2009 Regional System Plan

October 15, 2009

Table of Contents

List of Figures

List of Tables

Section 1
Executive Summary

ISO New England Inc. (ISO) is the not-for-profit corporation responsible for the reliable operation of New England's bulk power generation and transmission system. It also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional bulk power system. The planning process is open and transparent and invites advisory input from regional stakeholders, particularly members of the Planning Advisory Committee (PAC). The PAC is a stakeholder forum open to all parties interested in regional system planning activities in New England. Among their other duties, members review and comment on the Regional System Plan (RSP) scope of work, assumptions, and draft results.[1]

The electric power planning process in New England assesses the amount of resources the overall system and individual areas of the system need, the types of resources that can satisfy these needs, and any critical time constraints for addressing them. This process helps ensure system reliability, facilitate the efficient operation of the markets, and improve the economic performance of the system. Stakeholders responsible for developing needed resources commit to projects based on information developed during the ISO system planning process, as well as incentives from ISO-administered markets and other factors. When stakeholder responses to market incentives do not meet system needs, the ISO planning process identifies regulated transmission solutions, although the ISO does not have the authority to build and own needed resources or transmission.

Each year, the ISO prepares a comprehensive 10-year Regional System Plan that reports on the results of ISO system planning processes. Each plan includes forecasts of future loads (i.e., the demand for electricity measured in megawatts) and addresses how this demand may be satisfied by adding supply resources; demand resources, including demand response and energy efficiency; and new or upgraded transmission facilities.[2] Each year's plan summarizes New England-wide needs, as well as the needs in specific areas, and includes solutions and processes required to ensure the reliable and economic performance of the New England power system. The RSPs meet the criteria and requirements established by the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), and the ISO's *Transmission, Markets, and Services Tariff*, which states the ISO must proactively assess the future state of the system.[3] The plans also include information that serves as input for improving the design of the regional power markets and analysis of the economic performance of the New England system. In addition, the RSPs summarize the

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[1] PAC materials (2001–2009) are available online at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html.

[2] In general, *supply resources* are generating units that use nuclear energy, fossil fuels (such as natural gas, oil, or coal), or renewable fuels (such as water, wind, or the sun) to produce electricity. *Demand resources* are measures that reduce consumer demand for electricity from the bulk power system, such as using energy-efficient appliances and lighting, advanced cooling and heating technologies, electronic devices to cycle air conditioners on and off, and equipment to shift load to off-peak hours of demand. They also include using *distributed generation* (DG) (i.e., electricity generated on site). *Demand response* in wholesale electricity markets occurs when market participants reduce their consumption of electric energy from the network in exchange for compensation based on market prices.

[3] (1) Information on NERC requirements is available online at http://www.nerc.com (Princeton, NJ: NERC, 2008). (2) The ISO operates under several FERC tariffs, including the *ISO New England Transmission, Markets, and Services Tariff* (2009), of which Section II is the *Open Access Transmission Tariff* (OATT) and Section IV is the *Self-Funding Tariff*. These documents are available online at http://www.iso-ne.com/regulatory/tariff/index.html and http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

coordination of the ISO's short- and long-term plans with neighboring systems and identify the initiatives and other actions the ISO, state officials, regional policymakers, transmission owners (TOs), and other market participants and stakeholders can take to meet the needs of the system.

The results and conclusions of the RSPs are subject to many uncertainties and highly variable assumptions. Some factors subject to change are as follows:

- Demand forecasts, which are dependent on the economy, new federal appliance efficiency standards, and other considerations
- Resource availability, which is dependent on physical and economic parameters that affect the performance, development, and retirement of resources
- Timing of planned system improvements, which can be subject to siting and construction delays
- Fuel price forecasts, which change with world markets
- Market rules and governmental policies, which change the development of market resources and the transmission system

The many factors that change system needs influence the timing of required regulated transmission solutions, as specified by the ISO. For example, the development of generation and demand resources may delay the need for transmission development. Resource retirements also may delay or advance the need for transmission projects. While each RSP is a snapshot in time, the planning process is continuous, and the results are revisited as needed based on the latest available information.

The ISO's *2009 Regional System Plan* (RSP09) builds on the comprehensive work completed in its *2008 Regional System Plan* (RSP08), reaffirming applicable results and providing updates as needed.[4] The results of the recent load, resource, and transmission analyses of New England's bulk electric power system needs and solutions are presented for the 10-year planning period through 2018. These analyses account for uncertainties in assumptions about this period associated with changing demand, fuel prices, technologies, market rules, environmental requirements, and other relevant variables. The report describes the major factors influencing the development of the electric power system for these future years and how the region can provide a reliable and economic electric power system in compliance with state and federal regulations and guidelines.

1.1 Major Progress, Findings, and Observations

Based on the results of past RSPs and other reports, seven major 345 kilovolt (kV) transmission projects have been completed in four states, one additional project has completed its siting process, and five others either are going through siting or are expected to begin the siting process by the end of 2009. These projects reinforce the system's critical load pockets, such as Southwest Connecticut (SWCT) and Boston, and areas that have experienced significant load growth, such as Northwest Vermont (NWVT), southern Maine, and the New Hampshire seacoast area. Projects placed in service include Phases 1 and 2 of the Southwest Connecticut Reliability Project, Phases 1 and 2 of the Boston 345 kV Transmission Reliability Project, a portion of the Lower Southeast Massachusetts (SEMA)

[4] *2008 Regional System Plan* (October 16, 2008); available online at http://iso-ne.com/trans/rsp/2007/rsp07_final_101907_public_version.pdf or by contacting ISO Customer Service at 413-540-4220.

Upgrades, and the NWVT Reliability Project. The Northeast Reliability Interconnection (NRI) Project, a new interconnection to New Brunswick that increases the region's ability to import power from Canada also has been placed in service. Additionally, the replacement of an underwater transmission cable between Connecticut and Long Island was completed recently to preserve the integrity of this interregional tie line. From 2002 through 2009, over 300 projects will have been put into service, totaling more than $4.0 billion of new infrastructure investment.[5]

All these projects support the reliable operation of the power system for the short and long term. They also will enhance the region's ability to support a robust, competitive wholesale power market by reliably moving power from various internal and external sources to the region's load centers.

Beyond transmission development, the region has responded to the need for electric energy and capacity resources. Almost 12,500 megawatts (MW) of new generating projects have been interconnected with the system since the first publication of the ISO's Generator Interconnection Queue in November 1997. Over 1,900 MW of demand response and 560 MW of other types of demand resources currently are part of the regional power system. The New England markets continue to evolve and encourage the development of resources where and when they are needed.

RSP09 discusses several major results based on the load forecasts; market outcomes; economic studies; and other programs, projects, and initiatives. Anticipated load growth shown in RSP09 is lower than in RSP08, in large part because of the recent economic downturn. The Forward Capacity Market (FCM), the locational Forward Reserve Market (FRM), and various state-sponsored initiatives have resulted in the development of generation and demand resources to meet the needs of the New England region. Transmission projects recently placed in service and planned projects will improve the reliability of the system, support market efficiency, and reduce congestion costs and other out-of-market charges.[6] Certain previously planned transmission projects are under ISO review.

The region will continue to depend on natural gas for over 40% of its electric energy. However, natural gas industry measures to improve the reliability and diversity of the natural gas fuel supply and transportation have mitigated electric power system reliability concerns. Resource availability also has improved as a result of dual-fuel capability added by some generating units, as well as improved operating procedures, enhanced communications between electric power and natural gas system operators, and market incentives to generators to perform reliably when they are most needed.

Environmental regulations, such as the Regional Greenhouse Gas Initiative (RGGI) and Renewable Portfolio Standards (RPSs), are encouraging the development of clean renewable resources in the region. With the anticipated regional growth in wind plants and demand resources as a result of the FCM, the ISO is preparing to integrate these and "smart grid" technologies into the system. These technologies represent the next stage in the evolution of the power system to improve the data acquisition, analysis, control, and efficiency of the electric power grid. A request made by the New England governors for a study of increased renewable resources in the region and possible new

[5] Based on the July 2009 *RSP Project List* (i.e., *Transmission Projects Listing*), this total includes seven projects in 2002, 26 projects in 2003, 30 projects in 2004, 51 projects in 2005, 55 projects in 2006, 36 projects in 2007, and 64 projects in 2008. An additional 38 projects are expected to be in service in 2009 and an additional 36 projects in 2010.

[6] The ISO has approved "planned" transmission projects to meet identified system needs for which resource alternatives to transmission are insufficient. The *Transmission Project Listing* includes these "planned" projects, as well as "proposed" projects and projects under construction, all of which total approximately $5 billion. Cost estimates without transmission cost allocation approval, however, are subject to wide ranges of accuracy and change as projects progress. See Section 10.3 and http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html.

imports from Canada will further inform government officials as they establish policies that affect the future planning and development of the system.

The major findings of RSP09 and the sections of the report that contain more details about them are as follows:

Energy and Load Growth—The RSP09 forecasts of annual and peak use of electric energy are lower than those for RSP08. This mainly is due to the recent economic downturn, the inclusion of the federal energy-efficiency standards for appliances and commercial equipment, and to a lesser degree, changes in the ISO's forecasting models of annual and peak use of electric energy. These forecasts reflect the growth of the summer cooling load and a lower rate of growth of the winter heating load. The 50/50 summer peak forecast is 27,875 MW for 2009; 29,020 MW for 2012; and 30,960 MW for 2018. These values are lower than the RSP08 forecast by 605 MW for 2009; 800 MW for 2012; and 555 MW for 2017. The 10-year energy growth rate is 0.9% per year, while the 10-year summer peak load growth rate is 1.2% per year. The 10-year winter peak load growth rate is 0.4% per year. The lower RSP09 load forecast affects the need for new resources and may delay the timing of some transmission projects. (Section 3)

Capacity Needs and Resources—The Forward Capacity Market is expected to provide the capacity needed to meet resource adequacy requirements. The net Installed Capacity Requirement (ICR) is expected to grow from 32,137 MW in 2010 to a representative value of 34,454 MW by 2018. If all 37,283 MW of resources that cleared the second Forward Capacity Auction (FCA #2) are in commercial operation by 2011, New England will have adequate resources through 2018, assuming no generation or demand resources retire or permanently delist.[7] In addition, 6,652 MW of resources have qualified to participate in the third FCA (FCA #3) for the capacity commitment period beginning June 1, 2012.[8] Additional resources in needed locations near load centers also are being planned. A total of 1,169 MW of the new resources that cleared FCA #2 and over 4,100 MW of generation resources in the ISO Generator Interconnection Queue (as of March 2009) are proposed for the Greater Connecticut RSP subareas. In addition, over 2,900 MW of demand resources are being planned based on the results of FCA #2, and 555 MW of new demand resources have qualified for FCA #3. (Section 4)

Operating Reserves—Resources participating in the locational Forward Reserve Market are helping to satisfy the operating-reserve requirements of major import areas in New England to cover contingencies. RSP develops the representative needs of these major import areas as ranges to account for future uncertainties about the availability of resources, load variations due to weather, and other factors. Representative needs for Southwest Connecticut are 0 to 180 MW for 2009 to 2013. Over the same period, the needs for Greater Connecticut are 1,100 to 1,250 MW, and 0 to 175 MW for Boston. Existing and new "fast-start" and "spinning" reserve capacity will likely be used to meet

[7] Existing capacity resources are required to participate in the FCA and are automatically entered into the capacity auction. However, these resources may indicate a desire to be removed from the FCA by submitting a *delist bid* before the existing-capacity qualification deadline.

[8] (1) A *capacity commitment period* (also referred to as a *capability year*) runs from June 1 through May 31of the following year. (2) ISO New England Inc. *Informational Filing for Qualification in the Forward Capacity Market* (Docket No. ER09-___-000) (July 7, 2009); http://www.iso-ne.com/regulatory/ferc/filings/2009/jul/er09-___-000_07-07-09_info_filing_third_fca.pdf.

the operating-reserve requirements for the major import areas.[9] The addition of economic generation within the major import areas would decrease the need for operating reserves located within these areas. A Demand-Response Reserves Pilot program that allows demand resources to provide operating reserves will provide additional information on the performance of demand resources. (Section 5)

Fuel Diversity—New England will likely remain heavily dependent on natural gas as a primary fuel for generating electric energy for the foreseeable future. In 2008, natural gas plants represented 38% of the region's capacity and provided about 41% of the system's electrical energy. Continued enhancement of the regional and interregional natural gas infrastructure will help expand and diversify natural gas sources to meet New England's increasing demand for natural gas to produce electric power.[10] Also, operational risks have been reduced through the implementation of operating procedures and increased generator availability provided by market rule performance incentives. Converting gas-burning generators to dual-fuel capability increases their fuel flexibility and reduces the probability of generation interruptions when the natural gas supply is interrupted. While approximately 30% of the generators that burn natural gas as their primary fuel have dual-fuel capability, additional dual-fuel capability is desirable. Additional intraday gas nomination and confirmation cycles would improve the reliability of the fuel supply serving electric generating units. This change in the nomination cycles also would increase the flexibility of natural-gas-fired generators to vary their output in real time, which is necessary to facilitate the addition of variable-output (i.e., intermittent) resources, such as wind generation.[11] (Section 6)

Environmental Requirements—Recent changes to environmental regulations include the *Clean Air Interstate Rule* (CAIR); the Regional Greenhouse Gas Initiative (RGGI); and the *Clean Water Act* (CWA) Section 316b (dealing with cooling water intake requirements). After some legal challenges, CAIR has been reinstated and sets nitrogen oxide (NO_X) emissions limits during the ozone (O_3) season for the southern New England states. RGGI went into effect in 2009 for New England and four additional Northeastern states. The four carbon dioxide (CO_2) allowance auctions conducted by RGGI have cleared at $3.07/ton to $3.51/ton per allowance and have yielded $111 million for the New England states, most of which will be used for energy-efficiency programs. The U.S. Congress is deliberating bills for national cap-and-trade programs to cap greenhouse gases. These bills could change or eliminate the RGGI program. Section 316b of the CWA requires a significant reduction of the impacts of impingement and entrainment of aquatic organisms caused by the cooling water intake processes at existing power plants. A Supreme Court decision clarified that a benefit/cost ratio may be used to justify the choice for best available technology (BAT) to reduce these environmental impacts. (Section 7)

Renewable Portfolio Standards and Related Policies—Environmental regulations and policies are stimulating the need for developing renewable resources and energy efficiency. The state targets for

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[9] *Fast-start* resources are off-line, nonsynchronized resources (i.e., *nonspinning*) that can be electrically synchronized to the system and quickly reach rated capability. Synchronized (i.e., *spinning*) reserves are on-line reserves that can increase output.

[10] Improvements include a new liquefied natural gas (LNG) terminal in St. John's, New Brunswick; the Northeast Gateway Project and Neptune LNG terminals, both offshore of Gloucester, MA; increased sources of natural gas from shale, such as the Marcellus Shale discoveries, and developments in Atlantic Canada (Deep Panuke); and several improvements to natural gas pipelines and storage facilities.

[11] Currently, the North American Energy Standards Board (NAESB) requires natural gas transmission companies to make offers in a minimum of four natural gas nomination and confirmation cycles over a two-day period—two offers day ahead and two offers intraday (i.e., day-ahead timely, day-ahead evening, intraday #1, and intraday #2).

the proportion of electric energy demand to be met by renewable resources and energy efficiency will increase to approximately 23.5% of New England's total projected electric energy use by 2016 and to 30.1% by 2020. Of this 30.1%, 11.1% will be energy-efficiency programs, and the remaining 20% will be Renewable Portfolio Standards and related policies. The renewable resources in the ISO Generator Interconnection Queue, renewable resources from adjacent balancing authority areas, new renewable resources in New England not yet in the queue, small "behind-the-meter" projects, eligible renewable fuels in existing generators, and the use of state-established Alternative Compliance Payments (ACPs) are all possible solutions for meeting or exceeding the region's RPSs.

The 4,300 MW of renewable resources in the ISO Generator Interconnection Queue as of March 15, 2009, would be sufficient to meet the current incremental demand for the new renewable resource classes through 2020 if all were built and operating by then.[12] Typically, however, the attrition of projects in the queue has been significant since the queue was initiated in 1997. If only 40% of the renewable energy projects in the queue were built, the electric energy from these projects would meet the projected demand for new renewable sources of energy in New England through 2014. Load-serving entities (LSEs) may find that the ACP rates established by the states are more economical than paying for the renewable resources to meet the targets. (Section 7)

Integration of New Technologies—RSP09 summarizes several current actions to successfully integrate wind resources, demand-resources applications, and smart grid technologies. The ISO is conducting a major study of integrating wind resources into the New England system. This study is analyzing technical details of various planning, operating, and market aspects of wind integration. It will simulate cases that add wind resources up to 12,000 MW (i.e., 20% of the system's energy) and will include the conceptual development of a transmission system that can integrate large amounts of wind generation resources. The study will develop wind forecasting models for future ISO use and is scheduled to be completed in 2010. (Section 8)

The operational and market integration of demand resources associated with the growing dependence on these resources to almost 3,000 MW by 2011 requires planning. Accordingly, several tasks are being undertaken, including modifications to control room applications and ISO operating procedures, the creation of demand-designated entities (DDEs) for aggregating the operation of demand resources, and the implementation of new communications infrastructure.[13] (Section 8)

In addition to integrating renewable and demand resources, the ISO is actively conducting several other projects to develop a smart grid, which has gained considerable attention in 2008 and 2009. While several smart grid technologies have been applied successfully to the transmission system, additional research and development efforts are necessary to develop technical standards and business practices for fully realizing the potential of smart grid technologies to improve the overall efficiency of the electric power grid.[14] Developing industry standards for smart grid technologies is a major area of focus at the national level. Implementing time-of-use rate structures and successfully deploying "smart meters" potentially may allow consumers and LSEs to control demand. Using existing and

[12] The 4,300 MW includes all wind projects in New England, including the projects in the Maine Public Service (MPS) system.

[13] The ISO intends to work with stakeholders to create *demand-designated entities*, similar to generator-designated entities, which will be aggregators of active demand resources responsible for receiving and acting on dispatch instructions from the ISO. DDEs will be the only entities to which the ISO will communicate demand-resource dispatch instructions.

[14] Several technologies that have been integrated include flexible alternating-current transmission systems (FACTS), high-voltage direct-current (HVDC) facilities, and phasor measurement units (PMUs).

advanced storage technologies, including plug-in electric vehicles (PEVs), flywheels, and batteries, has the potential to support the successful integration of renewable energy resources. (Section 8)

Economic Planning Studies—In accordance with Attachment K of the ISO *Open Access Transmission Tariff* (OATT) and stakeholder requests received in 2008, the ISO completed economic analyses of several expansion scenarios.[15] These studies of system performance over the next 10 years show that production costs, LSE electric energy expenses, and emissions vary with the addition of various amounts and types of low-emitting generation resources at various locations. Some expansion scenarios postulated the addition of natural gas combined-cycle (NGCC) resources in Connecticut and Boston. Others examined various combinations of renewable resources in northern New England (along with imports from Canada) and in SEMA and Rhode Island (RI). The results of the production cost studies show the following: (Section 9)

- Natural gas will likely remain the dominant fuel for setting marginal electric energy prices.
- New England CO_2 and NO_X emissions decrease as more low-emission or zero-emission resources are added.
- In the absence of transmission improvements, increasing the injection of electric energy from additional wind or other resources in the north, such as adding 1,200 MW of wind energy north of the Orrington–South interface in Maine, will increase the amount of congestion along the north–south corridor from New Brunswick to Massachusetts.
- Increasing both the Orrington–South and Surowiec–South interfaces by 1,800 MW and increasing the North–South and Maine–New Hampshire interfaces by 1,200 MW would relieve congestion attributable to 3,600 MW of low-energy-cost resources injected into Orrington and an additional 1,200 MW of low-energy-cost resources injected into New Hampshire.
- The results of production cost studies of resource-expansion scenarios near load centers show no significant transmission congestion on the system for 2009 and through 2018. This is attributable to planned system improvements identified in previous RSPs that also will allow for the integration of future system resources. Some of the RSP09 economic studies showed congestion for some scenarios of resource expansions in northern New England areas remote from load centers.

Transmission System—Transmission planning studies are necessary to meet NERC, the Northeast Power Coordinating Council (NPCC), and ISO standards and criteria and to establish a plan to address the future reliability needs of the region. These studies have identified needs and justified transmission improvements throughout the region, and they have met all required planning criteria, as evidenced by the ISO successfully passing the April 2009 NERC/NPCC audit of reliability standards.[16] These studies, done collaboratively with transmission owners and other stakeholders, have determined the need for major new transmission improvements in various parts of the system.

All transmission projects are developed to serve the entire region reliably and are fully coordinated with other regions. These transmission upgrades are designed to maintain transmission system

[15] ISO New England *Open Access Transmission Tariff*, Section II, Attachment K, “Regional System Planning Process,” (December 7, 2007); http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/2-1-09_sect_ii.pdf.

[16] The NERC/NPCC audit report, *Compliance Audit Report Public Version: ISO New England Inc. April 20 to April 24, 2009* (May 7, 2009) is available online at http://www.npcc.org/compliance2/AuditSpot.aspx.

reliability and should also improve the economic performance of the system. Over the next five to 10 years, all these projects will enhance the region's ability to support a robust, competitive wholesale power market by reliably moving power from various internal and external sources to the region's load centers. (Section 10)

The Maine Power Reliability Program, which is going through the state siting proceeding, establishes a second 345 kV line in the north from Orrington to Surowiec. It also adds a 345 kV path across the Surowiec–South interface. While these new paths will provide basic infrastructure necessary to increase transfer capability out of Maine, they also will increase the ability to move power into Maine from New Hampshire and improve the ability of the transmission system within Maine to move power into the load pockets as necessary. (Section 10)

The New England East West Solution (NEEWS) is a group of projects that had been identified to improve system reliability. RSP09 shows that projects in the Springfield and Rhode Island areas should proceed as planned. Other parts of the NEEWS project are under review by the ISO, Northeast Utilities, and National Grid. The review is considering the RSP09 load forecast, system operating constraints, and resources acquired and delisted through the Forward Capacity Auctions. (Section 10)

At various times, generating units in New England load pockets have been in "must-run" situations to maintain area reliability. Transmission improvements placed in service have reduced costs associated with Reliability Agreements and second-contingency and voltage-control payments. Additional transmission plans have been developed to further reduce the dependence on certain generating units needed for reliability and the exposure to special load-shedding contingency procedures. The Lower SEMA project is one example in which transmission improvements already have reduced out-of-merit operating expenses and have improved system reliability; further improvements in Lower SEMA will significantly reduce the need to commit generation for second-contingency protection.

The *RSP Project List* (also known as the *Transmission Project Listing*) is a summary of transmission projects under consideration and required under Attachment K of the OATT to meet regional system needs. It also includes information on project status and cost estimates.[17] The list is updated at least three times per year, although the ISO regularly discusses system needs and the justification for transmission improvements with the PAC and the Reliability Committee, which provide guidance and comment on study scopes, assumptions, and results. Studies of transmission needs and solutions studies provide detailed information to stakeholders interested in developing alternatives to transmission projects. (Section 10)

Interregional Planning—ISO New England's planning activities are closely coordinated among the six New England states as well as with neighboring systems and nationally with the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission, and NERC. The ISO has achieved full compliance with all required NERC and NPCC planning standards and criteria. The Northeastern ISO/RTO (Independent System Operator/Regional Transmission Organization) Planning Protocol has further improved interregional planning among neighboring areas. Sharing resources with other systems, particularly to meet environmental emission requirements, will likely become increasingly necessary. Identifying the potential impacts that proposed generating units and transmission projects could have on neighboring systems is beneficial to support systemwide reliability and economic

[17] The current update of the *Transmission Project Listing* is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html. The descriptions of transmission projects in RSP09 are based on the July 2009 update.

performance. The ISO has coordinated system plans and has proactively initiated planning studies with other regions.

Regional planning authorities within the Eastern Interconnection have developed and coordinated transmission expansion plans. The Eastern Interconnection Planning Collaborative (EIPC) has been proposed to address national and international planning issues, to coordinate plans, and to conduct studies for the entire Eastern Interconnection with input from stakeholders, including federal, state, and Canadian provincial officials. The EIPC proposal includes studies of various transmission alternatives that will account for national, regional, and state energy, economic, and environmental objectives. As part of its functions, the EIPC could provide technical support to DOE wide-area technical planning studies. (Section 11)

Regional, State, and Federal Initiatives—The ISO has implemented FERC Order 890 planning process enhancements and has begun RSP09 economic studies with stakeholders for meeting the requirements of Attachment K of the OATT. The studies include ISO technical support to the New England governors as they develop a *Regional Blueprint for Renewable Resources*. These studies also include interregional production cost analysis conducted jointly with the New York ISO (NYISO) and PJM Interconnection.[18] (Section 11)

Several regional and state initiatives have been completed that improve the coordination of regional studies and enhance resource adequacy and system planning. The FCM should continue to encourage the development of resources to meet the regional installed capacity requirement. Because Forward Capacity Auctions are held more than three years in advance of the delivery period, future resources will be known in advance, which will facilitate the planning process for the entire system. Procedures have been implemented to better coordinate Generator Interconnection Queue and FCM resource analyses. Another initiative has resulted in improved timeliness and quality of cost estimates for transmission projects. (Section 11)

Active involvement and participation by all stakeholders, including public officials, state agencies, market participants, and other PAC members, are key elements of an open, transparent, and successful planning process. The ISO coordinates its planning efforts with the New England States Committee on Electricity (NESCOE), a regional state committee that serves as a forum for representatives from the states to participate in the ISO's stakeholder processes. The ISO has continued to work with other representatives of the New England states, primarily through the PAC but also through designated representative organizations, such as the New England Conference of Public Utilities Commissioners (NECPUC), the New England Governors' Conference (NEGC), and the Consumer Liaison Group. (Section 11)

1.2 Actions and Recommendations

The region will need to ensure the implementation of all the needed improvements identified in RSP09 for providing a reliable and economic electric power system in New England over the next 10 years. Required actions will include the development of appropriate market incentives and proactive decision making and cooperation among ISO New England, other ISOs and RTOs, state officials, regional and environmental policymakers, transmission owners, and other market participants and stakeholders.

[18] PJM Interconnection 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.

Based on RSP09, the ISO recommends the following actions for itself, policymakers, and stakeholders:

- **Complete Identified Transmission Projects**—Continue monitoring projected system conditions and needs. Update the *Transmission Project Listing* as improvements are identified and projects are completed or eliminated from the listing.
    - Ensure the timely implementation of "planned" transmission improvements, as identified in the *Transmission Project Listing*, which will improve the New England transmission infrastructure and maintain power system reliability over the next 10 years in accordance with federal and regional standards.
    - Improve project management cost estimates, cost transparency, and cost controls. Ensure the provision of timely and accurate transmission project cost estimates throughout the development of transmission projects.
- **Increase Coordination and Joint Planning with Neighboring Systems—**Improve the coordination of planning efforts with other balancing authority areas. Conduct joint planning studies and explore the ability to import power from and export power to the eastern Canadian provinces and New York. Participate in national and regional planning activities, including those of DOE, the Eastern Interconnection Planning Collaborative, the Joint ISO/RTO Planning Committee (JIPC), NPCC, and NERC.
- **Obtain Needed Resource Development through Markets**—Monitor the performance of the Forward Capacity Market, as summarized in the *Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements*, and the locational Forward Reserve Market, and examine the markets for improvements.[19]
- **Plan for and Operate Demand Resources**—Facilitate the further integration of demand resources, accounting for their potential activation times, duration, and frequency of use. Enhance the ISO's ability to audit demand-resource performance and to dispatch large amounts of demand resources reliably and efficiently.
- **Integrate Variable-Output System Resources—**Identify and address issues concerning the integration of large amounts of variable-output resources, especially wind. Through the open stakeholder process, identify and implement strategies for reliably planning and operating these resources. Review and adapt the market design to address operating and planning issues created by the addition of variable-output resources. Research and implement techniques to improve the forecasting of variable-output resources.
- **Address Fuel Diversity and Availability Issues—**Continue working with regional gas pipeline and local distribution companies (LDCs), such as the Northeast Gas Association (NGA) member companies to improve the coordination of electric power and gas system operations and planning activities. Analyze how market mechanisms and environmental regulations affect the diversity of the fuels used to generate electricity in New England. Assist stakeholders with the development of reliable and diverse energy technologies, such as renewable sources of energy, distributed generation, smart grid technologies, and imports from eastern Canada and New York.

[19] *Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements* (June 5, 2009); http://www.iso-ne.com/regulatory/ferc/filings/2009/jun/er09-1282-000_06-05-09_market_monitor_report_for_fcm.pdf.

- **Monitor Regional Environmental Goals**—Monitor the development of zero- or low-emitting resources, such as renewable resources and "clean" demand resources, compared with national, regional, and state environmental and renewable resource targets for these resources. Advise regulatory agencies of the potential impacts of environmental air and water regulations on electric power system reliability. Respond as appropriate to federal and state policies to integrate renewable resources. The region's stakeholders, including the ISO, the New England Power Pool (NEPOOL) participants, and state environmental agencies, should collaborate on the planning needed to meet these requirements.[20]
- **Support Research and Development**—Work with stakeholders to support research and development activities and the establishment of industry standards for integrating smart grid technologies. Participate in demonstration projects that improve the reliable activation and performance monitoring of demand resources and the interfaces for advanced metering. Consider a variety of applications for smart grid technologies, including energy storage, energy shifting, and ancillary services, such as frequency regulation. In the near term, conduct demonstration projects of smart grid technologies, such as plug-in electric vehicles. Develop a plan to implement smart grid technologies before they become more widespread.
- **Improve Understanding of Energy-Efficiency Programs**—Through the Regional Energy-Efficiency Initiative, gain a better understanding of the physical effects of the state-sponsored energy-efficiency programs and their potential for growth. Track the historical planned penetration of demand resources against the actual performance of these resources, and periodically review the load forecast model to identify improvements.
- **Support Regional, State, and Federal Policy Initiatives—**As needed, work with the PAC, NEPOOL, NECPUC, NESCOE, the Consumer Liaison Group, and other interested parties to support regional and federal policy initiatives. Participate in FERC regional conferences.[21] Continue providing required technical support to the New England states as they formulate the *Regional Blueprint for Renewable Resources*.

1.3 Summary

The publication of the *2009 Regional System Plan* and the projects shown in the current *Transmission Project Listing* meet the requirements of the ISO's FERC tariff to issue an annual system plan. With broad input from regional stakeholders, the RSP, *Transmission Project Listing*, needs studies, and solution studies identify detailed needs of New England's power system and the system improvements required for serving load reliably throughout New England for the next 10 years. The plan builds on the results of previous RSPs and other regional activities. Needed system resources have been identified and will be procured through the FCM and other markets. The transmission projects have been developed to coordinate major power transfers across the system, improve service to large and small load pockets, and meet transfer requirements with neighboring balancing authority

[20] NEPOOL was formed 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 stakeholders and market participants. More information on NEPOOL participants is available online at http://www.iso-ne.com/committees/nepool_part/index.html (2009).

[21] A FERC conference planned for fall 2009 will examine whether existing transmission planning processes adequately consider regional or interconnection-wide needs and solutions to ensure adequate and reliable supplies of electricity at just and reasonable rates. FERC also will explore whether the existing transmission planning processes sufficiently meet such emerging transmission challenges as the development of interregional transmission facilities, the integration of large amounts of location-constrained generation, and the interconnection of distributed energy resources; http://www.ferc.gov/news/news-releases/2009/2009-2/05-21-09-E-1.asp.

areas. The ongoing stakeholder review process and the ISO modification to the *Transmission Project Listing* will continue to reflect projected changes in the system and identify the transmission upgrades satisfying system needs.

Section 2
Introduction

ISO New England (ISO) is the not-for-profit Regional Transmission Organization (RTO) for the six New England states.[22] The ISO has three main responsibilities:

- 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 power system planning process

Approved by the Federal Energy Regulatory Commission (FERC) in 1997, the ISO became an RTO in 2005. In this role, the ISO has assumed broader authority over the daily operation of the region's transmission system and greater independence to manage the region's electric power system and competitive wholesale electricity markets. The ISO works closely with state officials, policymakers, transmission owners, other participants in the marketplace, and other regional stakeholders to carry out its functions and coordinates its planning efforts with neighboring regions.

The *2009 Regional System Plan* (RSP09) describes the annual Regional System Plan for the area served by ISO New England. As with each year's Regional System Plan, RSP09 discusses the projected annual and peak demand for electric energy over a 10-year period (2009 to 2018 for RSP09); identifies the amounts, locations, and types of resources that can satisfy system needs over this period; and outlines how incentives associated with recent improvements to the wholesale electricity markets will assist in obtaining supply and demand resources.[23] The RSP process identifies system needs and provides information to stakeholders who may develop market responses that meet these system needs. The report identifies the need for, as well as the status of, planned regulated transmission solutions that may be required when participant response is insufficient for providing resources to meet system needs.

RSP09 also addresses fuel diversity, environmental regulatory issues, and the integration of variable-output (i.e., intermittent) renewable resources and demand resources.[24] The results of system studies that quantified economic and environmental performance of various resource and transmission-

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[22] The ISO is not responsible for portions of northern and eastern Maine. The Northern Maine Independent System Administrator, Inc. is a nonprofit entity responsible for the administration of the northern Maine transmission system and electric power markets in Aroostook and Washington counties, which has a peak load of approximately 130 MW; see http://www.nmisa.com.

[23] In general, *demand* resources are measures that reduce consumer demand for electricity from the power system, such as the use of energy-efficient appliances and lighting, advanced cooling and heating technologies, electronic devices to cycle air conditioners on and off, and equipment to shift load to off-peak hours of demand. Other measures include the use of electricity generated on site (i.e., *distributed generation,* or DG). Demand resources also include installed measures, such as equipment, services, and strategies that result in additional and verifiable reductions in end-use demand on the electricity network during specific performance hours. *Supply resources* are generating units that use nuclear energy, fossil fuels (such as gas, oil, or coal), or renewable fuels (such as water, wind, or the sun) to produce electricity.

[24] *Renewable* sources of energy are those that are naturally replenished, such as solar, hydro, wind, selected biomass, geothermal, ocean thermal, and tidal sources of power. Landfill gas (LFG) (i.e., the gas that results from decomposition in landfills and either is collected, cleaned, and used for generation or is vented or flared) also is regarded as a renewable resource. Some states consider fuel cells to be renewable.

expansion scenarios also are included. The planning work of the ISOs and RTOs in the Northeast and in eastern Canada and interregional planning are summarized. Additionally, RSP09 discusses studies the ISO performed to support the New England governors' development of a strategic vision for the future of the New England electric power system.

This section summarizes the requirements for the ISO's Regional System Plans and its approach to the planning process. As background, this section provides an overview of the bulk power system and wholesale market structure in New England and the RSP subareas used in system planning studies. It also summarizes the key features included in each section of this year's plan.

2.1 RSP Requirements

The ISO's duties are regulated by its FERC-approved *Transmission, Markets, and Services Tariff*, a part of which is the *Open Access Transmission Tariff* (OATT).[25] Attachment K of the OATT establishes the requirements for the regional system planning process for New England. Attachment K specifies, among other things, that the RSP must discuss the assessment of the system needs of the pool transmission facilities (PTFs), the results of such assessments, and the projected transmission system improvements.[26] The RSP also must identify the projected annual and peak demands for electric energy for a five- to 10-year horizon, the needs for resources over this period, and how such resources are expected to be provided. Additionally, the RSP must include sufficient information to allow market participants, including merchant transmission project developers, to assess several factors to assist them in meeting identified system needs or to modify, offset, or defer proposed regulated transmission upgrades. These factors include the quantity, general locations, operating characteristics, and required availability criteria of incremental supply or demand-side resources.

As required by the tariff, the ISO works closely with the region's stakeholders through an open and transparent process. In particular, members of the PAC advise the ISO on the scope of work, assumptions, and draft results for the RSP and supporting studies, which include needs assessments and solution studies.[27] Stakeholders can use this detailed information to better identify specific locations for resource development and merchant transmission as alternatives to regulated transmission.

Regional System Plans must comply with North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) criteria and standards as well as ISO planning and operating procedures.[28] The RSPs also must conform to transmission owner criteria, rules,

[25] FERC Electric Tariff No. 3, *ISO New England Inc. Transmission, Markets, and Services Tariff* (Part II, Section 48) (2007); http://www.iso-ne.com/regulatory/tariff/index.html.

[26] Attachment K also requires the participating transmission owners to issue local system plans for nonpool transmission facilities through an open stakeholder process.

[27] (1) Any stakeholder can designate a representative to the PAC by providing written notice to the ISO. PAC materials (2001–2009) are available online at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html. (2) The needs assessments and solution studies that have been presented to the PAC are posted on the ISO Web site. Stakeholders also can obtain publically available network models of the transmission system through the FERC 715 process, which requires transmitting utilities that operate facilities rated at or above 100 kV to submit information to FERC annually; see http://www.ferc.gov/docs-filing/eforms/form-715/overview.asp.

[28] "NERC Reliability Standards" (Princeton, NJ: NERC, 2008); http://www.nerc.com/~filez/standards/Reliability_Standards.html. *NPCC Regional Standards* (New York: NPCC Inc., 2009); http://www.npcc.org/regStandards/Overview.aspx. *ISO New England Planning Procedures* (2009); http://www.iso-ne.com/rules_proceds/isone_plan/index.html. *Operating Procedures* (2009); http://www.iso-ne.com/rules_proceds/operating/index.html.

standards, guides, and policies consistent with NERC, NPCC, and ISO criteria, standards, and procedures. These will continue to evolve, particularly with the identification of issues raised by the large penetration of variable-output renewable resources, especially wind generation, and demand resources (refer to Section 8).

In developing the Regional System Plans, the ISO also is required to coordinate study efforts with surrounding RTOs and balancing authority areas and analyze information and data presented in neighboring plans.

Attachment K reflects the improvements to the regional system planning process adopted in 2008 to comply with the nine planning principles required by FERC Order 890.[29] Among the order's requirements is one that requires ISOs and RTOs to conduct an open and transparent transmission planning process that incorporates market responses into the assessments of system needs.

2.2 Approach to Regional System Planning

The primary purpose of the ISO's regional system planning process is to identify system enhancements required to ensure the reliability and efficiency of the system. To assess how to maintain the reliability of the New England bulk power system, while promoting the operation of efficient wholesale electricity markets, the ISO and its stakeholders analyze the system and its components as a whole. They account for the performance of these individual elements and the many varied and complex interactions that occur among the components and affect the overall performance of the system. During the planning process, the options for satisfying the defined needs are assessed to determine which would be effective, such as adding resources, reducing demand, upgrading the transmission system, or using a combination of market solutions and regulated transmission solutions.

The electric power planning process in New England assesses the amount of resources the overall system and individual areas of the system need, the types of resources that can satisfy these needs, and any critical time constraints for addressing them. This process helps to ensure system reliability, facilitate the efficient operation of the markets, and improve the economic performance of the system. Stakeholders responsible for developing needed resources commit to projects based on information developed during the ISO system planning process, as well as incentives from ISO-administered markets and other factors. When stakeholder responses (i.e., resource alternatives in response to market incentives and merchant transmission) do not meet identified system needs, the ISO planning process develops regulated transmission solutions, although the ISO does not have the authority to build needed resources or transmission. These transmission projects are part of the ISO's *RSP Project List* (also known as the *Transmission Project Listing*), which includes the status of transmission development over a project's lifecycle (see Section 10.3).[30]

The timing of projects necessary to satisfy system needs is subject to change as system conditions change. For example, the development of generation and demand resources may delay the need for transmission, but the retirement of generation resources may advance the need for transmission projects. The planning process identifies sufficient lead times for the construction of transmission

[29] *Preventing Undue Discrimination and Preference in Transmission Service, Final Rule*, 18 CFR Parts 35 and 37, Order No. 890 (Docket Nos. RM05-17-000 and RM05-25-000), (Washington, DC: FERC, February 16, 2007), http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

[30] Attachment K of the OATT specifies the requirements for the *RSP Project List*. The current list is available online at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html.

solutions to ensure the region meets planning and operating requirements, including criteria, standards, and procedures.

Regional system planning must account for the uncertainty in assumptions made about the next 10 years stemming from changing demand, fuel prices, technologies, market rules, and environmental requirements; other relevant events; and the physical conditions under which the system might be operating. While each RSP represents a snapshot in time, the planning process is continuous, and the results are revisited as needed based on the latest available information.

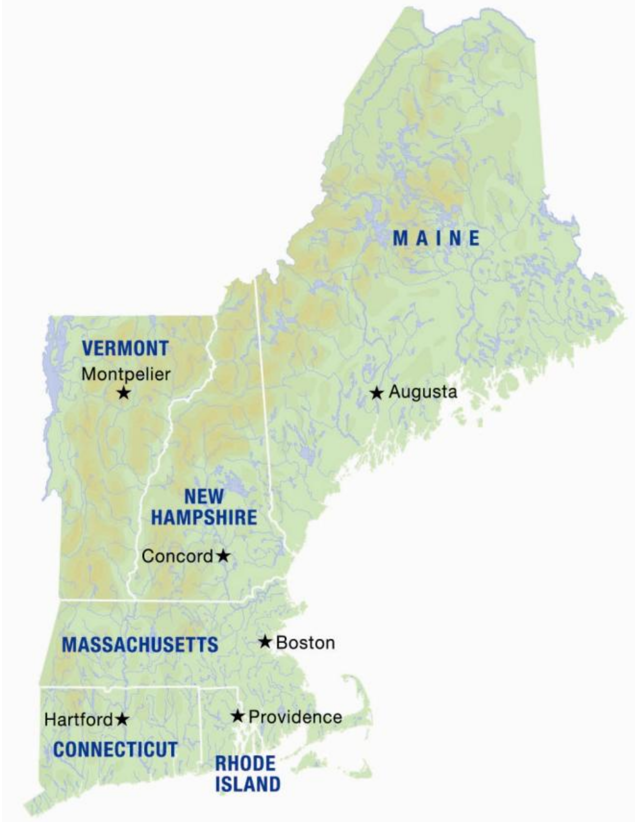
2.3 Overview of the New England Bulk Power System

Since 1971, New England's electric power grid has been planned and operated as a unified system of its New England Power Pool (NEPOOL) members.[31] The New England system integrates resources with the transmission system to serve all regional load (i.e., the demand for electricity measured in megawatts) regardless of state boundaries. Most of the transmission lines are relatively short and networked as a grid. Therefore, the electrical performance in one part of the system affects all areas of the system.

As shown in Figure 2-1, the New England regional electric power system serves 14 million people living in a 68,000 square-mile area. More than 350 generating units, representing approximately 32,000 megawatts (MW) of total generating capacity, produce electricity. Most of these facilities are connected to approximately 8,000 miles of high-voltage transmission lines. Thirteen tie lines interconnect New England with the neighboring states and provinces of New York and New Brunswick and Québec, Canada. As of summer 2009, almost 2,000 MW of demand resources were registered as part of ISO's demand-response programs.[32]

[31] NEPOOL was formed 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 stakeholders and market participants. More information on NEPOOL participants is available online at http://www.iso-ne.com/committees/nepool_part/index.html (2009).

[32] In exchange for compensation based on wholesale electricity prices, customers in demand-response programs reduce load quickly to enhance system reliability or in response to price signals. The almost 2,000 MW in ISO demand-resource programs does not include the demand response provided by other customer-based programs that are outside the ISO markets or control (i.e., *other demand resources,* ODRs). See Section 4.2.4 for more details on demand resources.



- 6.5 million households and businesses; population 14 million
- Over 350 generators
- Over 8,000 miles of high-voltage transmission lines
- 13 interconnections to electricity systems in New York and Canada
- More than 33,000 MW of total supply (includes 1,900 MW of demand-response capacity)
- All-time peak demand of 28,130 MW, set on August 2, 2006
- More than 400 participants in the marketplace (those who generate, buy, sell, transport, and use wholesale electricity and implement demand resources)
- $12 billion annual total energy market value (2008)
- More than $4.0 billion in transmission investment from 2002 through 2009 to enhance system reliability; approximately $5 billion planned over the next 10 years
- Six major 345-kilovolt projects constructed in four states.

Figure 2-1: Key facts about New England's bulk electric power system and wholesale electricity market, 2008.

Note: The total load on August 2, 2006, would have been 28,770 MW had it not been reduced by approximately 640 MW, which included a 490 MW demand reduction in response to ISO Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4); a 45 MW reduction of other interruptible OP 4 loads; and a 107 MW reduction of load as a result of price-response programs, which are outside of OP 4 actions. More information on OP 4 is available online at http://www.iso-ne.com/rules_proceds/operating/isone/op4/OP4_RTO_FIN.doc. Also see Section 4.

The ISO's all-time actual summer peak demand was 28,130 MW on August 2, 2006, which was due to extreme temperatures and humidity regionwide. In accordance with ISO operating procedures, demand-response programs were activated, which lowered the peak by approximately 640 MW. Without these programs, the peak would have been approximately 28,770 MW. The 2008 summer peak was much lower at 26,111 MW, and the 2008/2009 winter peak was 21,022 MW. The all-time actual winter peak of 22,818 MW occurred in 2004.

2.4 Overview of the New England Wholesale Electricity Market Structure

The Regional System Plan provides information that project developers can use for making investments in system improvements and participating in New England wholesale electricity markets. The RSP also identifies technical issues that help the ISO and its stakeholders formulate updates to the New England wholesale electricity markets. Participants can use this information to address the defined system or market needs, such as through investments in demand projects, distributed generation, other generation, or merchant transmission. They also can use information provided in transmission needs assessments and solution studies to propose alternative solutions to the regulated transmission solutions, for which they can be compensated through the ISO markets.

As shown in Figure 2-1, in 2008, more than 400 market participants completed approximately $12 billion of wholesale electricity transactions to generate, buy, sell, and transport wholesale electricity. Other products traded in New England's wholesale markets ensure proper system frequency and voltage, sufficient future capacity, seasonal and real-time reserve capacity, and system restoration capability after a blackout. Stakeholders also have the opportunity to hedge against the costs associated with transmission congestion. The wholesale electricity markets and market products in New England are as follows:[33]

- **Day-Ahead Energy Market**—allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time.
- **Real-Time Energy Market**—coordinates the dispatch of generation and demand resources to meet the instantaneous demand for electricity.
- **Forward Capacity Market (FCM)**—ensures the sufficiency of installed capacity, which includes demand resources, to meet the future demand for electricity by sending appropriate price signals to attract new investment and maintain existing investment both where and when needed.[34]
- **Financial transmission rights (FTRs)**—allows participants to hedge against the economic impacts associated with transmission congestion and provides a financial instrument to arbitrage differences between expected and actual day-ahead congestion.
- **Ancillary services**
    - **Regulation Market**—compensates resources that the ISO instructs to increase or decrease output moment by moment to balance the variations in demand and system frequency to meet industry standards.[35]
    - **Forward Reserve Market (FRM)**—compensates generators for the availability of their unloaded operating capacity that can be converted into electric energy within 10 or 30 minutes when needed to meet system contingencies, such as unexpected outages.[36]
    - **Real-time reserve pricing**—compensates on-line generators that offer their electric energy above the marginal cost for the increased value of their energy when the system or portions of the system are short of reserves. It also provides efficient price signals to generators when redispatch is needed to provide additional reserves to meet requirements.
    - **Voltage support**—compensates resources for maintaining voltage-control capability, which allows system operators to maintain transmission voltages within acceptable limits.

[33] For more information on New England wholesale electricity markets, see the ISO's *2008 Annual Markets Report* (AMR08) (June 16, 2009); http://www.iso-ne.com/markets/mktmonmit/rpts/index.html.

[34] *Installed capacity* is the megawatt capability of a generating unit, dispatchable load, external resource or transaction, or demand resource that qualifies as a participant in the ISO's Forward Capacity Market according to the market rules. Additional information is available online at http://www.iso-ne.com/markets/othrmkts_data/fcm/index.html.

[35] *Regulation* is the capability of specially equipped generators to increase or decrease their generation output every four seconds in response to signals they receive from the ISO to control slight changes on the system.

[36] *Unloaded* operating capacity is operational capacity not generating electric energy but able to convert to generating energy. A *contingency* is the sudden loss of a generation or transmission resource. A *first contingency* (N-1) is when the first power element (facility) of a system is lost, which has the largest impact on system reliability. A *second contingency* (N-1-1) is the loss of the facility that would have the largest impact on the system after the loss of the first facility.

The market structure for conducting wholesale electricity transactions in New England is Standard Market Design (SMD). One key feature of SMD is locational marginal pricing, which is a way for electric energy prices to efficiently reflect the variations in supply, demand, and transmission system limitations at every location where electric energy enters or exits the wholesale network. In New England, wholesale electricity prices are set at approximately 900 pricing points (i.e., *pnodes*) on the bulk power grid. *Locational marginal prices* (LMPs) differ among these locations as a result of each location's marginal cost of congestion and marginal cost of line losses. The congestion cost component of an LMP arises because of the need to dispatch individual generators to provide more or less energy because of transmission system constraints that limit the flow of economic power. Line losses are caused by physical resistance in the transmission system as electricity travels through the transmission lines, which produces heat and results in less power being withdrawn from the system than was injected. Line losses and their associated marginal costs are inherent to transmission lines and other grid infrastructure as electric energy flows from generators to loads. As with the marginal cost of congestion, the marginal cost of losses has an impact on the amount of generation that must be dispatched. The ISO operates the system to minimize total system costs.

If the system were entirely unconstrained and had no losses, all LMPs would be the same, reflecting only the cost of serving the next increment (in megawatts) of load. This incremental megawatt of load would be served by the generator with the lowest-cost electric energy available to serve that load, and energy from that generator would be able to flow to any node over the transmission system.

New England has five types of pnodes: one type is an external proxy node interface with neighboring balancing authority areas, and four types are internal to the New England system.[37] The internal pnodes include individual generator-unit nodes, load nodes, *load zones* (i.e., aggregations of load pnodes within a specific area), and the Hub. The Hub is a collection of locations that has a price intended to represent an uncongested price for electric energy; facilitate trading; and enhance transparency and liquidity in the marketplace. In New England, generators are paid the real-time LMP for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones.[38]

Import-constrained load zones are areas within New England that do not have enough local resources and transmission-import capability to serve local demand reliably. Export-constrained load zones are areas within New England where the available resources, after serving local load, exceed the areas' transmission capability to export excess electric energy. New England is divided into the following eight load zones: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).

A *capacity zone* is a geographic subregion of the New England Balancing Authority Area that may represent load zones that are export constrained, import constrained, or contiguous—neither export nor import constrained. Capacity zones are used in the Forward Capacity Auctions (FCA) (see Section 4.2).

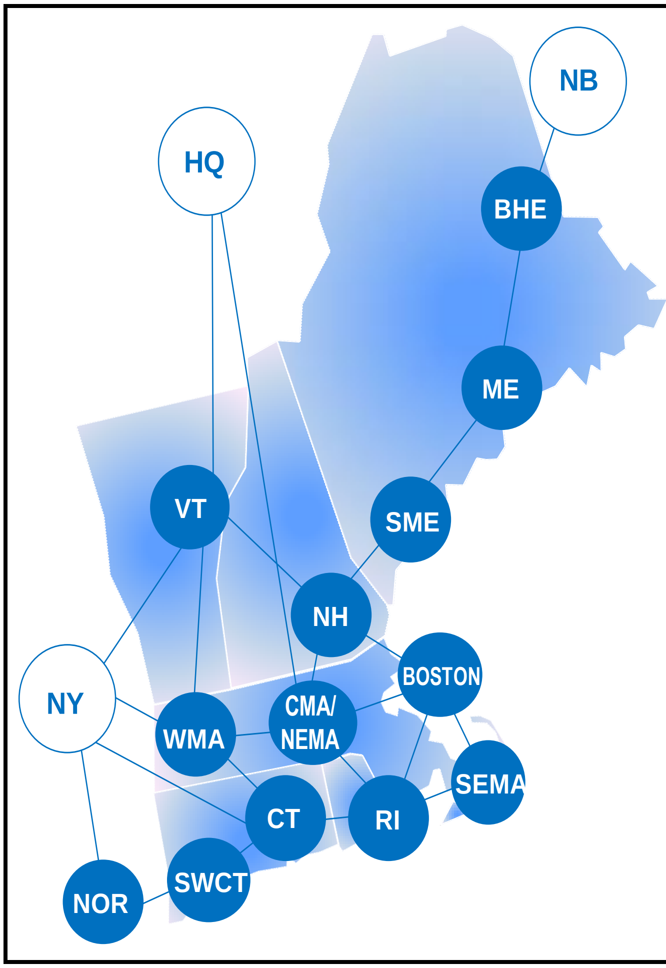
[37] A *balancing authority area* is a group of generation, transmission, and loads within the metered boundaries of the entity (*balancing authority*) that maintains the load-resource balance within the area. Balancing authority areas were formerly referred to as *control areas*. Further information is available in the NERC glossary online at http://www.nerc.com/docs/standards/rs/Glossary_12Feb08.pdf (accessed December 8, 2008).

[38] The ISO tariff allows loads that meet specified requirements to request and receive nodal pricing.

2.5 RSP Subareas

To assist in modeling and planning electricity resources in New England, the ISO established 13 subareas of the region's bulk electric power system. These subareas form a simplified model of load areas connected by the major transmission interfaces across the system. The simplified model illustrates possible physical limitations to the reliable flow of power that can evolve over time as the system changes.

Figure 2-2 shows the ISO subareas and three external balancing authority areas. While more detailed models are used for transmission planning studies and for the real-time operation of the system, the subarea representation shown in Figure 2-2 is suitable for RSP09 studies of resource adequacy, economic performance, and environmental emissions.[39]



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 and southwestern Maine
VT	Vermont/southwestern New Hampshire
BOSTON (all capitalized)	Greater Boston, including the North Shore
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts
WMA	Western Massachusetts
SEMA	Southeastern Massachusetts/ Newport, Rhode Island
RI	Rhode Island/bordering Massachusetts
CT	Northern and eastern Connecticut
SWCT	Southwestern Connecticut
NOR	Norwalk/Stamford, Connecticut
NB, HQ, and NY	New Brunswick (Maritimes), Hydro-Québec, and New York external balancing authority areas

Figure 2-2: RSP09 geographic scope of the New England bulk electric power system.

Notes: Some RSP studies investigate conditions in *Greater Connecticut*, which combines the NOR, SWCT, and CT subareas. This area has similar boundaries to the State of Connecticut but is slightly smaller because of electrical system configurations near the border with western Massachusetts. *Greater Southwest Connecticut* includes the southwest and western portions of Connecticut and consists of the NOR and SWCT subareas. NB includes New Brunswick, Nova Scotia, and Prince Edward Island (i.e., the Maritime provinces) plus the area served by the Northern Maine Independent System Administrator (USA).

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[39] The distribution of generation resources by RSP subarea is available online in the ISO's presentation, *New England System Plan System Overview*, slide 12 (March 31, 2009); http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/mar312009/a_system_overview.pdf.

2.6 Features of RSP09

RSP09 provides information about the region's 10-year electricity needs from 2009 through 2018 and outlines the status of planned, ongoing, and completed studies and transmission projects as of April 2009. RSP09 builds on the comprehensive results of the 2008 *Regional System Plan* (RSP08), which showed the need for transmission upgrades and the need for, as well as the amount, type, and location of, demand and supply resources.[40] Section 3 presents the load forecasts, and Section 4 provides an estimate of the systemwide long-term resource adequacy needs (i.e., the minimum amount of capacity the region will require). Section 4 also summarizes the capacity resource results of the second Forward Capacity Auction (FCA #2), including supply and demand resources. The section also includes the status of supply resources in the ISO Generator Interconnection Queue (the *queue*) (i.e., those generators that have submitted requests to interconnect to the ISO New England electric power system).

Section 5 discusses how to meet identified system and load-pocket needs for operating reserves through the locational Forward Reserve Market and describes the Demand-Response Reserve Pilot Program, which is testing whether demand response can contribute to operating reserves.[41]

Section 6 discusses fuel issues affecting the region and the improved natural gas supply situation. The section provides information on the natural gas system, the risks to the electric power system, and the ongoing actions to improve the reliability of the fuel supply to generators that burn natural gas. Section 7 provides an update on environmental issues associated with power plant air emissions and water discharges and renewable resources. Meeting these renewable resource policy goals most likely will result in increased amounts of variable-output renewable resources and demand-response resources. The integration issues and operational challenges of these types of resources are discussed in Section 8. Section 9 summarizes production analysis results from the "Attachment K" studies and shows the economic and environmental impacts of many varying levels of resource additions.[42]

Section 10 provides an overview of transmission planning, security, and upgrades. The section describes the status of transmission investment, transmission system performance and development, and specific transmission projects, planned and underway, including those to reduce dependence on generating units in small load pockets. Section 11 covers the status of national, interregional, and systemwide planning efforts and other initiatives for improving the reliability and security of the New England bulk power system, neighboring power systems, and the systems of the United States and North America as a whole. Section 11 also presents the status of studies supporting the New England governors' blueprint for developing renewable resources and transmission for the region. RSP09's conclusions and recommendations are presented in Section 12.

A list of acronyms and abbreviations used in RSP09 is included at the end of the report. All Web site addresses are current as of the time of publication.

