 kV breaker at North Bloomfield	CT	Increase reliability to supply load growth; prevent 345 kV line outage due to autotransformer failure
Replace additional CT circuit breakers	CT	Eliminate overstressed breakers
Add harmonic filter on 115 kV system near Stony Hill	CT	Mitigate transmission over voltages
Rebuild Greggs to Reeds Ferry 115 kV	NH	Improve voltage support
Replace additional NH circuit breakers	NH	Eliminate overstressed breakers

[a] Projects may have some non-PTF components (typically the transformer costs).

Table 9.5
New Distribution Substation Work and Corresponding Needs since October 2004 Update[a]

Project	RSP Subarea	Need
Expand Chelsea 115 kV Substation to include four circuit breakers and install third 115 kV transformer	BOSTON	Increase capacity to supply load
Build new W. Amesbury 115 kV Substation	BOSTON	Increase capacity to supply load
Replace 115 kV fuses at Ashfield Substation	WMA	Allow automatic transfer of station for contingency loss
Install third transformer at Pleasant Substation and ring bus	WMA	Increase capacity to supply load
Install 115 kV substation at Jacks Hill	WMA	Increase capacity to supply load
Build new Tower Hill Rd. Substation	RI	Increase capacity to supply load
Build new Farnum Pike Substation and taps	RI	Increase capacity to supply load
Install Slayton Hill new 115 kV switch	NH	Minimize extent of maintenance outages
Add a filter on the 115 kV bus at Stony Hill Substation	CT	Mitigate transmission over voltages

[a] Projects may have some non-PTF components (typically the transformer costs).

Of the 272 projects included in the July 2005 Transmission Project Update, 36 new projects have been identified as needed projects since RTEP04. Eighteen transmission projects have been completed since RTEP04 was issued, as shown in Table 9.6, Table 9.7, and Table 9.8, and 75 projects have been completed since RTEP01 was issued in 2000.

Table 9.6
New Transmission Line Placed In Service and Corresponding Needs since October 2004 Update[a]

Project	RSP Subarea	Need
New Rochester to Rochester tap 115 kV line	NH	Eliminate existing load-shedding scheme

[a] Projects may have some non-PTF components (typically the transformer costs).

Table 9.7
Transmission Upgrades Placed In Service and Corresponding Needs since October 2004 Update[(a)]

Project	RSP Subarea	Need
Re-tension the 115 kV C2 line from Auburn St. to Dupont	SEMA	Increase thermal capability of the line
Upgrade the 115 kV A94 line from Auburn St. to Parkview	SEMA	Increase thermal capability of the line
Upgrade the 115 kV S1 line from Belmont to Belmont tap	SEMA	Increase thermal capability of the line
Replace Western Massachusetts Electric Co. 115 kV circuit breakers	WMA	Eliminate overstressed, old breakers
Reconductor the 69 kV Y25S line from Harriman to Deerfield #5	WMA	Eliminate line overload
Reconductor the 115 kV X176 line from Palmer to Northeast Utilities border in Belchertown	WMA	Increase thermal capability of the line
Remove terminal limitations on South End to the Darien 115 kV 1877 line	CT	Increase thermal capability of the line
Remove terminal limitations on Montville to Haddam Neck 345 kV 364 line	CT	Increase thermal capability of the line
Relocate OH/UG 115 kV and 345 kV transmission facilities in I-95 Highway Quinnipiac Bridge area	CT	Accommodate project to relocate interstate highway and needed maintenance
Replace Connecticut Light and Power 115 kV circuit breakers	CT	Eliminate overstressed, old breakers

[(a)] Projects may have some non-PTF components (typically the transformer costs).

Table 9.8
Distribution Substation Work Placed In Service and Corresponding Needs since October 2004 Update[(a)]

Project	RSP Subarea	Need
Install third 115 kV transformer at Pleasant Substation configured into a ring bus	WMA	Provide voltage support
Build new Colburn 115 kV Substation tapping 110–510 and 110–511 115 kV lines	BOSTON	Improve system reliability in Boston
Build new Taft Corners Substation	VT	Increase capacity to supply load
Upgrade St. Albans tap as part of the Northern Loop Project	VT	Increase capacity to supply load
Add new transformer at Hanover Substation and 115 kV improvements	CT	Increase capacity to supply load
Add new transformer and 115 kV breaker at Todd Substation	CT	Increase capacity to supply load
Add transformers to New Shunock 115 kV Substation	CT	Increase capacity to supply load

[(a)] Projects may have some non-PTF components (typically the transformer costs).

Figure 9.1 shows the costs of New England's in-service transmission projects by year, since 2002.