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[40] *2008 Regional System Plan* (October 16, 2008); available online at http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf or by contacting ISO Customer Service at 413-540-4220.

[41] *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.

[42] The ISO *Open Access Transmission Tariff*, Section II, Attachment K, "Regional System Planning Process" (December 7, 2007) requires the ISO to conduct up to three economic studies in response to stakeholder requests for information on economic and environmental performance of the system under various expansion scenarios; http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/2-1-09_sect_ii.pdf.

Section 3
Forecasts of Annual and Peak Use of Electric Energy in New England

Load forecasts form the basis for evaluating the reliability of the bulk power system under various conditions and for determining whether and when improvements are needed. For example, lower load forecasts may defer the need for resources and transmission necessary to serve load pockets and may increase the need for transmission from export-constrained areas of the system. This section summarizes the short- and long-run forecasts of the annual and peak use of electric energy, New England-wide and in the states and subareas. The section describes the economic and demographic factors that drive the forecasts and explains the forecast methodology. It also summarizes the recent review of the ISO's forecast methodology, which reflects input from stakeholders and includes suggestions for improved transparency and technical accuracy.

3.1 Short- and Long-Run Forecasts

The ISO forecasts are estimates of the total amounts of electric energy that will be needed in the New England states annually and during seasonal peak hours. Each forecast cycle updates the data for the region's historical annual and peak use of electric energy by including an additional year of data, the most recent economic and demographic forecasts, and resettlement adjustments that include meter corrections.[43]

The current economic recession dominates the changes in the annual and seasonal peak-load forecasts. The economic analysis used by the ISO shows the New England economy starting to decline in mid-2008.[44] It forecasts the recession to reach its low point in late 2009 and the economy to begin to recover in 2010.

Table 3-1 summarizes the ISO's short-run forecasts of annual electric energy use and seasonal peak loads for 2009 and 2010. The *net energy for load* (NEL) shown in the table is the net generation output within an area, accounting for electric energy imports from other areas and electric energy exports to other areas. It also accounts for system losses but excludes the electric energy consumption required to operate pumped-storage plants. The peak loads shown in the table have a 50% chance of being exceeded and are expected to occur at a weighted New England-wide temperature of 90.4ºF (i.e., the 50/50 "reference" case). Peak loads with a 10% chance of being exceeded, expected to occur at a weighted New England-wide temperature of 94.2ºF, are considered the 90/10 "extreme" case.

[43] The ISO's Capacity, Energy, Load, and Transmission (CELT) reports and associated documentation contain more detailed information on short- and long-run forecast methodologies, models, and inputs; weather normalization; regional, state, subarea, and load-zone forecasts of annual electric energy use and peak loads; high- and low-forecast bandwidths; and retail electricity prices. They are available online at "CELT Forecasting Details 2009;" http://www.iso-ne.com/trans/celt/fsct_detail/index.html, and "CELT Report 2009;" http://www.iso-ne.com/trans/celt/report/index.html.

[44] Moody's *Economy.com* (Moody's Analytics, Inc.: Westchester, PA, 2009); http://www.economy.com/default.asp. Electricity load forecasters throughout the United States and New England use Moody's *Economy.com* economic forecasts.

Table 3-1
Summary of the Short-Run Forecasts of New England's Annual Use of Electric Energy and 50/50 Peak Loads

Parameter	2008[a]	2009	2010	% Change 2008–2009	% Change 2009–2010
Annual use of electric energy (1,000 MWh)[b] (NEL)	131,505	131,315	131,330	(0.1)	0.0
Summer peak (MW)	27,765	27,875	28,160	0.4	1.0
Winter peak (MW)[c]	22,130	22,100	22,105	(0.1)	0.0

(a) The weather-normal actual load is shown for the 2008 annual energy use and summer peak load.

(b) "MWh" refers to megawatt-hours.

(c) The winter peak could occur in the following year.

Like for the annual and seasonal peak-load forecasts, the current economic recession dominates the changes in the short-run forecast. Electric energy use is forecast to decline by 0.1% in 2009 and remain even (0.0%) in 2010. The summer peak load is forecast to grow 0.4% in 2009 and 1.0% in 2010. The winter peak load is forecast to be smaller by 0.1% in 2009 and remain the same (0.0%) in 2010.

Table 3-2 summarizes the ISO's long-run forecasts of annual electric energy use and seasonal peak load (50/50 and 90/10) for New England overall and for each state. The price of electricity and other economic and demographic factors (see Section 3.2) drive the annual use of electric energy and the growth of the seasonal peak.

Table 3-2
Summary of Annual and Peak Use of Electric Energy for New England and the States

State[a]	Net Energy for Load (1,000 MWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50		90/10			50/50		90/10		
	2009	2018	CAGR[b]	2009	2018	2009	2018	CAGR[b]	2009/10	2018/19	2009/10	2018/19	CAGR[b]
Connecticut	32,710	33,850	0.4	7,500	8,105	8,025	8,705	0.9	5,715	5,765	5,925	5,980	0.1
Maine	11,755	12,610	0.8	2,075	2,325	2,215	2,510	1.3	1,915	1,930	1,970	1,990	0.1
Massachusetts	60,420	67,095	1.2	12,925	14,455	13,765	15,445	1.3	10,030	10,505	10,365	10,840	0.5
New Hampshire	11,660	12,925	1.2	2,450	2,815	2,625	3,040	1.6	2,020	2,160	2,105	2,250	0.7
Rhode Island	8,460	9,025	0.7	1,850	2,085	2,025	2,295	1.3	1,395	1,440	1,435	1,480	0.4
Vermont	6,310	6,625	0.5	1,075	1,180	1,120	1,235	1.0	1,035	1,060	1,050	1,070	0.3
New England	**131,315**	**142,125**	**0.9**	**27,875**	**30,960**	**29,780**	**33,235**	**1.2**	**22,100**	**22,860**	**22,850**	**23,605**	**0.4**

(a) A variety of factors cause state growth rates to differ from the overall growth rate for New England. For example, New Hampshire has the fastest-growing economy in New England, and Connecticut has the slowest-growing economy in the region.

(b) CAGR stands for compound annual growth rate.

The compound annual growth rate for electric energy use is 0.9% for 2009 through 2018.[45] The CAGR for the summer peak load is 1.2% per year for 2009 through 2018, while the CAGR for the winter peak is 0.4%.

[45] The *compound annual growth rate* (CAGR) is calculated as follows:

3.2 Economic and Demographic Factors and Electric Energy Use

The ISO's forecasts of electric energy use in New England and each state are based on a total energy-use concept, which sums the total electric energy used residentially (40%), commercially (40%), and industrially (20%). Real income and the real price of electricity, which serve as proxies for overall economic and demographic conditions, are the primary factors applied to determine electric energy use. Table 3-3 summarizes these and other indicators of the New England economy.

Table 3-3
New England Economic and Demographic Forecast Summary

Factor	1980	2008	CAGR	2009	2018	CAGR
Summer peak (MW)	14,539	27,765	2.3	27,875	30,960.00	1.2
Net energy for load (1,000 MWh)	82,927	131,505	1.7	131,315	142,125	0.9
Population (thousands)	12,378	14,306	0.5	14,343	14,659	0.2
Real price of electricity (cents per kilowatt-hour [kWh], 1996 $)	11.99	11.40	(0.2)	11.71	11.71	0.0
Employment (thousands)	5,534	7,037	0.9	6,847	7,409	0.9
Real income (millions, 2000 $)	252,449	571,456	3.0	568,676	716,455	2.6
Real gross state product (millions, 2000 $)	267,595	643,217	3.2	635,864	815,095	2.8
Energy per household (MWh)	18.954	23.716	0.8	23.586	24.280	0.3
Real income per household (thousands) (2000 base year)	57.700	103.060	2.1	102.144	122.394	2.0

The forecast for 2009 to 2018 of the retail electricity price assumes increases will be held to the rate of inflation (2.1% average annual growth) and will incorporate the assumed transition costs from the FCM Settlement Agreement and assumed capacity costs from the Forward Capacity Market ($1.9 billion in 2010, decreasing to $1.75 billion in 2018).[46] The assumed capacity costs of the FCM are based on RSP08's projected systemwide requirements for installed capacity and an assumed capacity clearing price of $4.50/kW-month after adjustments for peak energy rent (PER) in 2010 and $3.60/kW-month in 2011.[47]

$$\text{Percent CAGR} = \left\{\left[\left(\frac{\text{Peak in Final Year}}{\text{Peak in Initial Year}}\right)^{\left(\frac{1}{\text{Final Year} - \text{Initial Year}}\right)} - 1\right] \times 100\right\}$$

[46] (1) The inflation rate was obtained from *Moody's Economy.com* as part of their December 2008 economic forecast. (2) The first year of service for FCM resources does not begin until June 2010, so these resources are being paid a transition payment for maintaining their availability and developing new capacity. The FCM Settlement Agreement specifies paying all capacity a flat rate until June 1, 2010. After the transition period ends, resources with capacity obligations obtained in the FCAs will be paid the Forward Capacity Auction clearing prices. (3) *Order Accepting in Part and Modifying in Part Standard Market Design Filing and Dismissing Compliance Filing*, FERC Docket Nos. ER02-2330-000 and EL00-62-039 (September 20, 2002), p. 37. For background information, see *Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues*, FERC Docket Nos. ER03-563-000, -030, -055 (filed March 6, 2006; as amended March 7, 2006). Refer to AMR08, Section 2.2 and Section 4, for more information on the FCM; http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

[47] *Peak energy rent* reduces capacity market payments for all capacity resources, typically when electricity demand is high and prices in the electric energy markets go above the PER threshold price, which is an estimate of the cost of the most expensive resource on the system. Section 4.2 contains additional information on the FCA.

The Forward Capacity Market treats and pays new demand resources and *other demand resources* (ODRs) in the transition period in a comparable manner as traditional supply resources in satisfying the Installed Capacity Requirement (ICR) values (see Section 4). Any actual load reductions from these resources that occurred in the historical period must be added back into the peak-load estimation to ensure their reductions are not double counted. The summer and winter peak forecasts account for the historical ODRs that existed in 2008—350 MW during the summer peak and 340 MW during the winter.

The *Economy.com* December 2008 economic forecast of real personal income was used as a surrogate for overall economic activity in the RSP09 forecast models. Figure 3-1 presents the forecasted real personal income and gross regional product for New England used in the RSP09 load and peak-load forecasts. The forecasts show that economic activity slowed in mid-2007 and declined sharply in 2008. The decline is forecast to reach its low point in late 2009, and a weak recovery is forecast to begin in 2010. Figure 3-2 presents historical and projected annual percent changes in real personal income for New England compared with the United States as a whole. The forecast assumes the present credit crisis is resolved and the federal economic stimulus bill, the *American Recovery and Reinvestment Act of 2009* (ARRA), passed in February 2009, is successful in turning the economy around.[48]

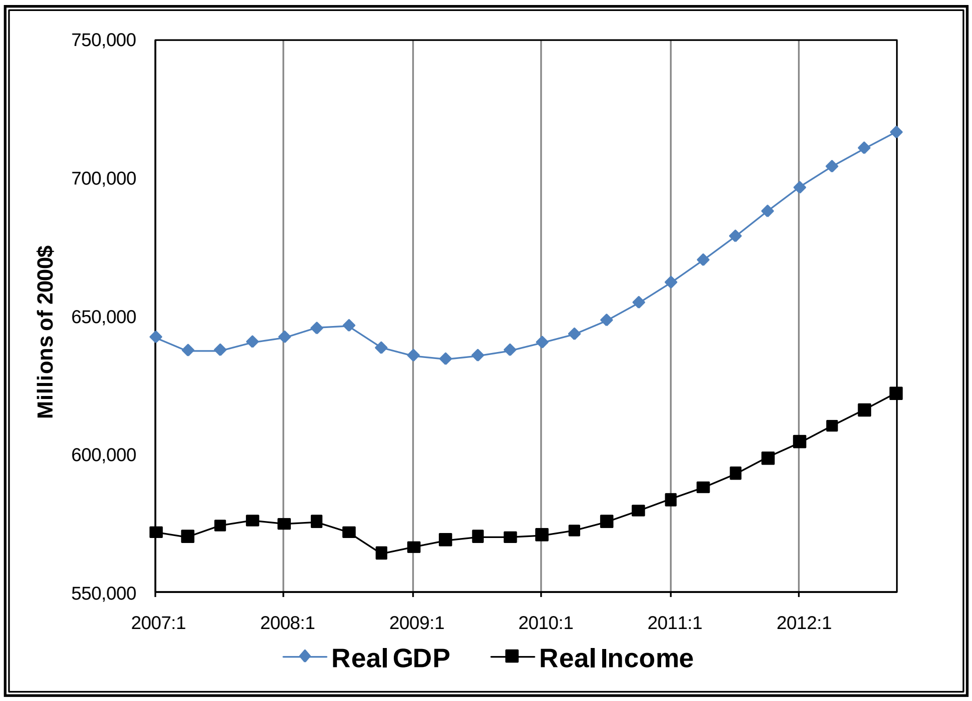

Figure 3-1: *Economy.com* forecasts of New England quarterly income and gross domestic product (millions, in 2000 $).

Source: Economy,com.

[48] (1) The *American Recovery and Reinvestment Act of 2009* (Stimulus Bill, Pub. L. 111-5, H.R. 1, S. 1) (February 17, 2009); http://www.gpo.gov/fdsys/pkg/PLAW-111publ5/content-detail.html. (2) Several articles by *Economy.com* that detail and explain its forecast are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/feb252009/index.html.

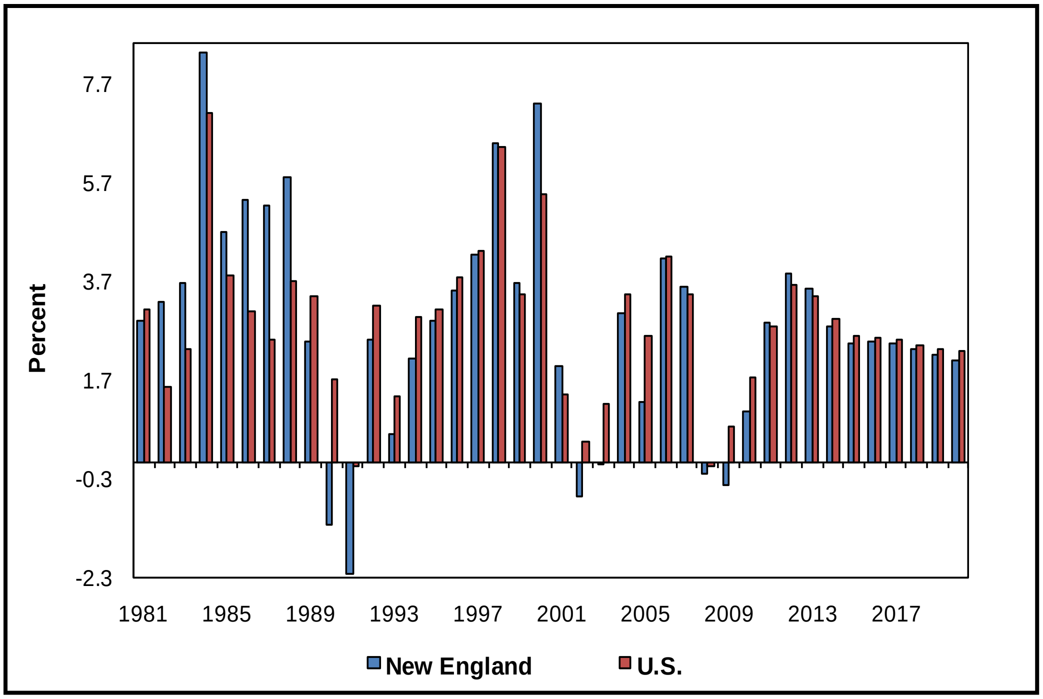

Figure 3-2: Historical and projected annual percentage changes in real personal income for New England compared with the United States as a whole.
Source: *Economy.com*. *Real Personal Income: Annual Percent Changes*

3.3 Load Forecast Methodology and Model Enhancements

As part of its continuing efforts to improve the load forecast, the ISO has made several changes to the forecast methodology. For example, the model of annual electric energy use incorporates flexible electricity price elasticity (i.e., changes in energy conservation in response to changes in electricity prices) and flexible cooling-degree-day weather elasticity (to respond to the greater penetration of air conditioning).[49]

In RSP08, the models of peak load included annual trends for the growth of the weather-sensitive and non-weather-sensitive components of seasonal peak load. These trends were estimated over the historical period for each month and each region and then incorporated into the peak econometric models. In RSP09, the following changes were made in the model to improve the quality of the load forecast:

- The annual use of electric energy replaced the trend of the non-weather-sensitive component of the peak load.
- The econometric model now directly estimates the trend of the weather-sensitive component of the peak load as opposed to calculating this component separately for each month.

[49] A *cooling-degree day* is a measurement that relates a day's temperature to the demand for electricity attributable to the use of air conditioning or refrigeration. It is an estimate of electric energy requirements and indicates fuel consumption for the air conditioning or refrigeration. Each cooling-degree day represents one degree that the daily mean temperature and humidity index are above the baseline of 65.

- The trend of the weather-sensitive component of the winter peak load growth was eliminated (it was not statistically significant).

These changes significantly simplified the model (from 120 separate equations to only 12 per region), while maintaining the weather and nonweather components of the peak, The changes also linked the nonweather component directly to electric energy use and thus economic conditions and created a better statistical fit with the historical data (reducing the standard error of the econometric model).

The forecasts of annual and peak energy use also include the impacts of new federal electric appliance efficiency standards that will go into effect in 2013 and would not be captured by the econometric models.[50]

The enhancements to the peak-energy-use models have allowed the ISO to use these models to forecast the long-run peak forecasts and to discontinue using the no-longer-applicable methodology that uses estimated load factors. Both seasonal peak models incorporate the annual use of electric energy directly. The winter peak does not have a weather-sensitive trend component, and the growth in the trend of the weather-sensitive component of the summer peak load is forecast to slow over the forecast period as the increase in air-conditioning saturations slows. The resulting annual summer-peak load factor continues its historical decline, as shown in Figure 3-3, but as the growth in the trend on the weather-sensitive component of the summer peak load slows, the trend in the load factor flattens; eventually, the trend in the load factors turns slightly positive.

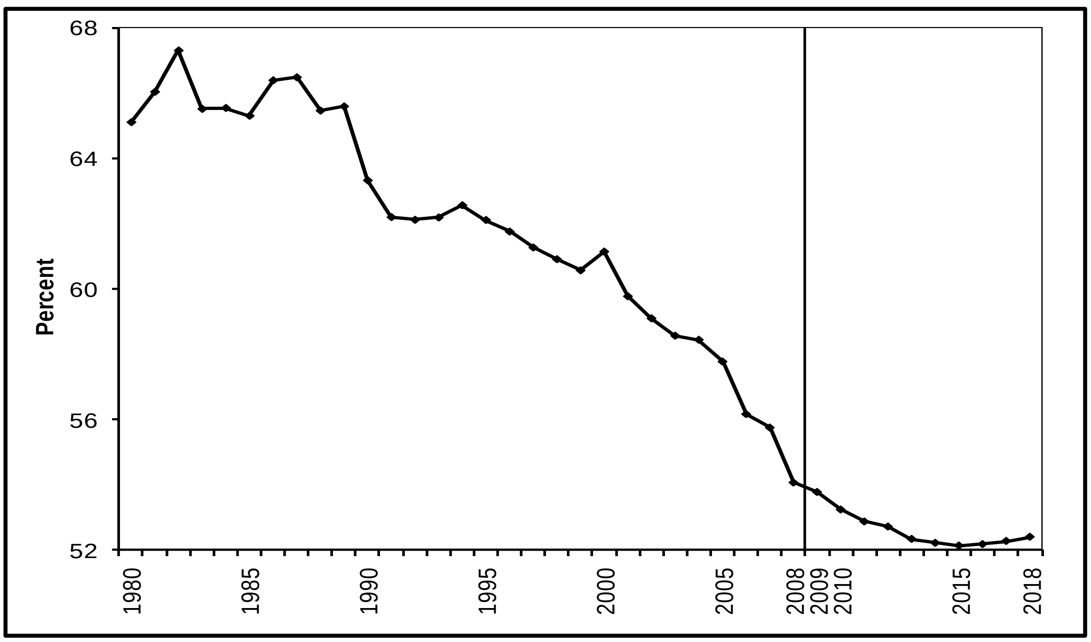

Figure 3-3: Historical and forecast annual summer-peak load factor, 1980 to 2018.

[50] Appliances and Commercial Equipment Standards Program (Washington, DC: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, April 24, 2009); http://www1.eere.energy.gov/buildings/appliance_standards/.

3.4 Subarea Use of Electric Energy

Much of the RSP09 reliability analysis depends on forecasts of the annual and peak use of electric energy in the subareas. These forecasts are summarized in Table 3-4 and provide important market information to stakeholders.[51] Table 3-5 shows the forecasts for the peak use of electric energy for the New England states and load zones. Table 3-6 shows the forecast for the RSP subareas and their relationship to the load zones and states.[52]

Table 3-4
Forecasts of Annual and Peak Use of Electric Energy in RSP Subareas, 2009 and 2018

Area	Net Energy for Load (1,000 MWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50 Load		90/10 Load			50/50 Load		90/10 Load		
	2009	2018	CAGR	2009	2018	2009	2018	CAGR	2009/10	2018/19	2009/10	2018/19	CAGR
BHE	1,880	2,010	0.7	325	350	345	380	0.8	315	325	325	335	0.3
ME	6,685	7,175	0.8	1,165	1,305	1,245	1,410	1.3	1,110	1,120	1,145	1,155	0.1
SME	3,175	3,415	0.8	585	665	625	720	1.4	490	490	505	505	0.0
NH	9,705	10,845	1.2	2,020	2,330	2,165	2,515	1.6	1,680	1,785	1,745	1,855	0.7
VT	7,130	7,720	0.9	1,265	1,400	1,330	1,480	1.1	1,195	1,240	1,220	1,265	0.4
BOSTON	26,440	28,580	0.9	5,690	6,260	6,060	6,695	1.1	4,305	4,485	4,450	4,630	0.5
CMA/NEMA	8,445	9,535	1.4	1,820	2,145	1,940	2,295	1.8	1,425	1,515	1,475	1,565	0.7
WMA	10,350	11,300	1.0	2,095	2,345	2,230	2,505	1.3	1,770	1,855	1,830	1,910	0.5
SEMA	13,495	14,670	0.9	2,945	3,270	3,140	3,505	1.2	2,250	2,345	2,325	2,420	0.5
RI	11,535	12,630	1.0	2,540	2,865	2,755	3,120	1.3	1,905	1,990	1,965	2,045	0.5
CT	15,825	16,365	0.4	3,575	3,805	3,825	4,085	0.7	2,780	2,745	2,885	2,850	(0.1)
SWCT	10,835	11,835	1.0	2,445	2,735	2,620	2,940	1.3	1,905	1,990	1,975	2,065	0.5
NOR	5,820	6,040	0.4	1,395	1,480	1,495	1,590	0.7	975	970	1,010	1,010	(0.1
ISO total	**131,315**	**142,125**	**0.9**	**27,875**	**30,960**	**29,780**	**33,235**	**1.2**	**22,100**	**22,860**	**22,850**	**23,605**	**0.4**

[51] Details of the loads are available online at the ISO Web site, "CELT Forecasting Details 2009;" http://www.iso-ne.com/trans/celt/fsct_detail/index.html. The full CELT report, *2009–2018 Forecast Report of Capacity, Energy, Loads, and Transmission,* is available online at http://www.iso-ne.com/trans/celt/report/2009/2009_celt_report_final_20090415.pdf.

[52] For additional information, refer to the pricing node tables available at the ISO Web site, "Settlement Model Information 2008;" http://www.iso-ne.com/stlmnts/stlmnt_mod_info/2008/index.html.

Table 3-5
Forecasts of Peak Use of Electric Energy for Load Zones and the New England States, 2009

Load Zone[(a)]	State	2009 Summer Peak-Load Forecast			
		50/50 Load		90/10 Load	
		MW	State Peak Load %	MW	State Peak Load %
CT	Connecticut	7,500	100	8,025	100
ME	Maine	2,075	100	2,215	100
NEMA/Boston	Massachusetts	5,615	43	5,980	43
SEMA		3,635	28	3,870	28
WCMA		3,675	29	3,915	29
	Massachusetts subtotal	12,925	100	13,765	100
NH	New Hampshire	2,450	100	2,625	100
RI	Rhode Island	1,850	100	2,025	100
VT	Vermont	1,075	100	1,120	100
Total		**27,875**		**29,775**	

(a) The total load-zone projections are similar to the state load projections and are available online at the ISO's "2009 Forecast Data File; http://www.iso-ne.com/trans/celt/fsct_detail/index.html; tab #2, "ISO-NE Control Area, States, Regional System Plan (RSP09) Subareas and SMD Load Zones Energy and Seasonal Peak-Load Forecast."

Table 3-6
Forecasts of Peak Use of Electric Energy for RSP Subareas, Load Zones, and the New England States

RSP Subarea	Load Zone[(a)]	State	2008 Summer Peak-Load Forecast					
			50/50 Load			90/10 Load		
			MW	Percentage		MW	Percentage	
				RSP Subarea	State Peak Load		RSP Subarea	State Peak Load
BHE	ME	Maine	**325**	100.0	15.9	**345**	100.0	15.8
ME	ME	Maine	1,115	95.7	53.6	1,190	95.6	53.6
	NH	New Hampshire	50	4.3	2.0	55	4.4	2.1
			1,165			**1,245**		
SME	ME	Maine	**585**	100.0	28.4	**625**	100.0	28.2
NH	ME	Maine	50	2.5	2.4	50	2.3	2.3
	NH	New Hampshire	1,900	94.1	77.6	2,035	94.0	77.5
	VT	Vermont	70	3.5	6.5	75	3.5	6.7
			2,020			**2,165**		
VT	NH	New Hampshire	340	26.9	13.9	360	27.1	13.7
	VT	Vermont	925	73.1	86.0	965	72.6	86.2
			1,265			**1,330**		
BOSTON	NH	New Hampshire	75	1.3	3.1	80	1.3	3.0
	NEMA/Boston	Massachusetts	5,615	98.7	43.4	5,980	98.6	43.4
			5,690			**6,060**		
CMA/NEMA	NH	New Hampshire	85	4.7	3.5	95	4.9	3.6
	WCMA	Massachusetts	1,735	95.3	13.4	1,850	95.4	13.4
			1,820			**1,940**		
WMA	VT	Vermont	75	3.6	7.0	80	3.6	7.1
	CT	Connecticut	80	3.8	1.1	85	3.8	1.1
	WCMA	Massachusetts	1,940	92.6	15.0	2,070	92.6	15.0
			2,095			**2,230**		
SEMA	RI	Rhode Island	155	5.3	8.4	170	5.4	8.4
	SEMA	Massachusetts	2,790	94.7	21.6	2,970	94.6	21.6
			2,945			**3,140**		
RI	RI	Rhode Island	1,695	66.7	91.6	1,855	67.3	91.6
	SEMA	Massachusetts	845	33.3	6.5	900	32.7	6.5
			2,540			**2,755**		
CT	CT	Connecticut	**3,575**	100.0	47.7	**3,825**	100.0	47.7
SWCT	CT	Connecticut	**2,445**	100.0	32.6	**2,620**	100.0	32.6
NOR	CT	Connecticut	**1,395**	100.0	18.6	**1,495**	100.0	18.6

3.5 Summary of Key Findings

The RSP09 forecasts of annual and peak use of electric energy are key inputs in establishing the system needs discussed in Sections 4 through 10. The RSP09 forecasts are lower than those for RSP08, mainly due to the current recession; the inclusion of the federal energy-efficiency standards for appliances and commercial equipment; and to a lesser degree, changes in the ISO's forecasting models of annual and peak use of electric energy:

- The recession is forecast to end by mid to late 2009 followed by weak economic growth in 2010. The economy is forecast to rebound through 2012 and then return to a long-run sustainable growth rate. The recovery assumes the resolution of the credit crisis and the success of the economic stimulus program.
- The 50/50 summer peak forecast is lower than in RSP08 by 605 MW in 2009, 800 MW in 2012, and 555 MW in 2017. The forecasts reflect the projected growth of the summer cooling load.
- The 50/50 winter peak forecast is lower than in RSP08 by 1,220 MW in 2009; 1,775 MW in 2012; and 2,200 MW in 2017. The difference from RSP08 grows over the entire forecast period because the trend of the weather-sensitive component of the winter peak has been eliminated.

Section 4
Resource Adequacy and Capacity

To ensure the New England bulk power system has adequate capacity resources to meet its reliability requirements under a wide range of existing and future system conditions, the ISO must routinely conduct a number of resource adequacy analyses. It must determine the amount of installed capacity the region needs, where capacity should be located, and the net operable capacity needed for the system overall under conditions of expected and extreme weather. These analyses provide estimates of the amounts and locations of supply and demand resources needed to ensure all requirements are met.

Before December 2006, the ISO operated an Installed Capacity (ICAP) Market for procuring the capacity needed to meet the regional ICR. In a regional settlement agreement focused on installed capacity, FERC approved the Forward Capacity Market in New England.[53] For this market, capacity is procured through annual Forward Capacity Auctions (FCAs). Each FCA procures at least the megawatt amount of capacity needed to meet the ICR established before the auction.[54] The purchased capacity will need to be available in the specified timeframe to ensure the region has adequate resources to meet regional resource needs. The first year of service for FCM resources begins in June 2010. Until that time, existing resources are being compensated with transition payments for maintaining their availability and developing capacity. Developer interest in building new resources to meet the region's capacity needs is reflected in the show of interest in FCM auctions and the ISO's Generator Interconnection Queue.

This section describes the requirements for resource adequacy over the planning period, the analyses conducted to determine specific systemwide and local-area resource adequacy needs, the results and findings of these analyses, and the region's efforts to meet the need for resources through the FCM and the ISO's Generator Interconnection Queue.

4.1 Systemwide Installed Capacity Requirement

For ensuring the system has adequate capacity resources, the ISO must first determine the regional Installed Capacity Requirement, which forms the basis of the systemwide total amount of new and existing resources that must be procured through the FCM and annual Forward Capacity Auctions. The ICR is determined using the well-established probabilistic loss-of-load-expectation (LOLE) analysis.[55] The LOLE analysis identifies the amount of installed capacity (MW) the system needs to meet the NPCC and ISO resource adequacy planning criterion to not disconnect firm load more

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[53] *Devon Power, LLC*, 115 FERC ¶ 61,340, *Order on Rehearing and Clarification*, 117 FERC ¶ 61,133 (Docket No. ER03-563, et al.) (2006). Also see *Settlement Agreement Resolving All Issues at § VIII.B* (FCM Settlement), filed in Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration and Settlement Agreement Resolving All Issues, *Devon Power, LLC, et al.* (Docket Nos. ER03-563-000, -030, -055) (filed March 6, 2006).

[54] (1) The amount procured may exceed the ICR as a result of either price floors established in the development of the FCM—in which case, all the resources offered to the market would clear below the established floor price—or because the size of the marginal resource that cleared in the auction was larger than the amount needed. The FCM rules allow for intermediate adjustments to the amount of procured capacity to account for expected changes in system conditions; see Section 4.2.2. (2) Established ICR values refer to the values that either have been approved by FERC or have been filed with FERC for approval.

[55] *Probabilistic analyses* use statistical estimates of the likelihood of an event taking place and explicitly recognize that the inputs are uncertain.

frequently than once in 10 years.[56] To meet this "once-in-10-years" LOLE requirement, a bulk power system needs installed capacity in an amount equal to the expected demand plus enough to handle any uncertainties associated with load or with the performance of the capacity resources.

The analysis for calculating the ICR for New England examines system resource adequacy under assumptions for the load forecast, resource availability, and possible *tie-line benefits* (i.e., the receipt of emergency electric energy from neighboring regions).[57] The model also accounts for the load and capacity relief that can be obtained from implementing operating procedures, including load-response programs. The ICR computation, using a single-bus model, does not consider the transmission system constraints within New England.[58] The ICR analysis models all known external firm ICAP purchases and sales, as reported in the ISO's *2009–2018 Forecast Report of Capacity, Energy, Loads, and Transmission* (2009 CELT Report).[59]

RSP09 presents the established ICR values for the 2009 through 2012 capacity commitment period and shows representative net ICR values for the 2013 through 2018 period.[60] The representative net ICR values do not indicate the amount of capacity the region must purchase but provide stakeholders with a general idea of the resource needs of the region. The assumptions used to develop the ICR values published in RSP09 were presented to and discussed thoroughly with the Power Supply Planning Committee (PSPC), the Reliability Committee (RC), and the Planning Advisory Committee.

4.1.1 ICR Values for the Transition Period Capability Year 2009/2010

Table 4-1 summarizes the ICR values for the 2009/2010 capability year. The ICR calculations assume 800 MW of total tie-line benefits emanating from the Maritimes and New York and the 1,200 MW of the Hydro-Québec Installed Capability Credit (HQICC) (the current FERC-approved level for this capability year). As shown, 2009 monthly ICRs range from a low of 31,809 MW for September 2009 to a high of 35,206 MW for October 2009. The monthly variations in the ICRs are a result of the calculation methodology and assumed system conditions.[61]

[56] Not meeting this criterion could result in a penalty, currently being developed by the NPCC, for the New England Balancing Authority Area. Additional information is available online at http://www.npcc.org/documents/regStandards/Criteria.aspx.

[57] Tie-line benefits account for both the transmission-transfer capability of the tie lines and the emergency capacity assistance that may be available from neighboring systems when and if New England would need it.

[58] A *bus* is a point of interconnection to the system. Internal transmission constraints are addressed through the modeling of local sourcing requirements (LSRs) and maximum capacity limits (MCLs); see Section 4.1.3.

[59] For the 2009 ICR calculations, the purchases and sales data are based on the values published in the ISO *2009–2018 Forecast Report of Capacity, Energy, Loads, and Transmission* (April 2009); copies of all CELT reports are located at http://www.iso-ne.com/trans/celt/index.html.

[60] (1) Representative *net ICR* values are the representative Installed Capacity Requirements for the region, minus the tie-reliability benefits associated with the Hydro-Québec Phase I/II Interface (termed HQICCs). As defined in the ISO's tariff, the *HQICC* is a monthly value that reflects the annual installed capacity benefits of the HQ Interconnection, as determined by the ISO using a standard methodology on file with FERC. The ISO calculates representative net ICR values solely to inform New England stakeholders; these values have not and will not be filed with FERC for approval. (2) A *capability year* (also referred to as a *capacity commitment* period) runs from June 1 through May 31of the following year.

[61] The detailed assumptions, methodology of simulations, and results are documented in detail in the *ISO New England Installed Capacity Requirements for the 2009–2010 Capability Year Report* (March 21, 2008); http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2008/icr2008-2009_report_final_3-21-2008.pdf.

Table 4-1
Systemwide Monthly Peak-Load Forecast, ICRs, and Resulting Reserves for the 2009/2010 Capability Year (MW)

Month	50/50 Peak Load	IC Requirements
Jun 09	24,570	31,834
Jul 09	27,875	31,821
Aug 09	27,875	31,823
Sep 09	22,070	31,809
Oct 09	18,545	35,206
Nov 09	19,925	35,204
Dec 09	22,100	34,004
Jan 10	22,100	33,991
Feb 10	21,145	33,980
Mar 10	20,130	35,160
Apr 10	17,705	35,113
May 10	20,100	35,148
Annual Resulting Reserves (calculated for August 2009)[(a)]	**14.1%**	

(a) "Resulting reserves (RRs) are the amount of capacity the system has over the expected systemwide peak demand. RRs often are expressed as a percentage of the annual 50/50 peak-load forecast. They are calculated by subtracting the 50/50 peak-load forecast for the year from the ICR and dividing that total by the 50/50 peak-load forecast. The RRs sometimes are mistakenly referred to as required reserves, although the ISO does not have a predefined required percentage for installed reserve capacity.

For the 2009/2010 capability year, the resulting reserve value is 14.1% (which reflects 800 MW of tie-line benefits and 1,200 MW of HQICC). This means New England has to carry an amount of installed capacity (or equivalent) equal to 114% of the projected 50/50 peak load for that period.

4.1.2 ICR Values for 2010/2011 through 2018/2019 Capability Years

Table 4-2 summarizes the 50/50 peak forecast, the net ICR values for the 2010/2011 and 2011/2012 capability years, and the representative net ICR values for the 2012/2013 through 2018/2019 capability years. The net ICR values for the 2010/2011 and 2011/2012 capability years reflect the latest ICR values established for those years, excluding the HQICCs. The values for the 2010/2011 and 2011/2012 capability years were approved by FERC. The ISO filed values for 2012/2013 with FERC in July 2009.[62] The representative net ICR values for 2013/2014 and beyond were calculated using the following assumptions:

[62] Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2012/2013 Capability Year (Docket No. ER09-____000) (July 7, 2009); http://www.iso-ne.com/regulatory/ferc/filings/2009/jul/er09-___-000_7-7-09_2012-2013_icr_values.pdf.

- The availability of 1,665 MW of total tie-line benefits from the three neighboring balancing authority areas of Québec, the Maritimes, and New York
- 2009 CELT Report loads
- Generating resource capability ratings and outage rates based on ratings and rates developed for calculating the ICR for the 2012/2013 capability year
- Demand-resource assumptions based on the types and amounts of capacity that have qualified as existing resources for the third FCA and availability-performance expectations developed by the Power Supply Planning Committee

Table 4-2
Actual and Representative Future New England Net Installed Capacity Requirements for 2010–2018 and Resulting Reserves

Year	Forecast 50/50 Peak	Representative Future Net ICR[(a)]	Resulting Reserves (%)
2010/2011	28,160	32,137	14.1
2011/2012	28,575	32,528	13.8
2012/2013	29,020	31,965	10.1
2013/2014	29,365	32,411	10.4
2014/2015	29,750	32,901	10.6
2015/2016	30,115	33,370	10.8
2016/2017	30,415	33,757	11.0
2017/2018	30,695	34,120	11.2
2018/2019	30,960	34,454	11.3

(a) "Representative Future Net ICR" is the representative ICR for the region, minus the tie-reliability benefits associated with the HQICCs. The ICR value for 2010/2011 reflects the value approved by FERC in its March 11, 2009, *Order Accepting Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2010/2011 Capability Year and Related Market Rule Revisions* (http://www.iso-ne.com/regulatory/ferc/orders/2009/mar/er09-640-000_3-11-09_order_accepting_icr_rev.pdf). The ICR value for 2011/2012 reflects the value approved by FERC in its November 7, 2008, *Order Accepting, With Conditions, Proposed Installed Capacity Requirement, Hydro Québec Interconnection Capability Credits, and Related Values (http://www.iso-ne.com/regulatory/ferc/orders/2008/nov/er08-1512-000_11-7-08_2011-2012_icr_order.pdf).* For the 2012/2013 capability year, the net ICR value represents the value approved by FERC in its August 14, 2009, *Filing of Installed Capacity Requirement, Hydro-Quebec Interconnection Capability Credits and Related Values for the 2012/2013 Capability Year* (http://www.iso-ne.com/regulatory/ferc/orders/2009/aug/er09-1415-000_8-14-09_accept%202012-2013%20icr.pdf). For the 2013/2014 through 2018/2019 capability years, representative net ICR values are presented reflecting the amount of capacity resources needed to meet the resource adequacy planning criterion.

As shown in Table 4-2, the annual net ICR values exhibit an increasing trend after 2011/2012 from 10.1% in 2012 to 11.3 % by 2018/2019. This increase in the percentage of resulting reserves is a result of assuming a fixed amount of tie benefits through time. As the system load increases and the tie benefits stay constant, the installed capacity needed to meet the resource adequacy planning criterion would increase as a percentage of the peak load. The percentage of resulting reserve associated with the net ICR values for 2010/2011 and 2011/2012 are 3% to 4% higher than the percentage values for the rest of the years because the RSP08 load forecasts used to calculate these net ICRs were higher than the RSP09 load forecasts used to calculate their resulting reserves' percentages.[63]

4.1.3 Other Resource Adequacy Analyses

The ISO also determines the maximum capacity limit (MCL) and local sourcing requirement (LSR) for certain load zones in New England. An *MCL* is the maximum amount of capacity that can be procured in an export-constrained load zone to meet the ICR. An *LSR* is the minimum amount of capacity that must be electrically located within an import-constrained load zone to meet the ICR. Areas that have either a local sourcing requirement or a maximum capacity limit are designated as capacity zones. These designations help ensure the capacity resources procured to satisfy the ICR can contribute effectively to total system reliability.

The representative values of LSRs and MCLs will be published in a separate report, targeted for publication by the fourth quarter of 2009.[64]

4.2 The Forward Capacity Market

The purpose of the FCM is to procure the required amount of installed capacity resources to maintain system reliability, consistent with the region's ICR. Qualified resources are procured through annual Forward Capacity Auctions governed by the market rules. The first FCA (FCA #1) took place in February 2008, procuring the capacity needed for the 2010/2011 capability year. The second FCA (FCA #2) occurred in December 2008, procuring the capacity needed for the 2011/2012 capability year. The third FCA, which will procure capacity needed for the 2012/2013 capability year, is scheduled for October 2009.

Because the first year of service for FCM resources does not begin until June 2010, existing capacity resources are being paid a transition payment from December 2006 through May 2010 for maintaining their availability and developing new capacity. During this time, all installed capacity resources will receive fixed payments based on their monthly ratings for *unforced capacity* (UCAP) (i.e., the megawatt amount of a resource or region's installed capacity that has been adjusted to account for availability). After the transition period, ICR values will be used to establish the amount of installed capacity that must be procured to meet systemwide resource adequacy needs, and resources with capacity obligations obtained in the FCAs will be paid the auction clearing prices.

This section summarizes the features of the Forward Capacity Market for procuring capacity resources.[65] It presents the results of the first and second Forward Capacity Auctions and how much

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[63] The 2011/2012 ICR was filed September 9, 2008, and was based on the 2008 load forecast: http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1512-000_9-9-08_2011-2012_icr_filing.pdf. The 2010/2011 ICR for the annual reconfiguration (not the primary FCA) was filed January 30, 2009 and also used the 2008 load forecast: http://www.iso-ne.com/regulatory/ferc/filings/2009/jan/er09-640-000_1-30-09_icr_filing.pdf.

[64] The ISO calculated representative LSR and MCL values covering 2013/2014 through 2018/2019 solely to inform New England stakeholders. These representative values will not be filed with FERC for approval. The actual LSR and MCL values for 2010/2011, 2011/2012, and 2012/2013 capability years can be found in the FERC filings at http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1512-000_9-9-08_2011-2012_icr_filing.pdf; http://www.iso-ne.com/regulatory/ferc/filings/2009/jan/er09-___-000_1-30-09_icr_filing.pdf; and http://www.iso-ne.com/regulatory/ferc/filings/2009/jul/er09-___-000_7-7-09_2012-2013_icr_values.pdf, respectively. FERC has approved the actual values.

[65] The ISO's *2008 Annual Markets Report* describes the FCM in more detail. The report is available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

capacity will be supplied by generating, import, and demand resources in the region. The effectiveness of adding new resources in various locations of the power system also is addressed.

4.2.1 The FCA Qualification Process

To enter into a Forward Capacity Auction, capacity resources must comply with the qualification and financial-assurance requirements of the FCM. Each resource type, including variable-output generation, must meet a specific set of rules for qualification to participate in the FCM. For new resources to qualify, each potential bidder of a new capacity resource must submit a predefined package of qualification materials to the ISO before each auction. Each packet specifies the location and capacity of the bidder's resources and potential projects that could be completed by the beginning of the capacity commitment period (i.e., the capability year). Table 4-3 shows the locations of new resources that cleared the first and second FCA.

Table 4-3
Total New Resources that Cleared in FCA #1 and #2, by State (MW and %)

	FCA #1		FCA #2	
State	MW	Percentage	MW	Percentage
CT	592	32.6	1,169	37.3
MA	757	41.7	243	7.8
RI	99	5.5	55	1.8
VT	121	6.7	12	0.4
NH	74	4.1	76	2.4
ME	170	9.4	49	1.5
Imports	0	0	1,529	48.8
Total	**1,813**	**100**	**3,134**	**100**

Note: The totals may not equal the sum of the rows because of rounding.

4.2.2 Forward Capacity Auction

The FCM's Forward Capacity Auctions are designed to procure capacity roughly three years (40 months) in advance of the commitment period. This lead time allows capacity suppliers to develop new capacity resources and enables the ISO to plan for these new resources.

Existing capacity resources are required to participate in the FCA and are automatically entered into the capacity auction. However, these resources may indicate a desire to be removed from the FCA by submitting a *delist* bid before the existing-capacity qualification deadline.[66] For example, high-priced capacity resources may choose to submit delist bids, indicating the resources do not want the capacity obligation below a certain price. Reconfiguration auctions also may procure any quantities not

[66] Various types of delist bids exist, including static, dynamic, permanent, export, and several others. Refer to AMR08, Section 2.2.3, for the more information on delist bids; http://www.iso-ne.com/markets/mktmonmit/rpts/index.html.

purchased in the FCA as a result of delisting at specific price thresholds.[67] These auctions allow minor quantity adjustments that reflect changes in the ICR, and they facilitate trading commitments made in the previous FCA.

Unless an existing capacity resource follows specific criteria to become delisted each year, it will be assigned a one-year capacity commitment period. New capacity that bids in the FCA can choose a capacity commitment period between one and five years. The FCM requires all new and existing capacity resources that obtain a capacity supply obligation (i.e., that clear the auction) to perform during shortage events, which occur when the region is not able to meet its load and operating-reserve requirements (see Section 4.4). Purchased resources that fail to perform during a shortage event receive reduced payments, a measure intended to improve the alignment between resource needs and available capacity.

4.2.3 Results of the Forward Capacity Auction for 2010/2011 and 2011/2012

Instead of the FCA #2 ending when supply equaled the demand in the auction, the auction ended when the established floor price of $3.60/kW-month was reached. As a result, the amount of capacity resources offered in the auction exceeded the amount of capacity needed to maintain resource adequacy in accordance with the region's net ICR. Consequently, the price that will be paid to all capacity resources was reduced for this capacity commitment period, in compliance with the market rules. The capacity clearing price of $3.60/kW-month was adjusted to about $3.12/kW-month to render a payment rate to all cleared capacity resources. This rate ensures the region does not pay more for capacity than the cost required to maintain resource adequacy.

Table 4-4 provides the capacity supply obligation totals (i.e., the total amount procured) for FCA #1 and #2. This table also includes some details on the types of capacity obligations procured, including the total real-time emergency generation (RTEG), self-supply obligation values that reflect bilateral capacity arrangements, and import capacity supply obligations from neighboring balancing authority areas.[68] Comparisons of the results of the second FCA with representative future net ICR values show when the region will need capacity or be surplus in the future. Subsequent auctions will procure resources to address any needs identified in the future.

[67] *Internal Market Monitoring Unit Review of the Forward Capacity Market Auction Results and Design Elements*, p. 15, Table 3-1, *Quantity Rule* (filed with FERC June 5, 2009); http://www.iso-ne.com/regulatory/ferc/filings/2009/jun/er09-1282-000_06-05-09_market_monitor_report_for_fcm.pdf.

[68] *Real-time emergency generation* is distributed generation the ISO calls on to operate during certain voltage-reduction or more severe actions but must limit its operation to comply with the generation's federal, state, or local air quality permit(s) or combination of permits. Real-time emergency generators are required to begin operating within 30 minutes, which results in increasing supply on the New England grid, and also to continue that operation until receiving a dispatch instruction allowing them to shut down.

Table 4-4
Summary of the First and Second FCA Obligations (MW)

Commitment Period	ICR	HQICC	Net ICR[a]	Capacity Supply Obligation	RTEG Capacity Supply Obligation	RTEG Utilization Ratio	Self-Supply Obligation	Import Capacity Supply Obligation
2010/2011	33,705[b]	1,400	32,305	34,077	875	0.686	1,593	934
2011/2012	33,439	911	32,528	37,283	759	0.791	1,696	2,298

(a) The ICR minus the HQICC is equal to the net ICR. The ICR is for the primary FCA, not the reconfiguration auction.

(b) For the second annual reconfiguration auction for this commitment period, the ICR was adjusted to 33,537 MW.

Table 4-5 contains the totals for each capacity zone. The capacity supply obligation total has been adjusted to reflect the market rule's real-time emergency-generation limit of 600 MW, which is the maximum quantity of this capacity resource type that can be counted toward the ICR. The capacity zones for both FCA #1 and FCA #2 include Maine and the "Rest-of-Pool." The auctions did not have any import-constrained capacity zones because each potential import-constrained area was determined to have sufficient existing capacity to meet the local sourcing requirements. Maine was modeled as an export-constrained capacity zone; its MCL was determined to be 3,395 MW for the second FCA.

Table 4-5
Results of FCA #1 and #2 by Capacity Zone (MW, $/kW-month)[a]

Commitment Period	Modeled Capacity Zone Name	Maximum Capacity Limit	Capacity Supply Obligation	RTEG Capacity Supply Obligation	Self-Supply Obligation	Capacity Clearing Price	Payment Rate	RTEG Payment Rate
2010/2011	Rest-of-Pool		30,572	838	1,584	4.500	4.25	2.92
2010/2011	Maine	3,855	3,505	37	9	4.500	4.25	2.92
2011/2012	Rest-of-Pool		33,468	727	1,687	3.600	3.12	2.47
2011/2012	Maine	3,395	3,815	32	9	3.600	3.12	2.47

(a) Values are rounded.

Table 4-6 shows the total capacity supply obligations (in number of resources and megawatts) procured by FCA #2 by state. The obligation amounts for each state are categorized according to resource status (i.e., new or existing resources) and capacity resource type (generation or demand resources). The table also shows the resources imported from neighboring regions.

Table 4-6
States' Capacity Supply Obligations for the 2011/2012 Capacity Commitment Period

State	Resource Status[a]	Generation[b] Number of Resources	Generation[b] Total MW	Demand[b] Number of Resources	Demand[b] Total MW	Total[c] Number of Resources	Total[c] Total MW
Massachusetts	Existing	178	13,028	183	982	361	14,010
	New	12	5	48	238	60	243
	Subtotal	**190**	**13,033**	**231**	**1,220**	**421**	**14,253**
Connecticut	Existing	94	7,199	964	734	1,058	7,934
	New	13	1,008	17	161	30	1,169
	Subtotal	**107**	**8,207**	**981**	**896**	**1,088**	**9,103**
Rhode Island	Existing	21	2,568	29	152	50	2,721
	New	3	37	11	18	14	55
	Subtotal	**24**	**2,605**	**40**	**171**	**64**	**2,776**
New Hampshire	Existing	115	4,119	32	86	147	4,205
	New	5	59	12	17	17	76
	Subtotal	**120**	**4,178**	**44**	**103**	**164**	**4,281**
Vermont	Existing	86	941	34	89	120	1,029
	New	1	0	8	12	9	12
	Subtotal	**87**	**941**	**42**	**101**	**129**	**1,042**
Maine	Existing	95	3,196	44	287	139	3,482
	New	4	48	7	1	11	49
	Subtotal	**99**	**3,244**	**51**	**287**	**150**	**3,531**
Import	Existing	na	na	na	na	6	769
	New	na	na	na	na	8	1,529
	Subtotal	**na**	**na**	**na**	**na**	**14**	**2,298**
Totals[d]	Existing	**589**	**31,050**	**1,286**	**2,329**	**1,881**	**34,149**
	New	**38**	**1,157**	**103**	**448**	**149**	**3,134**
Grand total[d]		**627**	**32,207**	**1,389**	**2,778[e]**	**2,030**	**37,283**

(a) Resource status counts new resources that chose to be treated as existing resources.

(b) Demand-resource amounts include real-time emergency generation capped at 600 MW per *Market Rule 1*.

(c) The totals include external imports.

(d) Values are rounded; the sum may not agree with the totals.

(e) The 2,278 total for demand resources reflects the 600 MW RTEG cap. An additional 159 MW of RTEGs above the cap also were procured, making the total demand resources 2,937 MW.

Several hundred demand resources, representing 2,778 MW, cleared in the second FCA. This total reflects the total RTEG market rule limit of 600 MW. An additional 159 MW of RTEGs above the 600 MW cap were procured, resulting in a total amount of demand resources of 2,937 MW. In addition, 38 new generation resources, representing 1,157 MW, are expected to be on line by June 1, 2011.

Table 4-6 shows generation resources that cleared the second FCA are predominantly located in Connecticut and Massachusetts. This suggests the FCM encourages the development of needed resources where and when they are required to meet system reliability requirements.

4.2.4 Capacity Available from Demand Resources

Three types of demand resources provide capacity in the New England Balancing Authority Area—demand resources, demand response, and other demand resources (ODRs). *Demand resources* are installed measures (i.e., products, equipment, systems, services, practices, and strategies) that result in verifiable reductions in end-use demand on the electricity network during specific performance hours. Such resources may include individual measures at individual customer facilities or a portfolio of measures from an aggregate of customer facilities. *Demand response* is a specific type of demand resource in which electricity consumers modify their electric energy consumption in response to incentives based on wholesale market prices. The type of resources categorized as *other demand resources* tend to reduce end-use demand on the electricity network across many hours but usually not in direct response to changing hourly wholesale price incentives. Demand resources of all types may provide reserve capacity and relief from capacity constraints, or they may support more economically efficient uses of electrical energy. Along with adequate supply and robust transmission infrastructure, demand resources are an important component of a well-functioning wholesale market.

The FCM demand resources that will begin delivery in the FCM's first capacity commitment period (i.e., June 1, 2010 to May 31, 2011) belong to one of two general categories: passive and active.

- **Passive projects** (e.g., energy efficiency), which are designed to save electric energy (MWh). The electric energy that passive projects save during peak hours helps fulfill ICRs. These projects do not reduce load based on real-time system conditions or ISO instructions. The FCM includes two types of passive projects:
  - **On peak**—passive, non-weather-sensitive loads, such as efficient lighting
  - **Seasonal peak**—passive, weather-sensitive loads, such as efficient heating and air conditioning (HVAC)
- **Active projects** (e.g., demand response), which are designed to reduce peaks in electric energy use and supply capacity by reducing peak load (MW). These resources can reduce load based on real-time system conditions or ISO instructions. The FCM includes two types of active projects:
  - **Real-time demand response—**active, individual resources, such as active load management and distributed generation at commercial and industrial facilities
  - **Real-time emergency generation—**active, emergency distributed generation

4.2.4.1 Demand Resources that Cleared FCA #2

Of the 2,937 MW of demand resources that cleared in FCA #2 and will count toward satisfying the ICR for the 2011/2012 delivery year, passive demand-response resources represent 983 MW, or 33%, and active demand-response resources represent 1,954 MW, or 67%. To meet the ICR requirements imposed under the market rules, the active demand-response value includes a 600 MW cap placed on the use of emergency generators. Table 4-7 shows the types and locations of demand resources that cleared in FCA #2.

Table 4-7
Demand-Resource Capacity that Cleared in FCA #2 (MW)[(a)]

Resource Type	ME	NH	VT	MA	CT	RI	Total
On-peak demand resource	26	57	69	378	125	58	**714**
Real-time demand-response resource	236	35	26	535	311	52	**1,195**
Real-time emergency-generation resource[(b)]	32	13	8	363	269	74	**759**
Seasonal-peak demand resource	0	0	0	19	248	2	**269**
Total	**294**	**106**	**103**	**1,296**	**952**	**186**	**2,937[(c)]**

(a) All megawatt values are increased to account for the reserve margin and loss factor. Totals may not equal the sum because of rounding.

(b) The use of real-time emergency-generation resources to meet the ICR is limited to 600 MW, but the 600 MW cap has not been applied to the values in this table.

(c) The 2,937 MW total of demand resources that cleared FCA #2 equals the 2,778 MW plus the 159 MW of excess RTEG that cleared in FCA #2.

The total demand-resource capacity represents approximately 9% of the representative ICR, with active resources representing approximately 5.5% of the net ICR, assuming 600 MW of RTEGs.

4.2.4.2 Demand-Response Programs

During the FCM transition period (between December 1, 2006, and May 31, 2010), the ISO is operating three reliability-activated and two price-activated demand-response programs for the New England wholesale electricity markets. The reliability-activated demand-response programs are considered capacity resources and are eligible to receive capacity transition payments. The three reliability demand-response programs are as follows:

- **Real-Time 30-Minute Demand-Response Program—**requires demand resources to respond within 30 minutes of the ISO's instructions to interrupt. Participants in this program include commercial and industrial facilities that reduce their energy consumption on instruction from the ISO and emergency generators with emissions permits that limit their use to times when reliability is threatened.
- **Real-Time Two-Hour Demand-Response Program—**requires demand resources to respond within two hours of the ISO's instructions to interrupt.
- **Real-Time Profiled-Response Program—**designed for participants with loads under their direct control capable of being interrupted within two hours of the ISO's instructions to do so. Individual customers participating in this program are not required to have an interval meter. Instead, participants are required to develop a measurement and verification plan for each of their individual customers, which must be submitted to the ISO for approval.

The real-time demand-response programs for reliability are activated during zonal or systemwide capacity deficiencies to help preserve system reliability. Because these demand-response resources are available only during capacity deficiencies, they cannot qualify as operating reserves, such as 30-minute operating reserves (see Section 5). Table 4-8 summarizes the projected total demand-response capacity based on November 1, 2008, enrollment.