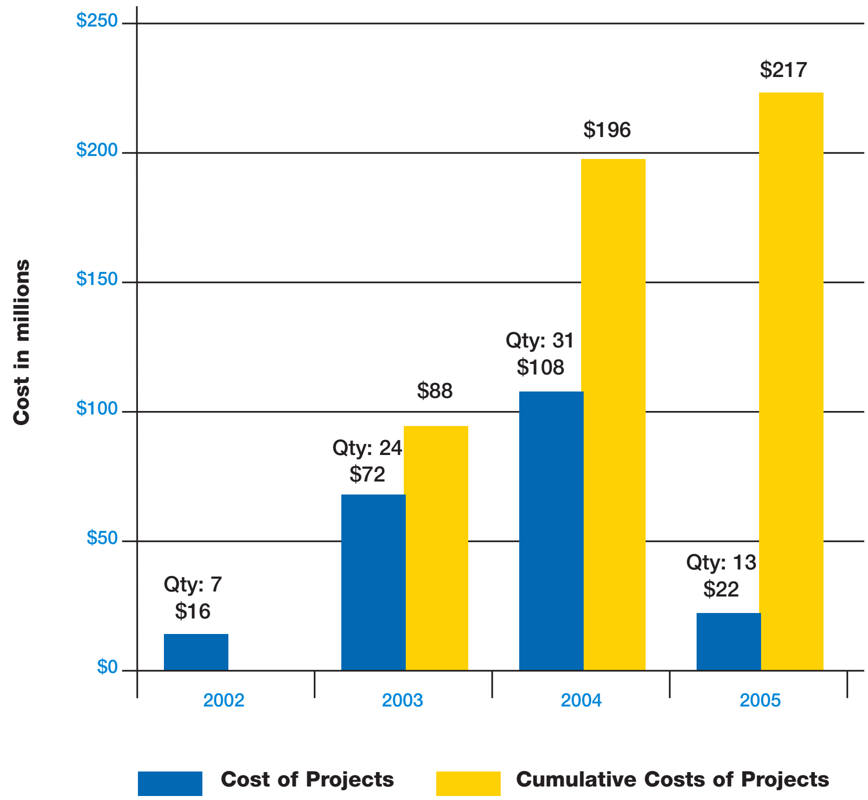


Figure 9.1 **Cost of in-service transmission projects in New England.**

Part IV Inter-Area Coordination and Regional Planning Initiatives

The August 14, 2003, blackout, which affected vast areas of New York, Ontario, and the Midwest, vividly demonstrated the need for effective interregional cooperation and power system coordination. It was evident during New England's January 2004 Cold Snap that the interconnected operation of the New England system improved the reliability of service and mitigated the adverse consequences of a lack of fuel diversity. Part IV takes into account the ISO New England's planning activities it conducts with the surrounding systems and its joint study efforts with national and international organizations and other ISOs and RTOs. This part also summarizes the planning that takes place within the New England region to ensure the infrastructure remains sound, the methodologies used to forecast loads and capacity remain appropriate, and the recommended improvements are made.

Section 10 describes the cooperative efforts taking place among the New England Control Area and its neighboring control areas and among the New England and Mid-Atlantic states, New York, the Canadian Maritimes, Québec, Ontario, and other areas to plan the interregional power system. This coordination is achieved through participation in the Northeast Power Coordinating Council and the Regional Reliability Council for New England, New York, Ontario, Québec, and the Maritimes. ISO New England also coordinates with other control areas and PJM through a Planning Protocol, which aims to reduce planning seams. Key findings of other control area plans are presented.

Section 11 explains several new planning initiatives that will require stakeholder participation and several years to complete. These initiatives are in response to changes in the industry and ISO New England's efforts to continuously improve practices. The section discusses the joint efforts taking place with the New England state governors to plan the region's power system, as well as a summary of the ISO's 10-year Horizon Year Study to identify and develop the New England bulk power system needs.

Section 10

Interregional Coordination

The ISO is participating in numerous interregional electric power system planning activities with neighboring states and Canadian provinces to ensure the widespread region has a reliable supply and transmission of electricity. Ongoing projects include those with the Northeast Power Coordinating Council and neighboring control areas in the United States and Canada. This section discusses the ISO's joint efforts to plan for a reliable electric power system in eastern North America and Canada.

10.1 NPCC Activities

The Northeast Power Coordinating Council is one of a number of main power system planning bodies in the United States with about 40 members from the utility and public sectors. Among its members are ISO New England, New York ISO, TransÉnergie Québec, and IESO-Ontario. The council was established not only to prevent major blackouts from occurring but also to ensure the continued reliability of the electric power network in the northeastern United States and some of the interconnected Canadian provinces.

As an active member of NPCC, ISO New England fully participates in interregional coordinated transmission studies with its neighboring control areas in New York, Québec, and the Maritime provinces. Further, NPCC participates with its neighboring regions—the East Central Area Reliability Council (ECAR) and the Mid-Atlantic Area Council (MAAC)—in the MAAC–ECAR–NPCC (MEN) Study Committee. It also takes part in the Joint Interregional Review Committee, where MEN is joined with the Virginia–Carolina Region (VACAR) of the Southeastern Electric Reliability Council (SERC). MEN conducts short-term studies to assure that developments in one region do not have significant adverse affects on other regions. Both NPCC and MEN studies address interregional reliability and ensure the coordination of member-system plans.

ISO New England remains committed to the goals and methods of the NPCC organization and reaffirms its determination to plan and operate the New England system in full compliance with NPCC criteria, guidelines, and procedures that address the security and adequacy of the interconnected bulk power supply system. The criteria address a number of activities, including document review and approval, design and operation of interconnected power systems, emergency operations, bulk power system protection, operating reserves, reliability compliance and enforcement, and special protection systems.

10.1.1 Task Force on Coordination of Planning

The NPCC Task Force on Coordination of Planning (TFCP) reviews the adequacy of the NPCC systems to supply load, considering forecast demand, installed and planned supply and demand resources, and required reserve margins. TFCP accomplishes its review in accordance with the NPCC *Guidelines for Area Review of Resource Adequacy* (Document B-8), based on a schedule set forth in the NPCC Reliability Assessment Program.[86]

[86] See <http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/B-08.pdf>.

The TFCP coordinates the compliance review of future control area plans, in accordance with another NPCC guideline, *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2).[87] The review process includes analyzing the potential effects of interregional control area resource plans, transmission system additions, and special protection systems, and also is based on a schedule set forth in the NPCC's Reliability Assessment Program. The TFCP may choose to review specific projects outside of the schedule, including those it determines might have an impact on the reliability of the NPCC bulk power system.