Table 4-8
Capacity Assumed for Demand-Response Programs for Summer 2009

Program[a]	Load Zone	Capacity Assumed for Summer 2009 (MW)[b]	Performance Rate (%)[c]
Real-Time 30-Minute Demand Response	CT[d]	805.9	62
	SWCT[d]	370.3	51
	ME	356.0	84
	NEMA/Boston	159.4	56
	NH	72.8	74
	RI	70.4	70
	SEMA	81.6	57
	VT	34.4	90
	WCMA	129.2	65
Real-Time Two-Hour Demand Response	ME	128.9	108
	NEMA/Boston	8.3	43
	NH	3.1	46
	RI	6.9	43
	SEMA	10.6	29
	VT	3.0	48
	WCMA	25.6	47
Profiled Response	ME	11.5	0
	VT	6.2	113
Total		**1,914.0**	

(a) Additional information about these programs is available online at the ISO Web site, "DR Brochure and Customer Tools" (2009); http://www.iso-ne.com/genrtion_resrcs/dr/broch_tools/index.html.

(b) The table projects demand-response enrollment for summer 2009 based on November 1, 2008, enrollment.

(c) The performance rate is based on event response to audits on August 20–22, 2008, and one OP 4 event in NEMA/Boston on May 8, 2008.

(d) The SWCT values are included in CT values and are not double counted in the 1,914.0 MW total.

4.2.4.3 Other Demand Resources

The category of *other demand resources* (ODRs) was created with the implementation of the FCM transition period and consists of three types of resources: energy efficiency, load management, and distributed generation projects implemented by market participants at retail customer facilities. Under the market rules governing the FCM transition period, the ISO began accepting registration and qualifying ODRs as capacity resources effective December 2006. Similar to reliability-activated demand-response resources, ODRs are eligible to receive capacity transition payments.

ODRs typically are nondispatchable assets, which perform differently than real-time demand-response assets. Currently, all registered *other demand resources* operate under ODR performance hours, which are on-peak periods between 5:00 p.m. and 7:00 p.m. nonholiday weekdays in December and January, and between 1:00 p.m. and 5:00 p.m. nonholiday weekdays in June, July, and August.

As of December 2008, 61 ODR projects, representing approximately 560 MW of capacity, were registered with the ISO. The ODRs receive capacity compensation only because their electric energy value is presumed to be compensated by avoiding energy consumption and associated retail energy charges. As such, all ODR capacity values are reported in megawatts rather than in megawatt-hours.

Table 4-8 shows the number of ODR projects and the capacity for the three types. A total of 505 MW of ODRs was projected for summer 2009 and is reflected in the 2009 ICR calculations.[69]

Table 4-8
Other Demand Resource Projects and Capacity as of December 2008

Type of Other Demand Resource	Number of Projects	Capacity[(a)] (MW)
Energy efficiency	44	531
Load management	1	0.8
Distributed generation	16	28.5
Total	**61**	**560.3**

(a) All megawatt values reflect increases to account for transmission and distribution (T&D) system losses.

4.2.5 Potential Capacity Available by Reflecting Wholesale Electricity Market Costs in Retail Electricity Prices

Dynamic retail pricing refers to retail electricity rates designed to reflect daily and hourly changes in wholesale electricity prices (e.g., real-time pricing, critical-peak pricing, variable-peak pricing).[70] These types of pricing structures support market-based demand response in the New England region.

A price-responsive demand initiative is underway with stakeholders and regulators that is examining the future of these types of programs after May 31, 2010. As part of this effort, the ISO will provide information and support to the New England states, as available resources permit, and will participate in forums and proceedings on dynamic retail pricing as requested by state public utility regulators.

During FCM deliberations, stakeholders agreed that the market rules should include a tariff change that would extend the present ISO-administered load-response programs through May 31, 2010, the day before demand resources would become available pursuant to FCA #1. To allow for further study and consultation with NEPOOL stakeholders and state utility regulatory agencies, the ISO commenced discussions on price-responsive demand in October 2008. The ISO filed a report with FERC on March 27, 2009, that proposed to extend the load-response programs for energy-based resources (e.g., real-time price-response and day-ahead load-response resources eligible to receive electric energy payments) for 18 months beyond May 31, 2010. This extension would allow the ISO, in consultation with NEPOOL stakeholders and state utility regulators, to decide on a policy and program design for the future. Any market rule changes necessary to implement the extension and the

[69] More information on the ICR calculation for 2009 is available in the ISO presentation to the Reliability Committee, *Installed Capacity Requirements for 2009/2010—Results and Assumptions (Revised),* slides 17 and 18; see http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2009/feb242009/icr0910_rc_02_24_09_revised_presentation.pdf.

[70] *Critical-peak pricing* is a type of dynamic pricing whereby the majority of kilowatt-hour usage is priced according to time of use; during hours when the system is experiencing high peak demand, electric energy usage is subject to higher hourly prices. *Variable-peak pricing* is a type of time-of-use rate in which the on-peak rate changes daily to reflect average day-ahead wholesale market prices during predetermined on-peak hours.

future design would be filed with FERC in adequate time to allow such energy-based resources to continue participating in wholesale electricity markets without interruption.[71]

4.2.6 Meeting Capacity Needs

Table 4-9 shows that no additional physical capacity would be needed to meet the representative future ICR until after the 2018/2019 capacity commitment period, assuming the 37,283 MW of capacity that cleared FCA #2 with supply obligations is in commercial operation by the 2011/2012 commitment period and continues to clear in the FCA each year thereafter.

Table 4-9
Actual and Representative Future New England Net Installed Capacity Requirements for 2010–2018 and Potential Surplus ICAP

Year	Forecast 50/50 Peak	Representative Future Net ICR[(a)]	Assumed Existing ICAP[(b)]	Potential Surplus ICAP[(c)]
2010/2011	28,160	32,137	34,021	1,884
2011/2012	28,575	32,528	37,021	4,493
2012/2013	29,020	31,965	37,021	5,056
2013/2014	29,365	32,411	35,091	2,680
2014/2015	29,750	32,901	35,091	2,190
2015/2016	30,115	33,370	35,091	1,721
2016/2017	30,415	33,757	35,091	1,334
2017/2018	30,695	34,120	35,091	971
2018/2019	30,960	34,454	35,091	637

(a) "Representative Future Net ICR" is the representative ICR for the region, minus the tie-reliability benefits associated with the HQICCs. The ICR value for 2010/2011 capability year reflects the value approved by FERC in its March 11, 2009, *Order Accepting Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2010/2011 Capability Year and Related Market Rule Revisions* (http://www.iso-ne.com/regulatory/ferc/orders/2009/mar/er09-640-000_3-11-09_order_accepting_icr_rev.pdf). The ICR value for 2011/2012 reflects the value approved by FERC in its November 7, 2008, *Order Accepting, With Conditions, Proposed Installed Capacity Requirement, Hydro Québec Interconnection Capability Credits, and Related Values* (http://www.iso-ne.com/regulatory/ferc/orders/2008/nov/er08-1512-000_11-7-08_2011-2012_icr_order.pdf). For 2012/2013, the net ICR value represents the value filed with FERC in July 2009 and is pending FERC approval. For the 2013/2014 to 2018/2019 capability years, representative net ICR values are presented reflecting the amount of capacity resources needed to meet the resource adequacy planning criterion.

(b) "Assumed Existing ICAP" for 2010/2011 and 2011/2012 reflect the amount of capacity resources that have cleared the FCA for those years but with reserve-margin gross up for both New York Power Authority imports (NYPA) and demand resources removed. The 2012/2013 value is based on the 2011/2012 value. The values for 2013/2014 and beyond are based on the 2011/2012 value but with nongrandfathered ICAP imports removed and the full amount of RTEGs included. The FCM resources that cleared the FCA equal 37,283 MW. The 35,091 MW shown equals 37,283 MW of FCA cleared – 14 MW of NYPA reserve margin gross up – 407 MW of demand-resource gross up – 1,930 MW of nongrandfathered imports + 159 MW of excess RTEG.

(c) "Potential Surplus ICAP" represents an approximation of the future capacity situation, assuming no resource additions or attritions during the study period. Capacity that cleared in FCA #2, excluding the nongrandfathered ICAP imports and adjusted for other factors described in note (b), is assumed to be in service in 2012 and will continue to be in service until the end of the study period.

[71] Report of ISO New England Inc. and New England Power Pool Regarding Treatment of Price-Responsive Demand in the New England Electricity Markets (FERC Docket No. ER08-830) (March 27, 2009); http://www.iso-ne.com/regulatory/ferc/filings/2009/mar/er09-830-001_09-3-27_price_responsiveness_report.pdf.

The actual amounts of capacity to be procured through the FCM process for future years will continue to be determined according to established FCM market rules. The amount of additional capacity and the installation timing to meet the future requirements will depend on future expected system load and resource conditions. Any changes in these conditions will be reflected in future RSPs and FCAs.

FCA #3 is scheduled to take place in October 2009 to purchase capacity resources needed for the 2012/2013 capacity commitment period. Table 4-10 shows the total megawatts of qualified new resources by capacity resource type for the 2012/2013 capacity commitment period, as of July 2009, which is the date of FERC's *Informational Filing for Qualification in the Forward Capacity Market*.[72]

Table 4-10
New Capacity Qualified for FCA #3

Resource Type	MW(a)
Generation	3,675
Demand resources	555
Imports	2,422
Total	**6,652**

(a) The total includes real-time emergency-generation resources for which qualification packages were submitted. Values are effective as of June 19, 2009, before resource sponsors withdrew 845 MW of generation and 2 MW of demand resources from the auction.

Qualification for new resource participation in the Forward Capacity Market has declined slightly from FCA #2 to the qualification process for FCA #3, but it remains strong, as illustrated in Figure 4-1.

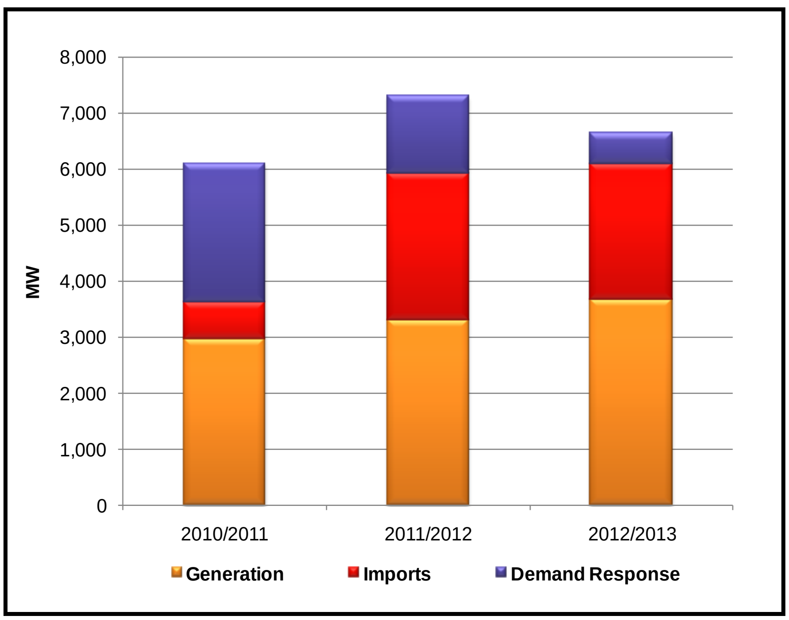

Figure 4-1: New resource qualification for participation in the FCAs.

[72] The July 7, 2009, filing, *Informational Filing for Qualification in the Forward Capacity Market,* is available online at http://www.iso-ne.com/regulatory/ferc/filings/2009/jul/er09-___-000_7-7-09_2012-2013_icr_values.pdf.

4.3 Operable Capacity Analysis

Using a deterministic approach, the ISO analyzes the systemwide operable capacity to estimate the net capacity that will be available under specific scenarios.[73] The analysis identifies *operable capacity margins* (i.e., the amount of resources that must be operational to meet peak demand plus operating-reserve requirements) under assumed 50/50 and 90/10 peak-load conditions. The results of these examinations show either a positive or negative operating margin in meeting system operating requirements. A negative margin for a specific scenario indicates the extent of possible mitigation actions that would be required through predefined protocols, as prescribed in ISO Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*, or Operating Procedure No. 7 (OP 7), *Action in an Emergency*.[74]

For RSP09, the ISO conducted a systemwide operable capacity analysis for 2010 to 2018, which did not account for RSP subareas. This section discusses the methodology used to conduct this analysis and summarizes its results.

4.3.1 Approach

The operable capacity analysis uses 50/50 and 90/10 peak-load forecasts. The systemwide capacity is the actual or the representative net ICR values for the region (the same as those listed in Table 4-2). A total of 2,000 MW of operating reserves were assumed to reflect the largest loss-of-source contingency at 1,400 MW plus one-half of a large generating unit operating at 1,200 MW or equivalently 600 MW. A total of 2,100 MW of resource outages were assumed on the basis of historical observations of the performance of supply resources. The results are a direct comparison of the operable capacity system requirements with the net ICR values.

4.3.2 Results

Figure 4-2 and Table 4-11 show the results of the systemwide operable capacity analysis. The results show that if the loads associated with the 50/50 forecast were to occur, New England could experience a negative operable capacity margin of approximately 120 MW as early as summer 2010 and would need to rely on OP 4 actions for demand and supply relief. This negative operable capacity margin would increase to approximately 1,150 MW by summer 2012 and then decrease to approximately 600 MW by summer 2018, assuming the system has no surplus capacity resources above the net ICR.

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[73] *Deterministic analyses* are snapshots of assumed specific conditions that do not attempt to quantify the likelihood that these conditions will actually materialize. The results are based on analyzing a set of conditions representing a specific scenario.

[74] Operating Procedure No. 4, *Action during a Capacity Deficiency* (March 5, 2008); http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html. Operating Procedure No.7, *Action in an Emergency* (August 19, 2008); http://www.iso-ne.com/rules_proceds/operating/isone/op7/index.html.

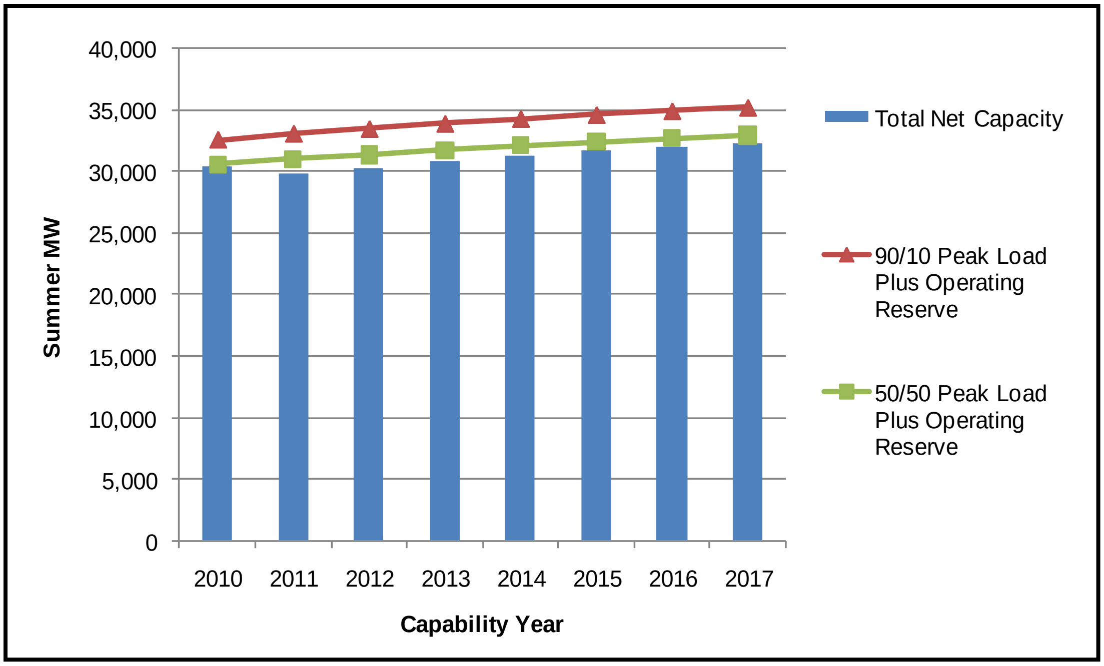


Figure 4-2: Projected New England operable capacity analysis, summer 2010–2018, assuming 50/50 and 90/10 loads (MW).

Table 4-11
Projected New England Operable Capacity Analysis for Summer 2010 to 2018, Assuming 50/50 loads (MW)

Capacity Situation (Summer MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018
Load (50/50 forecast)	28,160	28,575	29,020	29,365	29,750	30,115	30,415	30,695	30,960
Operating reserves	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Total requirement	30,160	30,575	31,020	31,365	31,750	32,115	32,415	32,695	32,960
Capacity	32,137	32,528	31,965	32,411	32,901	33,370	33,757	34,120	34,454
Assumed unavailable capacity	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)
Total net capacity	30,037	30,428	29,865	30,311	30,801	31,270	31,657	32,020	32,354
Operable capacity margin[(a)]	**(123)**	**(147)**	**(1,155)**	**(1,054)**	**(949)**	**(845)**	**(758)**	**(675)**	**(606)**

(a) "Operable capacity margin" equals "total net capacity" minus "total requirement."

Similarly, Figure 4-2 and Table 4-12 show that New England could experience larger negative operable capacity margins of approximately 2,100 MW as early as summer 2010 if the 90/10 peak loads occurred. Thus, starting in 2010, New England would need to rely on load and capacity relief from OP 4 actions under the projected 90/10 peak loads. Assuming the exact amount of resources needed to meet the once-in-10-years LOLE is purchased in the FCA, this negative operable capacity margin would increase to approximately 3,200 MW by 2012 and then decrease to approximately 2,900 MW by 2018.[75]

Table 4-12
Projected New England Operable Capacity Analysis for Summer 2010 to 2018, Assuming 90/10 Loads (MW)

Capacity Situation (Summer MW)	2010	2011	2012	2013	2014	2015	2016	2017	2018
Load (90/10 forecast)	30,110	30,580	31,075	31,470	31,900	32,305	32,635	32,950	33,235
Operating reserves	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Total requirement	32,110	32,580	33,075	33,470	33,900	34,305	34,635	34,950	35,235
Capacity	32,137	32,528	31,965	32,411	32,901	33,370	33,757	34,120	34,454
Assumed unavailable capacity	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)
Total net capacity	30,037	30,428	29,865	30,311	30,801	31,270	31,657	32,020	32,354
Operable capacity margin[a]	**(2,073)**	**(2,152)**	**(3,210)**	**(3,159)**	**(3,099)**	**(3,035)**	**(2,978)**	**(2,930)**	**(2,881)**

(a) "Operable capacity margin" equals "total net capacity" minus "total requirement."

4.3.3 Observations

On the basis of representative net ICR values, resources that cleared FCA #2 with supply obligations will be sufficient to meet the regional resource adequacy planning criterion during the 10-year study period, assuming no attrition to the existing capacity within New England and new FCM resources meet their planned in-service dates.

On the basis of the deterministic systemwide operable capacity analysis and assuming, under the FCM, the ISO purchases the minimum amount of capacity needed to meet the once-in-10-years LOLE criterion, New England will require approximately 2,000 to 3,200 MW of load and capacity relief from OP 4 actions to meet the 90/10 peak during the study period.[76]

4.4 Generating Units in the ISO Generator Interconnection Queue

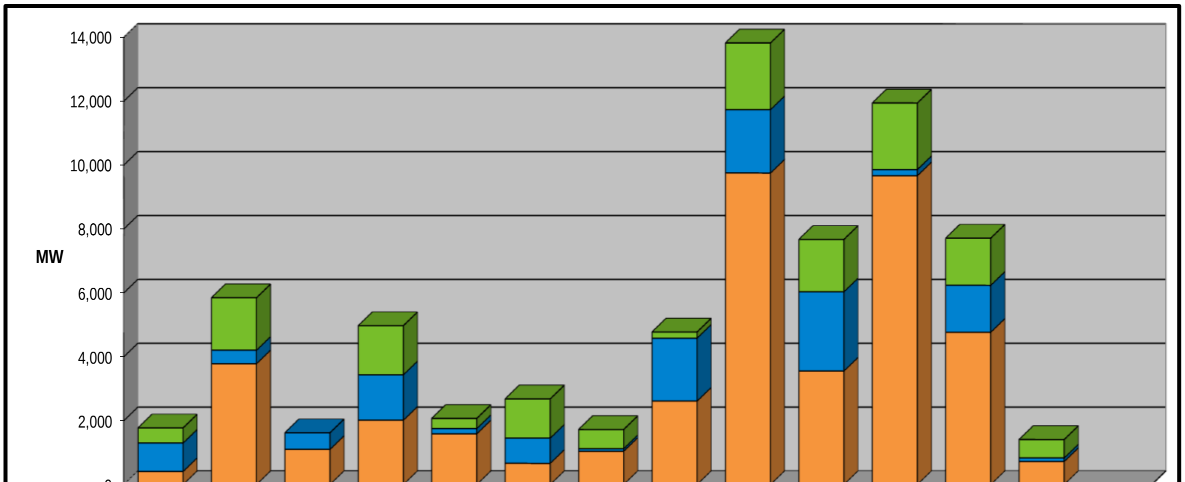
The interconnection requests in the ISO's Generator Interconnection Queue reflect the region's interest in building new generation capacity. Figure 4-3 shows the capacity of the 103 active generation-interconnection requests in the queue by RSP subarea as of March 15, 2009.[77] The four

[75] To obtain 3,200 MW of load and capacity relief, ISO system operators would need to implement Actions 1 through 13 of OP 4, which include allowing the depletion of the 30-minute and partial depletion of the 10-minute reserve (1,000 MW), scheduling market participants' submitted emergency transactions and arranging emergency purchases between balancing authority areas (1,600 MW–2,000 MW), and implementing 5% voltage reductions (600 MW).

[76] These amounts are consistent and achievable through the use of OP 4 actions that can provide over 4,200 MW through the use of tie benefits, 5% voltage reduction, and the depletion of the 10-minute operating reserve (to the minimum level of 200 MW).

[77] Projects involving only transmission or that did not increase an existing generator's capacity were excluded.

areas with the most proposed capacity additions are in the SEMA, RI, CT, and ME subareas. Together, these subareas have about 7,448 MW under development out of a total of 13,837 MW of active projects for New England. (Refer to Section 11.3.1 for a summary of a stakeholder process reviewing the queue issues.) A total of 4,132 MW is proposed for the three subareas in Connecticut, and 9,872 MW is proposed near the load centers located throughout southern New England.



	BHE	ME	SME	NH	VT	WMA	CMA	BOSTON	SEMA	RI	CT	SWCT	NOR	Total
Active	472	1,641	0	1,536	316	1,226	598	191	2,086	1,639	2,082	1,474	576	13,837
Commercial	891	422	520	1,422	165	790	81	1,971	1,985	2,480	192	1,469	111	12,499
Withdrawn	410	3,784	1,100	2,015	1,590	666	1,043	2,613	9,751	3,554	9,667	4,769	722	41,684

Figure 4-3: Capacity of generation-interconnection requests by RSP subarea.

Note: All capacities are based on the projects in the ISO Generator Interconnection Queue as of March 15, 2009, that would interconnect with the ISO system.

A summary of the projects in the queue as of March 15, 2009, is shown in Table 4-13. Since the first publication of the Generator Interconnection Queue in November 1997 through March 15, 2009, 60 generating projects (12,499 MW) out of 298 total generator applications (totaling 68,110 MW) have become commercial.[78] Since the queue's inception, proposed projects totaling approximately 41,700 MW have been withdrawn, reflecting a megawatt attrition rate of 61%. The 103 active projects in the queue as of March 15, 2009, total 13,837 MW. Figure 4-4 shows the resources in the ISO Generator Interconnection Queue, by state and fuel type, as of March 15, 2009.

[78] The projects that have been proposed but discontinued faced problems during their development associated with financing, licensing, insufficient market incentives, or other issues. More specific information on interconnection projects is available online at the ISO Web site, "Interconnection Status" (September 1, 2009); http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html.

Table 4-13
Summary of Queue Projects as of March 15, 2009

Category of Projects	Projects	Total Capacity (MW)
Commercial	60	12,499
Active	103	13,837
Withdrawn	135	41,684
Total	**298**	**68,110**

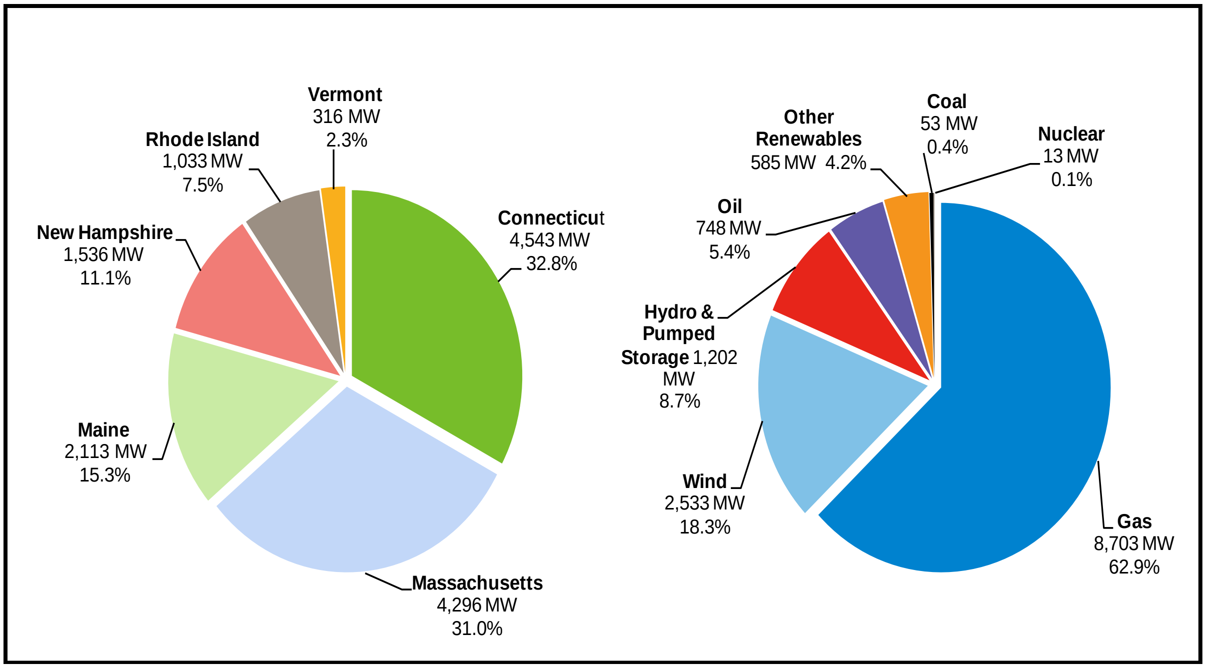


Figure 4-4: Resources in the ISO Generator Interconnection Queue, by state and fuel type, as of March 15, 2009 (MW and %).

Notes: The total for the State of Connecticut (4,543 MW) is greater than the total for the subareas, CT, SWCT, and NOR (4,132 MW; see Figure 4-3), because the area of the state is greater than the total area used for the subareas. The "Other Renewables" category includes wood, refuse, landfill gas (LFG), other bio gas, and fuel cells. The totals for all categories reflect all queue projects that would interconnect with the system and not all projects in New England.

As part of the FCA-qualification process, generators are subject to a review that evaluates whether transmission upgrades are needed to ensure the new generating capacity is incrementally useful within each capacity zone. Previous RSP and FCM studies have confirmed that interconnecting new resources close to the Connecticut, Boston, and SEMA load centers would improve the overall reliability of the system and could potentially defer the need for transmission improvements. However, individual system impact studies are necessary to fully assess the electrical performance of the system and determine reliable interconnections of generation resources.

4.5 Summary

If all the 37,283 MW of resources that cleared the second FCA are in commercial operation by 2011, New England will have adequate resources through 2018, assuming no retirements. While actual

ICRs will be determined in future years, the ISO is optimistic that adequate demand and supply resources will be purchased through the FCM auctions and will be installed in time to meet the projected capacity needs.

By design, meeting the ICR for New England could necessitate the use of specific OP 4 actions. The frequency and extent of OP 4 actions would vary based on several factors, including the amount of the net ICR, tie-line benefits, and actual system load. Study results show that the need for load and capacity relief from OP 4 actions could range from approximately 2,100 to 3,200 MW during extremely hot and humid conditions. The FCM will continue to provide incentives for developing resources in the desired quantity and needed locations. Because Forward Capacity Auctions are held more than three years in advance of the delivery period, future resources will be better known in advance, which will facilitate and improve the planning process.

Resources are being planned in needed locations near load centers. A total of 1,169 MW of the new FCM resources procured in FCA #2 are located in the Connecticut capacity zone. Of this total, 1,008 MW are new generation resources. In the ISO Generator Interconnection Queue, 4,100 MW of new resources are proposed for the Greater Connecticut subareas. In addition, demand resource programs have been implemented successfully, and future additions of demand resources have been planned as part of the FCM process.

Section 5
Operating Reserves

In addition to needing a certain level of resources for reliably meeting the region's actual demand for electricity, as discussed in Section 4, the system needs a certain amount of resources with operating characteristics that can provide operating reserves. The overall mix of resources providing operating reserves must be able to respond quickly to system contingencies stemming from equipment outages and forecast errors. These resources also may be called on to provide regulation service for maintaining operational control or to serve or reduce peak loads during high-demand conditions. A suboptimal mix of these operating-reserve characteristics could lead to the need for the system to use more costly resources to provide these services. In the worst case, reliability would be degraded.

Several types of resources in New England have the operating characteristics to provide operating reserves for responding to contingencies, helping to maintain operational control, and serving peak demand. The generating units that provide operating reserves can respond to contingencies within 10 or 30 minutes by offering reserve capability either synchronized or not synchronized to the power system. Synchronized (i.e., *spinning*) reserves are on-line reserves that can increase output. Nonsynchronized (i.e., *nonspinning*) reserves are off-line, "fast-start" resources that can be electrically synchronized to the system and quickly reach rated capability. *Dispatchable asset-related demand* (DARD) (i.e., demand that can be interrupted within 10 or 30 minutes in response to a dispatch order) also can provide operating reserves, meet or reduce peak demand, and avert the need to commit more costly resources to supply operating reserves.

This section discusses the need for operating reserves, both systemwide and in major import areas, and the use of specific types of fast-start and demand-response resources to fill these needs. An overview of the locational Forward Reserve Market (FRM) and a forecast of representative future operating-reserve requirements for Greater Southwest Connecticut, Greater Connecticut, and BOSTON are provided. This section also describes a pilot program evaluating the use of demand-response resources to provide operating reserves.

5.1 Requirements for Operating Reserves

During daily operations, the ISO determines operating-reserve requirements for the system as a whole as well as for major transmission import-constrained areas. The requirement for systemwide operating reserves is based on the two largest loss-of-source contingencies within New England, which typically consist of some combination of the two largest on-line generating units or imports on the Phase II interconnection with Québec (see Section 10.3). The operating reserves required within subareas of the system depend on many factors, including the economic dispatch of generation systemwide, the projected peak load of the subarea, the most critical contingency in the subarea, possible resource outages, and expected transmission-related import limitations. ISO operations personnel analyze and determine how the generating resources within the load pockets must be committed to meet the following day's operational requirements and withstand possible contingencies. The locational Forward Reserve Market is in place to procure these required operating reserves.

5.1.1 Systemwide Operating-Reserve Requirements

A certain amount of the bulk power system's resources must be available to provide operating reserves to assist in addressing systemwide contingencies, as follows:

- Loss of generating equipment within the New England Balancing Authority Area or within any other NPCC balancing authority area
- Loss of transmission equipment within or between NPCC balancing authority areas, which might reduce the capability to transfer energy within New England or between the New England Balancing Authority Area and any other area

The ISO's operating-reserve requirements, as established in Operating Procedure No. 8, *Operating Reserve and Regulation* (OP 8), protect the system from the impacts associated with a loss of generating or transmission equipment within New England.[79] According to OP 8, the ISO must maintain a sufficient amount of reserves during normal conditions in the New England Balancing Authority Area to be able to replace within 10 minutes the first-contingency loss (N-1) (i.e., when any power system element becomes unavailable). Typically, the maximum first-contingency loss is between 1,300 and 1,700 MW. In addition, OP 8 requires the ISO to maintain a sufficient amount of reserves to be able to replace within 30 minutes at least 50% of the second-contingency loss (N-1-1) (when a power system element is unavailable and another contingency occurs). Typically, 50% of the maximum second-contingency loss is between 600 and 750 MW.

In accordance with NERC and NPCC criteria for bulk power system operation, ISO Operating Procedure No. 19 (OP 19), *Transmission Operations*, requires the 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.[80] 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. To implement these requirements, OP 8 requires operating reserves to be distributed throughout the system. This ensures that the ISO can use them fully for any criteria contingency without exceeding transmission system limitations and that the operation of the system remains in accordance with NERC, NPCC, and ISO New England criteria and guidelines.

5.1.2 Forward Reserve Market Requirements for Major Import Areas

To maintain system reliability, OP 8 mandates the ISO to maintain certain reserve levels within subareas that rely on resources located outside the area. The amount and type of operating reserves a subarea needs depend on the system's reliability constraints and the characteristics of the generating units within the subarea. Subarea reserve requirements also vary as a function of system conditions related to load levels, unit commitment and dispatch, system topology, and special operational considerations.

Table 5-1 shows representative future operating-reserve requirements for Greater Southwest Connecticut, Greater Connecticut, and BOSTON. These estimated requirements are based on the same methodology used to calculate the requirements for the locational FRM. The estimates account for representative future system conditions for load, generation availability, N-1 and N-1-1 transfer limits, and the largest generation and transmission contingencies in each subarea. The representative values show a range to reflect load uncertainty. Actual market requirements are calculated immediately before each locational FRM procurement period and are based on historical data that

[79] ISO Operating Procedure No. 8, *Operating Reserves and Regulation* (June 5, 2009); http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html.

[80] ISO Operating Procedure No. 19, *Transmission Operations* (April 13, 2007); http://www.iso-ne.com/rules_proceds/operating/isone/op19/op19_rto_final.pdf.

reflect actual system conditions. The table also shows the existing amount of fast-start capability located in each subarea based on the fast-start resource offers into the recent FRM auctions.

Table 5-1
Representative Future Operating-Reserve Requirements in Major New England Import Areas (MW)

Area/Improvement	Market Period[a]	Fast-Start Resources Offered into the Forward Reserve Auction (MW)[b]	Representative Future Locational Forward Reserve Market Requirements (MW)	
			Summer (Jun to Sep)[c]	Winter (Oct to May)[c]
Greater Southwest Connecticut[d]	2009	402 (summer) 323 (winter)	22[e]	0
	2010		0 to 160	0
	2011		0 to 180	0
	2012		0 to 140	0
	2013		0 to 180	0
Greater Connecticut[f, g]	2009	999 (summer)[h] 1,026 (winter)[h]	1,145[e]	1,225
	2010		1,100 to 1,250	900 to 1,250
	2011		1,100 to 1,250	900 to 1,250
	2012		1,100 to 1,250	700 to 1,250
	2013		1,100 to 1,250	700 to 1,250
BOSTON[g, i]	2009	50 (summer) 367 (winter)	0[f]	0
	2010		0 to 100	0
	2011		0 to 100	0
	2012		0 to 100	0
	2013		0 to 175	0

(a) The market period is from June 1 through May 31 of the following year.

(b) These values are based on the megawatts of resources offered into the forward-reserve auction. The summer value is based on resources offered for the summer 2009 forward-reserve auction, and the winter value is based on resources offered for the winter 2008/2009 forward-reserve auction. A summary of the summer 2009 forward-reserve auction offers is available online at http://www.iso-ne.com/markets/othrmkts_data/res_mkt/cal_assump/index.html.

(c) "Summer" means June through September of a capability year; "winter" means October of the associated capability year through May of the following year (e.g., the 2009 winter values are for October 2009 through May 2010). The representative values show a range to reflect load uncertainty.

(d) Transmission import limits into Greater Southwest Connecticut reflect the in-service of the SWCT Reliability Project (Phase 2) in December 2008. The assumed N-1 and N-1-1 values are 3,200 MW and 2,300 MW, respectively.

(e) These values are actual locational forward-reserve requirements. Requirements for future years are projected on the basis of assumed contingencies.

(f) For Greater CT, the assumed values reflect an N-1 value of 2,500 MW but not the New England East–West Solution (NEEWS) project (see Section 10.3.2). The assumed N-1-1 value is 1,250 MW for 2009 and 1,300 MW for all other years.

(g) In some circumstances when transmission contingencies are more severe than generation contingencies, shedding some load may be acceptable.

(h) This value includes resources in Greater Southwest Connecticut. The amount offered to the Greater Connecticut summer 2009 locational forward 10-minute operating-reserve (LFTMOR) auction was 597 MW, and the amount offered to the winter 2008/2009 auction was 703 MW.

(i) Transmission import limits into Boston reflect the NSTAR 345 kilovolt (kV) Transmission Reliability Project (Phase II) in service in December 2008. The assumed N-1 and N-1-1 values are 4,900 MW and 3,700 MW, respectively. The operating-reserve values for NEMA/BOSTON would be lower without consideration of the common-mode failures of Mystic units #8 and #9 that were assumed to trip up to 1,400 MW because of exposure to a common failure of the fuel supply to the units.

Because the local contingency requirements in Greater SWCT are nested within CT (i.e., operating reserves meeting the Greater SWCT requirement also meet the Greater Connecticut requirement), installing the resources in the Greater SWCT area also would satisfy the need for resources located anywhere in Greater Connecticut.[81]

5.1.2.1 Greater Southwest Connecticut

The year-to-year changes in representative Forward Reserve Market requirements for Greater SWCT, as shown in Table 5-1, are a result of anticipated load growth. As a result of the completion of the SWCT Reliability Project, the import limit into this area has increased by approximately 850 MW, giving system operators more flexibility to use generation located within and outside the subarea to meet load and local 30-minute operating-reserve requirements. If maximizing the use of transmission import capability to meet demand is more economical, the subarea will require more local operating reserves to protect for the N-1-1 contingency. If using import capability to meet demand is less economical, generation located outside the subarea could be used to provide operating reserves, thus reducing operating-reserve support needed within the subarea.

As shown in Table 5-1, the 402 MW of fast-start resources in the Greater Southwest Connecticut area that had offered into last year's (2009) summer auction is more than the 0 to 180 MW needed during the 2010 through 2013 period to meet that area's local second-contingency operating-reserve requirements. The exact amount needed will depend on dispatch economics of the units inside and outside this area.

5.1.2.2 Greater Connecticut

The need for additional resources in Greater Connecticut to alleviate reliability and economic considerations can be met by adding fast-start resources, or resources with electric energy prices competitive with external resources. Greater Connecticut already has 999 MW of fast-start resources according to the amount of resources offered into the 2009 summer auction. Local summer reserve requirements are expected to remain at about 1,100 to 1,250 MW for the next several years. The additional need of 100 to 250 MW of reserves would be met through new fast-start capacity and spinning reserve capacity in Greater Connecticut. The addition of economical baseload generation within Greater Connecticut would decrease the need for reserves within that area.[82]

5.1.2.3 BOSTON

The FRM requirements for the BOSTON subarea, as shown in Table 5-1, are based on the relative economics of operating generating units within and outside the subarea. These requirements were obtained by evaluating load growth in conjunction with the increased import limits resulting from the implementation of the NSTAR 345 kV Transmission Reliability Project (Phase I and Phase II) transmission upgrades. The analysis also reflects the possible contingency of the simultaneous loss of Mystic units #8 and #9. With the increased import limits due to the completion of the NSTAR 345 kV Transmission Reliability Project Phase I and Phase II, operators will be able to optimize the use of regional generation to meet both load and reserve requirements. If the transmission lines were fully

[81] *Market Rule 1, Standard Market Design* (Section III of *FERC Electric Tariff No. 3*) (2009) defines the types of reserves that can meet these requirements; http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[82] *Baseload* generating units satisfy all or part of the minimum load of the system and, as a consequence, produce electric energy continuously and at a constant rate. These units usually are economic to operate day to day. *Intermediate-load* generating units are used during the transition between baseload and peak-load requirements. These units come on line during intermediate load levels and ramp up and down to follow the system load that peaks during the day and is at its lowest in the middle of the night. A *peaking unit* is designed to start up quickly on demand and operate for only a few hours, typically during system peak days, which amounts to a few hundred hours per year.

utilized to import lower-cost generation into BOSTON, this subarea would need to provide operating reserves to protect against the larger of either the loss of the largest generation source within the subarea or the loss of a transmission line into the subarea.[83] BOSTON has 50 MW of fast-start resources based on the summer 2009 auction. These resources plus new participants in the locational Forward Reserve Market will likely meet the local reserve requirements expected to be in the range of 0 to 175 MW during the study time frame of 2010 through 2013, depending on system conditions.

5.1.2.4 Summary of Forward Reserve Market Requirements in Major Load Pockets

Adding fast-start resources in either Greater SWCT or Greater Connecticut load pockets would provide needed operating flexibility as well as operating reserves, if the transmission interface were consistently operated near its N-1 limit to Connecticut. Alternatively, adding baseload resources that are on line most of the time in these areas would decrease the amounts of reserves required within these subareas. Boston will likely meet its locational reserve requirements through existing fast-start resources and new resources likely to participate in the locational FRM.

5.1.3 Operating Reserves for Subareas

As discussed, resources located within or outside a subarea may provide the subarea with operating reserves. The types of resources that can be used to provide operating reserves to subareas are on-line resources carrying spinning reserves, fast-start resources available within 10 or 30 minutes, and dispatchable asset-related demand. To the extent that the actual power imports into the subarea are less than the operating limit, the operating reserves may be provided from outside the subarea. This usually is the case when the subarea has sufficient in-merit generation. The remaining operating reserve must be supplied by local reserve within the subarea. These requirements may be met with DARD plus fast-start generation and additional in-merit generation operating at reduced output to provide spinning reserve (i.e., local second-contingency resources).

5.2 Demand-Response Reserves Pilot Program

The Demand-Response Reserves Pilot Program (DRR Pilot) is assessing whether the demand-response resources in New England are interested in providing a reserve product functionally equivalent to the type of reserves provided by central generating stations and combustion turbines. The program also is assessing whether these resources have the capability to provide these reserves. The program began its initial two-year phase in October 2006 and its second phase in October 2008.

5.2.1 DRR Pilot, Phase I

Phase I of the DRR Pilot program tested the ability of demand resources to reliably provide an operating-reserve-like response, while using a lower-cost communication methodology.[84] The pilot used the Internet-Based Communication System Open Solution (IBCS OS) to dispatch these resources and to provide near real-time data to system operators. Table 5-2 summarizes program participation and the number of events that occurred in the first phase of the DRR Pilot.

[83] In some circumstances, when transmission contingencies are more severe than generation contingencies, shedding some load may be acceptable.

[84] In this section, "lower cost" is measured against the Remote Intelligent Gateway (RIG) that was the ISO's standard for generation resources to receive electronic dispatch instructions when the DRR Pilot commenced in October 2006.

Table 5-2
DRR Pilot Summary Statistics, October 2006 through September 2008

Statistic	Winter 2006/2007	Summer 2007	Winter 2007/2008	Summer 2008
Participation (assets)	48	92	78	92
Participation (MW)	19.9	39.3	18.7	36.9
Number of activations	19	18	17	16
Number of statistically significant reductions	19	13	13	13

The performance of the assets participating in the first phase of the pilot was compared with that of diesel, small gas turbine, and all gas turbine generation resources for which NERC published "starting reliability" and "net output factor" performance indices as benchmarks.[85] The results, as shown in Table 5-3, indicate the similarity between the starting-reliability performance of the pilot program assets and the performance of small gas turbines, when a positive start for a demand-response asset was defined as a reduction in demand by at least 5% of the asset's committed reduction.[86] The DRR Pilot tested slightly below all the other performance benchmarks.

Table 5-3
Comparison of the Starting Reliability of DRR Pilot Program Resources with NERC Small Gas Turbines (%)

Period	DRR Pilot	NERC GADS[(a)]
Winter 2006/2007	93	91
Summer 2007	89	91
Winter 2007/2008	92	91
Summer 2008	89	91

(a) "GADS" refers to Generating Availability Data System.

A critical step in determining the amount of interruption provided by demand-response resources is the estimation of what a customer's load would have been without the actions taken. Several different methodologies for determining customer baselines were compared with the baseline methodology used in the DRR Pilot to evaluate whether different asset categories would benefit from different baseline methodologies. The analysis concluded that the present baseline with a positive and negative adjustment (based on the two hours preceding the interruption event) is the most appropriate of those analyzed.

[85] NERC uses the "starting reliability" and "net output factor" performance indices in its Generating Availability Data System (GADS). The formulae to calculate these indexes are included in the GADS *Data Reporting Instructions*, Appendix F, "Performance Indices and Equations" (2007); http://www.nerc.com/files/apd-f_Performance_Indexes_and_Equations.pdf.

[86] NERC GADS Starting Reliability = [(Actual Unit Starts/Attempted Unit Starts) x 100%]. An actual unit start is when the breaker is closed; it does not guarantee that the unit reaches full dispatch output. Therefore, the equivalent situation for demand response was set at reaching 5% of committed interruption reduction.

The early results of Phase I of the program indicated the demand resources in New England could respond to numerous interruption instructions over a season; their response was within 30 minutes; and, for some resources, response within 10 minutes might be practical. However, many issues remained to be resolved, including an improved way to measure the interruption performance during activation.

5.2.2 DRR Pilot, Phase II

On July 28, 2008, the ISO and the NEPOOL Participants Committee filed a proposal with FERC to extend the DRR Pilot program from October 1, 2008, through May 31, 2010, and to revise the program in several ways, which FERC approved in September 2008.[87] One revision allows the ISO to collect additional data to develop responsiveness metrics for demand resources and to improve the modeling of the likely real-time performance of smaller demand resources providing reserves. Another revision is supporting the design and development of a secure, lower-cost, real-time, two-way communication infrastructure for demand resources and allowing time to study and develop an appropriate plan to integrate that infrastructure into operations and the market systems.

Demand-resource performance during Phase II of the pilot will be measured using a customer baseline that will be adjusted upward or downward symmetrically depending on the customer's actual load in the two-hour period preceding the start of the activation. The symmetrical adjustments will match the customer baseline with the actual load just before the start of the activation (even if the customer's actual load is running higher or lower than normal). This change will more accurately indicate the actual load reduced during reserve activations. Beginning June 1, 2010, all demand resources registered as real-time demand resources and real-time emergency generation will have their baselines adjusted using this methodology. The event results for Phase II will be used to analyze notification lead times and the impact of weather and time-of-day on performance.

5.3 Summary of Key Findings and Follow-Up

Fast-start resources with a short lead time for project development can satisfy near-term operating-reserve requirements while providing operational flexibility to major load pockets and the system overall. Locating economical baseload generation within major load pockets decreases the amount of reserves required within the load pocket. Transmission improvements also can allow for the increased use of reserves from outside these areas. The Demand-Response Reserves Pilot program that allows demand resources to provide operating reserves will provide additional information on the performance of these resources.

[87] ISO New England Inc. and New England Power Pool, *Market Rule 1* FERC filing, *Revisions Concerning the Extension of the Demand-Response Reserves Pilot Program* (Docket No. ER08-___-000) (July 28, 2008); http://www.iso-ne.com/regulatory/ferc/filings/2008/jul/er08-1313-000-7-28-08_ddr_pilot_.pdf. FERC approval, *Tariff Revisions to Market Rule 1 Concerning the Extension of the Demand Response Reserves Pilot Program* (Docket No. ER08-1313-000) (September 9, 2008); http://www.iso-ne.com/regulatory/ferc/orders/2008/sep/er08-1313_ddr_order.pdf.

Section 6
Fuel Diversity

New England's power generation sector has had ongoing issues associated with the significant lack of fuel diversity, but actions have improved the reliability of the fuel supply and associated generator performance. Recent infrastructure enhancements to the regional natural gas systems should satisfy the needs of New England's core space heating and power generation markets for years to come. These improvements include new and expanded natural gas sources, pipelines, storage, and liquefied natural gas (LNG) facilities. The improvements in the natural gas system and the addition of dual-fuel electric power resources have reduced the historical concerns about electric power system reliability stemming from the high dependence on gas-fired generation within New England.

This section discusses the status of issues associated with resource diversity within New England and presents statistics on the current fuel mix and the amounts of electricity these fuels have generated. The section summarizes the regional infrastructure enhancements, discusses the forecast for renewable resource development, and identifies some residual fuel-related risks remaining within the generation sector that are being addressed.

6.1 2008 System Capacity and Fuel Mix

Figure 6-1 depicts New England's generation capacity mix by primary fuel type and percentage. Based on the ISO's CELT Report, the total 2009 summer (installed) capacity is forecast to be 31,443 MW with the following fuel mix:[88]

- Fossil-fuel-based generation accounts for over 70% of the installed capacity within the region
  - Natural-gas-fired generation represents the largest component at 38% (11,948 MW).
  - Oil-fired generation is second at 25% (7,743 MW).
  - Coal-fired generation is at 9% (2,788 MW).
- Nuclear generation is the third-largest component in the region at 14% (4,542 MW).
- Both hydroelectric capacity (1,694 MW) and pumped-storage capacity (1,689 MW) are at 5% each.
- Other renewable resources are at 3% (1,039 MW).[89]

Table 6-1 compares New England's generation capacity mix by fuel type to that of the nation's.

[88] *2009–2018 Forecast Report of Capacity, Energy, Loads, and Transmission* (April 2009); all the ISO's CELT reports are available at http://www.iso-ne.com/trans/celt/index.html.

[89] The renewable resources include landfill gas, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, and tire-derived fuels. LFG, which is produced by decomposition of landfill materials, either is collected, cleaned, and used for generation or is vented or flared.

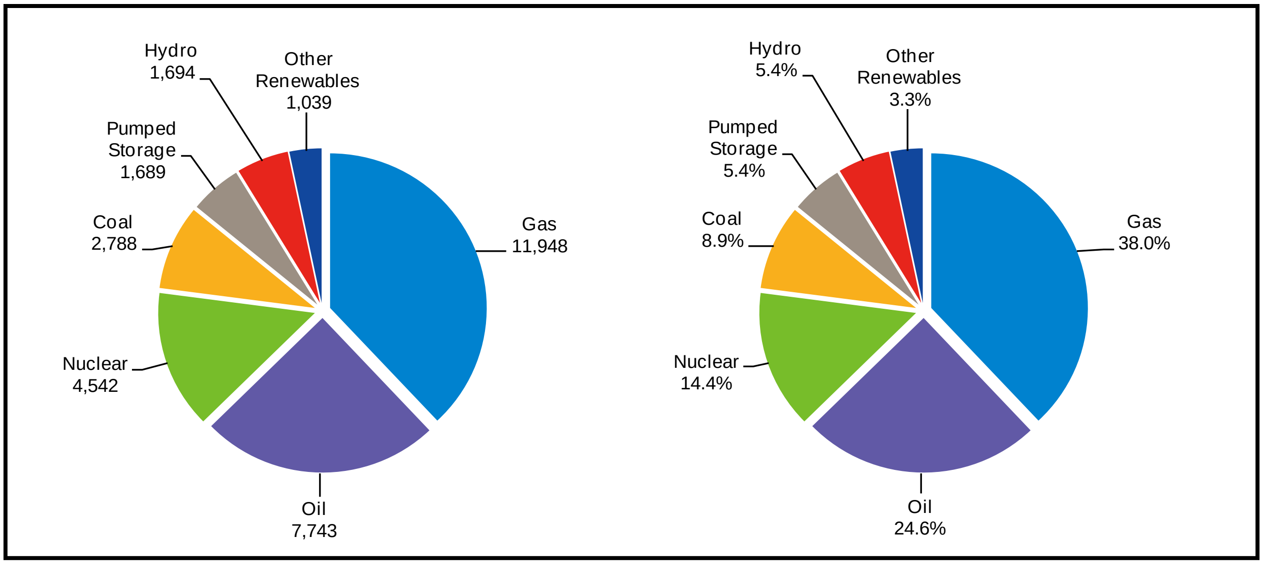


Figure 6-1: Generation capacity mix by primary fuel type, 2009 summer ratings (MW and %).
Note: The "Other Renewables" category includes LFG, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, and tire-derived fuels.

Table 6-1
New England's Generation Capacity Mix by Fuel Type
Compared with the Nationwide Capacity Mix (%)

Fuel	New England	United States
Coal	8.9	31.0
Natural Gas	38.0	39.6
Oil	24.6	5.6
Nuclear	14.4	9.9
Hydro (including pumped hydro) and other renewables	14.1	13.9

Figure 6-2 shows the production of electric energy by fuel type for 2008. As shown, natural gas, nuclear, and coal produced the majority of the region's electricity. In total, fossil fuels were used to for generating approximately 57% of the electric energy produced within New England in 2008. Natural gas generation produced the highest amount at over 51,000 gigawatt-hours (GWh) and approximately 41%. In addition, New England imported 14,243 GWh of electric energy and exported 5,004 GWh of energy, which resulted in net imports of 9,239 GWh.

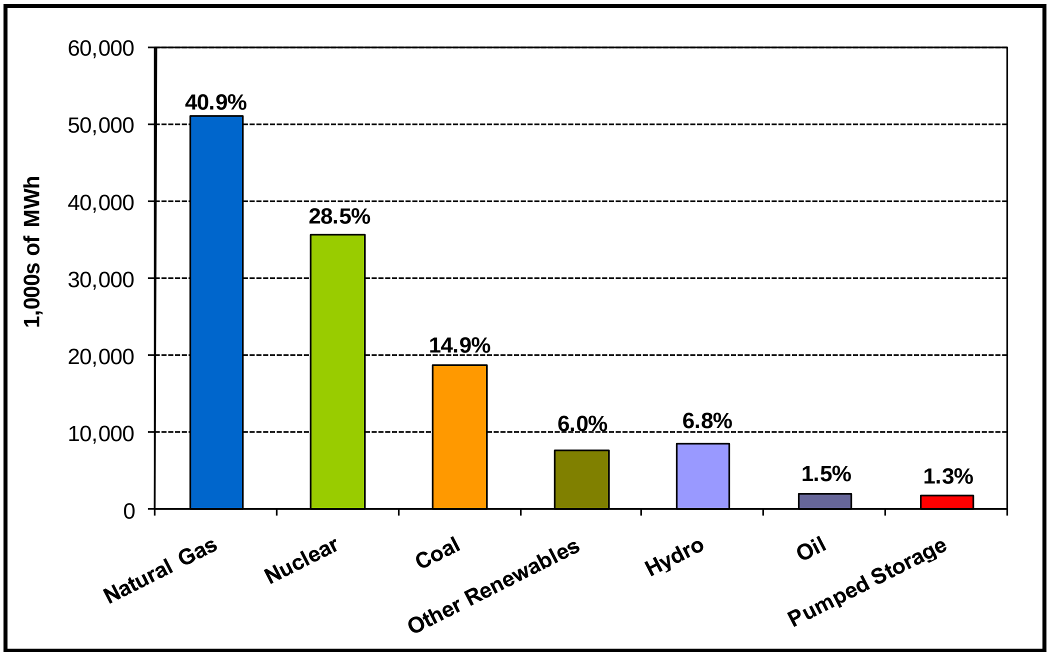


Figure 6-2: New England electric energy production by fuel type in 2008.

Notes: The "Other Renewables" category includes LFG, other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, and tire-derived fuels. The figure excludes 9,239 GWh of net imports.

Compared with the 57% of the electric energy fossil fuels produced in New England in 2008, these fuels produced 71% of the electric energy used in the United States. Nationwide, coal produced 49% compared with only 15% in New England, and natural gas produced 21% in the U.S. compared with 41% in New England. Additionally, nuclear fuel produced 20% of the nation's electric energy in 2008 compared with 29% in New England, and renewable resources provided 9% of the country's electric energy in 2008, compared with 13% in the region. Renewables, natural gas, and nuclear generation provided 50% of the electric energy nationwide in 2008; regionally, these fuels produced 82% of the electric energy.

6.2 Winter 2008/2009 Operational Overview

Winter 2008/2009 was a typical New England winter, and the system faced no major operational issues. The seasonal winter peak load of 21,022 MW took place on December 8, 2008, at 6 p.m. at 18°F. January was colder than normal, while December, February, and March were warmer than normal. The ISO did not need to implement any OP 4 actions to handle a capacity deficiency.[90] However, on two occasions, the ISO invoked Master/Local Control Center (M/LCC) Procedure No. 2, *Abnormal Conditions Alert* (MLCC2).[91] Once was on December 8, 2008, from 5:30 p.m. to 10:00 p.m. due to system capacity issues, and the second time was on December 12, 2008, from 3:30 a.m. to 10:00 p.m. due to an ice storm that hit central Massachusetts and southern New Hampshire.

[90] Operating Procedure No. 4, *Action during a Capacity Deficiency* (March 5, 2008); http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

[91] Master/Local Control Center (M/LCC) Procedure No. *2, Abnormal Conditions Alert* (March 12, 2009); http://www.iso-ne.com/rules_proceds/operating/mast_satllte/mlcc2.pdf.