NPCC coordinates the review of proposed new or modified special protection systems (that include special actions, such as generation rejection, transmission cross trips, and load rejections) in accordance with the *Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems* (Document C-16).[88]

NPCC committees also initiate interregional studies, including interregional control area studies, where improved reliability may be achievable through joint planning. The council evaluates control area assessments, area resource reviews, and interim and comprehensive reviews of transmission, which must be approved by the TFCP.

10.1.2 Compliance with NPCC Criteria and Standards

NPCC reliability criteria are specific and mandatory and address a wide variety of factors, including the following:

- Monitoring the performance of a control area's interconnection frequency
- Handling frequency disturbances
- Meeting customer demands for electricity
- Shedding load
- Restoring system operations
- Maintaining and testing system protection programs
- Maintaining operating reserves
- Rating transmission and generation facilities

Through a nonmonetary sanctioning system of its Reliability Compliance and Enforcement Program, the NPCC assesses and enforces compliance with these criteria, for which the interregional control areas have reporting responsibilities. In turn, the control areas assess and enforce market participant compliance to these criteria, for which the market participants have reporting responsibilities.

As the administrator of New England's Compliance Program, ISO New England surveys participants and has the ability to issue sanctions for noncompliance. ISO New England is grateful for the full cooperation it has received and is pleased to report full compliance with all planning requirements. Much work remains to be done as standards are revised or added, and continued vigilance and cooperation will be required of all participants.

[87] See <http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/A-02.pdf>.

[88] See <https://www.npcc.org/publicFiles/reliability/CriteriaGuidesProcedures/c-16.pdf>.

10.1.3 Comprehensive Area Transmission Review of the New England Bulk Power Transmission System

In its Comprehensive Area Transmission Review, the ISO must demonstrate to NPCC that the planned expansion of the New England bulk power transmission system complies with NPCC Document A-02. A main purpose of the transmission review study is to show that contingencies in New England will not have an adverse impact on neighboring systems. The 2005 assessment of the 2009 system considered normal criteria as well as extreme contingencies and reviewed special protection and dynamic control schemes, the loss of natural gas fuel delivery to multiple generating plants, and short-circuit performance.

The results of the New England Control Area transmission review study showed that New England would meet all NPCC requirements, if facilities with ISO Transmission Tariff Section I.3.9 approval, as of April 1, 2004, and the NSTAR 345 kV Transmission Reliability Project were in service as scheduled before 2009, and no unanticipated retirements were to take place.

The only exception to this scenario was that six circuit breakers at the Manchester (CT) 115 kV substation were found to be over their short-circuit interrupt capabilities. The plans outlined in this review recommend the continued vigilance of invoking operating procedures that limit the loss of source in New England and the need to upgrade or replace five circuit breakers at the Manchester 115 kV station to a higher short-circuit interrupt capability.

The Comprehensive Area Transmission Review Study also demonstrates the likely ability of the New England electric power system to withstand the loss of all generators served off a common major interstate gas pipeline. Upon loss of the pipeline, sufficient time would likely be available to start off-line generation and to convert gas-fired generating units with dual-fuel capability to oil.

10.1.4 Triennial Review of Resource Adequacy

The Triennial Review of Resource Adequacy is a companion to the Comprehensive Area Transmission Review, which each interregional control area must periodically perform to satisfy the guidelines of the NPCC Document A-2. The objective of the Triennial Review of Resource Adequacy is for each interregional control area to demonstrate it has both adequate installed and planned resources to meet the NPCC Resource Adequacy Design Criteria.

The results of the New England resource adequacy review show that the ISO must take actions to meet the NPCC resource adequacy criteria. These actions include completing the planned upgrades to the transmission system and adding new resources by 2010. If the planned transmission upgrades are delayed or the loads are higher than expected, New England will not have adequate resources to meet the NPCC criteria.

10.2 Northeastern ISO/RTO Planning Coordination Protocol

ISO New England, NYISO, and PJM have agreed to follow a Planning Protocol to enhance the coordination of planning activities and to better address planning seams issues among the interregional control areas. The Independent Electricity System Operator of Ontario, TransÉnergie Québec, and New Brunswick Power, while not parties to the protocol, have agreed to participate on a limited basis to share data and exchange information. They also will participate in studying the projects that may have an impact on the interregional control areas, thus ensuring better coordination of the development of the interconnected power system in the Northeast. Planning Protocol activities will be coordinated closely with the regional councils, NPCC and MAAC. The key elements of the protocol are to establish procedures that accomplish the following tasks:

- Exchange data and information to ensure proper coordination of databases and planning models for both individual and joint planning activities conducted by the parties
- Coordinate interconnection requests likely to have cross-border impacts
- Analyze firm transmission service requests likely to have cross-border impacts
- Develop the Northeast Coordinated System Plan
- Allocate costs associated with projects having cross-border impacts consistent with each party's tariff and applicable federal or provincial regulatory policy

The protocol created a technical steering committee known as the Joint ISO/RTO Planning Committee (JIPC) and composed of ISO/RTO planning staff. It also created an open stakeholder group similar to the New England PAC called the Inter-Area Planning Stakeholder Advisory Committee (IPSAC).[89] IPSAC issued a draft version of the 2005 Northeast Coordinated System Plan (NCSP05), which stakeholders discussed at the first IPSAC meeting held in June 2005. NCSP05 summarizes each of the interregional control area's plans and assessments, discusses regional activities, and identifies interregional control area issues. All planning activities appear to be well coordinated, as shown by the improved quality of system impact studies and system assessments that better account for neighboring systems. As discussed with the IPSAC, the ISO has identified issues for further study, and the JIPC will continue to coordinate study efforts.[90]

10.3 Key Findings of Area Plans

Resource adequacy is a common concern for the Northeast, with retirements a potential risk. Current and pending environmental regulations can have a significant impact on resource availability and hence the reliability of the interconnected system. Stresses on the gas system infrastructure may result from the planned retirement of coal units in Ontario, which may be replaced with gas-fired generation. However, the development of renewable energy resources, especially wind power, is underway in other control areas.