The ISO issued a *Cold Weather Watch* (Appendix H of *Market Rule 1*) on January 10, 2009, for January 15 and 16 because temperatures were forecast to be well below normal.[92] However, the actual load was only 20,701 MW on January 15, which registered as the overall monthly peak load but did not require any further action. Early communication between the ISO and market participants allowed them to prepare for the approaching cold weather, and gas-fired unit availability was sufficient. Communication and coordination between the ISO and the regional gas pipeline control divisions in preparation for the cold weather was excellent. Lower oil prices at the time resulted in many oil-fired fossil units clearing in the Day-Ahead Energy Market, and no supplemental reliability commitment of units was required.

No major issues with regional fuel supplies of coal, oil, or natural gas occurred during winter 2008/2009. However, the Sable Offshore Energy Project (SOEP) experienced several unplanned outages at its natural gas production facilities near Sable Island, Nova Scotia. In another event, LNG deliveries at the Northeast Gateway Deepwater Port LNG receiving facility, located 13 miles offshore from Cape Ann, Massachusetts, were curtailed because of an unplanned outage on the connection to the HubLine Pipeline operated by Algonquin Gas Transmission (AGT). This problem started January 29 and persisted through mid-April 2009. Regional gas control centers kept the ISO well abreast of these situations. No major or prolonged fuel-supply curtailments to gas-fired units or issues associated with natural gas quality or interchangeability were reported.

6.3 Expanding Natural Gas Supply and Infrastructure

Before the 1990s, New England was served by only two interstate natural gas pipelines, Algonquin Gas Transmission and the Tennessee Gas Pipeline (TGP). The Iroquois Gas Transmission System (IGTS) was commercialized in 1992. The Portland Natural Gas Transmission System (PNGTS) and the Maritimes and Northeast (M&NE) Pipeline were both commercialized in 1999. These five major interstate natural gas pipelines make up the majority of gas transportation capacity into and within the region.

As a result of events tied to the regional cold snap that occurred in January 2004, the forecast for new LNG supplies, and the natural progression of market expansion, the natural gas industry has invested heavily in natural gas infrastructure enhancements in the northeastern United States—both in and outside New England—and in eastern Canadian markets.[93] Some of these enhancements primarily were driven by the need to deliver new LNG supplies. More recently, work has begun for gaining access to new gas supplies emanating from the Rocky Mountain basins and other new, unconventional natural gas supply sources, such as Marcellus Shale, closer to New England.[94] In addition, development continues at the Deep Panuke project in Atlantic Canada.[95]

6.3.1 New LNG Supply Projects

Currently, LNG supplies about 25% to 30% of the natural gas used within New England on a peak winter day. GDF Suez LNG North America (NA) owns and operates the Distrigas of Massachusetts

[92] FERC Electric Tariff No. 3, Section III, *Market Rule 1,* Appendix H, *Operations during Cold Weather Conditions* (effective December 8, 2006)*;* http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_appendix_h_11-27-06.pdf.

[93] *Final Report on Electricity Supply Conditions in New England during the January 14–16, 2004 "Cold Snap"* (Cold Snap Report) (October 12, 2004); http://www.iso-ne.com/pubs/spcl_rpts/2004/final_report_jan2004_cold_snap.pdf.

[94] Marcellus Shale, a geographic formation in the Appalachian basin within the eastern United States, extends from Virginia into Ohio, Pennsylvania, and New York.

[95] *Offshore—Deep Panuke* (Calgary, Canada: EnCana, 2009); http://www.encana.com/operations/offshore/.

(DOMAC) facility, which is an LNG import and storage terminal located on the Mystic River in Everett, Massachusetts.[96] It currently receives about one LNG tanker delivery per week.[97] Since beginning commercial operations in 1971, Distrigas has been serving the regional needs for both regasification services and LNG trucking. Distrigas also is the sole supply source for the Mystic #8 and #9 power generators. To date, the Distrigas LNG supply chain has not experienced any major supply or delivery interruptions. New England will soon have access to three new LNG supply sources in addition to the existing Distrigas facility.

6.3.1.1 Northeast Gateway Deepwater Port, Offshore Gloucester, MA

In May 2008, the Northeast Gateway Deepwater Port accepted its first commercial delivery of LNG. Excelerate Energy owns and operates the Northeast Gateway, which is an LNG importer and provider of regasification services.[98] The physical infrastructure of Northeast Gateway consists of a dual-submerged turret-loading buoy system with approximately 16 miles of lateral pipeline connecting into the existing HubLine Pipeline in Massachusetts Bay.

6.3.1.2 Canaport LNG, Saint John, New Brunswick

In summer 2009, a new land-based LNG import and storage facility was commercialized just outside New England. The Canaport LNG Terminal, located in Saint John, New Brunswick, is an LNG import and storage terminal with the capability to regasify approximately 1.2 billion cubic feet per day (Bcf/d).[99] Canaport's LNG is regasified and delivered through the Brunswick Pipeline for delivery into Canadian and U.S. gas markets.[100] Natural gas is delivered into the United States through the Maritimes & Northeast (M&NE) Pipeline.[101] Canaport commenced commercial operations in summer 2009.

6.3.1.3 Neptune LNG Project, Offshore Gloucester, MA

GDF Suez Energy NA currently is constructing the Neptune LNG Project (Neptune LNG LLC), which also will serve as an LNG importer and provider of regasification services.[102] The Neptune Project is similar to the Northeast Gateway Project and has a projected in-service date of the fourth quarter of 2009.

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[96](1) "GDF" stands for Gaz de France. (2) *LNG Operations* (Houston: GDF SUEZ Energy North America, 2009); http://www.suezenergyna.com/ourcompanies/lngna.shtml.

[97] This delivery rate is seasonally dynamic; natural gas is supplied to both the power generation and core gas sectors.

[98] *Northeast Gateway Deepwater Port* (The Woodlands, TX: Excelerate Energy, accessed July 23 2009); http://www.excelerateenergy.com/northeast.html.

[99] The Canaport LNG project is a Canadian Limited Partnership between subsidiaries of Irving Oil Limited (25% owner) and Respol (75 % owner). See *Canaport LNG* (Saint John, NB, Canada: Canaport LNG, 2008); http://www.canaportlng.com/index.php.

[100] More information on the Brunswick Pipeline is available online at http://www.brunswickpipeline.com/home/index.cfm.

[101] The M&NE Pipeline (http://www.mnpp.com/us/) can receive approximately 0.85 Bcf/of natural gas from Canada for delivery into New England from various Canadian supply points, which include deepwater production from the Sable Offshore Energy Project and the soon-to-be commercialized (in 2010) Deep Panuke Project, along with land-based production from Corridor Resources' McCully gas field and regasified LNG from the Canaport facility.

[102] *Suez LNG NA* (Houston: GDF SUEZ Energy North America, 2009); http://www.suezenergyna.com/ourcompanies/lngna-neptune.shtml.

6.3.2 New Pipelines and Storage

The Northeast Gas Association (NGA) maintains a list of regional natural gas pipeline, LNG, and storage projects that recently have been or are scheduled to be commercialized.[103] Some of the major projects are near to New England.

6.3.2.1 New and Expanded Pipelines

During 2008, several regional natural gas pipeline projects were completed. Some major infrastructure additions that have a direct or indirect impact on New England include the following:[104]

- 2008/2009 Expansion Phase I (Iroquois Gas Transmission System)
- Maritimes & Northeast Phase IV (Spectra Energy)
- MarketAccess Expansion (Iroquois Gas Transmission System)
- Millennium Pipeline (NiSource, DTE Energy and National Grid)
- Ramapo Expansion (Spectra Energy/Algonquin)

Some of these projects were designed to improve the deliverability of the expected new LNG supplies to regional facilities. Some projects provide access to new gas supplies, underground storage, and other (interconnected) pipelines, while other pipeline projects were designed to mitigate known constraints and maximize throughput into major market centers.

6.3.2.2 New Storage

Natural gas storage is a critical part of the natural gas supply and delivery chain. The northeast U.S. has considerable underground storage, notably in Pennsylvania (9% of the overall U.S. total) and New York.[105] While unsuitable geology prevents New England from having any underground gas storage, aboveground LNG storage could be considered the functional equivalent. Aside from some recent storage expansions in New York and Pennsylvania, new underground storage fields within New Brunswick and Nova Scotia also are being considered.

Several gas storage projects have just started and others are nearing completion. Some major infrastructure additions are as follows:

- Greyhawk Storage (6 Bcf), located in southwest New York near the Pennsylvania line, is projecting a mid-2009 in-service date.[106]
- Steckman Ridge Storage (12 Bcf), located in south-central Pennsylvania, was put into service in April 2009.[107]
- The Salt Springs Storage Project (4 Bcf) is located in south-central New Brunswick approximately 50 kilometers from Saint John. This project currently is evaluating the

[103] Northeast Gas Association (Needham Heights, MA, 2009); http://www.northeastgas.org.

[104] *Regional Market Update* (Needham Heights, MA: NGA, February 2009).

[105] *Regional Market Update* (NGA, February 2009).

[106] Planned Enhancements, Northeast Pipelines & Storage Systems (NGA, March 10, 2009).

[107] *Frequently Asked Questions about Steckman Ridge* (Houston: Spectra Energy, 2009); http://qa.spectraenergy.com/what_we_do/projects/steckman_ridge/faq.

potential for underground salt cavern storage to supplement the Canaport LNG facility or other regional Canadian production.[108]

- Other salt cavern projects currently are being evaluated near Truro, Nova Scotia.

6.4 Electric Power Sector Outlook

Resource diversity within New England is expanding. Renewable projects are under development across the region as a result of state Renewable Portfolio Standards (RPSs) (see Section 7 for information on the states' RPS targets). Almost 100 MW of new wind energy projects have been commercialized, and others are scheduled to follow. In addition, the recently enacted *American Recovery and Reinvestment Act of 2009* (ARRA) has earmarked $8.5 billion (including loan guarantees) for renewable energy research and development.[109] (See Section 9 for information on the ISO's plans for integrating renewable resources, demand resources, and smart grid technologies.)

6.4.1 Lower Natural Gas and Oil Prices

One historical issue has been the volatility of natural gas prices because they routinely set the price of regional wholesale electric power.[110] Seasonal and weather variations, coupled with natural disasters, created historical volatility in wholesale natural gas prices across the nation.[111] In early to mid-2008, world oil prices increased dramatically, resulting in a proportional increase in natural gas prices.[112] This primarily was because natural gas is considered a "replacement" or "substitute" fuel for oil within both the industrial and power generation sectors. Within New England's natural gas spot markets, $15.00/million British thermal units (MMBtu) was a typical asking price in the middle of 2008, even during equilibrium conditions, compared with an average of approximately $4.00/MMBtu in April and May 2009.[113]

However, with the economic downturn, as consumer demand decreased and business activity slowed, inventories increased, and world oil and natural gas prices (LNG) fell accordingly. As of April 8, 2009, regional spot-market natural gas prices were in the $4.00 to $4.50/MMBtu range, which is almost a four-fold decrease from peak 2008 prices. As a result of this price volatility, system planners in both the natural gas and electric power industries must recalculate their forecast assumptions and sensitivities, although most economists project natural gas prices to grow at a minimal pace in the near-term (refer to Section 3).

6.4.2 Improved Supply Infrastructure, Including Renewables

Like the regional natural gas industry's infrastructure development (discussed in Section 6.3), the power generation sector also is being improved and expanded. As shown in Figure 4-4, most of the

[108] The project's in-service date is 2011/2012 and has an initial storage capacity of approximately 4 Bcf and the potential for multicavern storage expansion to 15 to 18 Bcf or more over 10 years.

[109] The *American Recovery and Reinvestment Act of 2009* (Stimulus Bill, Pub. L. 111-5, H.R. 1, S. 1) (February 17, 2009). http://www.wealthdaily.com/articles/renewable-energy-stimulus/1706.

[110] AMR08, Section 1.1 and 3.3.6.4 (June 16, 2009); http://www.iso-ne.com/markets/mktmonmit/rpts/other/amr08_final_061709.pdf.

[111] *2005 Annual Markets Report*, Sections 1.3 and 3.1.4.4 (ISO New England, June 1, 2006); http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2005/index.html. Also see AMR08, Sections 1.1.4 and 3.3.2.

[112] During the week of July 4, 2008, the average price of imported crude oil was $142.52/barrel. This price declined to $32.98/barrel in the last week of 2008 (AMR08, Section 1.1.5).

[113] AMR08, Sections 1.1.5 and 3.1.4.

projects in the ISO's Generator Interconnection Queue (as of March 15, 2009) either are renewable or gas-fired projects.[114] For the 13,837 MW of new resources that have requested interconnection studies, 3,143 MW are renewable projects, and 8,703 MW are gas-fired projects.[115] Several factors have been instrumental in encouraging the development of renewable generation projects. These include the states' Renewable Portfolio Standards and related programs (discussed in Section 7), which have increasing targets over the next 10 years for the amount of electricity renewable sources of energy must provide; tax incentives; and environmental regulations that increase the relative costs of electric energy production by fossil-fueled generation.

The gas-fired projects in the queue should be able to take advantage of the surplus natural gas supplies that will be made available from regionally expanded pipelines, which will connect new LNG projects and other new supplies, such as shale-gas basins. The fast-start and fast-ramping characteristics of the newer, gas-fired units will be able to balance the "ebb and flow" of intermittent energy output expected to come from future renewable projects (i.e., wind). To achieve the goal of reliably dispatching this electrical generation, natural gas must be provided when and where it is needed. Additional intraday gas nomination and confirmation cycles would improve the reliability of fuel supply to electric power generating units, which the North American Energy Standards Board (NAESB) has examined.[116] This change in the nomination cycles also would increase the flexibility of natural-gas-fired generators to vary their output in real time, which is necessary to facilitate the addition of variable-output resources, such as wind generation.

6.4.3 Adequate Dual-Fuel Capacity

In recent years, the number of single-fuel, gas-only generators that have invested in dual-fuel capability has increased.[117] These generators typically burn natural gas as their primary fuel but can switch to fuel oil if needed. Although, for some generators, switching from using one fuel source to another is a complex process, being dual-fuel capable provides reliability benefits when primary fuel supplies are constrained.

Of the approximately 40% of the New England generators that use natural gas as their primary fuel, about one-third are dual-fuel capable and use fuel oil as their secondary fuel source. In total, about 25% of New England's overall generation (over 7,500 MW) comprises dual-fuel units that can burn a combination of natural gas and heavy or light oil as both a primary or secondary fuel source.

6.5 Residual Risks

Over the past few years, several operational events have occurred in New England that revealed reliability issues associated with the interrelationships of the natural gas and electric power markets.

[114] ISO New England *Interconnection Status* (July 1, 2009); http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html.

[115] This includes projects that are proposing direct interconnection to the ISO system. The renewables include wind, small hydro, LFG, biomass, and fuel cells.

[116] Currently, NAESB requires natural gas transmission companies to make offers in a minimum of four natural gas nomination and confirmation cycles over a two-day period—two offers day ahead and two offers intraday (i.e., day-ahead timely, day-ahead evening, intraday #1, and intraday #2).

[117] Since the occurrence of the January 2004 cold snap, over 2,600 MW of single-fuel, gas-only stations have added secondary (liquid) fuel capability. (Cold Snap Report; http://www.iso-ne.com/pubs/spcl_rpts/2004/final_report_jan2004_cold_snap.pdf.)

Although the ISO and regional stakeholders have worked together to address most of these risks, some issues emanating from these events still remain.

6.5.1 Resource Commitment Uncertainties

The ability of gas-fired resources to meet their Day-Ahead Energy Market or Reserve Adequacy Analysis (RAA) commitments depends on their ability to nominate appropriate levels of fuel in advance of the operating day.[118] The differences between how the natural gas and electric industries schedule energy in advance of the operating day are further compounded by a fundamental difference between the operating day requirements for delivering natural gas and electric power. These differences pose little problem during most days, when electric energy margins and operational flexibility within the pipelines are sufficient. However, in very cold conditions or during contingencies on the regional gas grid, pipelines usually have limited capacity to serve customers with nonfirm contracts. Under these conditions, fuel deliveries are scheduled by contract priority and must be balanced between previously nominated quantities and delivered volumes. These natural gas scheduling and balancing requirements can restrict fuel deliveries to gas-fired generation, which then can limit gas-fired energy production. These issues can add complexity to dispatch decisions required to ensure that energy production is sufficient for meeting electric power demand. The ISO is evaluating modifications to the existing market rules to mitigate these risks.

6.5.2 Unforeseen Events in Real-Time Operations

Unplanned events that have an impact on the regional pipeline systems, coupled with the general inflexibility of the regional generation fleet to deliver fast-start, off-line operating reserves, directly affect bulk power system operations. The loss of supply, pipeline maintenance, and compressor failures can create conditions that temporarily reduce pipeline capacity. Because of pipeline reliability requirements, unscheduled gas deliveries to the electric power sector, as required for the start up of peaking units to provide 10-minute or 30-minute reserves (see Section 5), cannot always be accommodated.[119] Pipeline operational flow orders also may limit the ability of fast-start, gas-fired units to come on line and ramp up at nominal response rates or the ability of those units (once on line) to nominate incremental gas supply (for increased energy production) in response to an ISO dispatch instruction. Collectively, these issues can decrease the quantity and quality of operating reserves used to ensure bulk power system reliability or to provide backup for wind generation and other types of intermittent resources. The ISO is examining the existing market rules and the potential for modifications to the rules for mitigating these risks.

6.5.3 Gas Quality and Interchangeability

Given the expected increase in the use of imported LNG to supplement North American domestic gas supplies and based on the historical composition of domestic natural gas, new gas supplies may not be

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[118] As part of its Reserve Adequacy Analysis process, the ISO may be required to commit additional generating resources to support local-area reliability or to provide contingency coverage, which ensures that the system reliably serves all levels of cleared, anticipated, and actual demand; the required operating-reserve capacity is maintained; and transmission line loadings are safe. For this process, the ISO evaluates the set of generator schedules produced by the Day-Ahead Energy Market solution, any self-schedules that were submitted during the reoffer period, and the availability of resources for commitment near real time. The ISO will commit additional generation if the Day-Ahead Energy Market generation schedule, plus the self-scheduled resources and available off-line fast-start generation, does not meet the real-time forecasted demand and reserve requirements that ensure system reliability. See the ISO's AMR08 for additional information on the RAA.

[119] Pipeline reliability requirements call for maintaining pipeline conditions between minimum- and maximum-allowable operating pressure (MAOP).

fully interchangeable with existing supplies, which could have an adverse impact on end-use customers. On June 15, 2006, FERC issued a *Policy Statement on Natural Gas Quality and Interchangeability*, which delineated five guidelines and mandated that each natural gas pipeline's gas-quality tariff be updated to address the interchangeability of domestic and foreign gas supplies.[120] Some natural gas interchangeability issues are still being evaluated.

New England already has experienced gas-quality issues that have disrupted power plant operation.[121] In June 2008, an 800 MW combined-cycle (CC) power plant experienced four events in which output was either curtailed or lost as a result of fuel-related problems. In this case, the problem was due to the sensitivity of the newer gas-fired generation technologies to variations in the heat (Btu) content within the gas stream.[122] The natural gas and electric industries both are exploring several options to minimize these risks.

6.5.4 LNG Supply Risks

LNG supply risks stem from the potential market diversion of LNG shipments to other geographic regions as a result of the price variations created by international competition for LNG supply. Some of these “destination-flexible” LNG cargoes already have been diverted to more profitable markets around the globe. LNG projects that lack storage capability, specifically deepwater port projects, may be the first facilities to be affected by global differentials in LNG prices. Firm contracts between gas suppliers and end-use customers help minimize these risks and ensure the continued delivery of fuel.

6.5.5 Communication Barriers

The ability to operate the system reliably depends, in part, on the ISO’s ability to forecast demand, monitor operating conditions, and respond to contingencies. This requires recognizing possible limitations on fuel deliveries to generating resources, while accounting for other potential contingencies that temporarily could restrict these deliveries or other regional fuel supplies. This risk calls for improved coordination and communication between regional fuel suppliers and the electric power industry.

The ISO has taken several steps to more closely track the regional natural gas systems by subscribing to the natural gas pipelines’ electronic bulletin board (EBB) notices, which provide notifications about pipeline operating conditions. Although the ISO already has a good working relationship with all the gas control divisions of the regional pipelines, more training and coordinated interindustry drills would improve existing communication protocols. The ISO and the NGA currently are exploring these opportunities.

6.5.6 Price Exposure

In response to many of the natural-gas-related reliability issues the ISO encountered over the past few years, it has subsequently developed and implemented remedial measures to successfully manage

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[120] *Policy Statement on Natural Gas Quality and Interchangeability* (Docket No. PL04-3) (Washington, DC: FERC, June 15, 2006); http://elibrary.ferc.gov/idmws/docket_sheet.asp.

[121] Transmittal from the New England Power Generators Association (NEPGA) to Richard P. Sergel, President and Chief Executive Officer (CEO) of NERC (December 17, 2008).

[122] (1) Typically, the newer class of dry low NO_X (DLN), gas-fired combustion turbines is rated as “GE F-Class” and higher. (2) This can also be considered a “rate-of-change” issue.

possible fuel-shortage events.[123] The combined effects of a number of these measures, as follows, have diminished the operational risks associated with the high dependence on natural gas by New England's electric power generation sector:

- Direct engagement and interaction with regional stakeholders
- Improvements to market rules and procedures
- New interindustry coordination and communications protocols
- Prominent infrastructure additions within both sectors

Although most operational risks have been mitigated, economic risks remain because, in New England, the wholesale price of natural gas has a direct impact on the wholesale price of electric power. In 2008, natural-gas-fired generation set the LMP 62% of the time.[124] These wholesale electric energy prices were closely correlated with the regional price of natural gas.

6.5.7 Other Fuel-Supply Risks

Several other components to the regional fuel supply chains, in addition to the natural gas industry, can have an impact on the electric power sector. Problems within regional oil markets, for both heavy and light oil; constraints on transporting and importing coal; problems within the nuclear fuel cycle; or a combination of several of these problems can have an impact on New England's electric power operations and wholesale markets, albeit at diminished levels compared with the risks associated with the natural gas sector.

6.6 Summary

While natural gas remains the dominant fuel in New England's electric power system, the region's gas resource diversity has improved. This was the result of two new LNG terminals going into commercial operation and a third one scheduled to be operational in late 2009. In addition, new pipeline expansion projects have been designed to improve the ability to deliver LNG to the region. Also, two new gas storage projects in the Northeast have been operating this year, adding 18 Bcf of storage capacity in the Northeast region.

Regional gas prices on the spot market, which reached about $15/MMBtu in mid-2008, have dropped more than 70% to approximately $4/MMBtu in spring 2009. Oil has shown a similar pattern but typically remains more costly than gas on the basis of thermal equivalency. To help mitigate the dependency on natural gas as a single fuel when gas prices are high or supplies are scarce, about 30% of the region's gas-fired generating plants have dual-fuel capability to switch to oil for a short period of time.

Contingencies on the gas supply and transmission system could limit gas supply to generators anytime of the year. Effective communications between gas and electric industry operations help mitigate these and other reliability concerns, as shown by the winter 2008/2009 operating experience.

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[123] In response to the cold snap of January 2004, *Market Rule 1*, Appendix H (*Operations during Cold Weather Conditions*) was developed. In response to the oil and gas infrastructure damage in the Gulf of Mexico from hurricanes Katrina and Rita in fall 2005, ISO Operating Procedure No. 21 (OP 21), *Actions during an Energy Emergency*, was developed; http://www.iso-ne.com/rules_proceds/operating/isone/op21/index.html.

[124] AMR08, Section 3.3.6.4; http://www.iso-ne.com/markets/mktmonmit/rpts/index.html.

Differences in electric power and gas industry scheduling operations could lead to supply risks. Additional intraday gas nomination and confirmation cycles would further improve the reliability of fuel supply to electric generating units.

Gas quality and interchangeability are an emerging concern as more LNG is imported, which can bring different gas compositions that can affect the operation of some types of gas turbines. The natural gas and electric power industries are exploring options to minimize potential problems due to varying gas quality.

Section 7
Update of Environmental Policy Issues

This section discusses in detail the regulatory developments that have occurred since the publication of RSP08 associated with the environmental issues that could affect the power system over the next 10 years. [125] It provides updates on the U.S. *Clean Air Interstate Rule* (CAIR); carbon dioxide (CO_2) cap-and-trade programs, particularly the Regional Greenhouse Gas Initiative (RGGI,); and the Renewable Portfolio Standards (RPSs) and related programs of the New England states. It also summarizes complex analyses of how the region might comply with these regulations. Refer to RSP08, Section 8, for further discussion of these and other environmental topics that affect the electric power sector.

7.1 Clean Air Interstate Rule Update

The Environmental Protection Agency (EPA) established the *Clean Air Interstate Rule* in March 2005 to reduce precursors to ozone (O_3) and particulates over 28 eastern states (including Connecticut and Massachusetts) and the District of Columbia. CAIR's objective is to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_X), both of which contribute to the formation of fine particulates. NO_X emissions also contribute to the formation of ground-level ozone. CAIR was intended to cap nitrogen oxide (NO_X) emissions at 1.5 million tons starting in 2009 and at 1.3 million tons in 2015. CAIR also capped SO_2 levels.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the entire *Clean Air Interstate Rule* because it found a number of flaws with the rule.[126] However, on December 29, 2008, the court reversed its July decision and reinstated CAIR indefinitely until the U.S. Environmental Protection Agency (EPA) amends the rule or parties appeal the court's decision.

Connecticut and Massachusetts are the only two affected states in New England that would be required to reduce emissions under the CAIR NO_X cap during the ozone season, which is May through September. They had been relying on the provisions of CAIR to develop their own compliance rules and had been proceeding with CAIR compliance plans. Generators in these states also have been taking steps for compliance with these CAIR rules. Connecticut and Massachusetts are not subject to CAIR's annual SO_2 cap and annual NO_X cap.

The planning assumptions the ISO has been using in its production cost simulation studies assume the implementation of CAIR. The ISO will continue to monitor and evaluate developments relating to CAIR and any impacts this decision could have on New England stakeholders.

7.2 Carbon Dioxide Cap-and-Trade Update

In April 2007, the U.S. Supreme Court ordered EPA to evaluate CO_2 as a potential pollutant to regulate.[127] On April 17, 2009, EPA issued an Endangerment Finding that CO_2 and five other

[125] *2008 Regional System Plan*, ISO New England (October 16, 2008); http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf.

[126] North Carolina v. EPA, No. 05-1244, Slip Op. (D.C. Cir., July 11, 2008); http://pacer.cadc.uscourts.gov/docs/common/opinions/200807/05-1244-1127017.pdf.

[127] Massachusetts et al. Petitioners v. EPA et al. (No. 05-1120), 549 U.S. 497 (Decided April 2, 2007); http://www.supremecourtus.gov/opinions/06pdf/05-1120.pdf.

greenhouse gas (GHG) emissions are pollutants that threaten public health and welfare.[128] This means EPA has the responsibility to address the impact of GHGs and may regulate CO_2 similar to other air pollutants. The court ruling allows EPA to regulate GHGs, even if Congress does not take such action. The U.S. Congress currently is considering a number of bills with cap-and-trade features for major reductions in CO_2 and other greenhouse gases.

Four New England states recently have passed legislation, as summarized in Table 7-1, setting short-term and long-term multisector goals for reducing GHGs.

Table 7-1
New England States' Legislated Goals for GHG Reductions

State	Baseline Year	Reductions from Baseline Year				
		2010	2012	2020	2028	2050
CT	1990			Min. 10%		Min. 80% below 2001 levels
MA	1990			10–25%		80%
VT	1990		25%		50%	75%, if practicable
ME	1990	1990 levels		10%		75–80% below 2003 levels, if required
RI	Bill pending in the legislature					
NH	No legislation					

On June 2, 2008, Connecticut passed *An Act Concerning Connecticut Global Warming Solutions*.[129] This act requires the state to reduce GHG emissions at least 10% below 1990 levels by 2020 and at least 80% below 2001 levels by 2050. The act requires the governor's Steering Committee on Climate Change to issue an assessment in 2009 of the impacts of climate change on the state and then issue recommendations in 2010 on ways to reduce these impacts. On August 7, 2008, Massachusetts passed *the Global Warming Solutions Act*.[130] This act sets a greenhouse gas emissions limit of at least 80% below 1990 levels by 2050 and requires the Massachusetts Executive Office of Energy and Environmental Affairs, in consultation with the Departments of Environmental Protection and Energy Resources (by January 1, 2011) to set a 2020 statewide greenhouse gas emissions limit of between 10 and 25% below 1990 levels and a plan to achieve that limit. Interim 2030 and 2040 emissions limits must maximize the ability to meet the 2050 emissions limit. Vermont has set GHG goals of a 25% reduction by 2012 and a 50% reduction by 2028 from a 1990 baseline. Maine set a goal to reduce GHG emissions to 1990 levels by 2010 and 10% below those levels by 2020. These four states have yet to fully promulgate regulations for achieving these goals, and the potential impacts of these laws on the reliability and economics of the bulk electric power system are uncertain.

[128] "EPA News Release, April 17, 2009; http://yosemite.epa.gov/opa/admpress.nsf/0/0EF7DF675805295D8525759B00566924.

[129] *An Act Concerning Connecticut Global Warming Solutions* (Connecticut HB 5600; Public Act No. 08-98) (June 2, 2008); http://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm.

[130] *An Act Establishing the Global Warming Solutions Act* (Chapter 298 of the Massachusetts Acts of 2008; S.2540) (August 7, 2008); http://www.mass.gov/legis/laws/seslaw08/sl080298.htm.

7.2.1 Regional Greenhouse Gas Initiative

On January 1, 2009, the RGGI cap on CO_2 emissions from fossil fuel generating plants rated 25 MW or greater took effect in 10 states in the Northeast, including all the New England states. The annual 10-state cap is 188 million (short) tons through 2014. Each state is allocated a share of the allowances, as shown in Table 7-2, that make up the cap on the basis of historical emissions and negotiations.[131] From 2015 to 2018, the cap decreases 2.5% per year, or a total of 10% by 2018 to 169.3 million tons. At that time, the allocation of CO_2 emission allowances for the New England states would be reduced to 50.2 million tons.

Table 7-2
RGGI State Annual Allowance Allocations for 2009 to 2014

State	CO_2 Allocation Million (Short) Tons
Connecticut	10.70
Maine	5.95
Massachusetts	26.66
New Hampshire	8.62
Rhode Island	2.66
Vermont	1.23
New York	64.31
New Jersey	22.89
Delaware	7.56
Maryland	37.50
Total RGGI	**188.08**
Total New England	**55.82**

RGGI was implemented through individual state regulations. These regulations require 127 fossil fuel generating units in New England rated 25 MW or greater and administered by the ISO to have RGGI allowances to cover their CO_2 emissions over a three-year compliance period, the first one being 2009 to 2011. The first three-year compliance-period "true-up" deadline is March 1, 2012, for the compliance period ending December 31, 2011.[132] Plans call for quarterly auctions, and as of July 2009, RGGI, Inc. has held four allowance auctions: two in 2008 and two in 2009. Table 7-3 shows the results of these auctions for the 10 RGGI states combined.

[131] Under RGGI, one allowance equals the limited right to emit one ton of CO_2.

[132] The *true-up deadline* is the date by which RGGI-affected entities must have allowances and any offsets in their RGGI "allowance account" to cover their level of emissions from the previous three-year period.

Table 7-3
RGGI Allowance Auctions through the Second Quarter of 2009[a]

Date	2009 Allowances Sold for 2009–2011 (Tons)[b]	Clearing Price ($)	2012 Allowances Sold for 2012–2014 (Tons)[b]	Clearing Price ($)
Sep 25, 2008	12,565,387[c]	3.07	–	–
Dec 17, 2008	31,505,898	3.38	–	–
Mar 17, 2009	31,513,765	3.51	2,175,513	3.05
Jun 17, 2009	30,887,620	3.23	2,172,540	2.06
Total	**106,472,670**		**4,348,053**	

(a) Under RGGI, an allowance is the limited right to emit one ton of CO_2.

(b) Any unused allowances purchased in one auction can be carried forward to the next compliance period (i.e., banked).

(c) The number of allowances sold is lower since not all states participated in this first auction.

The New England states auctioned varying percentages of their RGGI allocations ranging from 71 to 100% with most being close to 100%. Generally, the New England states expect to use 70 to 100% of the proceeds from the auctions for energy-efficiency programs and other clean energy investments. The New England states holding the remaining allowances plan to use them for various purposes.

A total of 106.5 million 2009 allowances and 4.3 million 2012 allowances have been sold in the four auctions. For the New England states, these auctions yielded a total of $111 million in new revenue. Each of the two remaining 2009 quarterly auctions is scheduled to be held in September and December.

The generators affected by RGGI are responsible for acquiring the allowances they need based on their projected operation and corresponding CO_2 emissions over the three-year period. For the three auctions held, generators purchased over 80% of the allowances, and they may use the secondary market to supplement the allowances obtained from the RGGI auctions. Secondary market prices have been higher than the 2008–2009 auction prices but under $4/ton.[133]

7.2.2 Federal and Regional Initiatives

On June 26, 2009, the U.S. House of Representatives passed climate legislation based on a proposed bill by U.S. Representatives Edward Markey and Henry Waxman.[134] The bill provides a framework for debate and sets emissions caps for reducing GHGs 17% by 2020 from a 2005 baseline, 42% below the baseline by 2030, and 83% below the baseline by 2050.

Another cap-and-trade initiative under development is the Western Climate Initiative (WCI), which covers six GHGs.[135] While both the RGGI and WCI programs are potential models for an eventual

[133] "Market Comment," Carbon Market North America, *Point Carbon News*: Vol. 4 Issue 11 (March 20, 2009); http://www.pointcarbon.com/news/cmna/1.1081890.

[134] *Carbon Analysis: Climate Bill Passes House* (New York: Evolution Markets, July 1, 2009); http://new.evomarkets.com/pdf_documents/ANALYSIS:%20Climate%20Bill%20Passes%20House.pdf.

[135] (1) WCI includes the following states and Canadian provinces: Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, British Columbia, Manitoba, Ontario, and Quebec. See *Design Recommendation for the WCI Cap-and-Trade Program*, September 23, 2008; http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20432.PDF (prices here are based on conversion from metric tons to U.S. tons). The document also includes historical trading prices for carbon allowances in the European Union. (2) The six gases are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

federal cap-and-trade program, the WCI more comprehensively covers GHG emission sources in the economy, and it covers a much larger geographic region: seven western states and four Canadian provinces. The WCI GHG emissions to be capped would be about 1,000 million tons of CO_2 equivalent (compared with RGGI's 188 million tons).[136] The WCI cap would begin in 2012 and seek a 15% reduction in GHG from 2005 levels by 2020, somewhat similar to the federal proposal.

7.2.3 Future Allowance Prices, Impacts, and Issues

Future prices of CO_2 allowances are of major interest to the region, and several projections have been made. A 2008 report by Synapse Energy Economics provided low-, mid-, and high-range projections of yearly prices for CO_2 allowances from 2013 to 2030 in 2007 dollars.[137] The 2013 low estimate in the report is $10/ton, and the high estimate, for 2018, is $41/ton.

A recent PJM study examined the impact of CO_2 allowance prices on PJM wholesale electric energy prices in 2013.[138] The study simulated prices of CO_2 allowances on the basis of government agency studies of three federal legislative proposals for cap-and-trade programs. Separate studies of these proposals by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE) and EPA modeled CO_2 allowance prices ranging from $10 to $60/ton.[139] For comparison, RSP08 simulations (see Section 9 of this report) used a base price projection of $10/ton and a high price of $40/ton for the simulation years 2009 to 2018. These assumptions are within the range of estimates in the Synapse report but are not as high as the highest price of the government studies used as a basis of the PJM analysis.

The impact of allowance prices on the wholesale electricity market is that generators need to recover their CO_2 allowance cost in their energy market bid price similar to what they already do for the cost of SO_2 and NO_X allowances. Coal plants are the highest CO_2-emitting fossil fuel plants, and with a $4/ton allowance cost for CO_2, the added cost for a typical coal plant would be about $4/MWh. Similarly, natural gas combined-cycle (NGCC) plants also emit CO_2, and a $4/ton allowance cost would add about $2/MWh for these plants. If CO_2 allowance prices increased substantially to $30 to $40/ton, the economic production cost margin that makes the existing dispatch of coal plants less expensive compared with natural gas plants would collapse. This has the potential to reduce overall electric energy production by coal plants and affect the economics of their continued operation. Several measures available through RGGI afford generators some compliance flexibility, including buying more allowances in the RGGI auctions, using early-reduction and banked RGGI allowances, and acquiring offsets from within the RGGI states and outside the RGGI region.[140] RGGI would

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[136] *Equivalent* means converting the volume outputs of all GHG emissions to be able to compare their CO_2 global warming potential.

[137] D. Schlissel, et al., *Synapse 2008 CO_2 Price Forecasts* (Cambridge, MA: Synapse Energy Economics, July 2008); http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf.

[138] "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market;" http://www.pjm.com/documents/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx.

[139] See (1) U.S. DOE, EIA, *Energy Market and Economic Impacts of S.280*, the *Climate Stewardship and Innovation Act of 2007*, January 2008 (http://www.eia.doe.gov/oiaf/servicerpt/csia/pdf/sroiaf(2007)04.pdf) and associated output files (http://www.eia.doe.gov/oiaf/servicerpt/csia/index.html); and (2) U.S. EPA, *EPA Analysis of the Climate Stewardship and Innovation Act of 2007*, July 16, 2007 (http://www.epa.gov/climatechange/downloads/s280fullbrief.pdf) and associated spreadsheets with outputs (http://www.epa.gov/climatechange/downloads/dataannex.zip).

[140] Early-reduction RGGI allowances are those resulting from CO_2 reductions made before 2009 and recognized by RGGI. Early-reduction allowances can be banked, similar to the extra allowances purchased for previous and current compliance periods beyond what is needed for compliance.

allow the use of more offsets, if allowance prices rose above the price triggers of $7/ton and $10/ton. In addition, RGGI can expand the categories of allowable offset projects.

RGGI's impact on fossil fuel plant costs could result in a reduction in the number of hours fossil fuel plants operate. More expensive allowances could affect the reliability of the bulk electric power system in New England and the 10-state RGGI region as a whole. For example, a lack of liquidity in the allowance market, the retirement of allowances, higher energy combustion than forecast, or poor operation of carbon-free resources could lead to a shortage of allowances or offsets in the marketplace. Not having enough of the allowances or offsets RGGI requires could restrict the number of hours that plants could operate. While post-consumption SO_2 and NO_X control measures, such as scrubbers for SO_2 and selective catalytic reduction (SCR) for NO_X, serve to limit allowance prices, no such control options currently exist for CO_2. If they did, they could set a ceiling price on CO_2 allowances.

A potential RGGI issue discussed in RSP08 was "leakage," and RGGI is waiting for data from the NEPOOL Generation Information System (GIS) of imports and exports before addressing this matter.[141] If a federal cap-and-trade program were implemented, this issue would likely be resolved, assuming the federal regulations recognized carbon regulations in Canada.

Section 9 shows the results of simulations that include SO_2, NO_X, and CO_2 emissions for the "Attachment K" economic studies of the New England generation system from 2010 to 2018, the last year of the RGGI cap reduction.[142] These results, discussed in more detail in that section, show potential economic and environmental benefits of injecting variable amounts of renewable and low-emitting resources into the New England grid.

7.3 Update on Power Plant Cooling Water Issues

As discussed in RSP08, *Clean Water Act*, Section 316b (dealing with cooling water intake requirements) requires a significant reduction of the impacts of impingement and entrainment of aquatic organisms in existing power plants. The reduction measures must reflect the use of best available technology (BAT). The BAT requirements are implemented when the existing National Pollution Discharge Elimination System (NPDES) permits for power plants expire and subsequently are renewed, providing the opportunity to include the current BAT requirements. Currently, EPA provides guidance on renewal individually, permit by permit.

On April 1, 2009, the U.S. Supreme Court delivered an opinion that benefit/cost analyses could be used in determining the BAT permit requirements, which can significantly affect the outcome of deciding the BAT cooling intake requirements.[143] Without considering benefit/cost, existing generating plants potentially would need to retrofit cooling towers to meet these requirements. One New England plant's recent NPDES permit renewal requires cooling towers or alternatives with an equivalent performance.

[141] *Leakage* refers to an increase in lower-cost, imported power from non-RGGI control areas (i.e., Canada, the non-RGGI part of PJM, etc.). The concern is that this could increase the CO_2 emissions in New England by higher-carbon-emitting plants located outside the RGGI states that are not subject to the RGGI cap. To some degree, imports could offset the intended CO_2 reductions within the RGGI states and thereby compromise RGGI's effect.

[142] ISO New England *Open Access Transmission Tariff*, Section II, "Regional System Planning Process" (December 7, 2007); http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/09-3-6%20correct%20actual%20eff12-1-08.pdf.

[143] 07-588 Entergy Corporation v. Riverkeeper, Inc (Lower Court Case No. 04-6692ag, 04-6699ag) (Granted April 14, 2008); http://www.supremecourtus.gov/qp/07-00588qp.pdf.

A NERC study of this issue across the United States identified New England as one of the areas where the potential for cooling tower retrofit requirements on key existing plants could have an impact on a significant number of generators in the region. It also could affect system reliability through the reduction of plant capacity and, possibly, extended construction outages of key generating facilities. The ISO will monitor EPA's follow up regarding the Supreme Court's decision on the permitting process and the use of a benefit/cost application by generators. The ISO will need to determine whether any reliability evaluation is needed regarding the potential for retrofitting existing plants with cooling towers.

7.4 Renewable Portfolio Standards, Energy-Efficiency Goals, and Related State Policies

Renewable Portfolio Standards are a policy tool intended to stimulate the development of new renewable resources to achieve a more diverse, and "clean" generation portfolio. Five of the six New England states (Vermont excluded) have RPSs. Several states have additional related goals for stimulating the increased use of renewable resources and energy efficiency. Vermont has goals for renewable energy growth, as does Massachusetts with its 2008 *Green Communities Act* legislation. This act set new goals for energy efficiency and demand resources, established a class for existing renewable resources, and created an Alternative Portfolio Standard (APS) to encourage the development of certain new technologies.[144]

RPSs are policy targets generally affecting only the competitive retail suppliers in Connecticut, Massachusetts, Rhode Island, and New Hampshire but all retail suppliers in Maine.[145] The RPSs set growing-percentage targets for the electric energy supplied from new renewable resources. Retail electricity suppliers may choose to meet some or all of their obligations using renewable resources in the ISO Generator Interconnection Queue, resources from adjacent balancing authority areas, new resources in New England not yet in the queue, small "behind-the-meter" projects, eligible renewable fuels in existing generators, and funding alternatives through state-established Alternative Compliance Payments (ACPs).[146] The ACP serves as an administrative price cap on the cost of renewable sources of electric energy, and the ACP funds are used to promote the development of new renewable resources in the region.

The ISO has projected the overall regional RPS goals for the next 10 years on the basis of each state's individual RPS policy targets and has applied these state targets to the ISO's state electric energy forecasts for RSP09. The projections have appropriately deducted the retail suppliers not affected by the RPSs (i.e., usually municipal suppliers). The ISO also has projected the electric energy needed to meet other state policies and goals for growth in renewable resources, energy efficiency, and combined heat and power (CHP) resources.[147]

[144] *An Act Relative to Green Communities* (Chapter 169 of the Massachusetts Acts of 2008) (July 2, 2008); http://www.mass.gov/legis/laws/seslaw08/sl080169.htm. (Green Communities Act).

[145] In Connecticut, the Connecticut Municipal Electric Cooperative is required to submit a plan to use renewable resources as an alternative to meeting the state's RPS targets. In New Hampshire, the New Hampshire Electric Cooperative must meet the RPS targets.

[146] *Behind-the-meter* projects are generally small on-site generation resources that generally provide power to a customer's facility and, in some cases, sell excess power to the grid.

[147] Most CHP resources generate electricity from a depletable resource, such as oil or gas, and thus are different from renewable resources (e.g., wind, solar power, or sustainable biomass) that continually are regenerated. The benefit of CHP, however, is that it uses fuel more efficiently because, in addition to generating electricity, it makes use of thermal energy that other types of thermal power plants often waste.

The ISO compared the overall RPSs and related policy goals with renewable projects currently in various stages of development. This analysis and regional outlook do not represent a plan to meet state renewable requirements. Rather, they assess whether current projects in the ISO's Generator Interconnection Queue would be sufficient to meet the RPS goals while recognizing that contributions could come from other RPS sources not in the ISO queue.

7.4.1 New England States' RPSs

The states specify the types of renewable resources suitable for meeting their specific Renewable Portfolio Standards. These typically include small hydroelectric, solar, wind, biomass, landfill gas, tidal, wave, and ocean thermal resources. Widespread integration of some of these new technologies, such as wind power, into New England's bulk power system may present technical challenges, especially if their level of penetration grows to a significant percentage. These challenges are discussed in Section 8.

Table 7-4 and Table 7-5 summarize the RPS goals of the five New England states and also incorporate requirements of the Massachusetts Green Communities Act. Table 7-4 maps the specific renewable technologies permitted by the states' RPSs and shows those common among the states and those unique to a particular state's RPS. Table 7-5 lists the annual percentages of electric energy consumption of affected load-serving entities for the states' RPS classes from 2009 through 2020.

Table 7-4
Summary of Technologies Designated in Renewable Portfolio Standards in New England

Technology	CT Classes			MA Classes[a]			ME Classes		RI	NH Classes			
	I	II	III	I	IIa	IIb	I	II		I	II	III	IV
Solar thermal	✓			✓	✓		✓		✓	✓	✓		
Photovoltaic	✓			✓	✓		✓		✓	✓	✓		
Ocean thermal	✓			✓	✓				✓	✓			
Wave	✓			✓	✓				✓	✓			
Tidal	✓			✓	✓		✓		✓	✓			
Marine or hydro-kinetic				✓	✓								
Hydro	<5 MW	<5 MW		<25 MW	<5 MW		✓[b, c]	✓	<30 MW	✓			<5 MW
Wind	✓			✓	✓		✓		✓	✓			
Biomass, biofuels	Sustainable, advanced conversion low NO_X emissions[f]	✓		Low-emission, advanced technology[f]	✓		✓	✓[d]	✓ Includes co-firing with fossil fuels	✓		<25 MW	
Landfill gas	✓			✓	✓		✓		✓	✓[f]		✓[e]	
Anaerobic digester				✓	✓				✓	✓		✓	
Fuel cells[g]	✓			w/ renewable fuels	✓		✓		w/ renewable resources				
Geothermal				✓	✓		✓		✓	✓			
Municipal solid waste		✓				✓		✓w/ recycling					
Cogeneration, combined heat and power			Customer sites, minimum 50% fuel efficiency	Maximum of 2 MW[h]				✓[e]					
Energy efficiency			✓										

(a) The Massachusetts *Green Communities Act* divides the state's RPS into Class I and Class II resources, each of which allows primarily the same renewable technologies. Resources that began operating after December 31, 1997, are Class 1 renewables, and those that were in operation before that date are Class II renewables.

(b) These can be pumped hydro units.

(c) These resources must meet all federal and state fish-passage requirements.

(d) These can be high-efficiency units built through December 31, 1997.

(e) This category also includes biologically derived methane gas from sources such as biodiesel, yard waste, food waste, animal waste, sewage sludge, and septage.

(f) These terms are explained in the state's RPS legislation and regulations.

(g) Fuel cells are a relatively new "renewable" energy technology. These units emit negligible amounts of SO_2, NO_X, and particulates such that Connecticut does not require fuel cell installations to obtain air permits. For Massachusetts, an RPS fuel cell using an "eligible biomass fuel" includes landfill or anaerobic digester methane gas, hydrogen derived from such fuels, or hydrogen derived using the electrical output of a qualified renewable generation unit. For Rhode Island, RPS fuel cells using eligible renewable resources are shown in the table.

(h) These can be new in-state, on-site, behind-the-meter renewable units with a maximum size of 2 MW.

Table 7-5
Annual Percentages of Electric Energy Consumption of Affected Load-Serving Entities for the States' RPS Classes, 2009 to 2020

Year	CT Classes[(a)]			MA Classes[(b)]			ME Classes[(c)]		RI Classes[(d)]		NH RPS Classes[(e)]			
	I	II	III	I	IIa	IIb	I	II	Existing	New	I	II	III	IV
2009	6.0	3.0	3.0	4.0	3.6	3.5	2.0	30	2.0	2.0	0.5	0.0	4.5	1.0
2010	7.0		4.0	5.0	3.6	3.5	3.0		2.0	2.5	1.0	0.04	5.5	1.0
2011	8.0		4.0	6.0	3.6	3.5	4.0		2.0	3.5	2.0	0.08	6.5	1.0
2012	9.0		4.0	7.0	3.6	3.5	5.0		2.0	4.5	3.0	0.15	6.5	1.0
2013	10.0		4.0	8.0	3.6	3.5	6.0		2.0	5.5	4.0	0.2	6.5	1.0
2014	11.0		4.0	9.0	3.6	3.5	7.0		2.0	6.5	5.0	0.3	6.5	1.0
2015	12.5		4.0	10.0	3.6	3.5	8.0		2.0	8.0	6.0	0.3	6.5	1.0
2016	14.0		4.0	11.0	3.6	3.5	9.0		2.0	9.5	7.0	0.3	6.5	1.0
2017	15.5		4.0	12.0	3.6	3.5	10.0		2.0	11.0	8.0	0.3	6.5	1.0
2018	17.0		4.0	13.0	3.6	3.5	10.0		2.0	12.5	9.0	0.3	6.5	1.0
2019	19.5		4.0	14.0	3.6	3.5	10.0		2.0	14.0	10.0	0.3	6.5	1.0
2020	20.0		4.0	15.0	3.6	3.5	10.0		2.0	14.0	11.0	0.3	6.5	1.0
Use Generator Information System renewable energy certificates?	Yes			Yes			Yes		Yes		Yes			
Purchase of Renewable Energy Certificates (RECs) from outside ISO New England allowed?[(f)]	Yes, from adjacent areas, with confirmation of delivery of energy from the renewable energy source and reciprocal RPSs for NY, NJ, PA, MD, and DE.			Yes, from adjacent areas, with confirmation of delivery of energy			Yes, from adjacent areas		Yes, from adjacent areas		Yes, from adjacent areas, with confirmation of delivery of energy from the renewable energy source			

(a) All Connecticut Class I technologies except LFG and fuel cells can be used to meet Class II requirements. For Class III, CHP facilities can be used to offset generation on the grid with the more efficient on-site use of fuel.

(b) Class I has a minimum of 2% behind-the-meter resources. Class IIa is a minimum percentage for existing pre-1997 vintage LFG, hydro less than 5 MW, and biomass plants. Class IIb is a minimum percentage for pre-1997 vintage waste-to-energy plants.

(c) The 30% requirement refers to electric energy delivered to affected LSEs.

(d) Existing resources can make up no more than 2.0% of the RPS percentage.

(e) Class I increases an additional 1% per year from 2015 through 2025. Classes II to IV remain at the same percentages from 2015 through 2025.

(f) A *Renewable Energy Certificate* represents the environmental attributes of 1 MWh of electricity from a certified renewable generation source for a specific state's RPS. Providers of renewable energy are credited with RECs, which usually are sold or traded separately from the electric energy commodity.

As shown in Table 7-5, Connecticut has three classes of renewable resources; New Hampshire has four classes; and Massachusetts, Maine, and Rhode Island have two classes each. The Maine Public Utilities Commission (PUC) established regulations in 2007 that created a Class I and Class II for renewable sources of energy.[148] Class II became the previous 30% RPS for existing resources.[149] Under the Class I RPS, competitive suppliers in Maine must demonstrate that new renewable resources provide a percentage of their energy supply portfolio. This starts at 1% in 2008 and increases 1% annually through 2017. Alternatively, for any deficiency, they may use the ACP in lieu of having sufficient resources.

The main drivers for the growth of renewable resources in New England are the classes for new renewables: Rhode Island's RPS; Massachusetts's, Connecticut's, and Maine's Class I; and New Hampshire's Classes I and II. Massachusetts's Class I includes a provision to require on-site generation of up to 2 MW per site with a maximum percentage still to be determined. The Massachusetts Department of Energy Resources (DOER) plans to issue a rulemaking in 2009 that determines the minimum percentage of on-site generation comprising Class I resources, any specific technologies that qualify, and the ACP.

The classes for existing renewables include Connecticut's, Massachusetts's, and Maine's Class II, and New Hampshire's Classes III and IV. These existing classes are intended to retain the use of existing renewable resources, although the projected increase in electricity use for these states will lead to some increase in the electric energy from these classes. Some combination of increased energy efficiency and the use of CHP facilities that have a total fuel efficiency greater than 50% can be used to satisfy Connecticut's Class III. The percentages for this class are shown in Table 7-5.

With its *Green Communities Act*, Massachusetts established a Class II. In the state's RPS regulations, the Massachusetts DOER developed two Class II requirements: a minimum of 3.6% for the technologies shown in Table 7-4, and a minimum of 3.5% for municipal solid waste plants, both applying to plants in operation before December 31, 1997.

The Massachusetts *Green Communities Act* also established an Alternative Portfolio Standard (APS) similar to the RPS. The APS sets electric energy consumption targets for competitive retail electricity supplies (load-serving entities), which must use alternative technologies to meet the minimum APS percentage of their electric energy consumption. The technologies include CHP, flywheel storage, gasification with carbon sequestration, paper derived fuel, and efficient steam technology.[150] The Massachusetts DOER determined the APS percentages, starting in 2009, to be 1.0% and growing in increments of 0.5% per year to 2014, reaching 3.5%. The percentages would then increase at 0.25% increments per year, reaching 5% by 2020. Table 7-4 and Table 7-5 do not include the APS targets, which the ISO estimates would reflect about 300 MW by 2020 (operating at an 80% capacity factor).

[148] Maine Public Utilities Commission Revised Rules 65.407 Chapter 311 Portfolio Requirement (Effective November 6, 2007).

[149] Maine's RPS allows FERC-qualifying facilities (i.e., efficient cogeneration plants) to count toward meeting its goal of having renewable resources provide 30% of its electricity use. Maine's many paper mills typically meet this goal.

[150] Electric energy can be stored in a large rotating mass (e.g., flywheel), which can be called on to provide power for relatively brief periods.

7.4.2 Related Renewable Resource and Energy-Efficiency Developments

Another portion of the Massachusetts *Green Communities Act* is for the Secretary of Energy and Environmental Affairs to prepare a five-year plan for meeting the following renewable and energy-efficiency goals:

- Meet at least 25% of the state's electricity load by 2020 with demand resources that include energy efficiency, load management, demand response, and behind-the-meter generation.
- Have competitive LSEs meet at least 20% of their electricity load by 2020 through the use of new, renewable, and alternative energy generation. This goal encompasses the RPS target of 15%, plus the APS target of 5% by 2020. Section 7.4.3 discusses the assumptions the ISO has made about these goals.
- By 2020, reduce the amount of fossil fuels used in buildings by 10% from 2007 levels through increased efficiency.
- Plan to reduce total electric and nonelectric energy consumption in the state by at least 10% by 2017 through the development and implementation of a green communities program that encourages the use of renewable energy, demand reduction, conservation, and energy efficiency.

Vermont does not have an RPS, but in 2006, the state established a policy to meet all its growth in electricity use from 2005 to 2012 with new renewable resource projects.[151] To meet this requirement, Vermont set up a Sustainably Priced Energy Enterprise Development (SPEED) program, which aims to advance the establishment of long-term renewable purchase contracts between utilities and renewable project developers. Moreover, in March 2008, Vermont passed legislation that creates a state goal to have renewable energy resources, principally from farms and forests, provide 25% of the state's total electric energy load by 2025.[152]

In 2009, the Maine legislature and governor passed into law LD 1485, *An Act Regarding Maine's Energy Future*.[153] This comprehensive legislation establishes goals for Maine including weatherizing all residences and 50% of businesses by 2030, reducing energy consumption by 30% and peak energy by 100 MW by 2020, reducing the consumption of liquid fossil fuels by 30% by 2030, and lowering greenhouse gas emissions resulting from the heating and cooling of buildings.

7.4.3 New England States' Compliance with Renewable Portfolio Standards

Applicable loads in Massachusetts, Connecticut, and Maine already have complied with their states' RPS goals for several years, and Rhode Island had its first RPS compliance year in 2007.[154] Massachusetts's 2007 RPS Class I goal for competitive LSEs was to use renewable resources to supply 3.0% of the electricity they provide. The competitive LSEs in Massachusetts complied with this goal using essentially 100% of RPS-qualified generation. Of this amount, 49% came from biomass plants, 30% from LFG plants, and 19% from wind facilities. Geographically, 70% of the

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[151] *Sustainably Priced Energy Enterprise Development System*, Rule 4.300 (Montpelier, VT: Vermont Public Service Board, September 10, 2006); http://www.state.vt.us/psb/rules/OfficialAdoptedRules/4300_SPEED.pdf.

[152] *An Act Relating to the Vermont Energy Efficiency and Affordability Act* (S 209) (2008); http://www.leg.state.vt.us/docs/2008/bills/passed/S-209.HTM.