It is evident that known electric power transmission system bottlenecks may limit New England's access to varied sources of capacity and energy in surrounding control areas. While New England will benefit from the improved coordination of planning activities, outside control areas will not be able to fully solve the capacity and fuel-diversity issues raised in RSP05.

[89] The IPSAC Web site is: <http://www.interiso.com>.

[90] Further information on inter-ISO activities can also be found at: <http://www.interiso.com>.

ISO New England planning activities are closely coordinated with those of neighboring systems through participation in NPCC activities. The ISO has achieved full compliance with all required planning standards and expects the implementation of the Planning Protocol will further improve interregional control area planning. Sharing capacity resources, particularly during periods of fuel shortages, may become increasingly necessary; thus, identifying the impacts proposed generating units and transmission projects can have on neighboring systems is beneficial.

Table 10.1 summarizes the projected capacity margins for the NPCC control areas from 2006 through 2014. As shown, the New York Control Area and Ontario Control Area are projected to need new resources within the same timeframe as New England. Ontario also is under governmental pressure to phase out 6,500 MW of coal-fired generation. The table also shows the decreasing capacity margin for the Canadian Maritimes over the planning period. While Hydro-Québec has a large capacity margin during the summer, transmission limitations restrict the amount of capacity that can be exported to neighboring areas. From these data, the ISO concludes it should not heavily rely on neighboring systems for capacity during peak-load periods.

Table 10.1
Projected Surplus Capacity (MW)

Control Area	2006	2007	2008	2009	2010	2011	2012	2013	2014
ISO NE[a]					-172	-690	-1,380	-1,725	-2,070
HQ[b]	9,427	9,960	10,380	10,786	10,174	10,622	11,273	10,136	10,984
IESO[c]	618	693	113	102	-409	-681	-1,023	-1,467	-3,511
Maritimes[d]	854	801	733	255	699	534	425	313	196
New York[e]			-1,757	-2,277	-2,784	-3,232	-3,610	-3,940	-4,224

[a] Based on RSP05 Table 4.1 with 2,000 MW of tie benefits.

[b] Based on NPCC 2005 Draft Report, *Load, Capacity, Energy, Fuels and Transmission Report; assumes 10% reserve requirement for Hydro-Québec*.

[c] Based on Table A2, Median Demand Growth with Reference Resource Scenario, from *An Assessment of the Adequacy of the Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario*, IESO, August 15, 2005.

[d] Data provided by New Brunswick Power to ISO New England.

[e] Data provided by NYISO to ISO New England.

Section 11

New Regional Planning Initiatives

This section discusses the ISO's major new system planning initiatives to investigate the conditions of the bulk power system, the methodologies used to forecast loads and installed capacity requirements, electricity-related government policies, and data communications infrastructure. It also describes several applications of advanced technology solutions. These efforts will be completed in several years and thus do not coincide with the annual RSP cycle.

11.1 Horizon Year Study

As presented in the preceding sections, RSP05 assessed the conditions of the bulk power system for the 2006 to 2014 period based on system assumptions and known system requirements discussed with the PAC. The report provides information on generating resource and transmission adequacy and identifies needs for system improvements. While much has been achieved in developing RSP05, additional work remains to be done to create a more robust 10-year New England plan that more fully develops conceptual projects.

A Horizon Year Study provides long-term direction for developing the system, or a roadmap of long-term system improvements for creating a target system. This is achieved through the conceptual analysis of an extremely high load level, such as 40,000 MW. Scenario analysis such as this indicates the scope of transmission development that could be required to address various geographic scenarios of generation development.

The ISO's Horizon Year Study will ensure consistency of the 5- and 10-year improvements with longer-term system needs by promoting the effective use of transmission investment. It will provide direction on the use of rights-of-way and the potential for substation expansion, as well as an evaluation of whether the 345 kV and 115 kV transmission-voltage classes meet longer-term needs. The study will also review the long-term viability of each Special Protective Scheme used on the New England bulk power system to optimize transfer capability.

The ISO, the PAC, and a stakeholder working group will need to discuss many aspects of the Horizon Year Study, as many of the study's assumptions will drive the results. An appropriate load level must be determined, and scenarios of generation expansion must be identified that include inputs related to generator type, size, location, and fuel. The study also may examine the application of new technologies and voltage classes other than 345 kV and 115 kV.

ISO New England will lead stakeholders through this process by developing a study plan that incorporates system conditions, a planning schedule, and priorities. The ISO will likely use new simulation tools and methods for this study.

11.2 Review of Load-Forecast Methodology

The long-run peak-load forecast is an important driver in identifying the need for future system improvements. Through the open stakeholder process, the ISO remains committed to continuing efforts that will improve the quality of these forecasts. Projections of the system load factor and the methods of allocating loads to RSP subareas undergo continuous review. As part of this effort, the ISO will explore the possible use of new statistically adjusted models that combine the strengths of econometric and end-use models. These models are designed to capture the longer-term economic trends, while reflecting the impacts of end use saturations (e.g., from heating, cooling, appliances, etc.) and efficiencies.

11.3 Installed Capacity Methodology Review

As discussed in Section 2, the amount of installed capacity required systemwide is a probabilistic calculation, but the amount of capacity required to operate the system is calculated deterministically based on particular scenario analyses. RTEP04 identified the need to review the longstanding method of determining the requirements for installed capacity because of the gap between these requirements, needed from a planning perspective, and those requirements needed from an operating perspective. Some of the key concerns that must be addressed are as follows:

- Does the current loss-of-load expectation methodology adequately define the New England requirements?
- Does the current methodology represent the power system the ISO operates?
- Are the present input assumptions correct for the future?
- How does the methodology compare with the methodologies and practices of other power systems?
- Can we find a methodology that has broader stakeholder support?
- Is the current criterion of "1 day in 10 years" the right criterion? What are appropriate tradeoffs between reliability and costs, and who decides what the tradeoffs should be?
- Should transmission constraints be modeled in identifying installed capacity requirements?
- What is the correct process to determine the resource adequacy in load pockets?

ISO New England intends to initiate an open stakeholder process in the fourth quarter of 2005 to address these issues. Plans call for the filing of market rules with FERC by the fourth quarter in 2006.

11.4 New England States Committee on Electricity

The Governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont filed a joint petition with FERC in June 2004 to form a regional state committee (RSC) to be known as the New England States Committee on Electricity (NESCOE). The filing states:

> "NESCOE will make policy recommendations to the FERC and comment on proposed market rule or tariff changes proposed by RTO-NE or the transmission owners. . ." and ". . .focus on developing and making policy recommendations related to resource adequacy and system planning. NESCOE will also investigate and report to the New England Governors on policy questions concerning the

possibility of a regional authority for siting of interstate transmission facilities. NESCOE may expand its responsibility to include other issues that the Commission has identified as appropriate for RSC involvement, but only upon the unanimous approval of NESCOE members."

In July 2005, FERC deferred a ruling on the NESCOE filing, thus, NESCOE does not yet have FERC approval as an RSC.[91]

ISO New England will continue to work with stakeholders throughout the region, including state representatives, through their designated entities, which would include NESCOE.

11.5 Advanced Monitoring and Control of the Transmission Grid

One of the identified causes of the August 14, 2003, blackout was inadequate situational awareness by the system operators.[92] This led to deteriorating system conditions that ultimately resulted in the cascading event. The emergency management system for First Energy, the company that owns and operates the transmission facilities in the Cleveland area where the problem started, was not alarming properly, and the real-time contingency analysis was not providing accurate information about the state of the power system. In addition, adjacent systems were not receiving the proper topology of the First Energy system to perform an independent assessment of the state of the power system.

In New England, the ISO and the local control centers share power system data to estimate and analyze state and system contingencies, evaluate and adjust system conditions, and ensure system reliability. Just as First Energy experienced on August 14, 2003, New England can be vulnerable to inaccurate system data due to a failure of any number of computer systems across New England. Power system data for large areas of New England can be lost due to data-communication or computer system failures. If these failures were to take place during stressed system conditions, system operators could experience inadequate situational awareness. In the worst-case scenario, this can lead to low voltages, thermal overloads, instability, and/or cascading events resulting in a widespread blackout.

To evaluate this vulnerability and to respond to recommendations of the August 2004 Blackout Task Force, ISO New England is proposing to assess the existing data-communication and substation monitoring and control infrastructure, the type of information exchanged, and relevant operating procedures. This long-term assessment will review the methods system operators use to control the grid and how effectively the methods respond to system contingencies, which may include load shedding. Improving operational control will allow the local control centers and the ISO to better monitor the grid and more accurately initiate load shedding at a substation feeder level.

11.6 Application of Advanced Technology Solutions

In many instances, applying advanced technology solutions has effectively solved system problems. The ISO is committed to the prudent use of new technologies and works closely with transmission owners to identify and evaluate opportunities for applying advanced technologies. The ISO also actively participates in projects sponsored

[91] 112 FERC, Docket No. EL04-112, ¶61,049, Order Encouraging Further Stakeholder Discussions and Denying Rehearing in Part, July 7, 2005.

[92] Natural Resources Canada and U.S. Department of Energy, *The August 14 2003 Blackout One Year Later: Actions Taken in the United States and Canada to Reduce Blackout Risk*. Report to the U.S.–Canada Power System Outage Task Force. August 13, 2004.

by the Electric Power Research Institute (EPRI) and Power Systems Engineering Research Center (PSERC), two research organizations committed to advancing the electric power industry.

Improving the use of existing rights-of-way is a key concern. The use of compact structure design, high-temperature conductors, or real-time ratings of transmission lines can be effective techniques for increasing the thermal-transfer capabilities of the system within the existing rights-of-way land constraints. New types of underground cable, such as “XLPE,” are being proposed to resolve transient over voltages and other issues where underground transmission is needed. For example, XLPE cable is being proposed for Phase 2 of the Southwest Connecticut Reliability Project (see Section 8.1.5).

Voltage restrictions and stability concerns often require the addition of dynamic devices that can provide continuous control. Flexible alternating current controllers, known as FACTS, use power electronics to provide an exceptionally fast and dynamic system response. To date, New England has several installations of STATCOMs and SVCs, devices capable of providing instantaneous voltage support, and more are planned. The use of advanced control systems, possibly including adaptive control, also may provide system benefits. Alternatively, adding clutch devices to generating units and operating them as synchronous condensers can provide dynamic voltage support. The power industry is developing new types of synchronous condensers, some of which use superconductors. All these innovative voltage-control technologies will become increasingly important for addressing load-pocket voltage concerns. In addition, improved methods and software can be applied to optimize the use of existing voltage-control equipment.