[153] *An Act Regarding Maine's Energy Future,* Public Law, Chapter 372 D 1485, item 1 (124th Maine State Legislature, signed June 12, 2009, effective September 12, 2009); http://www.mainelegislature.org/legis/bills/bills_124th/chappdfs/PUBLIC372.pdf.

[154] These include regulated utilities and competitive suppliers.

Massachusetts competitive LSEs' electric energy came from New England projects, including 12% from Massachusetts, 35% from Maine, and 16% from New Hampshire. Resources also came from New York (17%) and Canada (13%).[155]

In Connecticut, for 2006 (the latest report available as of May 2009), the affected LSEs had RPS targets to use Class I resources to supply 2.0% of the total electric energy they provide, and, similarly, to use Class II resources to supply 3.0% of their total energy. Fifteen companies—13 licensed competitive suppliers and two distribution companies—had to comply with the RPS, and three did so using ACPs totaling about $3.5 million. The Connecticut report did not include any data on the type of renewable projects in use or their locations.[156]

The compliance report for Maine discusses the applicability of the new Class I for meeting the RPS. In 2007, Maine's Class I for new renewables, which went into effect in 2008, "requires" renewable resources, as shown in Table 7-4, to provide 1% of the retail suppliers' electric energy. Retail sales under contract or standard offers executed before September 20, 2007, are exempt until the end of the contract, leaving approximately 45% of the current standard offer load to meet the Class I goal. Those suppliers needing to comply must submit a compliance report by July 1, 2009. The ACP for 2008 is $58.58/MWh, if the supplier has insufficient renewable supply.[157]

In 2007, Rhode Island completed its first year with its RPS in place, setting 3.0% as the target with a minimum of 1% needing to be from new renewable resources. For the "new" category, biomass provided 49%; landfill gas, 44.4%; hydro, 2.4%; and ACP, 4.3%. About 63% of the projects providing RECs came from New England states, and 33% came from New York. Hydroelectric resources within New England provided almost 100% for the "existing" class.

New Hampshire's RPS started in 2008, and a compliance report for that year is expected in fall 2009.

7.4.4 Projected RPS and Renewable Resources in the ISO Queue

This section presents a New England-wide projection of the states' RPS electric energy targets for renewable resources and energy efficiency goals. It then shows the outlook for meeting these electric energy targets with just the renewable resources in the March 15, 2009, ISO Generator Interconnection Queue. It recognizes other sources of renewable resources and options are available to meet the RPS targets: resources outside New England, smaller resources behind the meter, and paying the ACP. The renewable resources in the ISO queue represent a large potential physical supply for RPS compliance in New England.

7.4.4.1 Projected Targets for RPSs and Related Energy-Efficiency Policies

To provide a New England-wide outlook for the five states with RPSs and other related state policies, the ISO projected the electric energy targets for all the RPS classes and related state policies, as previously presented. It also projected the potential growth of the RPS targets for "new renewable" classes. The RPS projections were based on the ISO's 10-year 2009 forecast for the electric energy demand for competitive retail suppliers and excluded relevant municipal utilities in states where these

[155] *Annual RPS Compliance Report for 2007* (Boston: MA DOER, November 24, 2008; revised December 1, 2008).

[156] *2006 RPS Compliance Report* (Hartford: CT Department of Public Utilities Control, March 20, 2008); http://www.dpuc.state.ct.us/electric.nsf/c0a9d87c63a283e88525742e0048bce1/12612e323072cfd0852574120061f52d?OpenDocument.

[157] *Annual Report on the New Renewable Resource Portfolio Requirement* (Augusta: Maine PUC, March 31, 2009); http://www.maine.gov/tools/whatsnew/attach.php?id=70627&an=1.

entities are exempt from meeting the RPSs.[158] To obtain the RPSs' projected targets for renewables for 2020, the forecast was extrapolated to 2020, assuming energy growth rates would be similar to the ISO's forecast for 2018. The Massachusetts's *Green Communities Act* energy-efficiency goal of reducing the state's overall use of electric energy 25% by 2020 was modeled as energy-efficiency percentages of statewide electric energy use. The percentages were projected to incrementally increase annually until the state achieves the 25% goal in 2020 (i.e., electric energy usage would be reduced by almost 15,000 GWh by 2020). The RPS percentages were then applied to the reduced level of electric energy consumption. For these analyses, the various state RPS classes and other policies have been grouped into four categories:

1. **Existing—**RPS classes using existing renewable resources. This includes the Class II category for Maine, Connecticut, and Massachusetts; Rhode Island's "existing" category; and New Hampshire's Classes III and IV. Massachusetts' new Class II has two components: one covering the technologies shown in Table 7-4 and in operation before December 31, 1997, and another class for just waste energy plants from the same time period. Table 7-5 shows the percentage targets for each component. All these have some growth in the use of renewable resources because of the ISO's estimated growth in the total demand for electric energy for each state over the next 10 years. New Hampshire's Classes III and IV also include, for several near-term years, some increase in the percentage targets shown in Table 7-5.

2. **New—**RPS classes focusing on using new renewable resources. This category includes increases in new renewable resources and includes Class I for Maine, Connecticut, and Massachusetts; Rhode Island's RPS class for new growth; and New Hampshire's Classes I and II.

3. **Other—**Other state policies for new renewable resources. This category includes Vermont's goal of renewable resources meeting 25% of the state's electric energy demand by 2025.

4. **Energy efficiency—**New energy-efficiency RPS classes and policy goals. This includes Connecticut's Class III targets, which also can be met by CHP and Massachusetts' goal of meeting 25% of energy demand with new energy-efficiency measures by 2020. Although the new Massachusetts APS category includes CHP, the APS has not been projected in this analysis for reasons explained previously.

For each of these four categories and for 2009, 2012, 2016, and 2020, Table 7-6 shows the RPS and policy goals based on the ISO's 2009 10-year forecast for annual electric energy use by state (net of noncompetitive suppliers' energy) and the corresponding RPS percentage requirements shown in Table 7-5. For each year, the table shows the total electric energy goal for each of these four categories of renewables. It also shows the totals of these categories as a percentage of the projected total electric energy demand in New England.

[158] The ISO projections did not account for customers that are still on "standard offer" for the next several years since these offers are not subject to the RPS until the contracts expire.

Table 7-6
Estimated New England RPS and Related Targets for Renewables and Energy Efficiency (GWh and %)

Line #	Use/Requirement Category	2009	2012	2016	2020
1	2009 ISO electric energy use forecast	131,315	134,015	139,025	145,308
2	Existing—RPS targets for existing renewables[(a)]	8,883	9,094	9,131	9,170
3	New—RPS targets for new renewables[(b)]	4,363	7,618	12,501	17,251
4	Other—other drivers for new renewables[(c)]	95	384	784	1,209
5	Energy efficiency—targets for new energy efficiency and CHP[(d)]	1,971	5,524	10,247	16,137
6	Total RPS targets for renewables and energy efficiency	15,312	22,619	32,663	43,767
7	Total RPS targets for renewables and energy efficiency as a percentage of New England's projected electric energy use[(e)]	11.7%	16.9%	23.5%	30.1%

(a) This category includes new MA Class II, ME Class II, RI Existing, and NH Classes III and IV. This RPS category grows through time as a result of the growth in electricity demand. NH's classes also include some growth in the use of renewable resources to meet the RPS percentage of electric energy use.

(b) This category includes CT Class I, ME Class I, MA Class I, RI's "new" category, and NH Classes I and II.

(c) This category includes VT's goal of renewable resources meeting 25% of the demand for electric energy by 2025.

(d) This incorporates only CT Class III (energy efficiency and CHP) and MA's goal of 25% energy efficiency by 2020 from its *Green Communities Act*.

(e) The numbers may not add to the totals shown because of rounding.

Figure 7-1 shows the projected cumulative targets for renewables and energy efficiency in New England based on RPSs and related policies similar to Table 7-6.

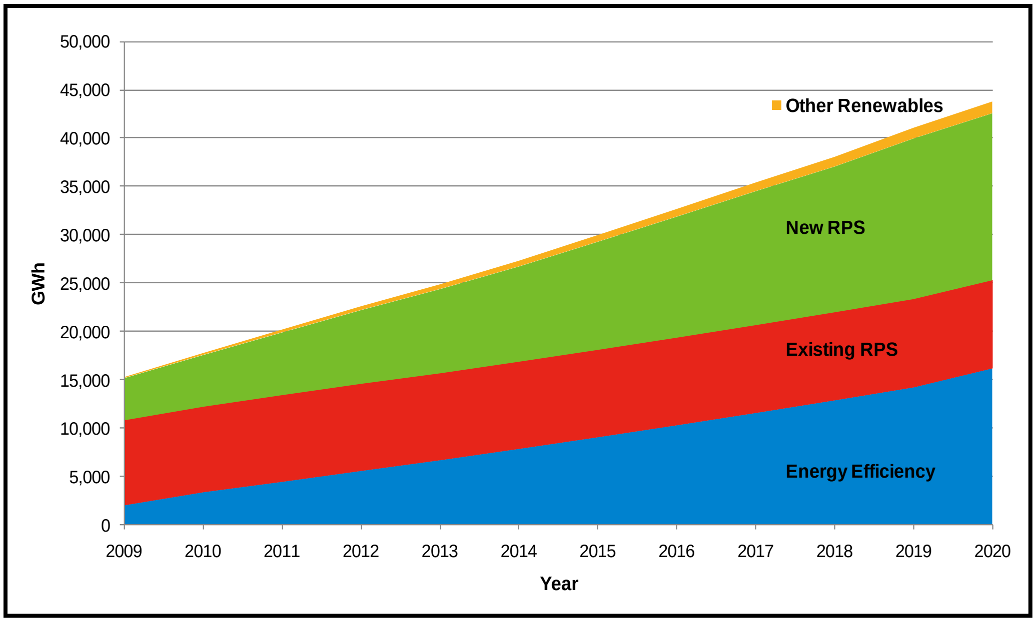


Figure 7-1: Projected cumulative targets for renewables and energy efficiency based on RPSs and related policies.

Table 7-7 shows that to meet the RPS for 2016, these four categories of renewables (i.e., existing, new, other, and energy-efficiency resources) need to supply about 23.5% of the total amount of electricity projected to be needed in New England and, similarly, about 30.1% for 2020.[159] Table 7-7 shows the percentages of for each of these categories of resources.

Table 7-7
New England RPS and Related Targets for Renewables and Energy Efficiency, by Category (%)

Category	2016	2020
Existing	6.6	6.3
New	9.0	11.9
Other	0.6	0.8
Energy efficiency/CHP	7.4	11.1
Total	**23.5**	**30.1**

Note: The numbers may not add to the totals because of rounding.

New renewable resources are the focus of the ISO's assessment because these resources represent the growth required in renewable resources.

Table 7-8 shows the RPS targets for incremental new renewable resources (as shown in Table 7-6, line 3). It shows the breakdown by state class of the RPSs for new renewable resources (line 1 to

[159] If Massachusetts's new legislative goal of having new renewable resources meet 20% of the state's energy load by 2020 were assumed to be met instead of the 15% the RPS requires, the 29.9% total supply from New England's RPS and energy-efficiency requirements would increase to 31.7%.

line 5) and the 2008 total New England RPS (line 6). Assuming the 2008 targets for RPS classes for new renewables are met by existing renewable resources and then subtracting the 2008 "new" RPS (line 7) from the total (line 6), the new incremental RPS would be 739 GWh of electricity annually for 2009; 3,994 GWh for 2012; 8,877 GWh for 2016; and 13,628 GWh for 2020 (line 8).

Table 7-8
Projected New England RPSs for "New" Renewables Beyond 2008 (GWh)[(a)]

Line #	State	2009	2012	2016	2020
1	**Connecticut Class I**	1,865	2,818	4,449	6,509
2	**Massachusetts Class I**	2,037	3,438	5,184	6,676
3	**Rhode Island "new"**	168	385	836	1,280
4	**New Hampshire Classes I and II[(b)]**	58	378	918	1,501
5	**Maine Class I**	235	600	1,114	1,285
6	**Total "new" RPS targets (from Table 7-6, line 3)[(c)]**	4,363	7,618	12,501	17,251
7	**2008 "new" RPS**	3,624	3,624	3,624	3,624
8	**Incremental "new" RPS beyond 2008[(d)]**	739	3,994	8,877	13,628

(a) The projection is based on the ISO's 2009 state electric energy use forecast deducting 5% for noncompetitive LSEs in CT, and similarly, 14% for MA and 0.6% for RI. Modest growth requirements in the "existing" and "other categories are not included here.

(b) New Hampshire's Classes I and II will go into effect in 2008 and 2010, respectively. However, NH's Class 1 requirement starts at 0.5% in 2009.

(c) The numbers may not add to the totals shown because of rounding.

(d) This assumes existing renewable projects in New England met the 2007 requirements for "new" renewable resources.

Figure 7-2 shows the annual cumulative RPS targets for new renewable resources included in Table 7-8 by state (lines 1 through 6) for each year of the forecast period. By 2020, the RPSs for Connecticut and Massachusetts will make up 75% of the total RPSs for new renewable resources for the New England states.

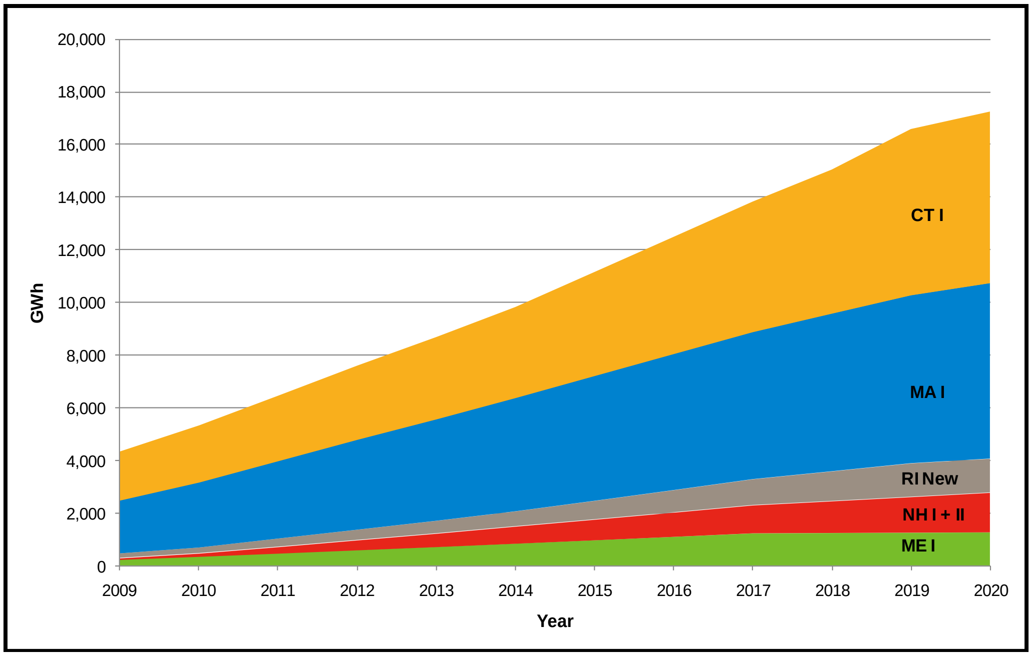


Figure 7-2: Cumulative RPS targets for new renewable resource classes by state.

7.4.4.2 Incremental RPS Targets for New Renewables Compared with Renewable Projects in the ISO Queue

Figure 7-3 shows the renewable resource projects in the ISO queue as of March 15, 2009. They total 4,343 MW, with wind projects comprising 86% of the total megawatts and biomass projects, 13%. The remaining 1% of the projects comprises landfill gas, hydroelectric, and fuel cell projects.

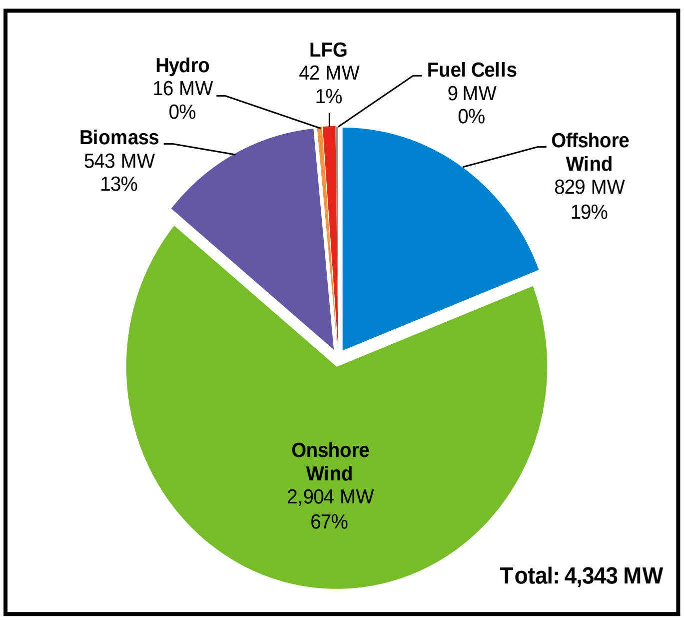


Figure 7-3: Proposed New England renewable resources in the ISO Generator Interconnection Queue as of March 15, 2009 (MW and percentage).

Note: Totals include all queue wind projects in New England.

To provide an estimate of the regional outlook for meeting the new incremental growth in the RPS Class 1 targets by 2020 with just resources in the ISO queue, Table 7-9 develops an estimate of total electric energy production from a total of 56 renewable energy projects in the queue (as of March 15, 2009). It is assumed these projects will become eligible to meet the total of the states' new RPS targets (line 8 of Table 7-8). The table shows estimates of the electricity that the proposed renewable projects in the queue might provide annually. These estimates are based on an assumed capacity factor for each type of renewable resource project. The estimates also assume all the projects would be built as proposed and the New England states would certify them as RPS projects so they can count as RECs toward compliance with the RPS.[160] Figure 7-4 also shows the projected energy from these resources similar to Table 7-9.

Table 7-9
Estimated Energy from New England Renewable Energy Projects in the ISO Queue as of March 15, 2009

Type (#) of Projects	Nameplate Capacity (MW)	Assumed Capacity Factor[(a)] (%)	Estimated Annual Electricity Production (GWh)
Hydro (3)	16	25	35
Landfill gas (3)	42	90	331
Biomass (14)	543	90	4,281
Wind onshore (32)[(b)]	2,904	32	8,140
Wind offshore (3)	829	37	2,687
Fuel Cells (1)	9	95	75
Total (56)	**4,343**	**40[(c)]**	**15,549**

(a) Capacity factors are based on the ISO's *2007 Scenario Analysis*. The wind capacity factors were adjusted to account for a generic assumption that wind turbines have a 90% availability. See http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

(b) Includes all wind projects in the ISO queue.

(c) An equivalent capacity factor = [{total energy production (GWh) x 1,000}/{total capacity (MW) X 8,760 hours}].

[160] The ISO recognizes each state must certify the resources to meet the RPS requirements. These state-certified projects include generators connected to the grid, behind the meter, and in adjacent control areas (where allowed).

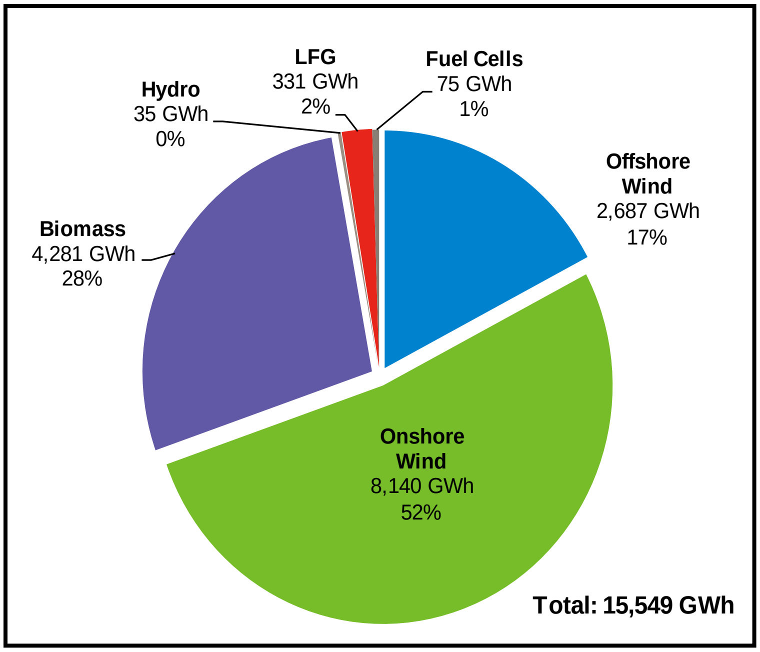


Figure 7-4: Estimated energy (GWh) from proposed New England renewable resources in the ISO's Generator Interconnection Queue as of March 15, 2009.

A comparison of the queue projects in Table 7-9 with the total resources in the "new" RPS category beyond 2008 (as shown in Table 7-8, line 8), indicates the New England renewable energy resources proposed in the queue would meet the New England RPS demand by 2020 only by assuming all the projects are completed successfully and operate as shown in the queue.

Table 7-10 shows the amount and percentage of projects (in total projects and megawatts) that have gone commercial, are active, or have withdrawn from the queue since the queue started in June 1996. It also shows the total number and megawatts of wind projects that have gone commercial or are active or have been withdrawn from the queue because wind is the dominant type of renewables project in the queue. A total of 45% of the projects withdrew, which represent 60% of the total megawatts withdrawn. Similarly, the number of wind projects decreased 38%, representing a decrease in total megawatts of 64%.

Table 7-10
Summary of All Projects and Wind Projects in ISO Queue as of March 15, 2009

Project Category	All Projects				Wind Projects			
	No.	%	MW	%	No.	%	MW	%
Commercial	60	20	12,499	18	2	3	83	1
Active	108	36	15,037	22	39	59	3,733[(b)]	35
Withdrawn	135	45	41,684	60	25	38	6,914	64
Total[(a)]	**303**	**100**	**69,220**	**100**	**66**	**100**	**10,730**	**100**

(a) Percentages may not sum to 100 because of rounding.

(b) This includes wind projects in New England not administered by ISO New England.

Figure 7-5 shows the annual new cumulative RPS targets for renewables from 2009 to 2020 compared with the annual potential electric energy production by renewable projects in the queue on the basis of the projected commercial operation date for these projects and assuming the capacity factors shown in Table 7-9. Given the uncertainty of the success of renewable projects, most of which are wind, and using guidance from the PAC, Figure 7-5 shows three levels of assumed project development: 20%, 40%, and 60% levels of assumed commercial operation. These reflect different assumed attrition levels of renewable projects of 80%, 60%, and 40%. These assumed levels cover a wider range of attrition of wind projects than historically occurred, as is shown in Table 7-10. If only 20% of the electric energy from the queue projects became commercially available, the total RPS targets for new renewables would not be met. Starting in 2012, the RPS targets for renewables would start to increase significantly from what the 20% level could provide. Similarly, at a 40% level, the projects would meet the RPS through 2014. At a 60% level, the queue projects would meet RPS targets through 2016.

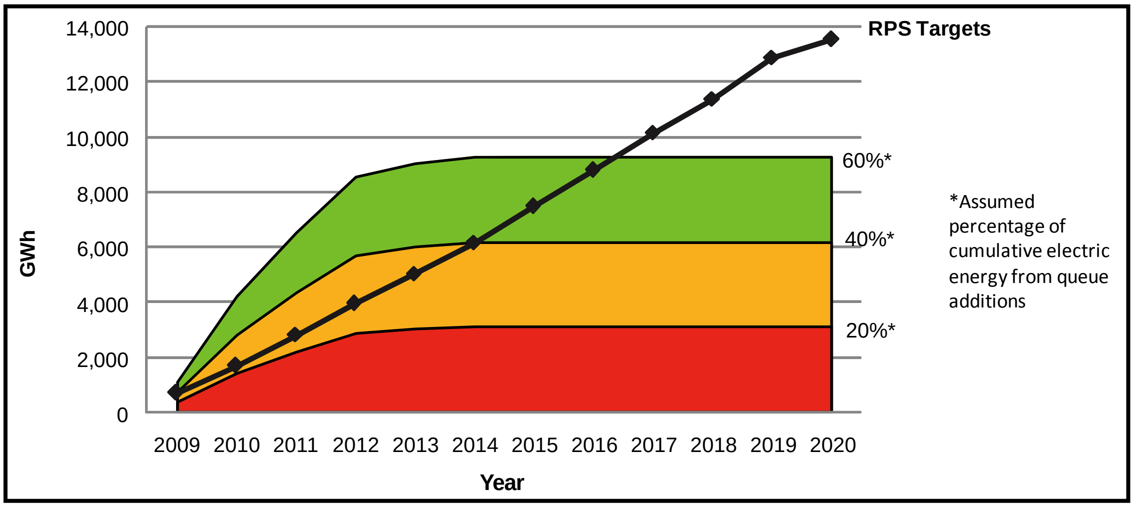


Figure 7-5: Various levels of cumulative electric energy estimated from new renewable projects in the ISO queue compared with RPS demand by year.

Notes: Various percentages of electric energy availability from queue projects have been assumed and are not projections of the projects' expected energy production. RPSs also can be met with projects behind the meter, imports, new projects not in the queue, and Alternative Compliance Payments.

7.4.4.3 Other Projects that Contribute to New England's Renewable Resource Supply

The ISO recognizes that renewable resources other than those projects in the ISO queue will be used to meet some of the RPS demand in New England.[161] These additional renewable projects include small, on-site and behind-the-meter renewable resources not in the queue, eligible renewable fuels in existing generators, and imported energy from renewable projects in adjacent balancing authority areas. In 2007, the Massachusetts RPS compliance resources from imports into New England amounted to 30%.[162] The Alternative Compliance Payment is a default that affected LSEs also could use for meeting RPS targets.

[161] Robert Grace, "Renewable Energy Resources in New England . . . Will They Be There When We Need Them," Presentation at the Northeast Energy and Commerce Association Fifteenth Annual New England Energy Conference, Newport, RI (Framingham, MA: Sustainable Energy Advantage, LLC, May 12, 2008).

[162] Annual RPS Compliance Report for 2007 (MA DOER, 2008).

To meet their RPS targets, Massachusetts and Connecticut have been certifying some existing renewable generators to qualify for the "new" RPS category and, in some cases, requiring technology upgrades. These new certified renewable generators likely will continue to provide partial compliance for the LSEs for new RPS classes.

7.5 Summary

Providing electricity at a reasonable cost while meeting environmental goals as mandated by air and water regulations can create competing requirements for reliably meeting New England's demand for electricity. The region's stakeholders, including the ISO, NEPOOL participants, and state environmental agencies should collaborate on any needed planning to meet these important requirements.

Only a few updates in environmental requirements have been made since RSP08 was published. After some legal challenges, CAIR has been reinstated and sets nitrogen oxide emissions caps during the ozone season for large fossil fuel electricity generators in Connecticut and Massachusetts.

RGGI is now in effect in New England as well as in New York, New Jersey, Maryland, and Delaware. Two auctions of RGGI CO_2 allowances were held in 2008 and two in 2009; two more will be held in 2009. For the four auctions held to date, the allowance prices were below $4/ton and yielded total revenues to the New England RGGI states of $111 million, most of which is intended to be used for energy-efficiency programs. Legislative proposals are now before the U.S. Congress that would establish a federal cap-and-trade program with requirements for reductions extending to about 2050 in most cases. The recent proposed EPA finding that CO_2 and other GHGs are an endangerment to human health and welfare allows EPA to regulate these gases like other air pollutants if Congress does not act on a legislative cap-and-trade proposal.

In April 2009, a U.S. Supreme Court decision clarified the criteria for best available technology for reducing the impacts of cooling water intakes from large existing thermal generating plants. The decision allows the use of a benefit/cost ratio in evaluating the impacts, but it is uncertain how EPA will apply this interpretation for permitting.

The total RPS and related energy-efficiency targets will increase to approximately 23.5% of New England's total projected energy use by 2016, and increase to 30.1% by 2020. State goals for new energy-efficiency programs make up about 11.1% of the 30.1%; the remainder is attributable to Renewable Portfolio Standards and related policies.

The ISO recognizes the uncertainty of success for projects in the current queue. Based on assumptions, these projects would likely meet the incremental growth in the RPS classes for "new" renewables sometime between 2012 and 2016. New projects entering the queue or being planned but not yet in the queue, small renewable projects behind the meter, or the purchase of RECs from projects in neighboring regions could meet any shortfalls. Alternatively, affected LSEs can make Alternative Compliance Payments to the states' clean energy funds, which help finance new renewable projects.

Section 8
Integration of New Technologies into New England's Electricity Grid

Larger-scale commercial wind farms are beginning to be developed, and many smaller-scale community-based projects already are operating or are under development in New England. However, wind resources are variable and produce electric energy only when the wind is blowing, which can lead to sudden changes in energy output. Thus, the integration of wind resources must be planned carefully to ensure reliable system operation. With thousands of megawatts of wind capacity in the ISO Generator Interconnection Queue that plan to begin commercial operation over the next few years (see Sections 4.4 and 7.4.4.2), the ISO will need to evaluate these resources and plan for any special forecasting and operating requirements, such as additional reserves, for the successful integration and operation of wind resources.

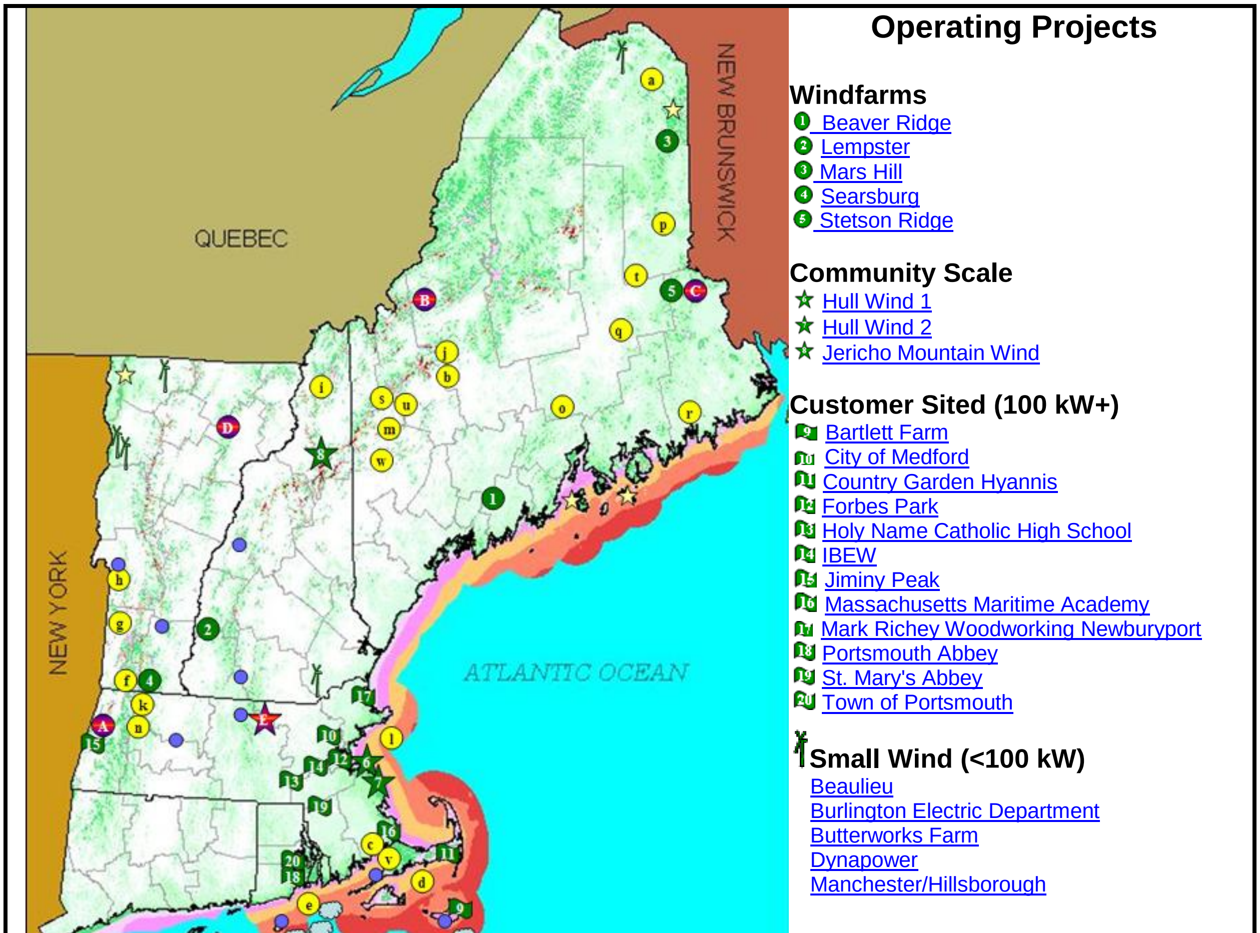
Similarly, as presented in Section 4, almost 2,000 MW of active demand resources have capacity supply obligations for the 2011/2012 capability period. This implies a more significant role for these resources in operating the system during peak-load periods and OP 4 events. Given this level of dependency on these resources, carefully planning their use and integration into system operations also is critical.

Finally, integrating "smart grid" technologies, including demand-resource applications, to improve the operation and efficiency of the electric power grid has become of great interest nationally. A number of research and development efforts already are underway in New England or are being planned to add these technologies to the grid and successfully operate them.

This section discusses the ISO's activities to integrate wind resources, active demand resources, and smart grid technologies into the New England electricity grid and, for active demand-resource activities, into the market rules. It addresses the status of these integration activities and discusses some of the technical issues associated with planning for and operating the electric power system with the addition of these types of resources. It also discusses a detailed ISO study of the New England electrical system with increased levels of installed wind resources. The section also summarizes plans for implementing new smart grid technologies.

8.1 Wind Integration Activities

As of March 2009, about 90 MW of utility-scale wind generation projects were on line in the ISO's system, of which 81 MW are offered into the electric energy market. New England has close to 4,000 MW of larger-scale wind projects in the Generator Interconnection Queue, with over 800 MW representing offshore projects and 2,900 MW representing onshore projects. Over 1,600 MW of larger-scale commercial wind farms could be operating by the end of 2010 on the basis of the resources in the queue. Figure 8-1 shows a map of planned and operating wind projects in New England.



Type of Project	Operating	Permitted or Under Construction	Planned	Retired
Wind farm	●	●	●	●
Community scale	★	★	★	
Customer sited (100 kW+)	⚑		⚑	
Small wind (<100 kW)				

Figure 8-1: Wind projects in New England as of April 7, 2009.

Source: Provided by Sustainable Energy Advantage, LLC. Developed under contract to the National Renewable Energy Laboratory with additional funding support from the Massachusetts Renewable Energy Trust. Current map is available at http://www.windpoweringamerica.gov/ne_projects.asp. Also see the U.S. DOE New England Wind Forum Web site; http://www.windpoweringamerica.gov/ne_projects.asp (April 2009).

The ISO's wind integration activities have three areas of focus: actively participating in NERC's Integrating Variable Generation Task Force (IVGTF), conducting a large-scale New England wind integration study—the New England Wind Integration Study (NEWIS), and facilitating the interconnection process for new wind generators.

8.1.1 NERC Integrating Variable Generation Task Force

In December 2007, NERC's Planning and Operating Committees created the Integrating Variable Generation Task Force and charged it with preparing a report to accomplish the following tasks:

- Raise industry awareness and understanding of the characteristics of variable generation and expected system planning and operational challenges for accommodating large amounts of variable generation.
- Identify shortcomings of existing approaches used by system planners and operators in assessing wind generation and the need for new approaches to plan, design, and operate the power system.
- Broadly assess NERC standards to identify possible gaps and requirements to ensure bulk power system reliability.[163]

The ISO is actively participating in the IVGTF and conducting two main assignments of the task force: (1) collaboratively developing proposed NERC wind planning and operating standards as a strawman for industry consideration, and (2) conducting wind research and summarizing specific analyses and studies that identify operational and planning issues concerning the integration of large amounts of wind generation into the bulk electric power system. The IVGTF has completed an assessment of bulk power system reliability issues associated with integrating large amounts of resources that are variable and uncertain and has issued these conclusions:

- Power system planners must consider the impacts of variable generation on power system planning and design and develop practices and methods needed to maintain long-term bulk power system reliability.
- Operators will require new tools and practices to maintain bulk power system reliability.
- A reference manual describing required changes to planning and operation of the bulk power and distribution systems to accommodate large amounts of variable generation will be useful to planners and operators.

The IVGTF recognizes that the impacts of variable generation resources like wind power are specific to a region because of differences in the characteristics of the load and the resources available to a region, as well as regional differences in operating and planning generation and transmission resources. Therefore, these conclusions are general and must be adapted for each region.

8.1.2 New England Wind Integration Study

Figure 8-2 shows areas in New England where the development of wind resources could potentially avoid environmentally sensitive and highly populated regions. The figure shows possible locations of up to 115 GW of onshore wind resources and 100 GW of offshore wind resources, but it is not a projection of total wind development. Most likely, only a small fraction of the potential 215 GW actually will be developed. Distributed wind development, which does not interconnect directly with the transmission system, also is possible, such as in local communities (see Figure 8-1).

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[163] See *Accommodating High Levels of Variable Generation* (Princeton, NJ: NERC, April 2009); http://www.aeso.ca/downloads/IVGTF_Report_041609(1).pdf.

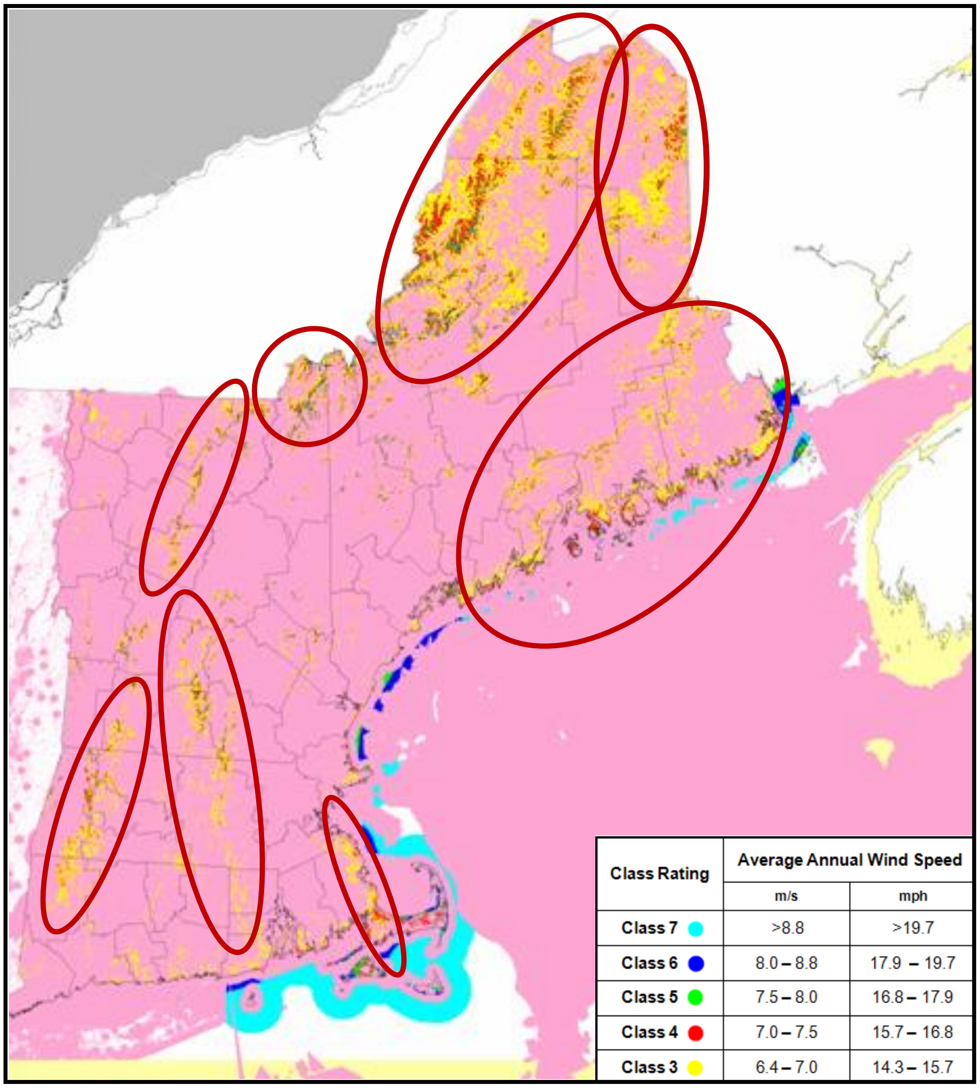

Figure 8-2: Areas in New England with the greatest wind potential.

Note: The pink indicates areas where the development of wind generation is less likely because of siting concerns and low annual wind speeds. The other colored areas are favorable for potential wind development .The ellipses show favorable clusters of the potential development of onshore wind generation. On the key, "m/s" refers to meters per second, and "mph" refers to miles per hour.

In 2008, the ISO issued a request for proposals (RFP) to conduct a New England Wind Integration Study (NEWIS).[164] The RFP has been awarded, and the study is underway. A vendor team led by General Electric Energy Applications and Systems Engineering with support from three consultants (EnerNex, AWS Truewind, and WindLogics) is performing the comprehensive wind power integration study. All the work must be conducted during 2009 and 2010. The following subsection describes the drivers, goals, and the tasks of the study.

[164] The NEWIS RFP and related materials are available on the ISO's Web site; http://www.iso-ne.com/aboutiso/vendor/exhibits/index.html.

8.1.2.1 Drivers

Successfully integrating wind power generation into the power system presents technical challenges because the characteristics differ significantly from conventional generation. These characteristics include limited controllability and high variability of power produced by wind turbines and the uncertainty in forecasting the amount of power that can be produced. To some extent, the variability and uncertainty inherent to wind power can be mitigated by increasing the geographic diversity of the interconnected wind power resources. The operation and planning of the New England power system will be affected by the expansion of wind power resources in New York and neighboring Canadian provinces. These resource additions in neighboring regions will likely provide opportunities for closer coordinated operation among the systems, additional interregional power transfers, and new transmission tie lines.

8.1.2.2 Goals

The goals of the NEWIS are as follows:

- To determine, for the ISO New England Balancing Authority Area, the operational, planning, and market impacts of integrating large-scale wind power, as well as the measures available to the ISO for mitigating these impacts and facilitating the integration of wind resources
- To make recommendations for implementing these mitigation and facilitation measures

In particular, the study will identify the potential adverse operating conditions created or exacerbated by the variability and unpredictability of wind power and recommend potential corrective activities. The study aims to capture the unique characteristics of New England's electrical system and wind resources in terms of load and ramping profiles, geography, topology, supply and demand resource characteristics, and the unique impact wind profiles could have on system operations and planning as wind penetration increases. While the study will address these issues, it will not project the likely total development of wind-powered generation in New England.

8.1.2.3 Tasks

The study is planned for completion by mid-2010 and is being structured around five tasks:

<u>Task 1: Wind Integration Study Survey.</u> The project team is conducting a survey of national and international studies of integrating wind resources into bulk electric power systems. This includes ISO studies, such as Phases I and II of the *Technical Assessment of Onshore and Offshore Wind Generation Potential in New England* and the *New England Electricity Scenario Analysis*, and actual wind integration experiences in bulk electric power systems.[165] The objective of the survey is to determine the applicability of these studies, such as the specific tools used, to the ISO's wind integration studies. The information captured during this task will be used to refine the assumptions and deliverables of the remaining tasks of the study.

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[165] These materials are available on the ISO's Web site; http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/. *New England Electricity Scenario Analysis: Exploring the Economic, Reliability, and Environmental Impacts of Various Resource Outcomes for Meeting the Region's Future Electricity Needs* (ISO New England, August 2, 2007); http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

Task 2: Technical Requirements for Interconnection. This task includes the development of specific recommendations for technical requirements for wind generation, addressing such aspects as its ability to reliably withstand low-voltage conditions, provide voltage support to the system, and adjust megawatt output to support the operation of the system. The task also will include data and telemetry requirements, maintenance and scheduling requirements, high wind cutout behavior, and the development of "best practice" methods of the equivalent load-carrying capability (ELCC) calculation used for establishing capacity values for global and incremental wind power generation.

This task also will investigate and recommend wind power forecasting methods for both the very short-term timeframe, which is useful in real-time operations, and the short- to medium-term timeframe, which is useful in unit dispatch and day-ahead unit commitment.

Task 3: Mesoscale Wind Forecasting and Wind Plant Models.[166] The study will develop an accurate and flexible mesoscale forecasting model for the New England wind resource area (including offshore wind resources) to allow for the simulation of power system and wind generation operations and interactions (e.g., unit commitment, scheduling, load following, and regulation) over the timescales of interest. The model will be designed to produce realistic time-series wind data over all terrain types for at least 2004, 2005, and 2006 to quantify the effects of interannual variability in wind generation and systemwide load.

Task 4: Scenario Development and Analysis. This task will simulate and analyze the impacts of several wind-development scenarios in New England on the performance of the electric power system. The scenarios of the future system will consider various levels of wind development up to 20% of the projected annual consumption of electric energy. Sensitivity analyses will include the impacts of the diversity of the wind portfolio on the performance of the electric power system for scenarios of low diversity, high diversity, and high correlation with system load.

This analysis will lead to recommendations for modifying existing procedures, guidelines, and standards to reliably accommodate the integration of new wind generation. The evaluation also will include a review of the ISO's market design considering a high penetration of wind generation and how this scenario could affect system reliability, contribute to inefficient market operation of the bulk electric power system, or do a combination of both.

Task 5: Scenario Simulation and Analysis. This task will simulate and analyze detailed scenarios to assess the measures needed to successfully integrate a high penetration of wind generation. The investigation will assess the type of forecast needed, such as forecasting lead time, the required accuracy, and implementation issues. The simulations also will evaluate the use of on-line generation for load following, regulation, and reserve maintenance and deliverability; the production of air emissions; the effects of carbon cost; and the effects on LMPs. Measures that would facilitate the integration of wind, such as changes to market rules, the addition of electrical storage to the power system, and the use of demand response also will be studied.

[166] Mesoscale forecasting is a regionwide meteorological forecasting generally over an area of five to several hundred kilometers.

8.1.3 Wind Generator Interconnection Facilitation

Wind generators wanting to interconnect to the ISO system face particular challenges attributable to the differences between wind power and conventional resources. The steps for interconnecting and subsequently operating wind generation include the following:

- Completing all phases of the ISO's specific commissioning protocol
- Meeting requirements for voice communications and data telemetry, depending on the type of markets in which the resource will be participating
- Designating an entity that has complete control over the resource and can be contacted at all times during normal and emergency conditions
- Submitting real-time, self-scheduling information so that the ISO can account for it in planning and operating analysis
- Providing other information, such as models, and meeting additional performance requirements, such as voltage control and dispatch

Additionally, wind generators are notified that the existing interconnection requirements are under review as part of the NEWIS, are interim, and may change once the ISO has received and evaluated the NEWIS recommendations.

8.1.4 Next Steps

The ISO plans to evaluate the recommendations from the study and will develop an implementation plan based on the outcomes of the NEWIS and other studies. In the near-term, results derived from NEWIS Task 2, Technical Requirements for Interconnection, will likely result in modifications to the ISO's interconnection requirements for wind generators. The balance of the wind integration efforts will be ranked by priority and be completed in accordance with the ISO's own project implementation schedule. The results of this study will help the region integrate significant wind resources into the electricity grid without impairing the reliability and operation of the grid.

8.2 Active Demand-Resource Integration under the FCM

As discussed in Section 4, over 1,900 MW of system demand was enrolled in the demand-response programs for summer 2009. With the start of the Forward Capacity Market in 2010, demand response, energy efficiency, and distributed generation all will be treated as capacity resources, and demand resources will represent over 9% (almost 3,000 MW) of the representative capacity resources needed (i.e., the ICR) in the New England electric power system by 2011. Of these total demand resources, approximately 6% of the ICR, or almost 2,000 MW, are active demand resources. The implementation of significant amounts of demand resources into New England has many advantages:

- Improving system reliability for both system planning and operations, which, if structured correctly, can address as well as avoid emergency conditions
- Delaying or reducing the need to build additional transmission, generation, distribution facilities, or a combination of new facilities
- Reducing land use and adverse environmental impacts, such as air emissions and water discharges
- Reducing reliance on imported fuels and improving the diversity of system resources

To gain all these benefits, the ISO must be prepared to integrate into New England's system the high level of demand resources that clear in the FCAs. This amount of new demand resources must effectively be integrated into system planning and operation and market administration, without creating undue barriers to participation. Because the integration of active demand resources is particularly challenging, the ISO is working toward integrating the FCM active demand-resource products into system planning and system and market operations by June 1, 2010.

To determine whether the expected levels of active demand resources that clear in the initial FCAs could be reliably integrated in New England without having a negative impact on market and system operations, the ISO performed an initial operable capacity analysis of active demand resources. The analysis focused on varying levels of participation by active demand resources during the initial FCM delivery years. This initial analysis showed that the 2010 active demand-resource levels met the criteria needed for system reliability; however, the analysis of the outcome of FCA #2 for the 2011/2012 delivery year identified operational issues and the potential need to change FCM market rules. Specific concerns were as follows:

- The ability of active demand resources to maintain reduction without "fatigue" during the anticipated hours of operation[167]
- Access to the resources outside the initially approved program hours and requirements
- The appropriateness of reserve "gross-up" rules[168]
- Auction transparency during the annual auctions
- Infrastructure and telemetering requirements for the active demand resources

The ISO led an open stakeholder process that included a review of the operable capacity analysis of active demand resources and revised FCM rules to accommodate these resources. This stakeholder process culminated with unanimous support at the NEPOOL Participants Committee and ultimately a filing with FERC on October 1, 2008, which FERC approved on October 28, 2008.[169] The revised rule included provisions on the following areas of concern:

- The dispatch and settlement rules governing active demand resources
- The eventual elimination of the critical-peak resource category and the conversion of these resources into other categories of demand resources
- Improved information to facilitate active demand-resource participation in Forward Capacity Auctions
- A clarification of the ISO's ability to impose appropriate sanctions when market participants with active demand resources do not comply with their obligations

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[167] An ISO concern is that these customers may become "fatigued" with frequent operation and not respond when required. For example, a customer in the business of making a product may prefer to fulfill an order rather than delay production through reduced energy consumption.

[168] *Gross-up* rules give credit for customer actions that both reduce load at the customer's meter and reduce power system losses.

[169] ISO New England Inc. and New England Power Pool FERC filing, *Tariff Revisions Regarding Elimination of the Reserve Margin Gross-Up for Demand Resources* (Docket No. ER09-___-000) (October 31, 2008); http://www.iso-ne.com/regulatory/ferc/filings/2008/oct/er09-209-000_10-31-08_dr_gross-up_filing.pdf.

The ISO's real-time operational practices are being revised to improve the integration of large quantities of active demand resources. These changes can be summarized as modifications to OP 4 and operator interfaces, the creation of demand-designated entities that can aggregate the operation of active demand resources, and the implementation of new communications infrastructure.

8.2.1 Modifications to ISO New England Operating Procedure 4

Currently, the implementation of OP 4 involves notifying stakeholders that the ISO is close to not meeting its full 10- and 30-minute operating-reserve requirements or has a transmission system problem preventing the ISO from maintaining first- or second-contingency coverage. The availability of active demand resources in large quantities and in shorter response times greatly expands the resources available to maintain operating reserves. As such, by reducing load in the appropriate locations, active demand resources can be used to free other supply resources for maintaining reserve requirements for a systemwide event and transmission security for local events. The ISO intends to modify OP 4 and divide the use of active demand resources into stages that more accurately will reflect the level of reliability on the system as various actions are undertaken.

8.2.2 Creation of Demand-Designated Entities

Coordinating operations between the ISO and the demand-resource network operating centers must be improved. The ISO intends to work with stakeholders to create *demand-designated entities* (DDEs), similar to generator-designated entities. These active demand-resource communication entities will be responsible for receiving and acting on dispatch instructions from the ISO. DDEs will be the only entities the ISO will communicate with regarding dispatch instructions for active demand resources.

In addition, the DDEs will be required to participate in training activities with the ISO and local control center staff to gain confidence and expertise in how these resources fit into the overall operation of the interconnected systems.

8.2.3 Operator Interfaces

The current operator interface for dispatching active demand resources is an Internet-based application separate from the integrated Energy Management System (EMS) tools that system operators use to dispatch conventional supply resources. As a result, the operators must use this stand-alone tool with no connectivity to the EMS during times of OP 4 implementation. This creates a hardship on system operators and draws them away from their primary tool sets at the most important times. ISO plans call for fully incorporating active demand resources into the dispatch management tools within the EMS, which will improve operator control over their dispatch and allow them to make active demand-resource dispatch decisions with real-time input from the rest of the software tools within the EMS.

8.2.4 Development of New Communications Infrastructure

The ISO is working with stakeholders to replace the current communication infrastructure located throughout the region. Currently, single points of failure can render all active demand-resource assets unusable during an emergency or economic dispatch. Active demand resources currently use the public Internet for dispatch instructions, and system operators have a limited view of the dispatch and reliability performance of assets. By June 1, 2010, active demand response will be modeled, monitored, and controlled by the ISO's EMS, giving system operators a secure and reliable means to dispatch these resources. The demand-response integration effort will complete the communications infrastructure enhancement by integrating the demand-response assets within the ISO's System Control and Data Acquisition (SCADA) functions.

8.2.5 Creation of Active Demand-Resource Dispatch Zones

A demand-resource dispatch zone is a group of nodes within a load zone that will be used to define and dispatch real-time demand-response (RTDR) resources or real-time emergency generation (RTEG) resources. This will allow for a more granular dispatch of active demand resources at times, locations, and quantities needed to address potential system problems without unnecessarily calling on other active demand resources. Figure 8-3 shows the dispatch zones the ISO will use to dispatch FCM active demand resources.

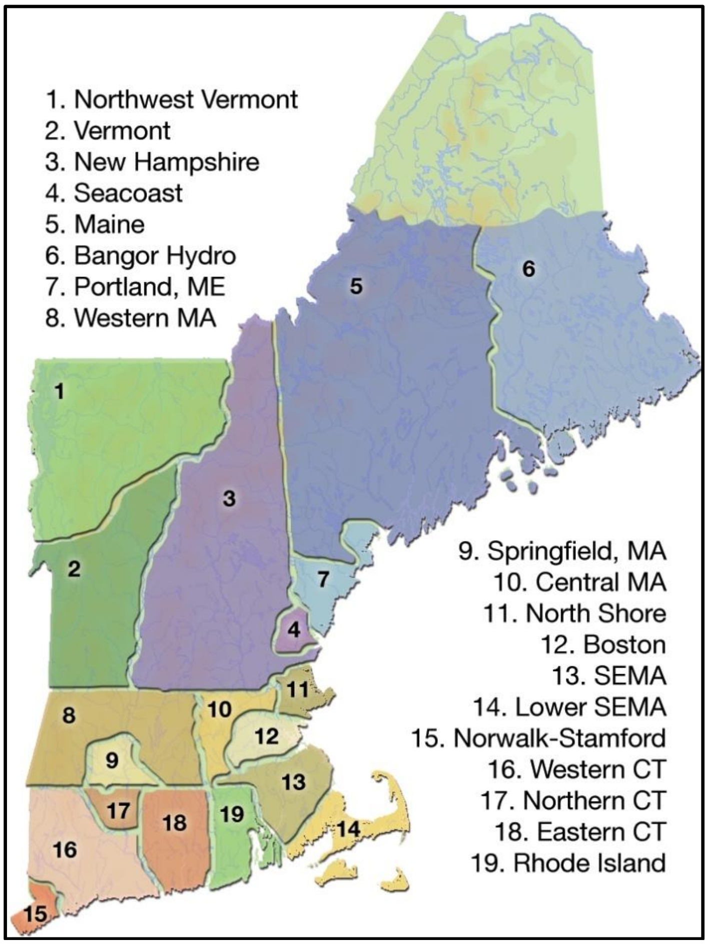

Figure 8-3: Active demand-resource dispatch zones in the ISO New England system.

8.3 Integration of Smart Grid Technologies

This section provides an overview of smart grid technologies and programs and the challenges to their implementation and discusses ISO activities using a number of smart grid technologies.

8.3.1 What is the Smart Grid?

The *Energy Independence and Security Act of 2007* (EISA) directs federal and state agencies to implement programs that advance the implementation of a smart grid. EISA describes smart grid as follows:[170]

> *a modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth*

The EISA law describes policies, timelines, and specific implementation milestones and sets out a number of objectives, as follows, which together characterize the smart grid the nation is to achieve:

- Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric power grid
- Dynamic optimization of grid operations and resources, with full cyber security
- Deployment and integration of distributed resources and distributed generation, including renewable resources
- Development and incorporation of demand response, demand resources, and energy-efficiency resources
- Deployment of ''smart'' technologies (i.e., real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communicating about grid operations and status, and facilitating distribution automation
- Integration of ''smart'' appliances and consumer devices (e.g., a home air conditioner able to be shut off remotely to reduce the demand for electric energy, such as during periods of peak demand)
- Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric vehicles (PEVs) and thermal-storage air conditioning
- Provision to consumers of timely information and control options (i.e., for making decisions about equipment use based on electricity prices)
- Development of standards for communication and interoperability of smart appliances and equipment connected to the electricity grid, including the infrastructure serving the grid
- Identification and lowering of unreasonable or unnecessary barriers hampering the adoption of smart grid technologies, practices, and services

One fundamental assertion of EISA is that the existing transmission and distribution infrastructure is capable of delivering greater efficiencies, and simply adding more generators and transmission lines is not the sole answer to America's future energy needs. The National Electrical Manufacturers Association and the Congressional Research Service state that the goal of smart grid is as follows:[171]

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[170] United States Congress (H.R. 6, 110th), *Energy Independence and Security Act of 2007* (GovTrack.us database of federal legislation: December 19, 2007); http://www.govtrack.us/congress/bill.xpd?bill=h110-6 (accessed Dec 2, 2008).

[171] (1) National Electrical Manufacturers Association, *Standardizing the Classification of Intelligence Levels and Performance of Electricity Supply Chains* (Rosslyn, VA: December 2007). (2) Congressional Research Service, Smart Grid Provisions in H.R. 6, 110th Congress (Washington, DC: December 20, 2007).

to use advanced, information-based technologies to increase power grid efficiency, reliability, and flexibility, and reduce the rate at which additional electric utility infrastructure needs to be built

In theory, the expanded deployment of intelligent load and supply devices that can sense and respond (S&R) to various signals (e.g., pricing, grid voltage stability, frequency) and communicate bidirectionally with utilities and system operators will enable the existing grid infrastructure to deliver greater efficiencies without compromising reliability. Demand devices, such as intelligent thermostats, will reduce consumption automatically during high-price periods, while supply devices, such as plug-in electric vehicles that store energy and communicate directly with the grid, will automatically provide energy during peak periods. A communication framework will ensure that system operators have visibility of and control over the capacity and capabilities of smart grid devices to ensure system security and reliability.

An evolutionary process will be required to achieve EISA's smart grid vision and real-time distributed control of the electricity grid. Traditional generating, transmission, and demand-response facilities, which are essential for meeting today's reliability requirements and electricity demand, will serve as the starting point and cornerstone for a smart grid. These facilities are anticipated to evolve into a smart grid through the addition of intelligent functions that will improve their overall efficiency.

The National Institute of Standards and Technology (NIST) has been directed to lead the development of interoperability standards and protocols needed for smart grid devices to operate with the power system. These standards and protocols are the critical path to develop and employ technologies required to achieve the EISA smart grid vision. The NIST "Interoperability Framework" will describe the standards and protocols smart devices must meet to enable the S&R and communication capabilities required for the automated real-time control of electricity supply and demand. The NIST 2008 work plan calls for the establishment of technical domain expert working groups that will be responsible for identifying interoperability issues and leading the development of standards that may become recommendations for adoption by FERC.

In related efforts, the North American Energy Standards Board is developing demand-response standards, and FERC and NERC have issued regulations that provide guidance to implement demand-response capabilities.

8.3.2 Operational Challenges and Opportunities

The challenges facing the implementation of a smart grid are daunting. The lack of standards and uncertainty over business practices (e.g., cost allocation between transmission and distribution) are just a few of the current issues. The shift from a centrally controlled grid, with relatively large, predictable resources, into a more distributed system that would rely on a greater number of smaller, variable-output resources—that in some cases would have the capability to increase or decrease energy automatically based on real-time information—will add significant complexity to the operation of the bulk power system. New, sophisticated optimization algorithms and control systems that co-optimize the secure and economical operation of existing supply and demand technologies with variable-output renewable resources and automated smart grid sense-and-respond devices will be needed. The volume of data is expected to increase exponentially with smart grid technologies, which will require more sophisticated network solutions than those presently in use. System and capacity planning processes will need to be enhanced to account for smart grid resources, and system operators and planners will require extensive training in new "smart-grid-aware" tools and techniques.

8.3.3 ISO Activities in Support of the Smart Grid

New England has a long history of using smart grid technologies:

- High-voltage direct-current (HVDC) facilities that control the flow of electric power
- Flexible alternating-current transmission systems (FACTS) that apply power electronics to devices that can instantaneously control the transmission system
- Phasor measurement units (PMUs) that improve the ability to observe the state of the system and provide vital information necessary to understand system events

The evolution and application of new smart grid technologies already is well underway in New England, and the ISO is implementing several smart grid projects in line with EISA's vision. For example, standards-based equipment that facilitates the integration of smart grid technologies is replacing the Remote Intelligent Gateway (RIG) communications equipment used in the collection of data points. Eastern Interconnect phasor measurement equipment is being installed at three major substations (Sherman Road, Millbury, and Northfield Mountain).[172] Additionally, the advanced grid simulator is being implemented.

In response to FERC Order 890 regarding the provision of regulation and frequency services by nongenerating resources, the ISO is conducting an Alternative Technology Regulation (ATR) Pilot Program.[173] The goal of the ATR Pilot Program is to allow the ISO to identify the impact on the New England system of alternative technologies with new and unique performance characteristics that might previously have been unable to participate in the Regulation Market. It also aims to allow the owners of the ATR resources to evaluate the technical and economic suitability of their technologies as market sources of regulation service. To date, flywheel technology has been successfully providing regulation services to the ISO New England grid under the pilot program.[174]

Another particularly noteworthy initiative well underway in New England is the integration of demand resources, which are being used to provide capacity and ancillary services (e.g., reserves) (see Section 4.2.4 and Section 5). As indicated above and in Section 4.2, the ISO's Forward Capacity Auction for 2011 produced almost 3,000 new "negawatts" of capacity obligations from demand resources (representing almost three-quarters of the new capacity that will come on line in 2011). Also, an ISO pilot program on using demand-response resources for ancillary services is underway.

Several smart-grid-related initiatives underway across New England and nationally may have an impact on the ISO and market participant activities, such as control room operations, planning, and settlements. The NIST initiative to develop an interoperability framework could have the greatest impact given that FERC could recommend the adoption of the standards identified in the framework, as indicated within NIST's *EISA Smart Grid Coordination Plan* for 2008.[175] This could require the

[172] More information about the DOE funding opportunities the ISO applied for (DE-FOA-0000058 DE-FOA-0000036) is available at http://www.energy.gov/recovery/infrastructurefunding.htm#SMARTGRID.

[173] *Alternative Technology Regulation Pilot Program Frequently Asked Questions* (2009); http://www.iso-ne.com/support/faq/atr/index.html#faq1.

[174] Beacon Power has installed 2 MW of flywheels, which have provided regulation services from a location in Tyngsboro, Massachusetts. *Beacon Power Connects Second Megawatt of Regulation Service* (New York: Business Wire, July 20, 2009); http://www.businesswire.com/portal/site/home/permalink/?ndmViewId=news_view&newsId=20090720005598&newsLang=en.

[175] National Institute of Standards and Technology, *NIST EISA Smart Grid Coordination Plan* (Gaithersburg, MD: June 2, 2008).

ISO to upgrade its market rules to account for the use of various types of smart grid equipment, incorporate the effects of smart grid into the electricity use forecasts, and update the co-optimization algorithms needed for the real-time operation of the system.

The ISO also is interested in the potential for using energy storage as a type of smart grid technology. In particular, PEVs can add off-peak charging load and storage capability for energy produced off peak. The implementation of a project in Tiverton, Rhode Island, using PEVs and vehicle-to-grid (V2G) technology also is expected to join the ATR program in fall 2009.[176]

An ISO white paper, *Overview of Smart Grid—Policies, Initiatives and Needs*, is a technical overview of the smart grid and how these technologies are being implemented to improve the power grid in New England and the rest of the country.[177] The paper describes various technologies, governmental programs, and other plans for implementation.

8.3.4 Implications of the EISA Smart Grid on System Planning and Operations

The implementation of smart grid technologies will likely require ongoing changes to the market rules and will significantly increase the complexity of operating and planning the electric power system. Because smart grid devices are capable of making intelligent decisions about energy consumption and supply, the ISO's ability to co-optimize these smart devices with existing grid infrastructure will require more sophisticated tools than those in use today. Additionally, an exponential growth in the number of assets under ISO control could accompany the implementation of the smart grid, especially if and when PEV and distributed generation technology reach critical mass. Smart grid applications also are expected to significantly increase the volume of data that will need to be gathered and analyzed, which will require more sophisticated solutions than those currently in use. New software programs and algorithms will be needed for energy balancing and control functions. Operators will require a new breed of visualization tools to aid situational awareness and improve decision making and response time. System planners will need smart-grid-aware tools that extract efficiencies from existing infrastructure when new "smart devices" are used.

Relatively few formal standards and business practices exist at present upon which to build smart grid tools and capabilities. DOE's Electricity Advisory Committee and Smart Grid Task Force are working diligently to provide a strategy and direction for smart-grid-related developments. NIST has recently begun an initiative to develop smart grid standards and business practices. Expert domain groups have been established to develop standards for "building-to-grid," "industrial-to-grid," "home-to-grid," and transmission and distribution functions.

The success of the EISA smart grid depends on several critical characteristics and a collaborative effort across the electricity supply chain. These characteristics include the following:

- A ubiquitous, reliable, and secure communications infrastructure
- A smart grid interoperability framework, which contains communication and control protocols that operate across the entire electricity supply chain (i.e., generators, transmission operators, distribution companies, consumers, marketers, regulators)

[176] V2G technology involves vehicles that can store electric energy and supply it for ancillary services (e.g., regulation services and spinning reserves).

[177] *Overview of Smart Grid—Policies, Initiatives and Needs* (February 17, 2009); http://www.iso-ne.com/pubs/whtpprs/smart_grid_report_021709_final.pdf.

- Long-term investment and implementation commitments across the entire supply chain
- Ubiquitous and timely deployment of smart-grid-enabled infrastructure
- A methodical and practical transition and implementation plan
- Practical regulations that satisfy the needs of stakeholders across the entire electricity supply chain

Research and development efforts are needed to create the technical and business practice standards that will facilitate a successful smart grid as envisioned in the *Energy Independence and Security Act of 2007*. Presently, the most urgent needs are for educational programs, knowledge sharing, and close coordination among the parties helping to create smart grid policies, regulations, and standards and plan smart grid projects.

8.4 Summary

With almost 4,000 MW of wind resources in the ISO New England Generator Interconnection Queue and almost 2,000 MW of future committed active demand resources, the ISO's planning for the integration of these new resources is well underway.

The ISO has initiated the New England Wind Integration Study, which will evaluate in detail the interconnection, operation, and market aspects of adding wind resources at several amounts higher than the amount in the present system. This study will simulate and evaluate scenarios for approximately 12,000 MW of wind resources in the region for load levels expected late in the next decade. The ISO has implemented a protocol for wind projects in the queue to facilitate their interconnection, startup, and operation.

New active demand-resource market rules and improved operator tools and procedures are under development. To integrate larger amounts of active demand resources into the grid, the ISO is making the following changes:

- Modifications to the ISO's OP 4
- Modifications to interfaces between operators and machines
- Creation of demand-designated entities similar to generating resources
- Implementation of new communications infrastructure

These steps will make the dispatch and control of these resources more direct and similar to the dispatch of generators.

Smart grid has gained considerable attention in 2008 and 2009. The ISO actively is implementing several smart grid projects, and several smart grid technologies have successfully been integrated into the transmission system. Additional research and development efforts are necessary to develop technical standards and business practices to fully utilize smart grid technologies on the distribution system and at consumer locations. Developing standards of smart grid technologies is a major area of focus at the national level, which the ISO is following. The potential for use of PEVs is one smart grid technology of particular interest to the ISO. PEVs can add off-peak charging load and also offer storage capability for renewable energy produced off-peak.

Section 9
System Performance and Production Cost Studies

RSP09 provides a range of information that can assist market participants and other stakeholders in evaluating various resource and transmission options for participating in New England's wholesale electricity markets. Under Attachment K to the OATT, the ISO is required to provide a forum for stakeholder review of the impact of alternative system-expansion scenarios. This includes information on system performance, such as estimated production costs, load-serving entity energy expenses, estimates of transmission congestion, and environmental metrics. The ISO analyzed a series of scenarios for a 10-year period from 2009 through 2018 to reflect various changes in demand-resource characteristics.

The purpose of these studies is to "test" future resource additions and the effect of transmission constraints in a context similar to the "what-if" framework of the 2007 Scenario Analysis.[178] While the 2009 evaluations are not an introduction to a specific Market Efficiency Transmission Upgrade (METU), also known as an "Attachment N" project, the results can be used to identify the need for additional targeted studies.[179]

The effect of future resource additions was assessed for the entire 10-year period beginning January 2009 and reflected system conditions, including load levels, transmission constraints, and available resources.[180] In aggregate, four levels of "tested" resource additions were hypothesized: 1,200 MW, 2,400 MW, 3,600 MW, and 4,800 MW. These resources were assumed to be located in various places in New England and the neighboring Canadian provinces. The resources represented various technologies, such as onshore wind, offshore wind, biomass, large hydro, "CANDU"-based nuclear, and conventional natural-gas-fueled resources.[181] The locations for the new resources were southern New England, southeastern New England, northern Vermont and northern New Hampshire, northern Maine, New Brunswick and the Atlantic provinces (Maritimes), and Québec.

The analyses used assumptions for factors such as fuel prices, unit availability, and load growth, all of which could affect system performance metrics. Because all the assumptions are uncertain, the modeling results indicate relative values and trends and are not intended to be accurate projections of future congestion, ultimate project economics, and environmental impacts.

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178 *New England Electricity Scenario Analysis* (August 2, 3007)*;* http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/scenario_analysis_final.pdf.

179 A Market Efficiency Transmission Upgrade is designed primarily to provide a net reduction in total production costs to supply the system load. Attachment N of the OATT describes the requirements for identifying a METU. For further details, see the ISO's OATT, Section II.B, Attachment N, "Procedures for Regional System Plan Upgrades;" http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html.

180 Historical system performance is discussed in ISO weekly, monthly, and annual market analyses and reports, which are available online at http://www.iso-ne.com/markets/mkt_anlys_rpts/index.html, and in histograms discussed with the PAC, *RSP09 2008 Historical Market Data: Locational Margin Prices Interface MW Flows*, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/jan212009/a_lmp_interface.pdf.

181 *CANDU* refers to Canada deuterium uranium, a Canadian-designed, pressurized, heavy-water power reactor that uses heavy water (deuterium oxide) as a moderator and coolant and natural uranium for fuel. See http://www.candu.org/candu_reactors.html.

This section provides an overview of the economic and environmental results of these analyses. Additional details and discussion of these simulations, assumptions, and results are documented in a supplemental report.[182]

9.1 Modeling and Assumptions

The 10-year simulations of the system expansion scenarios were conducted using the Interregional Electric Market Model (IREMM), a simulation tool the ISO has used in past production cost analyses for developing hourly, chronological system-production costs, and other metrics. The model was used to produce a base-case simulation and then to develop sensitivity cases with differing specific assumptions.

Most of the cases were designed to test the effects of injecting “carbon-free” or “carbon-neutral” electric energy into various areas of New England, despite the possibility of these resources creating congestion. The other cases were associated with the addition of conventional natural-gas-fueled resources in southern New England.

The data assumptions and modeling inputs were based on the following factors:

Load Forecast: The load and electric energy forecasts used in this analysis were based on the data presented in Table 3-2 of RSP08, which are different from the load and energy forecasts discussed in Section 3 of this report.

System Generation: The supply resources for the existing system were based on the April 2008 CELT report plus the new supply resources that cleared in FCA #1 for 2010/2011. Wind energy resources added from the ISO Generator Interconnection Queue were assumed to have an FCM-qualified capacity equal to 20% for this initial resource expansion. Under these assumptions, supply resources were adequate to meet the ICR until 2014.

RSP08 Supply Resources: Consistent with RSP08 assumptions, supply resources were added to meet the ICR after 2014. Resource additions were assumed based on approved final planning design status and the commercial in-service date in the ISO Generator Interconnection Queue.

Demand Resources: Demand resources were one of the types of supply resources included in the RSP08 case. Three types of demand resources were modeled based on the results of FCA #1: 700 MW of passive demand resources, which were represented as energy efficiency; 979 MW of near-peak demand resources, which were activated when the load approached seasonal peaks; and 709 MW of emergency generation activated in OP 4 at Action 12 (to implement voltage reductions).[183]

“Tested” Resources: The addition of carbon-free, carbon-neutral, or conventional resources was tested in the New England system to quantify the effects of these resources on the economic and environmental metrics. Because the resources were assumed to be added in the 2009 system, the results also can be interpreted as illustrating the effects of lower load forecasts or the addition of

[182] The results of this study will be available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html.

[183] Operating Procedure No. 4, *Action during a Capacity Deficiency* (March 5, 2008); http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

demand resources. These resources were assumed to be supplemental to the RSP08 resources. The dispatch of the "tested" resources displaces the most expensive existing resources, which tend to be older generators. This could lead to generator retirements that the simulations do not currently anticipate.

None of the metrics presented in this study consider the effect of the additional "tested" resources on any FCM or ancillary payments.

Transmission Interfaces: Interfaces between the 13 RSP load areas were modeled. Figure 9-1 shows the RSP transmission topography, and Table 9-1 shows the interface values reflecting the assumed completion of the New England East–West Solution in 2013 and the Southwest Connecticut reliability project in 2010 (refer to Section 10).[184]

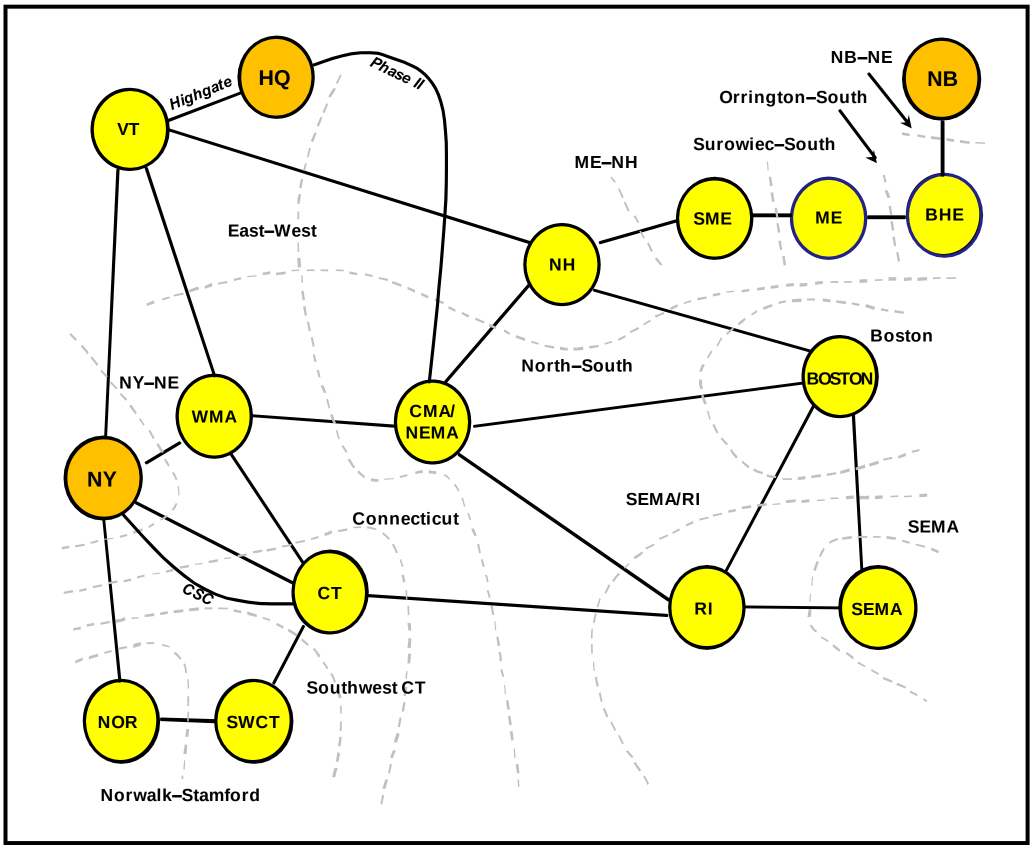

Figure 9-1: Transmission interfaces and RSP areas.

[184] The Southwest Connecticut Reliability Project actually was put in service in 2009.

Table 9-1
Assumed Transmission Interfaces Limits (MW)[(a, b)]

Interface	2009	2010	2011	2012	2013	2014	2015	2016	2017
New Brunswick–New England	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Orrington–South Export	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Surowiec–South	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150	1,150
Maine–New Hampshire	1,600	1,600	**1,575**	**1,550**	**1,525**	**1,500**	**1,475**	**1,450**	**1,450**
North–South	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700
Boston Import	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
SEMA Export	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit	No limit
SEMA/RI Export	3,000	3,000	3,000	3,000	**3,300**	**3,300**	**3,300**	**3,300**	**3,300**
East–West	2,800	2,800	2,800	2,800	**3,500**	**3,500**	**3,500**	**3,500**	**3,500**
Connecticut Import	2,500	2,500	2,500	2,500	**3,600**	**3,600**	**3,600**	**3,600**	**3,600**
Southwest Connecticut Import	2,350	**3,650**	**3,650**	**3,650**	**3,650**	**3,650**	**3,650**	**3,650**	**3,650**
Norwalk–Stamford	1,300	**1,650**	**1,650**	**1,650**	**1,650**	**1,650**	**1,650**	**1,650**	**1,650**
Cross-Sound Cable (Export)	330	330	330	330	330	330	330	330	330
Cross-Sound Cable (Import)	346	346	346	346	346	346	346	346	346
NY–NE Summer	1,525	1,525	1,525	1,525	1,525	1,525	1,525	1,525	1,525
NY–NE Winter	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
NE–NY Summer	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
NE–NY Winter	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325	1,325
HQ–NE (Highgate)	200	200	200	200	200	200	200	200	200
HQ–NE (Phase II)	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400

(a) The transmission limits shown are suitable for economic studies but may not be applicable for other analyses.

(b) **Bolded** values indicate change due to system improvements and load growth. No changes in transfer limits have been assumed for the Maine Power Reliability Program, but changes due to load growth have been reflected on the Maine—New Hampshire interface limit.

FTRs/ARRs: The FTR/ARR congestion values are equal to the product of the constrained interface flow and the price differential across the constrained interface.

Fuel-Price Forecast: The fuel-price forecast was based on DOE's *2008 Annual Energy Outlook* (AEO).[185] The fuel prices (in 2006 dollars) were useful in establishing the base cases from which the relative impacts of each of the sensitivity cases could be determined.

Allowance Prices: The emission values were modeled in the dispatch cost. SO_2 values were based on the assumptions used in the 2008 AEO energy forecast. NO_X values were used in the ozone season and were based on early-year 2008 prices. These NO_X values were applied only to resources in Connecticut, Massachusetts, New Hampshire, and Rhode Island. The CO_2 emissions allowance price for all cases was assumed to be $10/ton.

Emission Rates: SO_2 rates were based on the percentage of sulfur in the fuel currently used in a generating unit and any sulfur control technology at a plant. Most coal-fueled resources were assumed to install some form of scrubber control technology in 2012. CO_2 rates were based on the fuel type and standard EPA conversion rates. NO_X rates were based on a survey of emission data sources internal and external to the ISO.

9.2 Cases Considered

The framework for this analysis was to hypothesize many resource additions in various places within and outside New England as described in Table 9-2. These generalized resource expansion scenarios were then converted into 87 different cases with different proportions of each type of resource. Four of the cases tested new natural-gas-fired resources located in the load centers of southern New England.

[185] *2008 Annual Energy Outlook*, DOE/EIA-0383 (Washington DC: U.S. DOE, Energy Information Administration, June 2008); http://www.eia.doe.gov/oiaf/archive/aeo08/index.html.

Table 9-2
Overview of Resource Additions for the Cost and Emission Simulations (MW)

Source	Resource Type	Series Designation[a]												
		RSP08	#1	#2A	#2B	#2C	#3A	#3B	#3C	#3D	NGCC	NGCC	NGCT	NGCT
Orrington/ New Brunswick	hydro, onshore wind, and nuclear						1,200	2,400	1,200	2,400				
Orrington Renewable	onshore wind		1,200			1,200				1,200				
Vermont Renewable	mostly wind (onshore)		400		400	400								
NH Renewable	onshore wind and biomass		800		800	800								
Quebec into New Hampshire	hydro and onshore wind						1,200	1,200	2,400	1,200				
Southeast Massachusetts	offshore wind			800	800	800								
Rhode Island	offshore wind			400	400	400								
Boston	conventional natural gas fired										1,200	2,400	1,200	2,400
Southwest Connecticut	conventional natural gas fired										1,200	2,400	1,200	2,400
Total		**0**	**2,400**	**1,200**	**2,400**	**3,600**	**2,400**	**3,600**	**3,600**	**4,800**	**2,400**	**4,800**	**2,400**	**4,800**
Number of Cases		**1**	**3**	**1**	**3**	**3**	**18**	**18**	**18**	**18**	**1**	**1**	**1**	**1**

(a) No resources were added in the RSP08 case. The other series show the resources added to the RSP08 case.

The cases resulting in the largest amount of congestion were those that added resources in northern New England. The "#3D" series resulted in the most congestion due to the addition of 3,600 MW of resources north of the Orrington–South interface plus 1,200 MW north of the Maine–New Hampshire interface. This "#3D" series was selected for further investigation assuming hypothetical increases in the transmission-transfer capabilities but without the identification of specific transmission improvements. Eleven steps of increased transfer capability were considered, as shown in Table 9-3, with the last case approximating a 1,200 MW increase in transmission-transfer capability all along the Maine/New Hampshire corridor into Massachusetts.

Table 9-3
Incremental Increases in Transmission Interface Limits
Tested with 4,800 MW of Resource Additions
(3,600 MW North of the Orrington–South Interface) (MW)

Interface Test Group Number	Orrington–South	Surowiec–South	Maine–New Hamp.	North–South
1	0	0	0	0
2	600	0	0	0
3	600	600	0	0
4	1,200	600	0	0
5	1,200	1,200	0	0
6	1,800	1,200	0	0
7	1,800	1,800	0	0
8	1,800	1,800	600	0
9	1,800	1,800	600	600
10	1,800	1,800	1,200	600
11	1,800	1,800	1,200	1,200

9.3 Simulation Metrics—2009 to 2018

The key metrics used to compare the cases are production cost and LSE electric energy expense. The absolute values of these metrics are not the focus of this analysis because the aim is to quantify relative changes.

The production cost metric is based on the summation of dispatch costs for each unit multiplied by the amount of electric energy produced. This calculation is performed for all New England resources used to serve customer demands. Production costs for resources located in external areas are not included in this metric.

LSE energy expense is calculated by taking the hourly marginal energy cost (e.g., the LMP) in an RSP area and multiplying it by the hourly load in that same RSP area. New England's total LSE energy expense is the summation of each RSP area's LSE energy expense.

Within an import-constrained subarea, the one source of electric energy not paid the LMP, effectively, is a purchase brought into the congested subarea from an external subarea. The purchase of energy from an external subarea is modeled through a complex process that allows a certain amount of energy to flow into the constrained subarea and to be valued at essentially the selling area's LMP. The rights associated with this transmission path are referred to as Financial Transmission Rights (FTRs) (see Section 2.4).[186] A portion of the revenues associated with these FTRs may flow back to the LSEs as their share of the Auction Revenue Rights (ARRs).[187] Thus, a third metric is the "FTR/ARR" congestion estimate.

The analysis did not include other costs that New England wholesale electricity customers would pay, such as Forward Capacity Market payments, ancillary service costs, regulation costs, Renewable Energy Credits and Alternative Compliance Payments associated with Renewable Portfolio Standards, transmission costs, and other costs. Additionally RGGI allowances may have offsetting revenue streams originally sold to generators. These revenues are expected to flow back to the New England electricity consumers through state energy-efficiency programs as support payments for low-emitting resources and additional funds for demand response and conservation (see Section 7.2).

The environmental metrics are the total tons of CO_2, NO_X, and SO_2 emissions. While these are informative metrics, under cap-and-trade programs, the total number of tons emitted in the long term will equal the cap because the supply and demand for allowances affect the allowance prices, which will ensure the use of all allowances.

9.4 Overview of Simulation Results—2009 to 2018

Table 9-4 shows the metrics for the different case groupings. For each case grouping, average values of the cases considered in the series are shown. In addition to the average metric for each group, assuming RSP08 transmission assumptions, the average value for the "#3D" series with the maximum increase of transmission constraints is shown.[188]

[186] Also see the ISO's *2008 Annual Markets Report*, Section 2.6; http://www.iso-ne.com/markets/mktmonmit/rpts/index.html.

[187] *Auction Revenue Rights* are a mechanism used to distribute some of FTR auction revenue to congestion-paying load-serving entities and transmission customers that have supported the transmission system.

[188] Detailed numerical results underlying all the graphs for this analysis are available online at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2009/economicstudy.xls.

Table 9-4
Summary of Metrics for Scenario Groupings

Source	Series Designation													
	RSP08	#1	#2A	#2B	#2c	#3A	#3B	#3C	#3D	#3D Relaxed[(a)]	NGCC	NGCC	NGCT	NGCT
Total megawatts	0	2,400	1,200	2,400	3,600	2,400	3,600	3,600	4,800	4,800	2,400	4,800	2,400	4,800
Number of cases	1	3	1	3	3	18	18	18	18	18	1	1	1	1
10-year production cost ($ million)	48,858	45,010	46,280	44,271	42,560	42,111	40,428	39,113	40,240	37,000	47,195	45,951	48,854	48,855
10-year total LSE energy expense ($ million)	96,215	92,156	93,898	91,511	90,514	91,097	89,987	89,184	89,832	87,588	88,214	82,594	96,144	96,151
10-year total FTR/ARR ($ million)	0	446	2	1	423	428	3,980	844	4,484	1,429	0	0	0	0
10-year average annual CO_2 (mtons)	59.3	58.7	57.2	58.1	56.6	53.6	51.6	51.0	51.4	49.2	57.4	56.1	59.3	59.3
10-year average annual SO_2 (ktons)	101.8	101.2	101.2	101.1	100.9	100.5	100.3	98.9	100.3	99.3	99.8	98.3	101.8	101.8
10-year average annual NO_X (ktons)	33.2	33.3	32.4	33.2	32.8	31.3	30.2	30.6	30.0	30.1	30.3	28.7	33.2	33.2

(a) This 3D case is with relaxed transmission: Orrington–South and Surowiec–South at 1,800 MW and ME–NH and North–South at 1,200 MW.

9.4.1 Ten-Year Production Simulation Metrics

Figure 9-2 shows the total 10-year production simulation metric as a function of the annual amount of electric energy injected, or made available, in each case. As the amount of injected electric energy increases, the magnitude of the metric decreases. Figure 9-2 shows that the total annual New England system production costs decrease as additional low- or zero-cost energy is injected. In the RSP08 case (shown as the case injecting zero energy), the amount of injected energy effectively is zero.[189] The case with 4,800 MW of advanced combined-cycle resources in southern New England injected the maximum amount of energy of the cases investigated, about 37,000 GWh. The trend line for the production cost metrics for the cases with natural-gas-fired and biomass resources are higher than the cases that injected zero-cost resources because the natural-gas-fired alternatives and the biomass resources have an associated fuel cost. The relaxation of transmission constraints shows reduced production costs for the cases of additional low- or zero-cost energy injected into northern New England because of the displacement of more expensive generation in southern New England.

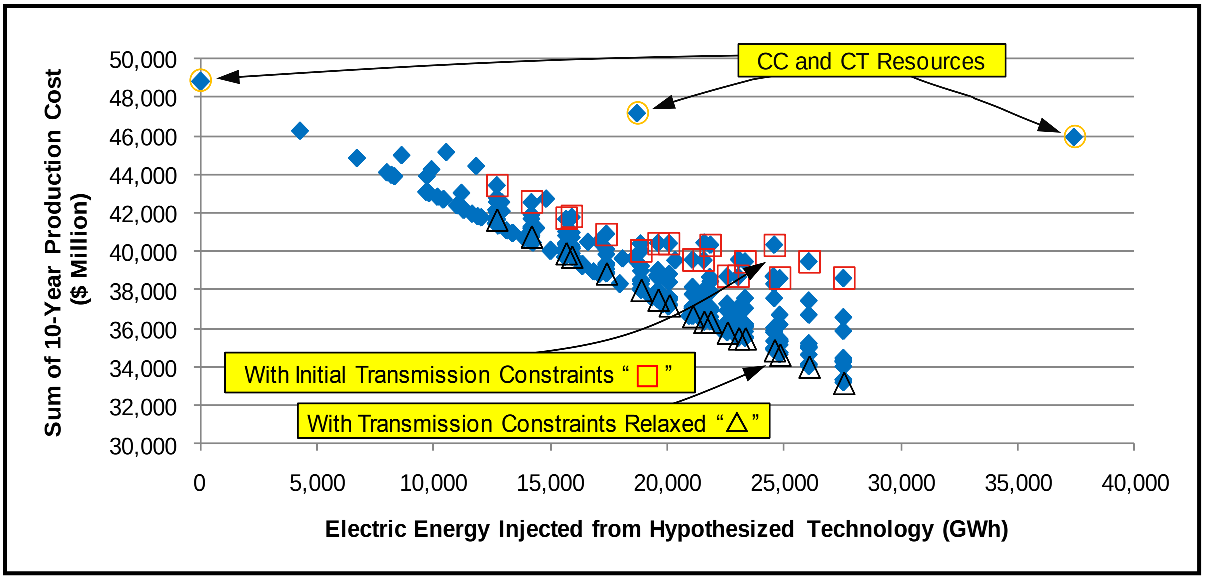

Figure 9-2: Total 10-year production costs for New England generators.

Note: No electric energy is assumed to be injected for the RSP08 case, and almost no energy is assumed to be injected for the cases with hypothesized peaking natural-gas-fired combustion turbines (NGCTs).

Figure 9-3 shows that the New England total LSE electric energy expense decreases as additional low- or zero-cost energy is injected. Because the electric energy price associated with the injected energy typically is below the price for the marginal price-setting resource, the metric for all cases is a function of the amount of energy injected. The effect of binding transmission constraints is to prevent some of the energy from flowing into load areas and thus to prevent the maximum possible reduction in the LSE energy expense. The series of "#3D" cases with transmission constraints is shown with red squares, and the corresponding case that eliminated virtually all the constraints is illustrated by the black triangles. The effect of the partial relaxation of transmission constraints is the potential reduction of the New England-wide LSE energy expense metric below the value of the black triangle because a small (3 to 5%) portion of the New England load has some locked-in energy with greatly

[189] The results of this case are similar to the sensitivity cases with either 2,400 or 4,800 MW of natural-gas-fired peaking combustion turbines added as "test" resources because the peaking units inject negligible amounts of energy.

depressed marginal energy prices. FTRs/ARRs would reduce LSE electric energy expenses, but these effects are not included in the figure.

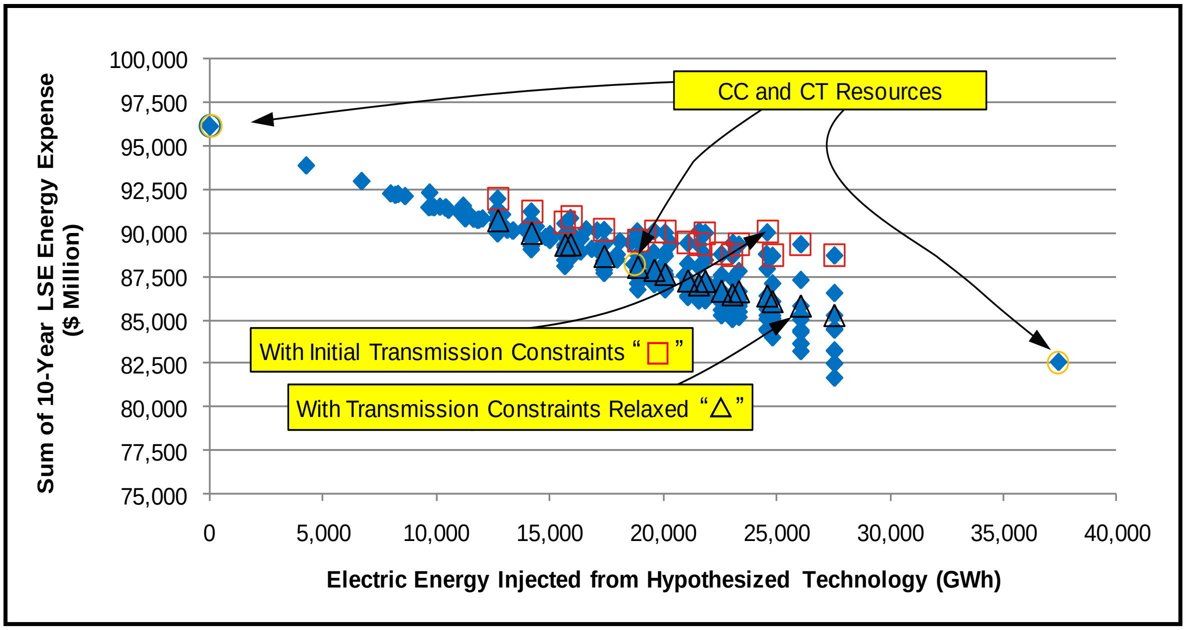

Figure 9-3: Total 10-year LSE electric energy expense without FTR/ARR offsets for the New England load.

Figure 9-4 shows the FTR/ARR congestion metric. This figure shows that an increase in the amount of electric energy injections in the north increases the amount of congestion. The three cases with the highest FTR/ARR congestion values are associated with the limited relief of transmission constraints because these cases created the greatest combination (product) of constrained flows and price differentials across constrained interfaces. Generally, the more that interface constraints are relaxed, the lower the FTR/ARR-based congestion.

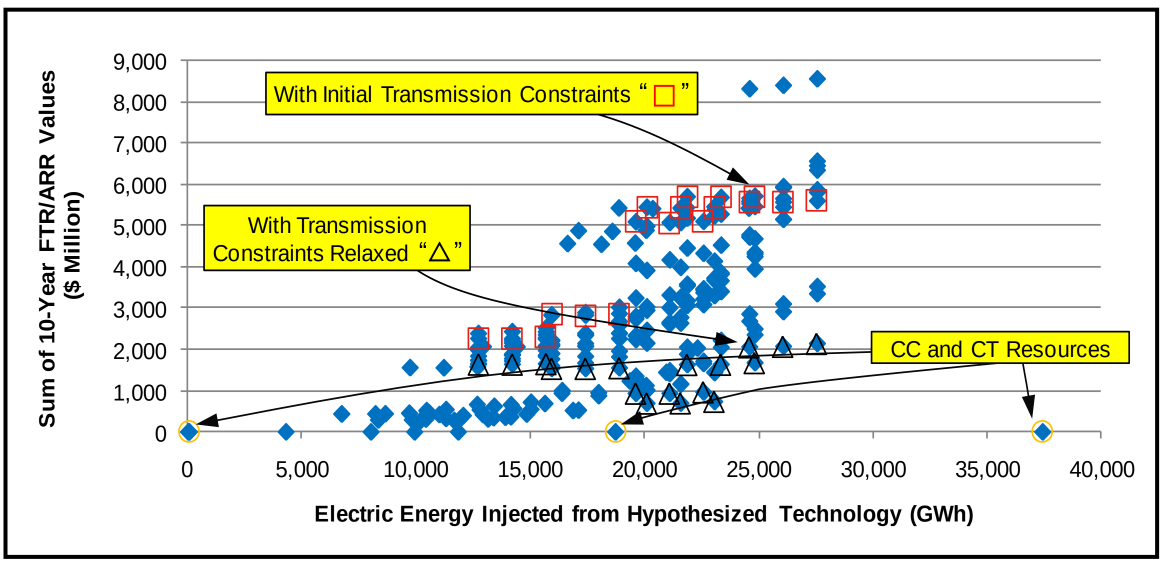

Figure 9-4: Total 10-year FTR/ARR offsets.

Figure 9-5 shows the LSE electric energy expense after adjusting for the FTR/ARR offsets. The LSEs are assumed to hold the FTRs/ARRs, which allow the LSEs to purchase some of its electric energy from the lower export-constrained area. Therefore, the LSE electric energy expense shown in Figure 9-5 is lower than that shown in Figure 9-3.

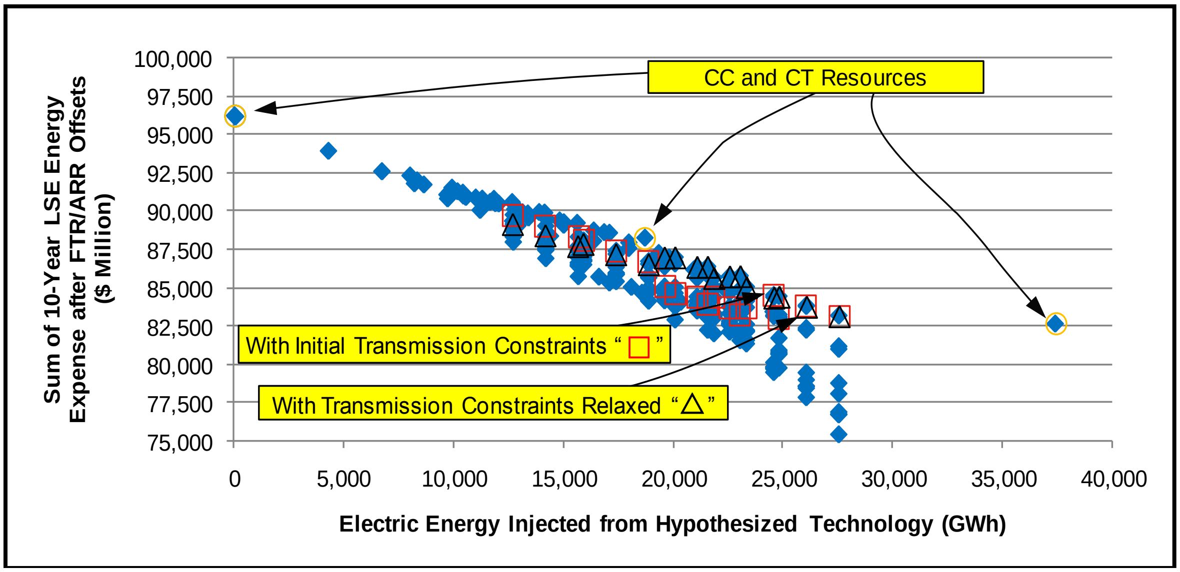

Figure 9-5: Total 10-Year LSE electric energy expense after FTR/ARR offsets for the New England load.

9.4.2 Ten-Year Environmental Metrics

Figure 9-6 through Figure 9-8 show the10-year average annual New England generator emissions for CO_2, NO_X, and SO_2, respectively, for all the cases. These figures show that the greater the amount of emission-free energy injected into, or made available, in New England, the lower the annual emission metrics. The figure also shows the effects of systemwide emissions from specific cases, such as those that added natural-gas-fueled combined-cycle and biomass fuel generation.

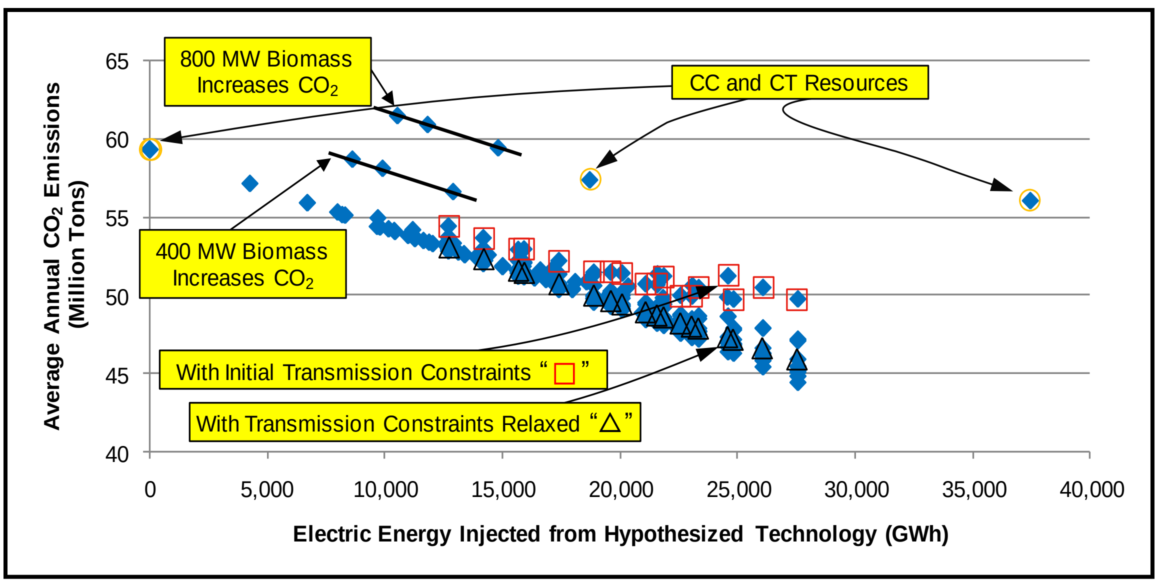

Figure 9-6: Ten-year average annual CO_2 emissions for New England generators.

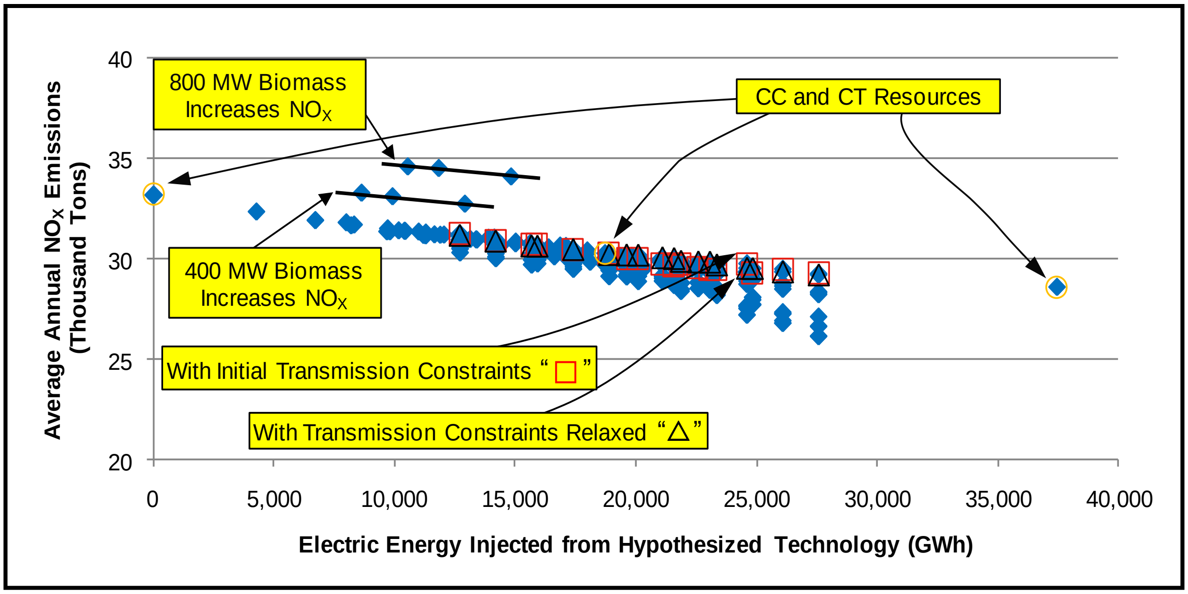

Figure 9-7: Ten-year average annual NO_X emissions for New England generators.

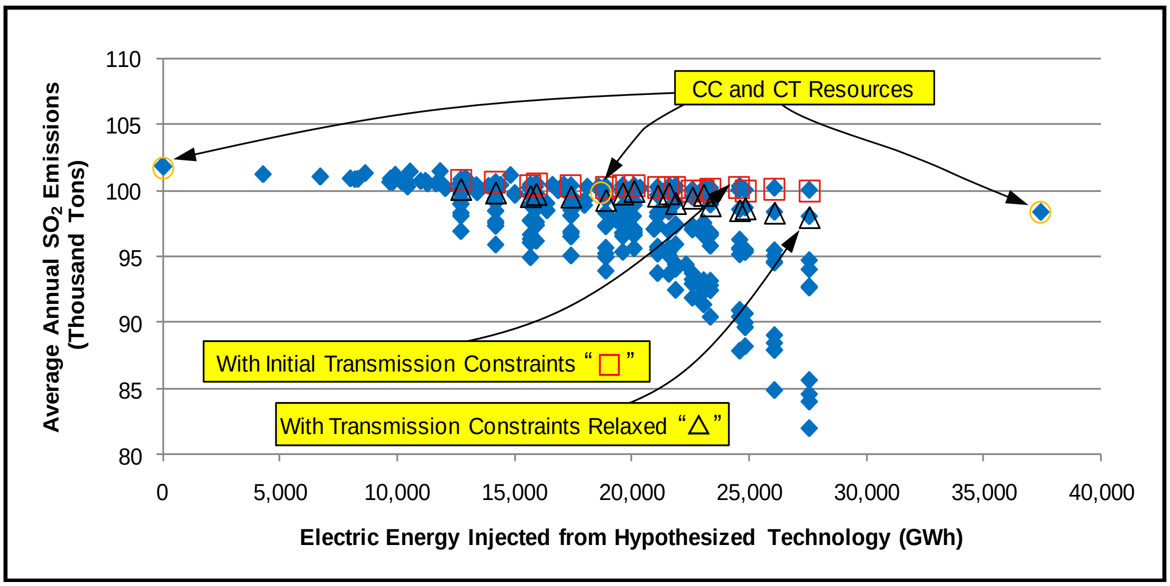

Figure 9-8: Ten-year average annual SO_2 emissions for New England generators.

Figure 9-6 shows that the average annual CO_2 emissions from all electric generating sources would be approximately 60 million tons/year. This amount is approximately 5 million tons higher than the number of RGGI allowances that would be required to support generation over this time period because resources less than 25 MW and biomass resources do not need RGGI allowances.[190] As emission-free electric energy is injected or made available to the system, the CO_2 emissions decrease. This figure specifically identifies the CO_2 emissions associated with the biomass resources. Although

[190] Biomass plants are considered to be *carbon neutral* (i.e., they have zero overall greenhouse gas emissions over their carbon cycle) because the fuels (e.g., trees) are renewable and the new trees capture the CO_2 emitted by the biomass plant.

the CO_2 emissions are higher with the addition of biomass generation than for the other cases, biomass plants can be counted as having net-zero CO_2 emissions over the carbon life cycle of the biomass fuel.

Figure 9-7 shows that the average annual NO_X emissions from all electric power generating sources would be approximately 33,000 tons per year. As emission-free energy is injected or made available to the system, the NO_X emissions decrease. This figure shows that the NO_X emissions associated with the biomass resources are higher than the cases that added other zero- or low-emitting resources.

Figure 9-8 shows that the 10-year average annual SO_2 emissions are effectively constant at 100,000 tons/year for all the scenarios whether or not the transmission constraints are binding. In some cases, however, interface constraints limit the output of higher SO_2-emitting generators located north of the North–South interface.

9.5 Effect of Additional Injected Energy

The more low-cost energy injected into New England, the lower the average clearing prices and consequently the lower the electric energy revenues for all resources. Figure 9-9 shows two price-duration curves. The higher curve is for the RSP08 case, while the lower curve is for the case with 4,800 MW of natural-gas-fired combined-cycle resources allocated equally between Connecticut and Boston. A horizontal line shows the dispatch cost for an illustrative 7,100 Btu/kWh combined-cycle resource. The area represented by the difference between the price-duration curve and the dispatch cost represents the net amount of energy market revenues that can be obtained by the illustrative resource. The RSP08 case has higher wholesale energy market clearing prices than the case with 4,800 MW of new NGCC injected into the system. Because a representative NGCC with a 7,100 BTU/kWh heat rate would have an electric energy cost of about $53/MWh, it would realize higher electric energy revenues in the RSP08 case compared with the case with new NGCC generating units added to the system.

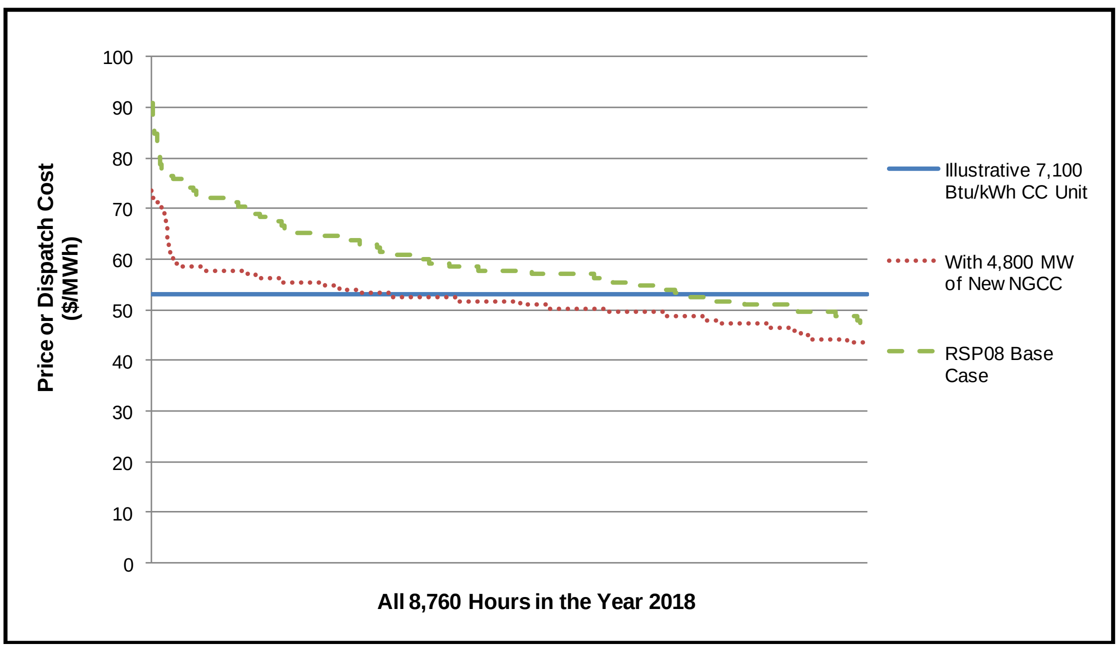

Figure 9-9: Example of net energy market revenues for an illustrative resource.

Table 9-5 shows the 10-year average net electric energy market revenues that resources would be paid, expressed in $/kW-year. The table shows results from a representative set of the more than 250 cases simulated. To provide a consistent comparison among the selected cases, an illustrative resource was extracted from the simulations representing a 7,100 Btu/kWh, natural-gas-fired combined-cycle resource in southern New England. For example, in the RSP08 case, this resource would have $83.01/kW-year in energy market revenues. In the case adding an additional 2,400 MW of advanced combined-cycle resources in southern New England, the lower average clearing prices produce a lower amount of energy market revenues totaling $46.74/kW-year. Further, adding 4,800 MW of advanced combined-cycle resources in southern New England decreases these energy market revenues to $23.83/kW-year.

Table 9-5
Effect of Additional Resources on Energy Market Revenues

Series	Subseries Case	Case Name	Location	Capacity	Technology	10-year Average Net Energy Market Revenue ($/kW-yr)	GWh Production (2018)
RSP08		Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	83.01	3,223
#1	2	Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	64.70	3,114
		1,200 MW wind and biomass	VT	400	onshore wind	191.25	1,240
			NH	400	onshore wind	191.25	1,239
			NH	400	biomass	171.75	3,153
#2A	na	Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	72.32	3,196
		Offshore wind 1,200 MW	RI	400	offshore wind	225.75	1,426
			SEMA	800	offshore wind	225.75	2,854
#2B	2	Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	61.19	3,096
		Off/onshore wind 2,400 MW	RI	400	offshore wind	220.00	1,426
			SEMA	800	offshore wind	220.00	2,854
			VT	400	onshore wind	190.00	1,240
			NH	400	onshore wind	190.00	1,239
			NH	400	biomass	168.50	3,153
#2C	2	Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	57.12	3,004
		Off/onshore wind 3,600 MW	RI	400	offshore wind	218.00	1,427
			SEMA	800	offshore wind	218.00	2,854
			VT	400	onshore wind	188.00	1,240
			NH	400	onshore wind	188.00	1,239
			NH	400	biomass	163.64	3,153
			BHE	1,200	onshore wind	122.17	3,001
#3A	3	Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	59.98	3,008
		NB nuclear and Québec wind	HQ	1,200	onshore wind	189.58	3,717
			NB	1,200	nuclear	371.68	8,932
NGCC	2,400	Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	46.74	2,718
		2,400 MW CC (6,500 Btu/kWh)	BOSTON	1,200	NGCC	81.46	9,459
			SWCT	1,200	NGCC	81.46	9,452
NGCC	4,800	Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	23.83	2,129
		4,800 MW CC (6,500 Btu/kWh)	BOSTON	2,400	NGCC	52.79	18,915
			SWCT	2,400	NGCC	52.69	17,891
NGCT	2,400	Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	83.64	3,224
		2,400 MW combustion turbine	BOSTON	1,200	NGCT	0.00	2
			SWCT	1,200	NGCT	0.01	18
NGCT	4,800	Illustrative 7,100 Btu/kWh CC unit	na	450	NGCC	80.85	3,224
		4,800 MW combustion turbine	BOSTON	2,400	NGCT	0.00	2
			SWCT	2,400	NGCT	0.01	18

The other cases have different amounts of energy injections, which affect the resulting average energy market clearing prices and energy market revenues differently. Such reductions in energy market revenues diminish the ability of the additional resources to be self-supporting in the New England energy market alone, and other sources of revenue, such as from the Forward Capacity Market, would be required.