11.7 Interregional Coordination Plans

Interregional planning activities will become more important in the future as the ISOs/RTOs move from participating in coordinated planning activities to being involved in greater joint planning efforts for needed transmission facilities. The implementation of the Northeast Planning Protocol and continued participation in NPCC activities will improve the joint planning projects with neighboring control areas. (Refer to Section 10.2.)

11.8 New Initatives Summary

ISO New England remains committed to continually improving the system through the open stakeholder process. Several planning initiatives include developing the Horizon Year Study, reviewing the methodologies for estimating load forecasts and installed capacity requirements, working with the newly formed NESCOE organization, and examining the reliability of the communications infrastructure needed to conduct advanced monitoring and control of the transmission grid. Another initiative is to apply advanced technology solutions, where practicable, to solve system problems.

Part V **Summary and Recommendations**

The ISO conducted a number of analyses for RSP05, which produced several key results and conclusions. The main results showed that for the system to meet the 1-day-in-10-year LOLE with 2,000 MW of tie benefits, it requires the addition of 170 MW by 2010. For the region to meet the 90/10 load forecast, 1,900 MW are needed by 2008. A number of uncertainties could affect these results, including load growth, generation attrition, generation forced outages, and changes in the ability of neighboring systems to provide tie benefits. With the planned transmission upgrades, the Greater Connecticut load pocket is the only one with a near-term deficit supply situation.

RSP05 also discusses the ISO's support for diversifying the region's fuel supply (and thus reduction in price risks) through more aggressive programs to widen the use of energy alternatives. It also supports efforts to reduce consumption and thus the need for additional resources though energy conservation and demand-response programs. To ensure areawide and systemwide reliability, 272 transmission projects, presently in various stages of planning and implementation, must be completed throughout New England over the next 10 years. These projects are estimated to cost about $3.0 billion.

Part V summarizes the major results of the load forecast, resource adequacy, fuel diversity, and transmission studies conducted for RSP05 and provides recommendations for future efforts. Section 12 highlights the ISO's conclusions of its probabilistic and deterministic analyses. Section 13 summarizes the ISO's recommendations for a range of activities, such as completing transmission projects, developing resources, enhancing fuel diversity, improving firmness of gas resources or flexibility to use alternatives, developing gas supplies, and increasing demand response.

Section 12

Summary of Results

Section 12 summarizes the results of the studies conducted for RSP05. Systemwide and load-pocket needs related to resources, fuel diversity, and transmission are discussed. Highlights of the market incentives and technical solutions recommended to solve the problems identified in RSP05 are presented, and new initiatives are listed.

12.1 Systemwide Needs

New England peak loads are projected to continue to grow at a rate of about 1.52% per year. The ISO conducted studies to analyze the region's future capacity needs to meet this growth. The ISO studied systemwide needs using probabilistic (LOLE) and deterministic (operable capacity) analyses.

Determining the systemwide needs was founded on the LOLE criterion that firm load cannot be interrupted more than 1 day in 10 years. The operable capacity methodology determined the capacity needed to meet a specified load level while satisfying all operating criteria, including an allowance for forced outages and contingencies. Table 12.1 shows the results of the LOLE and deterministic analyses.

Table 12.1
Systemwide Resource Needs

Method	MW Needed	Year
LOLE—meeting 1-day-in-10-year criterion	170	2010
Operable Capacity—90/10 load forecast	1,900	2008

12.2 Load-Pocket Needs

The ISO also studied installed capacity requirements in load pockets using the probabilistic and deterministic analyses. The probabilistic analysis identified the subareas at greatest risk based on long-term generator forced outages, unit retirements, or a load growth higher than forecasted. In accordance with planning procedures and criteria, the ISO also had to conduct operable capacity analyses for load pockets to address extreme conditions that could occur, the limited generation within load pockets, and the limited amount of capacity load pockets can typically import based on transmission capabilities. RSP05 presents the results of these studies to provide information on the amount of capacity needed and where and when it is needed. Table 12.2 shows these results.

The Greater Connecticut Subarea has the greatest risk of disconnecting firm customer loads and needs additional resources to cover serious resource deficiencies in the 2008 to 2012 timeframe. With the planned transmission upgrades, the only load pocket having a deficit operable capacity supply situation in the near term is the Greater Connecticut load pocket.

Table 12.2
Resource Needs for the Greater Connecticut Load Pocket

Method	MW Needed	Year
LOLE—meeting 1-day-in-10-year criterion, systemwide	270	2010
Operable Capacity—90/10 load forecast	670	2008

In addition, the ISO examined the type of capacity needed by load pockets, as shown in Table 12.3. This study assessed the need for resources with quick-start capability to meet operating contingencies in the load pockets. The results show the needs can be filled either with quick-start dual-fuel peaking units or through demand with quick-response capability.

Table 12.3
Quick-Start Needs by Load Pocket

Area	MW Needed	Year
Greater Connecticut	530	Now
Greater Southwest Connecticut	350	2009
BOSTON	500	Now

Adding 530 MW of additional quick-start resources in Connecticut now will meet the load-pocket needs of Connecticut, as well as the 2010 system needs. An additional benefit of adding quick-start resources in these load pockets will be reduced operating-reserve costs currently incurred for generating units running out of merit.

These results are subject to uncertainties that could change the projected needs. The major uncertainties relate to load forecasts, ties benefits, transmission-upgrade schedules, transmission-transfer limits between load pockets, and retirement of existing generators. The ISO will continuously monitor these major uncertainties.

12.3 Fuel Diversity

The ISO analyzed the amount of dual-fuel conversion needed to meet a range of LOLE risks and where such conversions should occur. Addressing the regional need to convert to dual fuel or firm gas-transportation contracts now will reduce the reliability risk during a future winter cold snap. Table 12.4 summarizes the results of this analysis, which assumed conversions could be accomplished by the winter of 2006/2007 at the earliest.