9.6 Observations

For the given assumptions, several observations were made about the results of the IREMM simulations, as summarized below and discussed in more detail in the supplemental report:

- Systemwide production costs and LSE electric energy expenses can be affected by the amount of lower-cost resources added.
- Natural gas will remain the dominant fuel for setting marginal electric energy prices.
- Virtually no congestion is apparent within New England under the RSP08 conditions.
- The effect of the FTR/ARR offsets will reduce the LSE energy expense because it allows LSEs to purchase electric energy at less expensive prices from export-constrained areas.
- CO_2 and NO_X emissions decrease as more low-emission or zero-emission resources are added.
- Biomass resources and efficient natural-gas-fired resources produce CO_2 emissions. Biomass plants do not need to obtain RGGI allowances for their emissions because they are considered to emit no greenhouse gas over their carbon cycle.
- Adding biomass resources increases NO_X emissions.
- Sulfur emissions are likely to be unaffected by the amount of additional resources injected.
- The addition of resources that inject a significant amount of electric energy into the market and reduce average clearing prices will diminish the ability of these resources to be self-supporting solely in the New England wholesale electric energy market.
- The addition of resources in portions of southern New England, such as Connecticut, Boston, and southeastern Massachusetts, will not result in congestion. The simulation results show no congestion for the case adding 2,400 MW of NGCC in both Boston and Connecticut. Similarly, a case adding 1,200 MW of wind generation in SEMA/RI also did not result in any congestion. These results also could be viewed as representative of an injection of electric energy through HVDC transmission into these areas.
- The addition of 1,200 MW of resources north of the North–South interface will not create significant congestion on that interface.
- Injections of 1,200 MW of wind energy north of the Orrington–South interface will result in congestion. Increasing the amount of injected energy from additional wind or other resources will exacerbate the congestion.
- Increasing both the Orrington–South and Surowiec–South interfaces by 1,800 MW and increasing the North–South and Maine–New Hampshire interfaces by 1,200 MW would relieve congestion attributable to 3,600 MW of low-energy-cost resources injected into Orrington and an additional 1,200 MW of low-energy-cost resources injected into New Hampshire.

Section 10
Transmission Security and Upgrades

Much progress has been made over the past five years analyzing the transmission system in New England, developing solutions to address existing and projected transmission system needs, and implementing these solutions. Fourteen major 345 kV projects have emerged from these efforts, which are critical for maintaining transmission system reliability. These transmission upgrades also will improve the economic performance of the system.

Seven of the 14 projects that have been placed in service include the two Southwest Connecticut Reliability Projects (Phase 1 and Phase 2), the Northeast Reliability Interconnection (NRI) Project, the two phases of the Boston 345 kV Transmission Reliability Project (Phase 1 and Phase 2), the Short-Term Lower SEMA Upgrades, and the Northwest Vermont (NWVT) Reliability Project. Five of the 14 projects currently are in siting or are expected to be in siting by the end of 2009, including the Maine Power Reliability Program (MPRP) and the New England East–West Solution (NEEWS), which has four major components. The last two of the 14 projects are the Vermont Southern Loop project, which has received its siting approval, and the Long-Term Lower SEMA Upgrades, which is in the planning and engineering stages.

Additionally, the expansion of the Wachusett, Monadnock, and Ward Hill substations in Massachusetts and the Barbour Hill, Haddam Neck, and Killingly substations in Connecticut has improved the ability of the transmission system to meet load growth. Three additional projects in the final stages of construction include improvements at Wakefield Junction and West Amesbury in Massachusetts, and Keene Road, Maine, substations. Over the next five to 10 years, all these projects will help maintain system reliability and enhance the region's ability to support a robust, competitive wholesale power market by reliably moving power from various internal and external sources to the region's load centers.

This section discusses the need for transmission security and the performance of the transmission system in New England. It addresses the need for transmission upgrades, including improvements to load and generation pockets, based on known plans for the addition of resources. It also updates the progress of the current major transmission projects in the region. Information regarding the detailed analyses associated with many of these efforts can be found in previous RSPs, various PAC presentations, and other ISO reports.[191]

10.1 Benefits of Transmission Security

A reliable, well-designed transmission system is essential for meeting mandatory reliability standards and providing regional transmission service that provides for the secure dispatch and operation of generation and delivers numerous products and services, as follows:

- Capacity
- Electric energy
- Operating reserves

[191] RSP08, Section 9; http://www.iso-ne.com/trans/rsp/2008/index.html. *Planning Advisory Committee*; http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html.

- Load-following
- Automatic generation control
- Immediate contingency response to sudden generator or transmission outages

A secure transmission system also plays an important role in the following functions:

- Improving the reliability of and access to supply resources
- Regulating voltage and minimizing voltage fluctuations
- Stabilizing the grid after transient events
- Facilitating the efficient use of existing regional resources
- Reducing the amount of reserves necessary for the secure operation of the system
- Facilitating the scheduling of equipment maintenance
- Assisting neighboring balancing authority areas, especially during major contingencies affecting their reliability

10.2 Transmission Planning Process

The bulk electric power system must be planned to meet reliability standards. These standards define what constitutes adequate regional transmission service. All proposed system modifications, including transmission and generation additions or significant load reductions or additions, must be analyzed and designed carefully to ensure systemwide coordination and continued system reliability. For example, infrastructure throughout many parts of the system, which was planned, designed, and built many years ago, is becoming increasingly inadequate. The system contains relatively old, low-capacity 115 kV lines, many of which were converted from 69 kV design. Additionally, a number of aging 345/115 kV transformers are connected to the 115 kV system. The continued use of this aging equipment increases the risk of the system experiencing extended equipment outages that cannot be repaired or replaced quickly. Thus, many of the transmission system projects underway in the region will improve the operation of those areas of the system currently complicated by, for example, restrictions on generator dispatch, the use of special protection systems (SPSs), varying load levels, and facility outages resulting from unplanned contingencies and maintenance conditions. Transmission projects can reduce or eliminate the complexities of operating the bulk power system that jeopardize reliability, an important consideration in developing plans.

Through an open stakeholder process, the ISO develops its plans for the region's networked transmission facilities to address system needs cost effectively. Stakeholders also provide input to the ISO, which reviews all plans to ensure they can be implemented without degrading the performance of the New England system, the NPCC region, or the remainder of the Eastern Interconnection.[192]

As part of its regional system planning process, which supports the ISO's compliance with NERC planning standards, and through a series of subarea studies, the ISO examines the performance of the system for a 10-year period on the basis of forecasted load levels and the expected transmission configuration. These individual subarea studies identify and summarize future system needs in a

[192] The *Eastern Interconnection* consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas (ERCOT) and Québec.

"needs assessment" that could include conceptual transmission solutions. After the results of the needs assessment are made available for stakeholder input, the potential transmission system solutions are evaluated thoroughly to determine the most cost-effective solution for the region. These study efforts and the proposed transmission solutions are documented in a "solutions study," which also is subject to stakeholder review and input. These studies, in aggregate, provide the basis to update the ISO's Regional System Plans and ensure an ongoing 10-year plan for the region consistent with the standards and criteria of NERC and the NPCC.

As part of the transmission planning process, the ISO accounts for the potential change in the timing of and need for transmission projects. Determining transmission system needs that address transmission-security concerns relating to transfer limits is highly dependent on available generation and load requirements. For example, an increase in available generation, demand resources, or a combination of both in load pockets, resulting from the Forward Capacity Auction process, and decreases in load requirements, such as from the economic downturn and as forecast in the 2009 load forecast (see Section 3), could delay the need for projects planned to improve transfer capabilities. Sensitivity analyses also are conducted to account for other factors, such as generation unavailability, maintenance-outage conditions, and potential retirement scenarios that could advance the need for transmission improvements. The ISO continuously reviews the need for and timing of these projects as new information becomes available through the open stakeholder process.

10.3 Transmission System Performance Needs Assessments and Upgrade Approvals

The New England bulk power system provides electricity to a diverse region ranging from rural agricultural areas to densely populated urban areas, and it integrates widely dispersed and varied types of power supply resources. The geographic distribution of New England's summer and winter peak loads is approximately 20% in the northern states of Maine, New Hampshire, and Vermont and 80% in the southern states of Massachusetts, Connecticut, and Rhode Island. Although the land area in the northern states is larger than the land area in the southern states, the greater urban development in the south creates the relatively larger southern demand and corresponding transmission density.

The New England bulk transmission system is composed of mostly 115 kV, 230 kV, and 345 kV transmission lines, which in northern New England are generally longer and fewer in number than in southern New England. The New England area has nine interconnections with New York: two 345 kV ties, one 230 kV tie, one 138 kV tie, three 115 kV ties, one 69 kV tie, and one 330 MW +/-150 kV HVDC tie.

Currently, New England and New Brunswick are connected through two 345 kV ties, the second of which was placed in service in December 2007.[193] New England 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 with terminal configurations allowing up to 2,000 MW to be delivered at Sandy Pond in Massachusetts.

The *Transmission Project Listing* is a summary of needed transmission projects for the region and includes information on project status and cost estimates.[194] The list is updated at least three times per

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[193] One exception is that Aroostook and Washington Counties in Maine are served radially from New Brunswick.

[194] RSP09 *Transmission Project Listing*, current update; http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html.

year, although the ISO regularly discusses the justification for transmission improvements with the PAC and the Reliability Committee, which provide guidance and comment on study scopes, assumptions, and results. The ISO's *Transmission, Markets, and Services Tariff*, Section II of Attachment K, describes the regional system planning process and defines a needs assessment and solution study.[195] The *Transmission Project Listing* classifies projects as they progress through the study and stakeholder planning processes as follows:

- **Concept—**a transmission project under consideration by its proponent as a potential solution to meet a need the ISO has identified in a needs assessment or the RSP but for which little or no analysis is available to support the transmission project.
- **Proposed—**a regulated transmission solution that (1) has been proposed in response to a specific need the ISO identified in a needs assessment or the RSP, and (2) has been evaluated or further defined and developed in a solutions study, as specified in Section 4.2(b) of Attachment K but has not received ISO approval under Section I.3.9 of the tariff.[196] The regulated transmission solution must include analysis sufficient to support an ISO determination, as communicated to the PAC, that it would likely meet the ISO-identified need included in the needs assessment or the RSP.
- **Planned—**a transmission upgrade the ISO has approved under Section I.3.9 of the tariff. Both a needs assessment and a solution study have been completed for planned projects.

Projects are considered part of the Regional System Plan consistent with their status and are subject to Schedule 12 of the tariff, which governs transmission cost allocation for the region. The need and timing of transmission projects are subject to periodic stakeholder review and ISO approval as system parameters change, such as the load forecast, resource additions and retirements, and other factors. PAC discussions and supporting documentation of needs assessments, solutions studies, and the *Transmission Project Listing* provide detailed information to stakeholders including developers interested in developing resource alternatives to transmission projects. Stakeholders interested in performing independent analyses can access databases as long as the ISO grants permission to access critical energy infrastructure information in accordance with FERC policies and ISO procedures.[197]

The following sections summarize the July 2009 status of several transmission planning studies and the need for upgrades.[198]

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[195] ISO New England *Open Access Transmission Tariff*, Section II, Attachment K, "Regional System Planning Process," (December 7, 2007); http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/2-1-09_sect_ii.pdf.

[196] This part of the ISO tariff covers the review of participants' proposed plans; see http://www.iso-ne.com/regulatory/tariff/sect_1/09-8-19_section_1.pdf.

[197] FERC form 715 requires transmitting utilities that operate facilities rated at or above 100 kV to submit information to FERC annually; see http://www.ferc.gov/docs-filing/eforms/form-715/overview.asp. The ISO Information Policy, Attachment D of the ISO's *Transmission, Markets, and Services Tariff*, addresses the requirements for controlling the disclosure of critical energy infrastructure information (CEII) and confidential information; see http://www.iso-ne.com/regulatory/tariff/attach_d/index.html.

[198] Further details about individual transmission projects can be obtained by contacting ISO Customer Service at (413) 540-4220.

10.3.1 Northern New England

The northern New England (NNE) area encompasses the transmission system in Maine, New Hampshire, and Vermont. Studies of each of these states are being conducted to address the transmission system's short- and long-term needs.

10.3.1.1 Northern New England Transmission

With the Northeast Reliability Interconnection in service, New England and New Brunswick now have two 345 kV interconnections leading into a 345 kV corridor at Orrington, Maine. The corridor spans hundreds of miles and eventually ties into Massachusetts. The transmission system throughout northern New England is limited in capacity; it is weak in places and faces numerous transmission security concerns. Underlying the limited number of 345 kV transmission facilities are a number of old, low-capacity, and long 115 kV lines. These lines serve a geographically dispersed load as well as the concentrated, more developed load centers in southern Maine, southern New Hampshire, and northwestern Vermont.

The two most significant issues facing the area have been to maintain the general performance of the long 345 kV corridor, particularly through Maine, and to maintain the reliability of supply to meet demand. The region faces thermal and voltage performance issues and stability concerns and is reliant on several SPSs that may be subject to incorrect or undesired operation. Rapid load growth has raised particular concerns in northwestern Vermont; the southern and seacoast areas of New Hampshire and Maine; various localized areas across Maine; and the tri-state "Monadnock" area of southeastern Vermont, southwestern New Hampshire, and north-central Massachusetts. The system of long 115 kV lines, with weak sources and high real- and reactive-power losses, is exceeding its ability to integrate generation and efficiently and effectively serve load. In many instances, the underlying systems of 34.5 kV, 46 kV, and 69 kV lines also are exceeding their capabilities and are being upgraded, placing greater demands on an already stressed 115 kV system.

Over the past several years, the addition of generation in Maine and New Hampshire, in combination with the area's limited transfer capability and limited transmission expansion, has increased the likelihood of many northern New England interfaces operating near their limits, creating restrictions on northern resources. Because these interface limits depend on generation dispatch, the operation of the system becomes more complex. Additional concerns in northern New England include limited system flexibility to accommodate maintenance outages, limited dynamic reactive-power resources, and high real- and reactive-power losses. However, load growth in the north, in combination with other system changes, is easing the stresses on some northern New England interfaces, such as the interface between Maine and New Hampshire. In fact, the power flows on some interfaces, which historically have been from north to south, frequently have reversed and are moving from south to north during a significant number of hours each year, highlighting new emerging system weaknesses in addition to those on the interfaces.[199]

Load growth also is causing reliability concerns and has led to new or worsening situations in areas with localized dependence on existing generation. Additionally, limitations in the ability of special protection systems to operate correctly are at times leading to requirements to operate generation out of merit to ensure adequate SPS functioning.

[199] For a summary of system flows and LMPs, see http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/jan172008/ahistmktdata.pdf. The link shows that power flowed from New Hampshire to Maine about 40% of the time during 2007.

10.3.1.2 Northern New England Transmission System Studies

Study efforts are progressing in various portions of Maine, New Hampshire, and Vermont to address a number of transmission system concerns. Some of these studies have focused on defining short-term needs and developing solutions, while others have made significant progress in evaluating potential system conditions 10 years into the future.

Maine. The long-term system needs of Bangor Hydro Electric (BHE) and Central Maine Power (CMP) have been identified. To improve the performance of the Bangor system, 115 kV transmission lines have been proposed. CMP is proposing 115 kV expansions in western Maine to address area thermal and voltage issues. Upgrades north of Augusta and near Rumford, including a new 115 kV substation, will reduce potential voltage concerns. System reinforcements at 115 kV, including the recent addition of a new substation at Maguire Road in southern Maine, will help serve southern Maine load in the near term. Projects proposed as part of the Maine Power Reliability Program must meet reliability requirements and be consistent with long-term planning objectives in both BHE and CMP's service territories. These projects include the addition of significant new 345 kV and 115 kV transmission facilities and new 345 KV autotransformers at key locations.

New Hampshire. A number of studies of the New Hampshire portion of the system have been conducted. The midterm needs of northern and central New Hampshire will be addressed by closing the Y-138 tie with Maine (see below). A number of 115 kV transmission reinforcements already are under development in southern New Hampshire. Studies have indicated a midterm need for additional 345/115 kV area autotransformers, most likely at Scobie, at Deerfield, and near Newington. Longer-term studies are in progress to determine the reinforcements necessary to support load growth in these areas.

A 10-year, two-phase study of the New Hampshire area is in progress. The focus of this study is on serving New Hampshire loads while maintaining overall regional system performance. The first phase of this study was the needs analysis, which identified the needs for system improvements to reliably serve load in the Seacoast area as well as the southern, central, and western areas of New Hampshire. Due to the poor system performance shown by the N-1 (first-contingency) assessment, an N-1-1 (second-contingency) analysis was not performed as part of this study. This will be addressed as part of the second phase of the study, which will analyze the transmission alternatives to address the concerns found in the needs analysis. These transmission alternatives will include adding 345/115 kV autotransformers, 345 kV or 115 kV transmission lines, and reactive compensation. The study is projected to be completed in 2010.

Vermont. Study efforts to assess the needs of Vermont also have progressed. A set of transmission reinforcements as part of the Northwest Vermont Reliability Project, which is in service, was designed to address the diminishing reliability of the broad northwestern portion of Vermont's system in the near term and midterm. The project includes a new 36-mile, 345 kV line; a new 28-mile, 115 kV line; 345 kV autotransformers and substation improvements, two 230/115 kV three-winding transformers; two additional 115 kV phase-angle regulating transformers; four dynamic voltage-control devices; and static compensation.

A number of solutions have been studied to address concerns in southern Vermont, including issues of lower voltage facilities, specifically between Bennington and Brattleboro. Transmission upgrades in the Burlington area have been designed to maintain adequate supply in the event of a transmission or underlying system outage as well as to address load growth. A longer-term analysis conducted by the Vermont Electric Power Company (VELCO) confirmed Vermont state transmission system reliability concerns highlighted in previous analyses. The results of the *2006 Vermont Transmission System Long-Range Plan* (2006 VT LRP) demonstrate a need for a combination of further expansion of the 115 kV and 345 kV transmission facilities. System reinforcements resulting from the 2006 VT LRP include the addition of 345 kV and 115 kV infrastructure in Southern Vermont as part of the Southern Loop Project.

The Vermont system continues to be studied to assess and resolve potential reliability issues. Moreover, Vermont regulations require VELCO to develop a 10-year plan every three years. Accordingly, collaborative efforts between the ISO, VELCO, National Grid, and Northeast Utilities began in spring 2008 to develop the scope of this plan, which will update Vermont's 2006 long-range plan and the assessment of the reliability of Vermont's transmission system. The needs assessment for the *2009 Vermont Transmission System Long-Range Plan* (2009 VT LRP) was drafted in November 2008 and presented to the PAC in February 2009. The study identified several thermal and voltage violations, some severe and widespread, for multiple element contingencies and facility-out conditions. Facility-out conditions included the Vermont Yankee plant being out of service, capturing its potential retirement. Currently, several alternatives are being investigated to address the identified system needs, including reactive compensation throughout Vermont; variations of new 345 kV or 230 kV facilities internal or external to the state or both; and new or upgraded 115 kV facilities, among others. The 2009 VT LRP was published by VELCO on July 1, 2009. The ISO will continue to proceed with the appropriate regional stakeholder processes before it approves any final plans for Vermont.

Monadnock region. The Monadnock region encompasses a three-state area of southeastern Vermont (Brattleboro to Bellows Falls and Ascutney), southwestern New Hampshire (Keene north to Claremont), and north-central Massachusetts (Pratts Junction to the northern border with New Hampshire). In addition to supplying local demand, the transmission facilities in this region are critical for supporting a wider area, including most of Vermont and northern New Hampshire. A new 345/115 kV substation at Fitzwilliam, New Hampshire, along the Amherst–Vermont Yankee 345 kV line, and a number of 115 kV upgrades have been developed to address existing and midterm voltage and thermal performance concerns. Most of these upgrades are complete. The remaining components are expected to be completed in 2009. Studies indicate the likely need for future transmission system reinforcements in this area and will be revisited in the New Hampshire 10-year assessment.

10.3.1.3 Projects and Alternatives

The ISO has identified alternatives that address transmission system performance issues, either individually or in combination. Some of the alternatives, as described in the previous sections, address more subregional reliability issues and also have the ancillary benefit of improving the performance of major transmission corridors. The alternatives are as follows:

- **Southern Loop (i.e., the Coolidge Connector) Project**: The *2006 Vermont Transmission System Long Range Plan* identified significant system performance concerns for key contingencies occurring under heavy import conditions. A number of components that address the thermal and voltage problems these contingencies would cause are expected to be in service in 2011:
    - Installation of the new Vernon–Newfane–Coolidge 345 kV line with requisite station upgrades
    - Installation of a new Vernon 345/115 kV substation, including a new 345/115 kV autotransformer

- Installation of a new Newfane 345/115 kV substation
- Expansion of the Coolidge 345 kV substation

- **Closing the Y-138 line.** This project, actively under construction, addresses near-term central New Hampshire reliability needs and will somewhat improve the Surowiec–South and Maine–New Hampshire voltage and thermal performance problems. The planned in-service date for this project is the third quarter of 2009.
- **New Hampshire Seacoast Reliability Project.** Additional 345 kV transformer capacity is necessary to reduce autotransformer loadings and 115 kV transmission line power flows. The specific components of the project necessary to address these concerns will be developed as part of a future study of the area to be completed in 2009 to 2010.
- **Deerfield Substation Expansion Project.** This project adds a second 345/115 kV autotransformer at the Deerfield substation in New Hampshire. In addition, three new 345 kV circuit breakers will be added to eliminate problematic criteria contingencies. A new 115 kV circuit breaker also will be added between 115 kV bus #2 and the D118 line. To mitigate area overloads, the L175 line will be rebuilt and the M183 and C129 lines will be reconductored. A new 115 kV circuit breaker and an additional 115/34.5 kV transformer will be added at the Rochester substation. The project is planned to be placed in service in 2012.
- **Littleton Reconfiguration Project.** To improve system performance, this project adds 115 kV breakers at the Littleton substation in New Hampshire and relocates the Littleton 230/115 kV autotransformer from the 115 kV bus to a new bay position. The planned in-service date for the project is December 2010.
- **Rumford–Woodstock–Kimball Road (RWK) Corridor Transmission Project.** The northwestern Maine transmission system is influenced heavily by pulp and paper industrial load, but it also has significant area generation, which presently is the area's main source of voltage support. The needs for additional transmission and voltage support have been identified. The RWK project upgrades include constructing a new transmission line, upgrading existing transmission lines, installing additional capacitor banks, and changing substation configurations. All these upgrades will increase the system reliability of the western Maine network. While some pieces already have been placed in service, the planned in-service date for the entire project is the end of 2009.
- **Heywood Road (formerly Benton) Project.** Transmission upgrades are required to mitigate low voltages and voltage collapse in the Skowhegan–Waterville–Winslow area in Maine that could result from the contingent loss of critical lines in the area. A new switchyard connecting section 83 and section 67A and a new section 241 in a six-breaker ring-bus configuration will provide an additional path from Coopers Mills (formerly Maxcys) substation) to the Waterville–Winslow area. (Section 83 is a 115 kV line between Winslow and Wyman Hydro, section 67A is a 115 kV tap off section 67 between Detroit, Maine, and Coopers Mills (Maxcys) going to Rice Rips, Maine, and section 241 is a new 115 kV line between Heywood Road and Wyman Hydro.) This new switchyard will improve the system voltage performance. The upgraded Heywood Road switchyard will be located along an existing right-of-way where sections 67A and 83 can be joined at a common point. This project also includes the addition of a 20 MVAR capacitor bank at the Heywood Road

switchyard and an upgrade of portions of section 67A between the tap point of section 67 and the switchyard.[200] The planned in-service date for this project is 2009.

- **Maine Power Reliability Program.** The MPRP provides a 10-year look at the Maine transmission system and has identified the following inadequacies:
    - **Insufficient 345 kV transmission—**Maine currently has two 345 kV transmission paths from southern to central Maine and two 345 kV ties from northern Maine to New Brunswick. In the central part of the system, Maine has a single 345 kV path, which limits reliability performance and is a weak link in the system.
    - **Insufficient 345/115 kV transformation capacity—**The reliability of Maine's 115 kV system depends on the capacity and availability of autotransformers at five locations. Overloads of the autotransformers with all-lines-in service illustrate insufficient transformation capacity.
    - **Insufficient 345 kV transmission support for Portland and southern Maine—** The largest load pocket in Maine is subject to thermal and voltage reliability issues.
    - **Insufficient transmission infrastructure in western, central, and southern Maine regions—**Each of these regions in Maine represents a major load pocket that depends on local generation to meet reliability standards.
    - **Insufficient transmission infrastructure in midcoast and "downeast" Maine regions—**These regions in Maine (i.e., from Bucksport to Eastport) represent load pockets that have no local generation and fully depend on the transmission system.

- The MPRP Transmission Alternatives study has identified transmission upgrades to serve load pockets and ensure the system will meet national and regional transmission reliability criteria.[201] These projects will provide the ancillary benefit of facilitating the maintenance of the system in Maine. The selected alternative, referred to in the transmission alternatives study as "N5S1," consists of significant additions of new 345 kV lines, 115 kV lines, 115 kV capacitors; 345/115 kV autotransformers; line rebuilds; and the separation of circuits sharing common towers. The new 345 kV lines in the north create a 345 kV path from Orrington to Surowiec, while the new 345 kV lines in the south create a third parallel path from Surowiec to Three Rivers in southern Maine. While these new paths are expected to increase transfer capability out of Maine, they also will increase the ability to move power into Maine from New Hampshire and improve the ability of the transmission system within Maine to move power into the load pockets as necessary. The major 345 kV components of the plan are as follows:
    - New 345 kV line construction
        - Orrington–Albion Road
        - Albion Road–Coopers Mills
        - Coopers Mills–Larrabee Road
        - Larrabee Road–Surowiec
        - Surowiec–Raven Farm

[200] MVAR stands for "megavolt-ampere reactive."

[201] The Maine Power Reliability Program Transmission Alternatives Assessment for the Maine Transmission System (May 30, 2008) describes the original version of this project in more detail. The CMP Maine Power Reliability Program Proposed Plan Application Analyses Addendum Report (February 6, 2009) updates the project descriptions. Contact ISO Customer Support at (413) 540-4220 to inquire about accessing the MPRP Transmission Alternatives Assessment.

- South Gorham–Maguire Road
- Maguire Road–Three Rivers

- New 345/115 kV autotransformers
  - Albion Road
  - Larrabee Road
  - Raven Farm
  - Maguire Road
  - South Gorham

- Separation of double-circuit towers (DCTs)
  - 345 kV Kennebec River Crossing 375/377
  - 345 kV Maine Yankee 375/392

- Rerate 345 kV transmission lines
  - Section 378 (345 kV Maine Yankee–Mason)

On July 1, 2008, CMP submitted a siting application for these MPRP projects to the Maine Public Utilities Commission.[202] The siting process currently is in progress.

- **Maine Power Connection.** Currently, the Maine Public Service (MPS) territory is served solely by interconnections to New Brunswick and is part of the Maritimes Balancing Authority Area.[203] With participation by CMP and ISO New England, the MPS has been studying a new interconnection between its system and the Maine Electric Power Company (MEPCO) section of the New England transmission system as part of the interconnection of the Aroostook Wind Energy (AWE) plant to the MPS system. The completion of these studies has been deferred while the AWE developers reconsider the scope of their project.

- **Chester Area Project.** This project adds a 345/115 kV transformer at Keene Road in Chester, Maine, to provide necessary backup to the area load and allows for rebuilding section (line) 64. Currently, section 64 needs to be rebuilt, and the area's subtransmission system is incapable of supporting area loads while construction is underway. In addition, the section 64 rebuild and the installation of the Keene Road autotransformer will provide area support following the loss of both autotransformers at Orrington.

10.3.2 Southern New England

The southern New England area encompasses the Massachusetts, Rhode Island, and Connecticut transmission system. Studies of these states are being conducted to address a wide range of transmission system concerns, both short and long term.

10.3.2.1 Southern New England Transmission

The 345 kV facilities that traverse southern New England comprise the primary infrastructure integrating southern New England, northern New England, and the Maritimes Balancing Authority

[202] Central Maine Power Company and Public Service of New Hampshire, Request for Certificate of Public Convenience and Necessity for the Maine Power Reliability Program Consisting of the Construction of Approximately 350 miles of 345 kV and 115 kV Transmission Lines (State of Maine PUC Docket No. 2008-255) (July 31, 2008); http://mpuc.informe.org/easyfile/cache/easyfile_doc207087.PDF.

[203] MPS is part of the area administered by the Northern Maine Independent System Administrator.

Area with the rest of the Eastern Interconnection. This network serves the majority of New England demand, integrating a substantial portion of the region's resources.

Although recent improvements have been made, the southern New England system continues to face thermal, low-voltage, high-voltage, and short-circuit concerns under some system conditions. The most significant concerns involve maintaining the reliability of supply to serve load and developing the transmission infrastructure to integrate generation throughout this area. In many areas, an aging low-capacity 115 kV system has been overtaxed and no longer is able to serve load and support generation reliably. Upgrades to the bulk power system are being planned and developed to ensure the system can meet its current level of demand and prepare for future load growth (see Section 3).

10.3.2.2 Southern New England Transmission System Studies

Study efforts in southern New England have been progressing to address a wide range of system concerns. Major past and ongoing efforts have focused on the load areas with the most significant risks to reliability and threats to the bulk power system, particularly the Boston area and southwestern Connecticut. More recently, plans have been developed to address the reliability of other parts of the system, particularly Connecticut, the Springfield, Massachusetts, area, central and western Massachusetts, Rhode Island, and southeastern Massachusetts, including Cape Cod. These efforts also are addressing the broader requirements of the overall east–west transmission system. New analyses of the Boston and southwestern Connecticut areas, as well as for the Pittsfield area of western Massachusetts, are underway. Studies also are scheduled for eastern Connecticut, the Manchester–Barbour Hill area of Connecticut, and northwestern Connecticut. While many of the major efforts have primarily focused on near-term and midrange concerns, several longer-term analyses have been completed, and others are being conducted.

Massachusetts. A number of studies have addressed the Boston and northeastern Massachusetts areas. The first and second phases of the NSTAR 345 kV Transmission Reliability Project have been placed in service. This project included the construction of a new Stoughton 345 kV switching station and the installation of three new underground 345 kV lines and associated 345/115 kV autotransformers. A second 17.5-mile cable now connects the Stoughton and K Street substations, supplementing the first Stoughton to K Street circuit and one 11-mile cable connecting the Stoughton and Hyde Park substations.

The Ward Hill substation reinforcements already have been placed in service. Studies have been completed to support the Merrimack Valley/North Shore Project in the North Shore area, which consists of upgrades that should support area reliability in the long term. These upgrades currently are in the engineering and construction stages. New studies are underway to determine possible long-term needs for the Boston and northeastern Massachusetts areas through 2018.

To help address light-load voltage control in Boston, 345 kV shunt reactors were installed at North Cambridge and Lexington stations in 2005 and 2006, respectively. Historically, the Boston area has been operated under the assumption that at least one generating unit would be on line during light-load conditions in the Boston area to help maintain the stability of the eastern portions of the New England system. This synchronized generating unit provided dynamic voltage control through its excitation system.

Extensive studies, completed in 2008, investigated the possibility of eliminating the need to run Boston-area generation for these purposes and to avoid mounting operating costs for running this local generation. The studies arrived at several conclusions. First, the studies confirmed that the

Boston area can be operated reliably without running any generation in the Boston area to control steady-state high voltages during light-load periods. Second, a generator or device with dynamic voltage-control capability is not needed during light-load periods to maintain transient stability in Boston and eastern portions of New England. Third, an additional static reactor in the Boston area could further help control steady-state high voltages and provide needed light-load reactive-compensation reserves. This reactor has been installed at the Mystic station. Current studies and their preliminary results indicate the need in the short term for an additional reactor to the south, possibly at West Walpole.

A long-term reliability needs assessment for 2013 and 2018 is in the final stages for the Greater Boston area. Criteria violations have been summarized into eight categories, which include areas to the north, the west, the south, and in downtown Boston. Key outages in the north can cause overloads on the ties into Greater Boston and on 115 kV lines north of Boston. The 115 kV lines in the Tewksbury, Lexington, and Woburn areas overload when subjected to critical contingency outages. Additional contingencies cause overloads in the downtown area and on lines between Boston and Wakefield Junction. Overload issues arise between Holbrook and West Walpole for other outages. Lastly, outages result in overloaded lines and low voltages in the Sudbury, Marlboro, and Northborough areas. Over 50% of these issues can occur in the 2013 timeframe under certain system conditions. Possible solutions to these violations currently are being formulated. Components of the improvements being considered to improve Boston and the surrounding areas consist of 115 kV upgrades, new 345 kV transmission from Scobie and Seabrook, and an HVDC line from northern New England to the Greater Boston area.

The central Massachusetts transmission system, located to the west of the Boston area, is instrumental in integrating imports from the ±450 kV HVDC Phase II interconnection to Hydro-Québec and distributing that power to the 345 kV system as well as to the lower-voltage systems. Recent studies have developed a 10-year plan for central Massachusetts and portions of western Massachusetts. This plan calls for adding a third autotransformer at the Wachusett 345/115 kV substation and a second 230/115 kV autotransformer at Bear Swamp, replacing transformers at Pratts Junction and Carpenter Hill substations, adding a new 115 kV line from Millbury to Webster, and implementing several other 115 kV upgrades.

A previous analysis identified needs for the remaining portions of western Massachusetts (i.e., the Berkshire County area). Studies have been restarted with more current assumptions to redefine the needs and to determine subsequent solutions. Possible solutions include adding 345/115 kV autotransformers, upgrading considerable lengths of old 115 kV transmission lines, and installing additional capacitors to mitigate both thermal and voltage concerns.

The comprehensive New England East–West Solution analysis performed for the entire southern New England region confirmed numerous reliability problems in the Greater Springfield area.[204] The transmission system in the Springfield area consists of a large number of old DCT structures and aging 115 kV cable systems. This system also serves as a path for power flow to the Connecticut load

[204] The comprehensive analysis of system needs for the southern New England region is known as the Southern New England Transmission Reinforcement (SNETR) study. As part of this effort, in January 2008, the ISO issued the *Southern New England Transmission Reliability Needs Analysis* report. Both public (redacted) and private versions of this report are available on the ISO's Web site. Contact ISO Customer Services at (413) 540-4220 for additional information. This major study effort has spawned a short-term group of projects in Rhode Island (which became part of the Greater Rhode Island plan) and the major longer-term projects.

pocket. Under stressed system conditions of high load levels, various generation dispatches, and high external interface flows, a number of facilities in the Greater Springfield area can overload and experience low-voltage conditions. (Projects to address these problems in Greater Springfield are discussed further as part of the overall plan for the Southern New England region.)

A needs analysis of the area surrounding the Auburn Street substation found overloads of the existing 345/115 kV autotransformer and several 115 kV lines, voltage problems, and breaker overstresses. The solution to eliminate these identified reliability deficiencies includes a new bay configuration at the Auburn Street substation along with the installation of a second autotransformer and the replacement of a number of breakers. The 115 kV lines from Auburn Street to Parkview and from Bridgewater to East Bridgewater will be reconductored. Changes to the original Auburn substation equipment layout have been made through the engineering and design phases of the project.

Recent operating experience has identified the need to develop procedures for committing generating units in lower southeastern Massachusetts. Procedures now in place ensure the commitment of adequate generation to address second-contingency protection for the loss of two major 345 kV lines. This situation has resulted in some significant out-of-merit operating costs. Studies of what has become known as the Lower SEMA area have been completed, which resulted in both short- and long-term plans to reduce the reliance on these units. The short-term upgrades recently have been completed, and engineering has begun on the long-term upgrades. The short-term plan included the following system improvements:

- Looping the Bridgewater–Pilgrim 345 kV line into the Carver substation
- Adding a second Carver autotransformer
- Expanding the Carver 345 kV and 115 kV substations and the Brook Street and Barnstable 115 kV substations
- Upgrading the Kingston terminal of the 191 line between Kingston and Auburn Street
- Installing a second Carver–Tremont 115 kV line
- Connecting the spare conductors of the Jordan Road–Auburn Street line as a new Brook Street–Auburn Street 115 kV circuit
- Adding 115 kV breakers at Auburn Street
- Reconnecting the Auburn Street–Kingston line to a new position at Auburn Street
- Adding a static VAR compensator at Barnstable

The long-term plan includes adding a new 345 kV transmission line from the Carver substation to an expanded Sandwich substation with a 345/115 kV autotransformer and a new 115 kV line from Bourne to Sandwich. The Bourne to Barnstable portion of this new 345 kV line will use an existing 115 kV line built to 345 kV standards. It also involves placing the existing 345 kV Cape Cod Canal crossing on separate towers to eliminate a DCT contingency and reconductoring the 115 kV D21 line between Bell Rock and High Hill. These upgrades are intended to eliminate the need to commit generation for second-contingency protection. In addition to these upgrades, a 115 kV line from Canal to Barnstable is planned to address load growth on the Cape Cod peninsula.

Reliability concerns with the 115 kV system in the Bridgewater–Somerset–Tiverton areas of southeastern Massachusetts and the adjoining area in Rhode Island had been identified previously.

The solutions to these concerns were a group of upgrades that have been combined with the advanced Rhode Island upgrades (associated with the Southern New England Transmission Reinforcement [SNETR]/NEEWS studies) to become what is now known as the Greater Rhode Island (GRI) Transmission Reinforcements. Proposed GRI solutions in the Massachusetts area include, among other projects, the construction of new 115 kV transmission circuits from Brayton Point to Somerset and from Somerset to Bell Rock and a new 345/115 kV substation in Plainville. These upgrades currently are in the engineering and construction stages.

Rhode Island. Proposed GRI solutions in Rhode Island include the expansion of the Kent County substation with an additional 345/115 kV autotransformer, the reconductoring of the Pawtucket to Somerset (MA) 115 kV line, and the reconductoring of various 115 kV line sections in the Newport and Fall River (MA) areas. Previous studies of the southwestern Rhode Island (SWRI) area had identified the need for 115 kV upgrades to address long-term reliability issues and allow the retirement of the 1870 line special protection system. All these SWRI upgrades have been placed in service. The comprehensive SNETR/NEEWS analysis performed for the entire southern New England region revealed other reliability problems on the Rhode Island system (discussed below).

Connecticut. The Bethel–Norwalk Phase 1 of the SWCT Reliability Project, which includes a 20-mile 345 kV circuit from the Plumtree substation in Bethel to the Norwalk substation and a 345/115 kV autotransformer at Norwalk, was energized in late 2006. The Middletown–Norwalk phase of the project (Phase 2) was energized in late 2008. Phase 2 included a 69-mile 345 kV circuit from the Middletown area to Norwalk and 24 miles of double-circuit 345 kV XLPE-type underground cables. One 345/115 kV autotransformer was installed in the Norwalk substation, one was installed in the East Devon substation, and two were installed in the Singer substation. The Norwalk–Glenbrook 115 kV cable project also was placed in service in 2008. The completion of these three major projects has provided much needed flexibility in the day-to-day operations of the system by improving the reliability of service to this densely populated, high-load area of the New England system.

Past studies have shown that additional long-term 115 kV reinforcements may be required, particularly in the Bridgeport, New Haven, and Cos Cob areas. These reinforcements will be identified in the current SWCT needs assessment (discussed below). The Norwalk Harbor–Northport, NY, 138 kV cable (NNC) replacement project (formerly known as the 1385 cable) was placed in service during summer 2008. This project will help ensure the reliability of the tie between these two balancing authority areas.

The commissioning of the new Haddam 345/115 kV station in 2006 improved the reliability of service to the Middletown area, although operating studies suggest a second 345/115 kV transformer may be needed to maintain longer-term reliability. The reliability of the eastern Connecticut transmission system was significantly enhanced after the Killingly 345/115 kV substation went into service in 2007. The Barbour Hill 345/115kV autotransformer was placed in service to address reliability concerns in the Manchester/Barbour Hill area. The Rood Avenue substation and Oxford substation projects are in various stages of engineering and construction. These projects, along with the Trumbull substation project that was placed in service in June 2008, are expected to relieve overburdened distribution substations and improve local service reliability.

Long-term transmission reliability needs for the southwest Connecticut area are being assessed now to develop alternative proposals for further evaluation. Some of the needs to be addressed include low-voltage problems on the 115 kV system in the Naugatuck Valley area and thermal overload problems along the 115 kV Stony Hill corridor and the corridor down to Cos Cob. Analysis has identified circuit breakers in the southwest Connecticut area, for example at the Grand Avenue and Pequonnock 115 kV substations, which are almost or already subject to fault levels in excess of their rated capabilities under some conditions. A plan for rebuilding the Grand Avenue 115 kV substation has been developed and currently is in the engineering phase. An operating procedure has been developed to eliminate the possibility of any overstressed conditions occurring at Pequonnock before the long-term improvement now being developed can be implemented. Addressing these short-circuit problems will facilitate the interconnection of proposed generators in the southwest Connecticut area.

Other analysis has revealed that the transmission reliability of the Hartford area suffers under certain generation-outage conditions. Solutions have been identified and currently are being reviewed in greater detail. In addition, studies examining the reliability of the northwestern area of Connecticut are in the initial stages.

Southern New England region. Previously conducted regional planning studies identified a number of different emerging reliability issues whose solutions were initially pursued independently. These issues include the need for additional 345/115 kV transformation and 345 kV line-out coverage in the Rhode Island area, the need for reinforcements in the Springfield, Massachusetts, area, and the need for increased transfer capability into and through Connecticut.

As early as the *2005 Regional System Plan* (RSP05), the many interrelationships among the existing 345 kV bulk supply systems of the Springfield area, Rhode Island, and the Connecticut–Rhode Island–Massachusetts area and their possible reinforcement projects began to emerge.[205] As a result, the SNETR analysis comprehensively studied the widespread problems to ensure that solutions could be coordinated and would be regionally effective. RSP07 summarized the needs, the options, and the most likely preferred plan. The combination of projects was labeled the New England East–West Solution (NEEWS) as proposed by Northeast Utilities and National Grid. The routing, cost, and engineering analyses have been completed, and except for some additions and modifications to the 115 kV upgrades, primarily in the Springfield area, the preferred plan as proposed in 2007 has remained mostly unchanged. However, as a result of more than 1,000 MW of new resources clearing in FCA #2 within Connecticut and to the west of the New England East–West interface, portions of the NEEWS project require further review.

In review, the pre-FCA #2 analyses showed reliability concerns in the southern New England transmission system:

- Regional east–west power flows are limited across New England because of potential thermal and voltage violations to area transmission facilities under contingency conditions.
- The Springfield, Massachusetts, area experiences thermal overloads under forecasted normal conditions and significant thermal overloads and voltage problems under numerous contingencies. The severity of these problems increases when the system tries to move power into Connecticut from the rest of New England.
- Power transfers into and out of Connecticut are limited and eventually may result in the inability to serve load under many probable system conditions.

[205] *2005 Regional System Plan*, Section 5 (October 20, 2005) is available online at http://www.iso-ne.com/trans/rsp/2005/index.html or by contacting ISO Customer Service at 413-540-4220.

- East-to-west power flows inside Connecticut stress the existing system and could result in future thermal overloads under contingency conditions.
- The Rhode Island system is overly dependent on limited transmission lines or autotransformers to serve its needs, resulting in thermal overloads and voltage problems for contingency conditions.

All these concerns were associated with the significant degree of load growth experienced in the Southern New England region and highlighted violations of reliability standards within the study horizon. Some of these violations could occur in today's system under specific extreme or severely stressed conditions. Currently, operator actions are employed to address these events, but such system actions no longer will be viable as system loading increases and the resulting overload conditions worsen.

The original analyses performed for the 10-year period revealed a number of system deficiencies in transmission security, specifically in meeting area-transmission requirements and transfer capabilities. These deficiencies formed the basis for the needed transmission system improvements.

The original need assessment was based on the 2005 CELT load forecast, which is not significantly different from the latest 2009 CELT forecast. Although resources are planned for Connecticut as a result of FCA #1 and #2, additional analyses, including detailed load flow analysis, are required before any potential revision to the year of need for the full NEEWS projects can be determined. The following list describes specific transmission-security concerns related to transfer capability in the SNE region as they were identified in the original needs analyses and as they currently stand based on the latest forecast data and FCA results:

- As originally studied, Connecticut-area power-transfer capabilities would not meet transmission security requirements as early as 2009, with such deficiencies increasing through and beyond the 10-year planning horizon. The operable capacity studies supported by load flow analysis showed that Connecticut would need either transmission improvements or over 1,500 MW of supply or demand resources by 2016. With FCM, an updated review has shown that with the resources planned, Connecticut should meet reliability requirements for 2010 and 2011. However, as part of the first FCM auction process (June 2010 to May 2011), the ISO needed to deny two generator delist bids to respect transmission reliability concerns (see Section 5.1.2). The ISO will continue to closely monitor the balance between the total megawatts of capacity resources seeking to delist and the total megawatts of new entry under future FCM auctions.
- Using past planning assumptions about future generation additions and retirements within the Connecticut area, the initial study showed the need for transmission upgrades as early as 2009 and, by 2016, for an import level of 3,600 MW for N-1 and 2,400 MW for N-1-1 conditions. Additional detailed load flow analyses, including sensitivity analyses, are required to reflect generator and demand-response resources committed for Connecticut.
- The past studies also showed internal elements in Connecticut limited east–west power transfers across the central part of the state. The movement of power from east to west in conjunction with higher import levels to serve Connecticut resulted in overloads of transmission facilities located within the state. Additional detailed load flow analyses are required to assess the impact of resource additions resulting from the FCM.

- Past analyses and operating experience have illustrated that the Connecticut portion of the system is weakly interconnected with the rest of New England, thus presenting a number of operating difficulties. These difficulties include the possible failure of lines to reclose automatically and the need to prevent potential torsional damage to the Lake Road plant (a capacity resource).
- The 345 kV system may not be adequate to sufficiently integrate western and eastern New England resources.
- Past analyses have illustrated the criticality of key transmission facilities for regional steady state, voltage, and stability performance.
- The 345 kV transmission system in the southeastern Massachusetts and Rhode Island areas cannot reliably support the necessary power transfers into Rhode Island and southeastern Massachusetts and across the New England East–West interface under N-1-1 conditions and certain dispatch scenarios. Recent analyses have shown that these remain problem areas.
- Rhode Island and Springfield have insufficient transmission system capability to meet their load margins through 2016. Springfield can be exposed to reliability issues at current load levels, depending on system conditions; hence the area's current need for "must-run" generation situations at certain times (see Section 10.4).

The specific transmission-security concerns in the SNE region associated with area transmission reliability requirements, as determined in the past analyses but still existing today, are as follows:

- In the Springfield area, local DCT outages, stuck-breaker outages, and single-element outages result in severe thermal overloads and low-voltage conditions. These weaknesses are independent of the ability to handle power flows into Connecticut and can occur at almost any load level without adequate system posturing.
- The flow of power through the Springfield 115 kV system into Connecticut increases when the major 345 kV tie-line between western Massachusetts and Connecticut (the Ludlow–Manchester–North Bloomfield 345 kV line) is out of service because of either an unplanned or a planned outage. As a result, numerous overloads occur for all years simulated on the Springfield 115 kV system. These overloads are exacerbated when Connecticut transfers increase.
- The severity, number, and location of the Springfield overloads and low voltages strongly depend on the area's generation availability and dispatch. Additional load growth and potential unit retirements would significantly aggravate these problems. As a result, network constraints in the Springfield area limit the ability to serve local load under contingency conditions and limit Connecticut load-serving capability under certain area-dispatch conditions.
- Thermal and voltage violations are observed on the transmission facilities in Rhode Island. Causal factors include high load growth (especially in southwestern Rhode Island and the coastal communities) and planned or unplanned unit or transmission outages.
- The Rhode Island 115 kV system is significantly constrained when a 345 kV line is out of service. The outage of any one of a number of 345 kV transmission lines results in limits to power-transfer capability into Rhode Island. For line-out conditions, the next critical contingency involving the loss of a 345/115 kV autotransformer or a second 345 kV line would result in numerous thermal and voltage violations. This condition could occur as early as 2009, depending on load level and generator availability.

After considerable analyses of the alternatives based on the past needs assessment, the following plan consisting of a number of projects currently with in-service dates ranging from 2012 to 2013 was selected. (A number of the less complex Rhode Island improvements were put on an accelerated schedule with in-service dates of 2010 to 2011.) The major components of the plan are as follows:

- A new Millbury–West Farnum–Lake Road–Card 345 kV line
- A second West Farnum–Kent County 345 kV line
- Two additional Kent County 345/115 kV autotransformers
- A new 345/115 kV substation and autotransformer in the 345 kV line from Brayton Point to ANP–Bellingham
- A new North Bloomfield–Frost Bridge 345 kV line
- Expansion of the Frost Bridge 345 kV substation and the addition of a second 345/115 kV autotransformer
- A new Ludlow–Agawam–North Bloomfield 345 kV line
- Reconfiguration and expansion of the Ludlow 345 kV substation
- Replacement of two 345 kV/115 kV autotransformers at Ludlow
- A new 345 substation with two 345/115 kV autotransformers at Agawam
- A new 345/115 kV autotransformer at North Bloomfield
- A new 115 kV switching station at Cadwell
- Reconfiguration of the Fairmont substation into a breaker-and-a-half arrangement
- Four 345 kV 120 MVAR capacitor banks at Montville
- Two 345 kV 120 MVAR capacitor banks at Ludlow

The plan also includes other projects ranging from relatively minor ones, such as upgrading 115 kV substation terminal equipment, to more involved projects, such as replacing double-circuit-tower construction with single-circuit towers and reconductoring 115 kV lines.

To reiterate, as a result of new resources in Connecticut, the new Milbury–West Farnum–Lake Road–Card 345 kV line and the new North Bloomfield–Frost Bridge 345 kV line and its associated autotransformer at Frost Bridge are still being reviewed. The studies will be accounting for updated load forecasts and other system changes and will be fully coordinated with the PAC.

10.4 Transmission Improvements to Load and Generation Pockets

The performance of the transmission system is highly dependent on embedded generators operating to maintain reliability in several smaller areas of the system. Consistent with ISO operating requirements, the generators may be required to provide voltage support or to avoid overloads of transmission system elements. Reliability may be threatened when only a few generating units are available to provide system support, especially when considering normal levels of unplanned or scheduled outages of generators or transmission facilities. This transmission system dependence on local-area generating units typically results in relatively high reliability payments associated with out-of-merit unit commitments (see Section 10.5).[206]

Transmission solutions are needed for the areas where developers have not proposed adding new resources to relieve transmission system performance concerns. The ISO is studying many of these areas, and transmission projects are being planned for some areas, while other areas already have projects under construction to mitigate dependence on the embedded generating units. The major load pockets needing generators for local reliability support are as follows:

- Massachusetts—the Boston area, the North Shore area, southeastern Massachusetts, western Massachusetts, and the Springfield area
- Connecticut—all generation in the state

The following sections describe several of the areas currently depending on generating units to maintain reliability and provide the status of the transmission projects that will reduce the need to run these units.

10.4.1 Maine

Generation in western Maine is required to provide voltage support for the 115 kV transmission system. Low-voltage conditions can develop in parts of western Maine geographically and electrically distant from the 345 kV system during both pre- and post-contingency scenarios. Several 115 kV contingencies can result in unacceptably low voltages on many of the 115 kV buses in the western Maine area.

Generation also is required for maintaining system reliability following second contingencies involving flows from New Hampshire to Maine. In addition, in 2008, Sable Offshore Energy's production facility sustained a series of problems that, on several occasions, disrupted the supply of gas to generators in Maine (see Section 6.2). This in turn depleted electric power capacity in Maine, which depends heavily on gas generation. In such scenarios, available generation in Maine must be on line to maintain system reliability in that state. The system did not experience any reliability problems because operating procedures helped anticipate the gas supply problems.

10.4.2 Boston Area

The cost of operating local generation to control high voltages in Boston has been significant. An extensive high-voltage study of Boston was conducted to investigate whether the need to run local generation during light load periods could be eliminated. The study concluded that the area can be operated reliably without any generation in the Boston area to control high voltages during light-load periods, no dynamic voltage control device would be needed with all lines in service, and an additional static reactor in the Boston area could help control high voltages, especially during line-out conditions. The voltage control payments for this area in 2008 were reduced by 60% from the 2007

[206] Resources that are needed for reliability but cannot recover their costs through the electric energy and ancillary services markets (i.e., for regulation service and reserves) may require out-of-market compensation. These resources receive either daily reliability payments or payments through cost-of-service Reliability Agreements. Daily reliability payments compensate resources needed during particular hours for first-contingency and second-contingency protection, voltage reliability, or out-of-merit operation of special-constraint resources. Reliability Agreements compensate eligible resources with monthly fixed-cost payments for maintaining capacity that provides reliability services and for ensuring that these resources will continue to be available. These contractual arrangements are subject to approval by FERC.

payments and should be reduced further in 2009 following the installation of additional planned reactors.

Running local generation for second-contingency coverage under some conditions also has been needed. This did not occur as frequently in 2008 as it did in 2007. The installation of the third Stoughton cable in early 2009 should address this need.

10.4.3 Southeastern Massachusetts

In the southeastern part of Massachusetts, the Canal generating units have been run to control the high-voltage conditions that exist during light-load periods and to provide for transmission security during virtually all load levels, resulting in significant costs in 2007, which increased roughly 50% for 2008. As detailed in Section 10.3.2.2, short-term plans are in place, portions of which already are under construction or in service, and long-term studies are in progress to reduce the reliance on these units. Recent improvements in Lower SEMA already have reduced the need for out-of-merit generation support.

10.4.4 Western Massachusetts

The primary supplies for the Pittsfield area consist of the Berkshire autotransformer, the Bear Swamp autotransformer, and the Pittsfield generating units. The Pittsfield units are located in an extremely weak part of the system. Without these facilities, the area relies on a 115 kV transmission system unable to provide adequate voltage support in the area under certain conditions. Plans are in place to reinforce the supply from Bear Swamp by adding an additional autotransformer and replacing limiting terminal equipment in 2010. Studies of alternative transmission solutions surrounding the Berkshire substation are in process and should be completed by 2010. These studies determined the need for a new autotransformer at Berkshire that allows the old transformer to function as a spare bank.

10.4.5 Springfield Area

The West Springfield station and Berkshire Power plants are needed to support local reliability during peak hours and to avoid overloads in violation of reliability criteria. A solution for the Greater Springfield area has been formulated as part of the NEEWS study (see Section 10.3.2.2). This solution will accommodate load growth as well as reduce dependence on operating these local units for local reliability. It also may allow for the eventual retirement of the older of these units.

10.4.6 Connecticut

Most of the existing generation in Connecticut is necessary to ensure reliable service until the new resources secured through the FCA are in place. Until that time, imports into Connecticut will be constrained by both thermal and voltage limits for contingency events. As a result of the resources committed from the FCA, the project needs for the interstate and the central Connecticut components of the NEEWS project will be reevaluated.

10.4.7 Southwest Connecticut Area

Only two Southwest Connecticut units qualified for significant second-contingency payments in 2008. These are Norwalk Harbor units #1 and #2. Moving forward, these payments will likely be eliminated because the Glenbrook–Norwalk and Middletown–Norwalk projects were completed in late 2008.

10.5 Transmission Plans to Mitigate Out-of-Merit Operating Situations

In 2008, in the New England system, various units qualified for, or received, reliability payments, whether under a Reliability Agreement or as compensation for providing second-contingency protection or voltage control.

For the generating units with effective Reliability Agreements in place, agreements pending at FERC, and terminated contracts, the total annualized fixed-income requirement was about $585 million. This requirement has now decreased to just under $220 million for the units that still have contracts in place. All current cost-of-service agreements terminate at the beginning of the first Forward Capacity Market period beginning June 1, 2010.[207]

Table 10-1 lists the SMD load zones where units that received significant second-contingency or voltage-control payments in 2008 are located. The transmission improvements shown in Table 10-1 will improve system reliability and lessen the economic dependence on these generators.

Table 10-1
2008 Summary of Significant Second-Contingency and Voltage-Control Payments

Unit Location	2008 Second-Contingency Payments	2008 Voltage-Control Payments	Reliability Requirement	Mitigating Transmission Solutions[(a)]
NEMA	$10,510,315	$17,367,355	Operable capacity, transmission security, and voltage control	(1) NSTAR 345 kV Transmission Reliability Project (Phases I and II) (2) Being identified in the Boston voltage study
SEMA	$143,455,450	$6,898,248	Operable capacity, transmission security, and voltage control	Lower SEMA short-term and long-term upgrades
CT	$24,238,958	$337,195	SWCT transmission security	SWCT Reliability Project
ME	$2,725,445	$3,626,191	Transmission security and voltage control	Maine Power Reliability Program

(a) Mitigating solutions should help reduce problems and their associated costs but may not necessarily fully eliminate them.

As part of the FCM rules (Section 4.2), the ISO reviews each delist bid to determine whether the capacity associated with the delist bid is needed for the reliability of the New England bulk power system. Capacity that is determined not to be needed for reliability will be allowed to delist.