Table 12.4
Minimum Amount of Gas-Only Capacity Needed to Meet the 0.1 Day/Winter Risk Level (MW)

Winter (Dec. to Feb.)	2005/2006	2006/2007	2007/2008	2008/2009	2009/2010
Total New England	≥1,148	≥392	≥641	≥892	≥1,385
Southern Subareas	≥1,148	≥392	≥641	≥892	≥1,385
BOSTON	≥1,148	≥297	≥146	≥186	≥226
Greater CT	≥0	≥0	≥0	≥0	≥29
Greater SWCT	≥0	≥0	≥0	≥0	≥29

The above table shows that most of the conversions must take place in the Southern Subarea to most effectively improve reliability during the winter months. About two-thirds of New England generation relies on gas or oil as its primary fuel. A more diverse portfolio is highly desirable since gas and oil are the most expensive fuels, are highly volatile in price, and are increasingly dependant on imported supply. The ISO supports a much more aggressive pursuit of alternative fuel sources as a means of diversifying the region's fuel supply and reducing price risks in the future.

Appendix A discusses the implications of environmental considerations and distributed resources for developing new resources. Nonmarket resource incentives and state requirements, including conservation and demand-response programs, Renewable Portfolio Standards, and distributed generation, will add new diversified resources in the region. The tightening of state and federal air emission regulations over the 10-year planning period, including the possible implementation of a regional cap on CO_2 emissions from electric power generators, will also affect the resources provided by the market or by nonmarket options.

Appendix B discusses the region's proposed generating projects, including the projects in the Interconnection Queue and the diversity of fuel types for proposed generation projects.

12.4 Market Mechanisms

RSP05 also discusses market mechanisms that could provide appropriate market signals for encouraging investment in needed resources. Improvements to the capacity market could send the proper price signals for meeting long-term resource needs and address the need for firm fuel supply or back-up fuel supply, such as oil. Improvements to the ASM are intended to send the appropriate price signals to encourage existing resources and new investment to provide quick-start capacity in constrained load pockets. These improvements will also facilitate demand-side participation in the market and increase the quantity of demand resources.

12.5 Transmission

RSP05 identifies the region's needed transmission improvements and provides a roadmap for identifying the system's needed improvements in the long term. The region has 272 transmission projects in various stages of planning, construction, and implementation, with a total cost of about $3.0 billion. The ISO and the transmission owners collaboratively conducted the studies that support these projects.

These projects are required over the next 10 years to ensure local-area and systemwide reliability in accordance with NERC, NPCC, and ISO planning criteria and to facilitate the future operation of the system. These upgrades may be needed to address electrical performance problems, such as those related to voltage or stability; to serve growing loads; or as a backstop for market solutions to system needs. The transmission improvements in load/generation pockets will reduce local-area and systemwide dependency on the generators to provide either economic operating reserves or reserves based on reliability needs and the need to commit generating resources out of merit.

Six of the 272 transmission projects are major and have significant reliability impacts on the region. These projects include the Northwest Vermont Reliability Project, the Northeast Reliability Interconnect Project, the Southwest Connecticut Reliability Project (Phase 1 and Phase 2), the Southern New England Reinforcement Project, and the NSTAR 345 kV Transmission Project.

Appendices C and D contain details on ISO New England's transmission projects.

12.6 Summary of System Needs

Table 12.5 summarizes key RSP05 results and findings. The table shows that an additional 170 MW of resources will be needed to meet the systemwide Installed Capacity Requirement by 2010. This result assumes no units will retire between now and then and load-growth and other assumptions hold true. However, before 2010, as load grows and total capacity just meets the reliability requirement, the need for operation under OP 4 during high-load hours will become more commonplace.

Table 12.5
Summary of RSP05 System Needs and Solutions, Based on RSP05 Assumptions and Analyses

System Needs	Solutions	Specific Requirements
Meet load-pocket requirements	Add resources to satisfy reliability needs (preferably quick-start resources)	For Greater Connecticut: Operable Capacity: - Need 30 MW by 2006 (90/10 load) - Need 670 MW by 2009 (90/10 load)
Meet systemwide operable capacity forecast requirements	Meet systemwide needs by adding quick-start resources that satisfy load-pocket needs	- Need 160 MW by 2008 (50/50 load) - Need 1,900 MW by 2008 (90/10 load)
Provide operating reserves	Add incremental quick-start resources or units with energy prices competitive with resources external to the load pockets	For Greater Connecticut: - Need 530 MW by 2006 *The preferred location for adding quick-start resources for meeting the needs of Greater Connecticut is Greater SWCT because this area needs 350 MW by 2009* - Need 500 MW in BOSTON by 2006
Meet systemwide 1-day-in-10-year LOLE criterion	Meet systemwide needs by meeting load-pocket needs	- Need 170 MW systemwide by 2010
Reliably operate system when gas is not available	Achieve greater fuel diversity by adding incremental dual-fuel conversions in southern New England, predominantly BOSTON	- Need 400 MW by winter 2006/2007 - Need an additional 250 MW every winter through 2008/2009 - Need an additional 500 MW in winter 2009/2010

Table 12.5 identifies a number of needs for reliable operation both regionwide and in load pockets. Specifically, during times of extreme peak loads, additional capacity over the amount committed to firm contracts and/or using OP 4 actions during emergency conditions is needed. The fragile state of the transmission system, which limits the import of electricity into Greater Connecticut, and the lack of sufficient 30-minute-response resources within Greater Connecticut make that state especially vulnerable to risks of unreliable operation or, in extreme conditions, load shedding. Quick-start resources and additional diversity and firmness of fuel supply are needed to reduce the operational risks shown in the table.

The results in the Table 12.5 also indicate that Greater Connecticut is short of quick-start generating capacity to provide for operating-reserve coverage. Adding 530 MW of quick-start resources and demand-response resources with quick response times in Greater Connecticut at this time will satisfy this state's quick-start resource needs to protect against the second-contingency loss of a facility. This measure will also satisfy New England's resource adequacy needs. The Greater Southwest Connecticut Subarea will need approximately 350 MW of quick-start resources in 2009, when Phase 2 of the Southwest Connecticut Reliability Project is in service, to protect against the second-contingency loss of the largest facility. Quick-start resources added in Greater Southwest Connecticut will also serve the State of Connecticut's quick-start resource and demand needs. BOSTON, another subarea of New England, needs 500 MW of quick-start resources now to protect against second-contingency losses. Adding quick-start resources in BOSTON will also serve New England's capacity resource needs. These resource additions will help reduce operating-reserve costs in these areas.

To mitigate the impact that natural gas shortages could have on system reliability during the winter, the region must convert approximately 400 MW of gas-fired generation to dual-fuel capability. Study results indicate that converting gas-fired generation in southern New England and increasing the amount by 250 MW per year through winter 2008/2009 could improve system reliability during cold snaps. An additional 500 MW is required by winter 2009/2010, with conversions in BOSTON preferred throughout the study period.

12.7 New Initiatives

RSP05 identifies several new ISO initiatives to improve its planning process and assure the future reliability of service to the region's load:

- Develop a Horizon Year Study to provide longer-term direction for New England's transmission development.
- Review the load-forecast methodology to improve its quality.
- Conduct a comprehensive review of all the methodologies, criteria, and assumptions used to calculate the Installed Capacity Requirements for the system and load pockets. The review will take about 18 months to complete, with any revisions incorporated in the calculation used to generate the IC Requirements for Power Year 2007–2008.
- Initiate a long-term program to improve the monitoring and control of the grid. This effort will assess the data-communication and substation monitoring and control equipment presently installed on the grid and the effectiveness of the methods and facilities system operators use to respond to contingencies, including load shedding.
- Identify and address those issues that obstruct the market from providing, in response to price signals, the resources needed to reliably operate the power grid. These measures will reduce the commitments made to generating resources operating out of economic merit order to satisfy power system criteria. One area of focus for this project will be to identify key upgrades to the power system infrastructure that would reduce or eliminate the need to commit out-of-market generation to control voltage.
- Investigate the pricing rules and operating procedures to ensure that they are consistent with each other and that barriers do not exist for properly pricing or efficiently using resources.
- Evaluate and apply advanced technology solutions to maximize the thermal use of existing rights-of-way and improve voltage performance. These solutions include the use of new conductor technologies and innovative voltage-control devices.
- Conduct interregional transmission planning. Implementation of the Northeast Planning Protocol and continued participation in NPCC activities will improve coordination with neighboring control areas.
- Review the long-term viability of each Special Protective Scheme used on the New England bulk power system to optimize transfer capability.

Section 13

Recommendations

The following are the ISO's recommendations to assure, through market incentives where appropriate, a reliable and more robust electric power supply system is implemented in New England over the next 10 years:

- **Complete Transmission Projects**—Improve the New England infrastructure and maintain power system reliability in New England over the next 10 years by supporting the timely completion of ongoing transmission improvements identified in RSP05. The report currently contains 272 projects, which will continue to be modified on an ongoing basis as new improvements are identified and projects are completed or eliminated from the listing.

- **Develop Resources**—Increase systemwide resources by at least 160 MW in the 2008 to 2010 timeframe. Add 670 MW in the Greater Connecticut load pocket by 2009 to satisfy reliability needs. Increase quick-start resources by 530 MW in Greater Connecticut now and by 500 MW in BOSTON to improve operating flexibility and efficiency. Greater Southwest Connecticut also needs 350 MW of quick-start resources by 2009, but if added by 2006, it can help satisfy Greater Connecticut's reliability needs. These needs are not mutually exclusive; quick-start resource additions in Greater Connecticut or BOSTON will satisfy system requirements. Additions to quick-start resources in Greater Connecticut will satisfy load-pocket needs as well as system needs.

- **Enhance Fuel Diversity**—Develop mechanisms to attract an improved diversity of fuel types for the New England fleet of supply resources. This should include clean coal technologies and additional nuclear resources. In addition, investigate the impact of developing alternative resources, such as wind and distributed generation, on the operation and long-term security of the power system.

- **Improve Firmness or Flexibility of Gas Resources**—Firm up gas supply arrangements for at least 400 MW or convert 400 MW to dual-fuel operations in southern New England by 2006 to 2007. This will provide for reliable operation of the system during periods of high demand when natural gas may be unavailable for electricity generation. Increase the arrangements or conversions by 250 MW per year through 2008/2009 and by another 500 MW by 2009/2010.

- **Develop Gas Supplies**—Develop new gas supplies and delivery capacity, including LNG facilities, to meet increased demand in New England.

- **Increase Demand Response**—Increase the penetration of demand response as part of the overall supply to assure reliability and ensure its operability.

- **Improve Operational Control**—Initiate a long-term program to improve the monitoring and control of the grid, to prepare for the upcoming period in New England when capacity will become more constrained and to respond to recommendations of the August 2003 Blackout Task Force. This will allow the local control centers and the ISO to better monitor the grid and more accurately initiate load shedding at a substation feeder level.

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