For the second Forward Capacity Auction, for the 2011/2012 capacity commitment period, 365 delist bids totaling approximately 890 MW of summer-qualified capacity were submitted. In accordance with Planning Procedure No. 10 (PP 10), *Planning Procedure to Support the Forward Capacity*

[207] See *Reliability Agreement Summary with Fixed Costs* (April 7, 2009) and *Reliabilty Agreement Status Summary* (July 31, 2009) at http://www.iso-ne.com/genrtion_resrcs/reports/rmr/index.html.

Market, the ISO reviewed and analyzed these bids and determined that none of the capacity associated with these delist bids was needed for reliability.[208] In an April 17, 2009, order, FERC accepted the ISO's determination.[209]

During the ISO's review of the delist bids submitted in the first FCA, for the 2010/2011 capacity commitment period, the ISO's analysis indicated that allowing either of the two Norwalk Harbor units to leave the market would have resulted in the inability of the Connecticut subarea to meet the area transmission requirements specified in ISO Planning Procedure No. 3 (PP 3), *Reliability Standards for the New England Bulk Power Supply System*. The Norwalk Harbor units, located in Southwest Connecticut, represent 162 MW and 168 MW of summer qualified capacity. An ISO analysis performed after the first FCA determined that, primarily as a result of a recent drop in the 2010 peak-load forecast, the largest Norwalk Harbor unit (168 MW) is not needed for reliability and can be allowed to delist from the market for the 2010/2011 capacity commitment period.

The PAC stakeholder process has helped identify load pocket needs and solutions that have mitigated dependencies on running local generation out of merit. Many of the solutions constructed by the transmission owners, coupled with resources procured through the FCA, have reduced dependencies on out-of-merit generation.

10.6 Summary

To date, seven major 345 kV transmission projects have been completed in four states, one additional project has completed siting, and five others either are in siting or are expected to be in siting by the end of 2009. These projects reinforce critical load pockets, such as in Southwest Connecticut and Boston, and areas that have experienced significant load growth, such as Northwest Vermont. These projects also include a new interconnection to New Brunswick, which increases the ability of New England to import power from Canada. The replacement of an existing underwater transmission cable (the NNC) between Connecticut and Long Island also has been completed recently to preserve the integrity of this tie line.

The Maine Power Reliability Program, which now is in the state siting process, establishes a second 345 kV line in the north from Orrington to Surowiec. It also will add new 345 kV lines in southern Maine, creating a third parallel path from Surowiec to Three Rivers in southern Maine. This program will reinforce and augment the 345/115 kV transformation capability in various load centers of Maine for greater reliability to area loads. While these new paths provide basic infrastructure to increase transfer capability out of Maine, they also will increase the ability to move power into Maine from New Hampshire and improve the ability of the transmission system within Maine to move power into the load pockets as necessary.

The New England East–West Solution series of projects have been identified to improve system reliability. RSP09 shows that projects in the Springfield and Rhode Island areas should proceed as planned but that the need for a 345 kV line planned into and through Connecticut is under review. This review is considering the RSP09 load forecast, system operating constraints, and existing and new resources acquired and delisted through the Forward Capacity Auctions.

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[208] ISO Planning Procedure No. 10 (PP 10), *System Planning Activities Conducted to Support the Forward Capacity Market* (July 2009); http://www.iso-ne.com/rules_proceds/isone_plan/pp10_r6.pdf.

[209] *FERC Order Accepting Results of Forward Capacity Auction*, 127 FERC ¶ 61,040 (Docket No. ER09-467-000) (Washington, DC: FERC, April 16, 2009); http://www.iso-ne.com/regulatory/ferc/orders/2009/apr/er09-467-000_4-16-09_fca_results_ordr.pdf.

Load pockets in New England have required "must-run" situations for generating units to maintain area reliability at various times. Costs associated with Reliability Agreements and second-contingency and voltage-control payments have been mitigated through transmission improvements. Additional transmission plans have been developed to further reduce the dependence on generating units needed for reliability. An example is the Lower SEMA projects whereby short-term improvements already have reduced dependence on the Cape Cod Canal generating units; further long-term improvements will eliminate the need to commit generation for second-contingency protection. Finally, in 2010, FCM resources are expected to further reduce dependencies on existing out-of-merit generation.

From 2002 through 2009, over 300 projects will have been put into service, with an investment totaling over $4.0 billion.[210] Additional projects totaling approximately $5 billion are summarized in the *Transmission Project Listing*, which is updated periodically.[211] All transmission projects are developed to serve the entire region reliably and are fully coordinated regionally and interregionally. Most projects on the *Transmission Project Listing* remain subject to regional cost allocation.

[210] Based on the July 2009 *Transmission Projects Listing*, this total includes seven projects in 2002, 26 projects in 2003, 30 projects in 2004, 51 projects in 2005, 55 projects in 2006, 36 projects in 2007, and 64 projects in 2008. An additional 38 projects are expected to be in service in 2009 and an additional 36 projects in 2010.

[211] Cost estimates without transmission cost allocation approval are subject to wide ranges of accuracy and change as projects progress. Many projects, especially those in the early stages of development, do not have cost estimates.

Section 11
Interregional Planning and Regional Initiatives

The ISO is participating in numerous national, interregional, and systemwide initiatives with the U.S. Department of Energy, the Northeast Power Coordinating Council, and other balancing authority areas in the United States and Canada. The aim of these projects, as described in this section, is to ensure the coordination of planning efforts to enhance the widespread reliability of the bulk electric power system. The ISO's goal is to work within the region and with neighboring areas to investigate the challenges to and possibilities for integrating renewable resources.

11.1 Federal Mandates and Related Initiatives

The *Energy Policy Act of 2005* (EPAct) (amending the *Federal Power Act*) mandates DOE and FERC to accomplish several tasks. The mandates include ensuring the reliability of the transmission infrastructure by overseeing the siting of transmission system expansion and the establishment of National Interest Electric Transmission Corridors (NIETCs). They also include the implementation of enforceable reliability standards administered by the North American Electric Reliability Corporation.[212]

11.1.1 U.S. DOE Study of National Interest Electric Transmission Corridors

The aim of Section 1221 of EPAct is to ensure the timely siting of needed transmission infrastructure and attention to other issues involving national concerns, such as economic growth and security.[213] To further this goal, the act delegates authority to DOE for designating geographic areas known as National Interest Electric Transmission Corridors. These NIETCs are areas that experience, for example, transmission capacity constraints or congestion that adversely affect consumers. FERC has the authority to permit the construction of specific transmission projects within designated NIETCs under certain circumstances, such as when state authorities lack the power to permit the project or take interstate benefits into consideration, or when state authorities fail to authorize the project. In the 2005 Congestion Study of the Eastern Interconnection, DOE designated the Mid-Atlantic Area National Corridor from south of the Washington, DC, area, to north of the area between Utica and Albany, New York. That corridor omits all areas of New England.[214]

Section 216(h)(9)(C) of EPAct requires the U.S. Secretary of Energy to consult regularly with, among others, transmission organizations (i.e., ISOs, RTOs, independent transmission providers, or other FERC-approved transmission organizations). DOE is under obligation to study the congestion of the U.S. bulk power system by 2009 with the goal of updating its designation of NIETCs. A NIETC provision under the *American Recovery and Reinvestment Act of 2009* (i.e., the federal stimulus bill), Section 409, requires an analysis of significant areas of renewable resources constrained by lack of access to adequate transmission capacity.[215]

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[212] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending the *Federal Power Act* to add a new Section 216).

[213] Federal Power Act §216(a)(2).

[214] A map of the Mid-Atlantic Area National Corridor is available online at http://nietc.anl.gov/documents/docs/NIETC_MidAtlantic_Area_Corridor_Map.pdf.

[215] The *American Recovery and Reinvestment Act of 2009* (Stimulus Bill) Pub. L. No. 111-5, H.R. 1, S. 1 (February 17, 2009); http://www.gpo.gov/fdsys/pkg/PLAW-111publ5/content-detail.html.

DOE has consulted with ISO New England and other planning authorities that participated in several workshops.[216] The ISO will monitor future DOE studies and coordinate activities with other ISOs and RTOs as well as policymakers and electric power industry stakeholders in New England. The materials the ISO submitted to DOE suggest New England has less congestion than other areas of the country.

11.1.2 Eastern Interconnection Planning Collaborative

Regional planning authorities within and across regions have developed and coordinated transmission expansion plans in the Eastern Interconnection. With input from stakeholders, including federal, state, and Canadian provincial officials, these authorities have proposed the Eastern Interconnection Planning Collaborative (EIPC) to address national and international planning issues, coordinate plans, and conduct studies for the entire Eastern Interconnection. The proposal includes the EIPC conducting studies of various transmission alternatives that can be assessed for their alignment with national, regional, and state energy, economic, and environmental objectives. As part of its functions, the EIPC could provide technical support to DOE congestion studies. DOE has announced a funding opportunity to facilitate the development of and strengthen the capabilities in each of the three interconnections serving the lower 48 states, to analyze transmission requirements under a broad range of alternative futures, and to develop long-term interconnection-wide transmission expansion plans.[217] EIPC submitted a proposal to DOE in September 2009.

11.1.3 Electric Reliability Organization Overview

The *Federal Power Act* directed FERC to establish one Electric Reliability Organization (ERO) with the statutory responsibilities to establish and enforce standards for the North American bulk power system and periodically publish reliability reports.[218] FERC designated the North American Electric Reliability Corporation as the ERO. As the RTO for New England, the ISO is charged with making sure its operations comply with applicable NERC standards. In addition, the ISO has participated in regional and interregional studies required for compliance. Through its committee structure, NERC regularly publishes reports that assess the reliability of the North American bulk electric power system. Annual long-term reliability assessments evaluate the future adequacy of the bulk electric power system in the United States and Canada for a 10-year period. The report projects electricity supply and demand, evaluates resource and transmission system adequacy, and discusses key issues and trends that could affect reliability. Summer and winter assessments evaluate the adequacy of electricity supplies in the United States and Canada for the upcoming summer and winter peak-demand periods. Special regional, interregional, or interconnection-wide assessments are conducted as needed.

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[216] Workshop materials are available online at the DOE Web site, *2009 National Electric Transmission Congestion Study* (Washington, DC: DOE Office of Electricity Delivery and Energy Reliability, accessed July 27, 2009); http://congestion09.anl.gov//.

[217] (1) The interconnections are the Western Interconnection, the Eastern Interconnection, and the Texas Interconnection. (2) *Recovery Act—Resource Assessment and Interconnection-Level Transmission Analysis and Planning* (Washington, DC: DOE, June 15, 2009). A synopsis of this grant opportunity is included at the following Grants.gov Web site: http://www.grants.gov/search/search.do;jsessionid=jx21K2Nhhcl4Ty7LrF2D1XsmW1qqz1FR1Xt1q27NfN6jnvBdTK1D!772105606?oppId=47961&flag2006=false&mode=VIEW.

[218] "NERC Company Overview FAQs" provides information about NERC as the ERO (Princeton, NJ: NERC, 2008); http://www.nerc.com/page.php?cid=1|7|114.

11.2 Interregional Coordination

The ISO is participating in the ISO/RTO Council (IRC), an association of the North American Independent System Operators and Regional Transmission Organizations. The ISO also is actively participating in NPCC interregional planning activities, the Joint ISO/RTO Planning Committee (JIPC), and a number of other activities designed to reduce seams issues with other ISOs and RTOs.

11.2.1 IRC Activities

Created in April 2003, the ISO/RTO Council is an industry group consisting of the 10 functioning ISOs and RTOs in North America. These ISOs and RTOs serve two-thirds of the electricity customers in the United States and more than 50% of Canada's population. The IRC works collaboratively to develop effective processes, tools, and standard methods for improving competitive electricity markets across North America. In fulfilling this mission, the IRC balances reliability considerations with market practices that encourage the addition of needed resources. As a result, each ISO/RTO manages efficient, robust markets that provide competitive and reliable electricity service, consistent with its individual market and reliability criteria.

While the IRC members have different authorities, they have many planning responsibilities in common because of their similar missions to independently and fairly administer an open, transparent planning process consistent with established FERC policy. As part of the ISO/RTO authorization to operate, each ISO/RTO has led a planning effort among its participants through an open stakeholder process. In addition, with the implementation of Order No. 890, ISOs/RTOs have upgraded their planning processes to meet FERC's objectives.[219] Specifically, the transmission planning process must provide for coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. This ensures a level playing field for infrastructure development driven efficiently by competition and meeting all reliability requirements.

The IRC has coordinated filings with FERC on many issues, such as those concerning the administration of the ISO's Generator Interconnection Queue and other technical issues. For example, the IRC has identified issues and is acting to address the challenges of integrating demand resources and wind generation and, through its representatives, is leveraging the efforts of NERC's Integrating Variable Generation Task Force (see Section 8.1). The IRC has representation on other NERC task forces and committees.

11.2.2 Northeast Power Coordinating Council

The Northeast Power Coordinating Council is one of eight regional entities located throughout the United States, Canada, and portions of Mexico responsible for enhancing and promoting the reliable and efficient operation of the interconnected bulk power system. The NPCC's geographic area is northeastern North America and includes New York, the six New England states, Ontario, Québec,

[219] *Preventing Undue Discrimination and Preference in Transmission Service, Final Rule*, 18 CFR Parts 35 and 37, Order No. 890 (Docket Nos. RM05-17-000 and RM05-25-000) (Washington, DC: FERC, February 16, 2007); http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf. Also see *Open Access Transmission Tariff Reform, Order No. 890 Final Rule* (Washington, DC: FERC, 2007); http://www.ferc.gov/industries/electric/indus-act/oatt-reform/sum-compl-filing.asp. While not FERC jurisdictional, the Canadian ISO/RTO processes are intended to comply with Order 890 requirements.

and the Maritime provinces in Canada.[220] Pursuant to separate agreements NPCC has with its members and NERC and by a Memorandum of Understanding with the applicable Canadian authorities, the NPCC provides the following activities and services to its geographic area:

- Statutory activities—develop regional reliability standards; assess compliance with and enforce these standards; coordinate system planning, design, and operation; and assess reliability
- Nonstatutory criteria services—establish regionally specific criteria and monitor and enforce compliance with these criteria

ISO New England is committed to the goals and methods of the NPCC organization and remains determined to plan and operate the New England system in full compliance with NPCC criteria, standards, guidelines, and procedures. It also is committed to participating in NPCC interregional studies and planning initiatives.

11.2.2.1 NPCC Criteria and NERC Standards

To meet all reliability objectives for the Northeast, in some cases, the NPCC criteria represent more stringent and more specific requirements than the NERC ERO requirements. The NPCC membership currently is bound through the execution of the NPCC *Membership Agreement* to adhere to these criteria, and ISO New England also includes, by reference, NPCC criteria in its governing documents (e.g., Transmission Operating Agreement). In addition, the ERO has delegated to NPCC the authority to create regional standards to enhance the reliability of the international, interconnected bulk power system in northeastern North America.

The NPCC enforces the ISO's compliance with NPCC criteria. Using NERC's Uniform Compliance Monitoring and Enforcement Program, the NPCC also assesses and enforces the ISO's compliance with NERC's reliability standards. Additionally, the NPCC monitors and enforces registered entities' (e.g., generator owners, transmission owners, load-serving entities) compliance with NERC standards within New England. This includes the need for system protection and other equipment upgrades required of bulk power system facilities.

11.2.2.2 2009 NPCC Compliance Audit of NERC Reliability Standards

In April 2009, ISO New England successfully passed its on-site NERC Reliability Standards Compliance audit conducted by NPCC in its capacity as a regional entity with NERC-delegated enforcement authority. The NERC/NPCC audit evaluated the ISO's compliance with 41 reliability standards and 324 requirements and subrequirements identified in the NERC 2009 Implementation Plan.[221] The audit also evaluated the ISO's compliance with additional requirements under the NERC Critical Infrastructure Protection Standards (e.g., CIP-002 through -009).[222] The audit involved a large portion of the ISO's business, concentrating on operations and planning. For evaluating the ISO's compliance with planning requirements, the audit focused on NERC Standards TPL-001 through TPL-003 that cover required system performance standards under normal conditions, following the

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[220] As full members, New Brunswick and Nova Scotia also ensure that NPCC reliability issues are addressed for Prince Edward Island.

[221] *NERC Compliance Monitoring and Enforcement Program, 2009 Implementation Plan* (Princeton, NJ: NERC, September 2008); http://www.nerc.com/files/2009_NERC_CMEP_Implementation_Plan_final.pdf.

[222] *NERC Reliability Standards: Critical Infrastructure Protection* (Princeton, NJ: NERC, various dates); http://www.nerc.com/page.php?cid=2%7C20.

loss of a single bulk electric power system element, and following the loss of two or more bulk electric system elements, respectively.[223] The ISO demonstrated its compliance with these standards in the *2008 Comprehensive Area Transmission Review of the New England Transmission System* (CATR) and specific New England transmission planning studies (e.g., MPRP) conducted by the ISO and individual transmission owners (see Section 10).[224] CATR primarily evaluated the stability performance of the New England transmission system and referenced specific studies for assessing steady-state system performance. In total, these studies provided a comprehensive review of the electric power system in New England in accordance with the applicable NERC TPL standards and NPCC criteria. The NPCC audit report is available to the public.[225]

11.2.2.3 Coordinated Planning

The NPCC initiates studies of its geographic areas and coordinates member-system plans to facilitate interregional improvements to reliability. The NPCC also evaluates its areas' assessments, resource reviews, and interim and comprehensive transmission system reviews. The NPCC conducts short-term assessments to ensure that developments in one region do not have significant adverse effects on other regions. As a member of NPCC, ISO New England fully participates in NPCC-coordinated interregional studies with its neighboring areas.

11.2.3 Northeastern ISO/RTO Planning Coordination Protocol

ISO New England, NYISO, and PJM follow a planning protocol to enhance the coordination of planning activities and address planning seams issues among the interregional balancing authority areas.[226] Hydro-Québec TransÉnergie, Independent Electric System Operator (IESO) of Ontario, New Brunswick System Operator (NBSO), and New Brunswick Power participate on a limited basis to share data and information. The key elements of the protocol are to establish procedures that accomplish the following tasks:

- Exchange data and information to ensure the proper coordination of databases and planning models for both individual and joint planning activities conducted by all 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 the costs associated with projects having cross-border impacts consistent with each party's tariff and applicable federal or provincial regulatory policy

To implement the protocol, the group formed the Joint ISO/RTO Planning Committee and an open stakeholder group called the Inter-Area Planning Stakeholder Advisory Committee (IPSAC).[227]

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[223] *NERC Reliability Standards for the Bulk Electric Systems of North America*, TPL-001 through TPL-003 (Princeton, NJ: NERC, May 2009); http://www.nerc.com/page.php?cid=2%7C20.

[224] This NPCC document is not posted.

[225] Compliance Audit Report Public Version: ISO New England Inc. April 20 to April 24, 2009 (New York: NPCC, May 7, 2009); http://www.npcc.org/compliance2/AuditSpot.aspx.

[226] Additional information about the protocol is available online at http://www.interiso.com/public/document/Northeastern%20ISO-RTO%20Planning%20Protocol.pdf.

[227] See the IPSAC Web sites at http://www.interiso.com and http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/index.html.

Through the open stakeholder process, the JIPC has addressed several interregional, balancing authority area issues. The *Northeast Coordinated System Plan* summarizes completed and ongoing work activities conducted by the JIPC:[228]

- Studying transmission upgrades, including new ties that increase the transfer limits between the ISO/RTOs, such as the study of a new tie between Plattsburgh, NY, and Vermont
- Coordinating interconnection queue studies and transmission improvements to ensure reliable interregional planning
- Studying cross-border transmission security issues, including the consideration of loss-of-source (LOS) contingencies and limiting constraints in the Northeast
- Improving modeling and conducting studies that have improved the quality of resource adequacy studies
- Studying the impact of wind and other renewables on interregional operations and planning
- Assessing fuel diversity and system operation under fuel-shortage situations
- Summarizing environmental regulations and assessing their potential impacts on interregional planning

Using input from the IPSAC, JIPC plans call for conducting additional interregional transmission reliability and economic analyses that may identify transmission bottlenecks and the benefits of transmission upgrades to relieve these bottlenecks. In addition, cross-border transmission cost allocation discussions are planned following the completion of technical studies. The ISO/RTOs regularly provide the status of "seams issues," including the schedules for addressing the planning issues and studies discussed in the NCSP.[229] The Seams Report is noticed by FERC.

11.3 Regional and State Initiatives

Several regional and state initiatives are taking place to improve the coordination of regional studies and enhance resource adequacy and system planning.

11.3.1 Generator Interconnection Queue and Forward Capacity Market Participation Issues

FERC approved changes to the OATT that better integrate the ISO Generator Interconnection Process with the Forward Capacity Market qualification process.[230] The changes created two types of interconnection service. One is a capacity network resource-interconnection service for capacity resources, and the second is network resource-interconnection service for "energy-only" resources. For capacity resources, the interconnection procedures address intrazonal deliverability requirements consistent with the FCM deliverability standard. A "first-cleared, first-served" construct was implemented to allocate limited interconnection capacity rights to generating resources that have demonstrated their ability and commitment to provide capacity. In addition, the changes create an

[228] *2008 Northeast Coordinated Electric System Plan ISO New England, New York ISO and PJM* (March 27, 2009); http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/2009/ncsp04-01-09.pdf.

[229] Seams issues materials are available online at http://www.iso-ne.com/regulatory/seams/2008/index.html.

[230] *Order Accepting Tariff Revisions* (FERC Docket Nos. ER04-432-006, ER04-433-006, ER07-546-013, ER07-547-003, and ER09-237-000) (January 30, 2009); http://www.iso-ne.com/regulatory/ferc/orders/2009/jan/er09-237-000_1-31-09_fcm_queue.pdf.

opportunity for new generating facilities to participate in the FCM, even where interconnection impacts overlap, while affording some certainty to long lead-time generating facilities. The changes also improve the efficiency of managing the interconnection queue by increasing the requirements of project developers to meet milestones, such as site control, and pay deposits at various stages of the interconnection process.

11.3.2 Regional Energy-Efficiency Initiative

Energy-efficiency programs in the New England states have begun to grow with the infusion of funding from the Regional Greenhouse Gas Initiative auctions (see Section 7.2.1), federal stimulus money, and other state-sponsored initiatives designed to reduce energy consumption. The Forward Capacity Market also encourages energy-efficiency participation. In early 2009, the ISO set up an informal working group, the Regional Energy Efficiency Initiative (REEI), to collect information about state and utility energy-efficiency programs and initiatives and their estimated impacts on long-run consumption. More specifically, the group is seeking more details about state programs; expected program lifetimes; funding levels; expected annual energy and seasonal peak savings; time-of-year, time-of-day, locational, or peak differences in energy savings; and risk assessments. The ISO can use the aggregated data to improve its understanding of the long-run impact of energy-efficiency programs and develop the most complete data set possible to serve as a resource for future analysis.

Thus far, the states presented information to the group on their energy-efficiency programs.[231] A national expert on energy-efficiency described a national study of the potential for future energy-efficiency development, and some of the region's utilities made presentations on their programs. Additionally, ISO staff presented information on the ISO's load forecasting methodology, focusing on energy efficiency; energy efficiency and the ISO's tariff; and energy efficiency as a supply resource. The group plans to continue gathering information, including state assessments of future energy-efficiency savings.

11.3.3 Coordination among the New England States

The six New England states have formed a regional state committee known as the New England States Committee on Electricity (NESCOE). NESCOE serves as a forum for representatives from the states to participate in the RTO's or ISO's decision-making processes, especially those dealing with resource adequacy and system planning and expansion issues.[232] The ISO has worked with NESCOE representatives and has continued to work with other representatives of the New England states, primarily through the PAC but also through designated representative organizations such as NECPUC and the New England Governors' Conference (NEGC). NESCOE has become actively involved in the ISO's regional planning process.

11.3.4 State Requests for Proposals and Integrated Resource Plan Activities

In February 2009, the Connecticut Department of Public Utility Control (CT DPUC) approved the first integrated resource plan (IRP) developed by the state's electric utilities and the Connecticut Energy Advisory Board (CEAB) pursuant to legislation passed in 2007.[233] The DPUC determined that

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[231] Regional Energy Efficiency Initiative materials are available at http://www.iso-ne.com/committees/comm_wkgrps/othr/reei/mtrls/index.html.

[232] *Wholesale Power Market Platform* (SMD Notice of Proposed Rulemaking White Paper) (Docket No. RM01-12-000) (Washington, DC: FERC, April 28, 2003).

[233] (1) *DPUC Review of the Integrated Resource Plan* (Docket No. 08-07-01) (New Britain, CT: Connecticut DPUC, February 18, 2009);

Connecticut meets regional reliability requirements, will have sufficient resources during the IRP's 10-year planning horizon, and thus should not procure additional resources at this time. The state's utilities are required to submit plans annually to the CEAB. The CT DPUC currently is reviewing the 2009 IRP.

In recent years, Connecticut has issued several RFPs providing financial incentives for the development of capacity and peaking resources in the state, which requires these resources to participate in the New England wholesale electricity market. This participation has contributed to the large amount of generating resources clearing in the FCM in Connecticut (see Section 4.2.3).

In 2008, New Hampshire established a commission to develop a plan for expanding transmission capacity in the northern part of the state (i.e., Coos County) to promote the development of renewable sources of energy in that area.[234] In late 2008, the commission reported the need for further discussion of cost allocation for transmission upgrades in Coos County. The legislature enacted a bill, effective July 16, 2009, to extend the commission through 2010 and requiring the commission, whenever possible, to seek federal funds to upgrade the 115 kV transmission system in Coos County. The commission also must establish an appropriate method for sharing the costs and benefits of such an upgrade between ratepayers and generators for developing renewable resources in northern New Hampshire.

In 2008, the Maine Governor's Task Force on Wind Power Development recommended adding at least 3,000 MW of wind in the state by 2020. The legislature acted on the task force's conclusions by approving legislation to expedite the siting of wind projects. Governor Baldacci also has created an Ocean Energy Task Force to develop the state's ocean energy potential, particularly offshore wind.

In 2008, the Vermont Department of Public Service released a draft of the *Vermont Comprehensive Energy Plan 2009—An Update to the 2005 Twenty-Year Electric Plan*.[235] The draft is expected to be adopted in 2009. The final plan will contain a number of actions and recommendations for policymakers, legislators, and regulators and will help the state manage the transition from the use of traditional fossil fuels to cleaner energy supplies.

In 2008, the State of Rhode Island selected Deepwater Wind to develop an offshore wind project near Block Island. The initiative is intended to help achieve the state's renewable resource goals.

The Massachusetts Department of Public Utilities is in the process of implementing provisions in the *2008 Green Communities Act* to allow developers of renewable energy projects to enter into long-term contracts with the state's electric utilities. Also under the act, the Secretary of Energy and Environmental Affairs is in the process of developing the Green Communities Plan to support cities and towns in improving energy efficiency.

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http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/e38fd40db43adb3a85257562007065bc?OpenDocument. (2) *An Act Concerning Electricity and Energy Efficiency* (Connecticut House Bill No. 7432; Public Act 07-242) (Approved June 4, 2007). See the CEAB Web site for additional information; http://www.ctenergy.org/.

[234] *An Act Establishing a Commission to Develop a Plan for the Expansion of Transmission Capacity in the North Country* (New Hampshire SB 383) (Effective July 7, 2008); http://www.gencourt.state.nh.us/legislation/2008/SB0383.html and http://www.gencourt.state.nh.us/legislation/2009/SB0085.html.

[235] The draft legislation of the *Vermont Comprehensive Energy Plan 2009* is available at http://publicservice.vermont.gov/planning/CEP%20%20WEB%20DRAFT%20FINAL%206-4-08.pdf). It was prepared pursuant to the Vermont *Act Relating to the Vermont Energy Efficiency and Affordability Acts* (S. 209; Act 92 of 2008); http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2008/acts/ACT092.HTM.

11.3.5 ISO Economic Studies

As part of Attachment K of the ISO's *Open Access Transmission Tariff*, the ISO conducts up to three economic studies each year at the request of stakeholders to provide information on economic and environmental performance of the system under various expansion scenarios. The studies completed in response to requests received in 2008 are summarized in Section 9 of this report.

At the March and April 2009 PAC meetings, New England stakeholders submitted another round of requests for economic studies.[236] The requests were for studying the Seabrook–Boston/Canal HVDC cable, the Green Line project, generation upgrades at SEMA, the replacement of old generating plants with natural gas combined-cycle units, and an increase in the ability to transfer power between New York and New England. The New England governors requested the identification of significant sources of renewable energy and the most effective means of integrating them into the grid. The ISO evaluated these requests with input from the Planning Advisory Committee and developed a scope of work for the studies. Priority studies will be conducted in response to the New England governors' request and will address, in whole or in part, the requests made by other stakeholders. In addition, studies conducted with the JIPC will show the effects of increasing the transfer capability between New York and New England.

11.3.6 New England Governors' Regional Blueprint

As part of the economic study request by the New England governors, the ISO is providing technical support for developing a blueprint for integrating large-scale sources of renewable energy into the region's electric power grid. The study is of future scenarios that include the large-scale integration of renewables in the 20-year timeframe (about 2030). The targeted level of wind integration, up to 12,000 MW of nameplate capacity, is intended to be consistent with the ISO's wind integration study (see Section 8.1.2). The offshore wind is distributed evenly among Maine, Massachusetts, and Rhode Island. The study approach is to evaluate specific economic and environmental characteristics of a range of future resource scenarios; it is not to add resources to meet projections of future demand for electricity or to add specific types of resources to meet any particular state or federal policy objectives.

The states developed the study assumptions with technical support from the ISO. The assumptions include demand and supply levels for New England, representative future Installed Capacity Requirements, demand-resource penetration, plug-in electric vehicle penetration, a Maine proposal for converting homes from oil to electric heat, the level of existing resources (generation, demand resources, and imports), four wind integration cases, electric energy storage, the retirement of older oil- and coal-fired generators, and the expansion of interconnections with neighboring regions. The study will evaluate a range for most assumptions (i.e., low, medium, and high).

The study results are intended to inform the governors' decisions about how to meet their stated goal of providing cost-effective, low-carbon, secure electric energy to New England consumers.

[236] Planning Advisory Committee materials for March 31, 2009, and April 22, 2009, are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/mar312009/index.html and http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/apr222009/index.html.

11.3.7 RTO Responsiveness and Governance Working Group

The RTO Responsiveness and Governance Working Group was created following FERC's issuance of Order 719.[237] The order addresses the responsiveness of RTOs and ISOs to their customers and other stakeholders, as well as issues involving market monitoring, demand resources, and long-term contracting. The working group, co-chaired by representatives from the ISO, NEPOOL, NECPUC, and consumer advocacy groups, met eight times in 2009 and developed proposals designed to improve consumer advocates' relationships with the ISO; ensure consumers' views are understood; enhance the responsiveness of the ISO; and incorporate the concepts of cost-consciousness and economic analysis into the ISO's mission statement. Those proposals are contained in ISO New England's Order 719 compliance filing.[238]

To improve the working relationship with consumer advocates and ensure consumers' views are heard, the ISO agreed to provide a new Consumer Liaison Group with the same types of information and staff support the ISO provides to NECPUC. Additionally, an ISO staff contact will help end users and consumer representatives navigate the stakeholder processes and understand key issues.
In terms of the board's responsiveness, the ISO agreed to post the agendas of board committee meetings in addition to the agendas of full board meetings, which already are posted on the Internet; clarify that any stakeholder can submit written materials on any topic; and provide more detail on board and board committee activities in the CEO's monthly reports to the NEPOOL Participants Committee.

With the required vote from NEPOOL, the ISO also has recast its objectives for its mission statement and agreed to add two important goals: it will strive to be cost-effective in all aspects of its operations, and it will provide quantitative and qualitative information, including costs of major initiatives, which will allow all stakeholders to consider the need for and the implications of the initiatives.

While ISO procedures and practices already were in compliance with FERC's responsiveness requirements, the working group's discussions with the wide range of participants resulted in suggested improvements that will make the ISO even more responsive to the region. The measures will enhance transparency without compromising the integrity of the ISO's governance.

11.3.8 Project Cost Estimation and Controls Working Group

To address concerns about transmission project cost estimates and cost overruns, in late 2008, the ISO, NECPUC, and the region's transmission owners established the Project Cost Estimation and Controls Working Group. The group was formed to develop recommendations leading to more consistent and transparent estimates for proposed transmission projects. In early 2009, representatives of transmission companies met separately from the working group and developed guidelines designed to standardize cost estimates and how these estimates are reported across all companies and projects. The group presented scopes of work and draft proposals for improving cost estimates and controls to the PAC and the Reliability Committee.

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[237] FERC Order 719. *Wholesale Competition in Regions with Organized Electric Markets* (18 CFR Part 35) (Docket Nos. RM07-19-000 and AD07-7-000) (Issued October 17, 2008); http://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf.

[238] *Filing of ISO New England Inc. and New England Power Pool in Response to Order No. 719* (Docket No. ER09-1051-000); http://www.iso-ne.com/regulatory/ferc/filings/2009/apr/er09-1051-000_4-28-09_order%20719.pdf.

The guidelines include a report template that requests consistent information in set categories, providing a basis for comparing all project proposals. The template is intended to fully capture all project cost estimates, including financing and cost escalation, based on the anticipated value of the dollar in the year of expenditure. The guidelines also recommend periodically updating information on large or complex projects to enhance the understanding of project scope, design, and cost changes and forming a new committee to actively review cost estimates. The guidelines continue to evolve as feedback from both the Project Cost Estimation and Controls Working Group and New England stakeholders are incorporated. Many of the concepts have been incorporated into ISO Planning Procedure No. 4, *Procedure for Pool-Supported PTF Cost Review,* in 2009.[239] The next phase of the group's work will focus on updating procedures for transmission cost allocation review and processing, reviewing best practices used by other RTOs and ISOs, and developing the proposal for the new committee.

11.4 Summary of Interregional Planning and Regional Initiatives

ISO New England's planning activities are closely coordinated among the six New England states as well as with neighboring systems and the federal government. The ISO has achieved full compliance with all required planning standards and has successfully implemented the northeastern ISO/RTO Planning Protocol, which has further improved interregional planning among neighboring areas. Sharing capacity resources with other systems, particularly to meet environmental emission requirements, will likely become increasingly necessary. Thus, identifying the potential impacts proposed resources and transmission projects could have on both New England and neighboring systems is beneficial to support the reliable and economic performance of the overall system.

[239] Additional information on PP 4, *Procedure of Pool-Supported PTF Cost Review* (August 7, 2009) is available online at http://www.iso-ne.com/rules_proceds/isone_plan/index.html. An explanation of the Regional Network System rate and projections for the years 2010 through 2013 were provided to the Reliability Committee; see http://iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2009/jul20212009/index.html.

Section 12
Conclusions and Key Findings

The ISO's *2009 Regional System Plan* builds on the results of past RSPs and discusses several major results. The load growth anticipated in RSP08 is expected to be delayed by one-and-one-half to two years. These lower loads, coupled with the success of the Forward Capacity Market and the locational Forward Reserve Market have resulted in the development of generation and demand resources expected to meet the needs of the New England region over the full 10-year planning horizon. While the region also has been successful in building needed transmission, the lower load growth and the development of resources where and when they are needed can delay selected transmission projects. The region will continue to depend on natural gas for approximately 40% of its electric energy, but the ISO and regional stakeholders have taken measures to improve the reliability of gas plants and the diversity of the gas supply resources.

Environmental regulations, such as the Regional Greenhouse Gas Initiative and Renewable Portfolio Standards, are encouraging the development of clean renewable resources in the region. With the anticipated growth in wind plants in New England and the increase in demand resources as a result of the FCM, the ISO is preparing to integrate more of these resources into the system. Integrating smart grid technologies into the system also is being considered to improve the electric power system's performance and operating flexibility. The New England governors' request for a study of increased renewable resources in the region and possible new imports from Canada can help provide guidance in planning the future development of the system. Interregional planning activities will become increasingly important to ensure the coordination of studies of the widespread growth in the use of renewable resources throughout the United States and Canada and the transmission projects that may be needed to access the remote development of these resources.

The transmission system in New England has evolved significantly over the past several years. A number of major projects have been placed in service since RSP08, and a number are under construction or well into the siting process. Along with the reliability improvements they bring to the system, these transmission upgrades support market efficiency, and the region already has seen a reduction in congestion costs and other out-of-market charges, such as second-contingency and voltage-control payments.

12.1 RSP Tariff Requirements

Attachment K of the OATT specifies that the RSP must discuss the assessment of the system needs of the pool transmission facilities, the results of such assessments, and the projected transmission system improvements. The RSP also must identify the projected annual and peak demands for electric energy for a five- to 10-year horizon, the needs for resources over this period, and how such resources are expected to be provided. Additionally, the RSP must include sufficient information to allow market participants, including merchant transmission project developers, to assess several factors to assist them in meeting identified system needs or to modify, offset, or defer proposed regulated transmission upgrades. These factors include the quantity, general locations, operating characteristics, and required availability criteria of incremental supply and demand-side resources.

As required by the tariff, the ISO works closely with the region's stakeholders through an open and transparent process. In particular, members of the PAC advise the ISO on the scope of work, assumptions, and draft results for the RSP and supporting studies. These studies include needs assessments and solution studies. Stakeholders can use this detailed information to better identify specific locations for resource development and merchant transmission as alternatives to regulated transmission solutions.

As part of the planning process, the ISO approves transmission projects to meet identified system needs, for which resource alternatives and merchant transmission are insufficient. The transmission projects are included in the ISO's *Transmission Project Listing*.

The ISO has continually met all the requirements of Attachment K of the OATT.

12.2 RSP09 Outlook

RSP09 draws the following conclusions about the outlook for New England's electric power system over the next 10 years:

Forecasts for the Annual and Peak Use of Electric Energy—The RSP09 10-year forecast for electric energy demand is generally lower than the RSP08 forecast, indicating a 0.9% average growth rate in the annual use of electric energy and a 1.2% average growth rate in summer peak use. By the end of the 10-year period, the summer peak would be about 500 MW lower than in the RSP08 forecast under a 50/50 forecast scenario.

Capacity Need and Resource Development—The results of the Forward Capacity Market are exceeding the "representative" 34,454 MW value for resources needed by 2018. Assuming the resources that cleared FCA #2 will be in commercial operation by 2011/2012 and continue through 2018/2019, over 600 MW of resources would be surplus by 2018/2019. Resources are being planned for the needed locations. This is evidenced by the approximately 1,200 MW of the new resources that cleared FCA #2 and over 4,100 MW (30%) of generation resources proposed in the ISO's Generator Interconnection Queue for the Greater Connecticut RSP subareas (CT, SWCT, and NOR).

Operating Reserve—The Forward Reserve Market is satisfying the needs of major import areas in New England that require operating reserve to cover contingencies. The Greater Connecticut import area still has the greatest representative reserve need of 1,100 to 1,250 MW for 2009 to 2013. The representative needs for the SWCT and Boston import areas range from 0 MW to approximately 180 MW. Existing and new fast-start and spinning reserve capacity will likely be used to meet the operating-reserve requirements for the major import areas. The addition of economic generation within the major import areas would decrease the need for operating reserves located within those areas. The Demand-Response Reserves Pilot program will offer additional information on the performance of demand resources in providing operating reserve.

Fuel Diversity—New England will continue to remain over 40% dependent on natural gas as the dominant fuel for the region's electric energy generation. Continued enhancement of the regional and interregional natural gas infrastructure serving New England and its neighboring systems, including new LNG terminals and new natural gas sources, will help expand and diversify the region's natural gas sources. Converting gas-fired generation to dual-fuel capability improves reliability and reduces exposure to high fuel prices. Other risk factors have been mitigated through modifications to operating procedures and the wholesale electricity markets.

Environmental Requirements— The U.S. *Clean Air Interstate Rule* and *Clean Water Act*, Section 316b, and the Regional Greenhouse Gas Initiative are environmental requirements that will affect or are affecting the region's generators. The ISO monitors these requirements and reflects their impacts where appropriate in its planning studies. Beginning in 2009, RGGI requires fossil fuel generators in the region 25 MW and larger to purchase sufficient CO_2 allowances to cover their CO_2 emissions. A \$4/ton cost for an allowance would add about \$4/MWh to the operating cost of a typical coal plant and about half that cost to a natural gas combined-cycle plant. RGGI allowance auctions to date have provided \$111 million to the six New England states. These funds will be used mainly to fund energy-efficiency projects.

Renewable Portfolio Standards and Related Policies—An ISO analysis based on the 2009 energy forecast shows that Renewable Portfolio Standards and other related goals would result in total demand for renewable resources and energy efficiency reaching 23.5% of system energy by 2016 and 30.1% by 2020. Typically, the queue has experienced a significant attrition of projects since it began in June 1996. If only 40% of the renewable energy projects in the queue were built, the electric energy from these projects would meet the projected demand for renewable energy in New England up to 2014. However, other resources, such as resources from adjacent balancing authority areas, new renewable projects in New England not yet in the queue, small, behind-the-meter projects, and existing generators that use eligible renewable fuels, could fill the need beyond 2014. Other options, such as making Alternative Compliance Payments, could fill this need as well.

Integration of New Technologies—Given the prospect for thousands of megawatts of growth in wind resources in the region, the ISO is undertaking a detailed wind integration study of up to 12,000 MW of wind development. This will assist the ISO in planning for the reliable integration of a large amount of variable-output resources into system planning and operation as well as the New England's wholesale electricity markets. The ISO also is taking steps to integrate demand resources, which may represent over 9% of system capacity by 2011, into system operations and the markets.

Smart Grid—EISA describes the "smart grid" as "a modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth." The federal *Energy Independence and Security Act of 2007* is calling for a major increase in the use of smart grid technologies to improve the operation and planning of the electricity grid. The National Institute of Standards and Technology is developing standards for these technologies and their use on the grid. While the ISO already is experienced in using some of these technologies, it is working toward improving the data acquisition, analysis, control, and efficiency of the electric power grid. Considerable research and development is needed to benefit fully from these rapidly evolving technologies. The use of thermal and electricity storage technologies, such as plug-in electric vehicles that can store off-peak energy, has the potential to support the successful integration of renewable energy resources.

Energy Costs and Emissions—Injecting from 1,200 to 4,800 MW of additional low- and zero-emitting resources into various points on the system should lower LSE electric energy expenses and CO_2 and NO_X emissions. Congestion shows up on the northern interfaces when higher levels of generation are added, but this can be relieved by increasing these interface transfer limits. Natural gas still remains the dominant fuel even at the highest amount of low- and zero-emitting energy injection. Adding relatively inexpensive resources, such as natural gas combined-cycle generation, near the load centers in southern New England has the potential to reduce production costs and LSE energy expenses without causing congestion.

Transmission System—Transmission studies have been completed and show the transmission additions required for the ISO's continued compliance with the various industry reliability standards and criteria. Past studies have resulted in the construction and implementation of over 300 projects since 2002 at a total cost of more than \$4 billion. These include seven major 345 kV projects completed in four states, another project that completed its siting process, and five others in siting proceedings or expected to begin the siting process by the end of 2009. Since the issuance of RSP08, 33 needed transmission projects have been placed in service. These projects include the second phase of the Southwest Connecticut Reliability Project and the second phase of the NSTAR Reliability Project. These transmission projects are required to provide reliable electric service to load pockets throughout the system, such as in Southwest Connecticut and Boston, and to meet the demand in areas with significant load growth, such as Northwest Vermont, southern Maine, and the New Hampshire seacoast area. Transmission improvements already have reduced the costs of generation that must run for reliability reasons, especially in Lower SEMA. Additional transmission improvements are planned in that area to further reduce reliance on must-run generation.

With a lower peak-load forecast and the development of FCM resources, the need for some transmission projects may possibly be delayed. Delisted resources may advance the need for transmission projects. The year of need is under review for the interstate and cross-state portions of 345 kV improvements that are part of NEEWS. The other portions of NEEWS in Springfield and Rhode Island should proceed as planned to serve load reliably in those areas. The *Transmission Project Listing* identifies approximately $5 billion of transmission projects that are "proposed," "planned," or under construction. The list includes the MPRP, a project adding major 345 kV facilities from the north to southern parts of Maine. Other transmission projects are necessary to serve demand reliably in load pockets, reduce dependencies on must-run generation, and meet load growth throughout the system. Completing studies of projects identified as "concept" and "proposed" will be needed. The ISO also should proceed with projects identified as "planned" in the *Transmission Project Listing*.

Transmission planning efforts have been coordinated with neighboring systems, resulting in new in-service tie lines with New Brunswick and Long Island. A joint analysis with NYISO is evaluating the need for a new tie between Plattsburgh, NY, and Vermont.

Interregional Planning—ISO New England's planning activities are closely coordinated among the six New England states as well as with neighboring systems and the federal government. The ISO has achieved full compliance with all required planning standards and criteria, as shown by the successful audit conducted by the Northeast Power Coordinating Council. The Northeastern ISO/RTO Planning Protocol has further improved interregional planning among neighboring areas. Sharing capacity resources with other systems, particularly to meet environmental emission requirements, will likely become increasingly necessary. Identifying the potential impacts that proposed generating units and transmission projects could have on neighboring systems is beneficial for the reliable and economic performance of the overall system. The ISO has coordinated system plans and proactively initiated planning studies with other regions. The Eastern Interconnection Planning Collaborative has been proposed to coordinate plans across the entire Eastern Interconnection and to support DOE's wide-area technical planning studies.

The ISO has implemented FERC Order 890 and has begun RSP09 economic studies with stakeholder input under the requirements of Attachment K of the *Open Access Transmission Tariff*. These studies are being conducted in response to a request from the New England governors who are developing a *Regional Blueprint for Renewable Resources* in the region. ISO New England, NYISO, and PJM Interconnection also are conducting joint interregional production cost studies.

Several recent regional and state initiatives have improved the coordination of regional studies and enhanced resource adequacy and system planning. The ISO has implemented procedures to improve the coordination between the Generator Interconnection Queue process and the three-year process for bringing FCM resources on line after clearing a Forward Capacity Auction. Another initiative has resulted in improved timeliness and quality of cost estimates for transmission projects.

Active involvement and participation by all regional stakeholders, including public officials, state agencies, market participants, and other PAC members, are key elements of an open, transparent, and successful planning process. The ISO coordinates its planning efforts with the New England States Committee on Electricity. This is a regional state committee serving as a forum for representatives from the states to participate in the RTOs' or ISOs' decision-making processes, especially those dealing with resource adequacy and system planning and expansion issues. The ISO has continued to work with other representatives of the New England states, primarily through the PAC but also through designated representative organizations, such as the New England Committee of Public Utilities Commissioners and the New England Governors' Conference. The ISO also coordinates study activities on a national level with DOE, FERC, NERC, and other organizations.

List of Acronyms and Abbreviations

Acronym/Abbreviation	Description
AEO	*Annual Energy Outlook*
ACP	Alternative Compliance Payment
AGT	Algonquin Gas Transmission
AMR08	*2008 Annual Markets Report*
APS	Alternative Portfolio Standard
ARR	Auction Revenue Rights
ARRA	*American Recovery and Reinvestment Act of 2009*
AWE	Aroostook Wind Energy
BAT	best available technology
Bcf; Bcf/d	billion cubic feet; billion cubic feet per day
BHE	1) RSP subarea of Northeastern Maine 2) Bangor Hydro Electric (Company)
BOSTON	RSP subarea of Greater Boston, including the North Shore
Btu	British thermal unit
CAGR	compound annual growth rate
CAIR	*Clean Air Interstate Rule*
CATR	*Comprehensive Area Transmission Review of the New England Transmission System*
CC	combined cycle
CEAB	Connecticut Energy Advisory Board
CEII	Critical Energy Infrastructure Information
CELT	capacity, energy, loads, and transmission
CEO	chief executive officer
2009 CELT Report	*2009–2018 Forecast Report of Capacity, Energy, Loads, and Transmission*
CHP	combined heat and power
CIP	critical infrastructure protection
CIP-002 through -009	NERC Critical Infrastructure Protection Standards
CMA/NEMA	RSP subarea comprising central Massachusetts and northeastern Massachusetts
CMP	Central Maine Power (Company)
CO_2	carbon dioxide
CRS	Congressional Research Service
CT	1) State of Connecticut 2) RSP subarea that includes northern and eastern Connecticut 3) Connecticut load zone
CT DEP	Connecticut Department of Environmental Protection
CT DPUC	Connecticut Department of Public Utilities Commission
CWA	*Clean Water Act*

Acronym/Abbreviation	Description
DARD	dispatchable asset-related demand
D.C. Cir.	District of Columbia Circuit (Court)
DCT	double-circuit tower
DDE	demand-designated entity
DE	Delaware
DG	distributed generation
DLN	dry low nitrogen oxide
DOE	U.S. Department of Energy
DOER	Department of Energy Resources (Massachusetts)
DOMAC	Distrigas of Massachusetts
DPUC	Department of Public Utilities Control
DRR Pilot	Demand-Response Reserve Pilot Program
Ebb	electronic bulletin board
EIA	Energy Information Administration (U.S. DOT)
EIPC	Eastern Interconnection Planning Collaborative
EISA	*Energy Independence and Security Act of 2007*
ELCC	equivalent load-carrying capability
EMS	Energy Management System
EPA	U.S. Environmental Protection Agency
EPAct	*Energy Policy Act of 2005*
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FACTS	Flexible Alternating-Current Transmission System
FCA	Forward Capacity Auction
FCA #1	First Forward Capacity Auction
FCA #2	Second Forward Capacity Auction
FCA #3	Third Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FTR	financial transmission rights
GADS	Generating Availability Data System
GDF	Gaz de France
GE F-Class	General Electric's F class of gas turbines
GIS	Generation Information System
GHG	greenhouse gas
Greater Connecticut	RSP study area that includes the RSP subareas of NOR, SWCT, and CT

Acronym/Abbreviation	Description
Greater Southwest Connecticut	RSP study area that includes the southwestern and western portions of Connecticut and comprises the SWCT and NOR subareas
GRI	Greater Rhode Island
GW	gigawatt
GWh	gigawatt-hour(s)
HB	House Bill
HQ	Hydro-Québec Balancing Authority Area
HQICC	Hydro-Québec Installed Capability Credit
H.R.	House of Representatives
HVAC	heating, ventilation, and air conditioning
HVDC	high-voltage direct current
IBCS OS	Internet-Based Communication System Open Solution
ICAP	installed capacity
ICR	Installed Capacity Requirement
IESO	Independent Electric System Operator (Ontario, Canada)
IGTS	Iroquois Gas Transmission System
IPSAC	Inter-Area Planning Stakeholder Advisory Committee
IRC	ISO/RTO Council
IREMM	Interregional Electric Market Model
IRP	integrated resource plan
ISO	Independent System Operator of New England; ISO New England
ISO/RTO	Independent System Operator/Regional Transmission Organization
ISOs	Independent System Operators
IVGTF	Integrating Variable Generation Task Force (NERC)
JIPC	Joint ISO/RTO Planning Committee
kton	kiloton
kV	kilovolt(s)
kW	kilowatt
kWh	kilowatt-hour
LDC	local distribution company
LFG	landfill gas
LFTMOR	locational forward 10-minute operating reserve
LLC	limited liability company
LMP	locational marginal price
LNG	liquefied natural gas
LOLE	loss-of-load expectation
LOS	loss of source
LSE	load-serving entity

Acronym/Abbreviation	Description
LSR	local sourcing requirement
M&NE	Maritimes and Northeast (Pipeline)
M/LCC	Master/Local Control Center
MA	Massachusetts
MA DOER	Massachusetts Department of Energy Resources
MAOP	maximum allowable operating pressure
MCL	maximum capacity limit
MD	Maryland
ME	1) State of Maine 2) RSP subarea that includes western and central Maine and Saco Valley, New Hampshire 3) Maine load zone
MEPCO	Maine Electric Power Company, Inc.
METU	Market Efficiency Transmission Upgrade
MLCC2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
mph	miles per hour
MPRP	Maine Power Reliability Program
m/s	meters per second
MPS	Maine Public Service
MVAR	megavolt-ampere reactive
MW	megawatt(s)
mtons	million tons
MWh	megawatt-hour(s)
N-1	first-contingency loss
N-1-1	second-contingency loss
na	not applicable
NA	North America
NAESB	North American Energy Standards Board
NB	New Brunswick
n.d.	no date
NBSO	New Brunswick System Operator
NECPUC	New England Conference of Public Utilities Commissioners
NEEWS	New England East–West Solution
NEGC	New England Governors' Conference
NEL	net energy for load
NEMA	1) RSP subarea for Northeast Massachusetts 2) Northeast Massachusetts load zone
NEMA/Boston	Combined load zone that includes Northeast Massachusetts and the Boston area

Acronym/Abbreviation	Description
NEPGA	New England Power Generators Association
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NESCOE	New England States Committee on Electricity
NEWIS	New England Wind Integration Study
NGA	Northeast Gas Association
NGCC	natural gas combined cycle
NGCT	natural gas combustion turbine
NH	1) State of New Hampshire 2) RSP subarea comprising northern, eastern, and central New Hampshire; eastern Vermont; and southwestern Maine 3) New Hampshire load zone
NIETC	National Interest Electric Transmission Corridors
NIST	National Institute of Standards and Technology
NJ	New Jersey
NNC	Norwalk Harbor–Northport Cable
NNE	northern New England
No.	number
NOR	RSP subarea that includes Norwalk and Stamford, Connecticut
NO_X	nitrogen oxide(s)
NPCC	Northeast Power Coordinating Council, Inc.
NPDES	National Pollution Discharge Elimination System
NRI	Northeast Reliability Interconnection
NWVT	Northwest Vermont
NY	New York Balancing Authority Area
NYISO	New York Independent System Operator
NYPA	New York Power Authority
O_3	ozone
OATT	Open Access Transmission Tariff
ODR	other demand resource
OP 4	ISO Operating Procedure No. 4, *Action during a Capacity Deficiency*
OP 7	ISO Operating Procedure No. 7, *Action in an Emergency*
OP 8	ISO Operating Procedure No. 8, *Operating Reserve and Regulation*
OP 19	ISO Operating Procedure No. 19, *Transmission Operations*
OP 21	ISO Operating Procedure No. 21, *Action during an Energy Emergency*
PA	Pennsylvania
PAC	Planning Advisory Committee
PER	peak energy rent

Acronym/Abbreviation	Description
PEV	plug-in electric vehicle
PJM	PJM Interconnection LLC, 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
PMU	phasor measurement unit
Pnode	pricing node
PNGTS	Portland Natural Gas Transmission System
PP 3	ISO Planning Procedure No. 3, *Reliability Standards for the New England Bulk Power Supply System*
PP 4	*Procedure of Pool-Supported PTF Cost Review*
PP 10	ISO Planning Procedure No. 10, *Planning Procedure to Support the Forward Capacity Market*
PSPC	Power Supply Planning Committee
PTF	pool transmission facility
Pub. L.	public law
PUC	Public Utilities Commission
queue (the)	ISO Generator Interconnection Queue
RAA	Reserve Adequacy Analysis
RC	Reliability Committee
REC	Renewable Energy Certificate
REEI	Regional Energy Efficiency Initiative
RI	1) State of Rhode Island 2) RSP subarea that includes the part of Rhode Island bordering Massachusetts 3) Rhode Island load zone
RIG	Remote Intelligent Gateway
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
RR	resulting reserve
RSP	Regional System Plan
RSP05	*2005 Regional System Plan*
RSP08	*2008 Regional System Plan*
RSP09	*2009 Regional System Plan*
RTDR	real-time demand response
RTEG	real-time emergency generation
RTO	Regional Transmission Organization
RWK	Rumford–Woodstock–Kimball Road
SB	Senate Bill
S&R	sense and respond

Acronym/Abbreviation	Description
SCADA	System Control and Data Acquisition
SEMA	1) RSP subarea comprising southeastern Massachusetts and Newport, Rhode Island 2) Southeastern Massachusetts load zone
Lower SEMA	lower southeastern Massachusetts
SMD	Standard Market Design
SME	RSP subarea for Southeastern Maine
SNE	southern New England
SNETR	Southern New England Transmission Reinforcement
SO_2	sulfur dioxide
SOEP	Sable Offshore Energy Project
SPEED	Sustainably Priced Energy Enterprise Development
SPS	special protection system
SRC	selective catalytic reduction
Stat.	statute
SWCT	RSP subarea for Southwest Connecticut
SWRI	Southwest Rhode Island
TBD	to be determined
TGP	Tennessee Gas Pipeline
TO	transmission owner
TPL-001	NERC Reliability Standard, *System Performance Under Normal Conditions*
TPL-002	NERC Reliability Standard, *System Performance Following Loss of a Single Bulk Electric System Element*
TPL-003	NERC Reliability Standard, *System Performance Following Loss of Two or More Bulk Electric System Elements*
UCAP	unforced capacity
U.S.	United States
VELCO	Vermont Electric Power Company
VT	1) State of Vermont 2) RSP subarea that includes Vermont and southwestern New Hampshire 3) Vermont load zone
2006 VT LMR	*2006 Vermont Transmission System Long-Range Plan*
WCI	Western Climate Initiative
WCMA	West Central Massachusetts load zone
WMA	RSP subarea for Western Massachusetts
w/o	without
WSCC	winter seasonal claimed capability