ISO New England

2013 Regional System Plan

Executive Summary

Reliability is the core of ISO New England's mission, fulfilled by three interconnected and interdependent responsibilities.

Overseeing the day-to-day operation of New England's electric power generation and transmission system

Managing comprehensive regional power system planning

Developing and administering the region's competitive wholesale electricity markets

Preface

ISO New England Inc. is the not-for-profit corporation responsible for the reliable operation of New England's electric power system. It also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional power system.

The planning process includes the preparation of an annual *Regional System Plan* (RSP) in accordance with the ISO's *Open Access Transmission Tariff* (OATT) and other parts of the *Transmission, Markets, and Services Tariff* (ISO tariff), approved by the Federal Energy Regulatory Commission (FERC).[1] Regional System Plans meet the tariff requirements by including the following:

- Forecasts of future annual energy use and peak loads (i.e., the demand for electricity) for a five- to 10-year planning horizon and the need for resources (i.e., capacity)
- Information about the amounts, locations, and characteristics of market responses (e.g., generation or demand resources or elective transmission upgrades) that can meet the defined system needs to satisfy demand—systemwide and in specific areas
- Descriptions of transmission projects for the region that could meet the identified needs, as summarized in an *RSP Project List*, which includes information on project status and cost estimates and is updated several times each year[2]

RSPs also must summarize the ISO's coordination of its short- and long-term system plans with those of neighboring systems, the results of economic studies of the New England power system, and information that can be used for improving the design of the regional wholesale electricity markets. In addition to these requirements, the RSPs identify the initiatives and other actions the ISO, state officials, regional policymakers, participating transmission owners, and other New England Power Pool (NEPOOL) market participants and stakeholders have taken to meet, or in other ways change, the needs of the system.[3]

The *2013 Regional System Plan* (RSP13) and the regional system planning process, which identifies the region's electricity needs and plans for meeting these needs for 2013 through 2022, were developed in full accordance with the requirements established in the OATT.

Regional System Planning Results

New England's transmission owners have placed in service transmission projects throughout the region to provide solutions to the needs identified through the regional planning process, as detailed in past RSPs and supporting reports. These projects have reinforced the transmission facilities serving the entire region with upgrades identified in all six New England states. The projects also have reinforced the system in critical "load pockets," such as Southwest Connecticut (SWCT) and Boston, allowing the import of power from other parts of the system. New interconnections with neighboring power systems also have been placed in service, strengthening the region's ability to interchange power with these systems. From 2002 to June 2013, 475 projects were put into service, totaling approximately $5.5 billion of new infrastructure investment.

In addition to transmission development, market participants and the states have responded to the need for electric energy and capacity resources. Since November 1997, 14,896 megawatts (MW) of new generating projects have interconnected to the New England power system, and 3,363 MW of primarily older, less efficient resources have retired from the system. Demand resources, currently totaling 1,850 MW, are part of the regional power system, and 2,563 MW are expected by 2016. New England state annual investments in energy-efficiency programs are currently in the range of $500 to 600 million. These investments are expected to grow to approximately $800 million per year and remain a large part of the expansion in demand resources.

RSP12 Review and Approval

The regional system planning process in New England is open and transparent and reflects advisory input from regional stakeholders, particularly members of the Planning Advisory Committee (PAC), according to the requirements specified in the OATT. The PAC is open to all parties interested in regional system planning activities in New England.

The ISO and the PAC have discussed study proposals, scopes of work, assumptions, draft and final study results, and other materials appearing in RSP13. From September 2012 through August 2013, the ISO hosted 17 PAC meetings, which 182 stakeholder representatives from 122 entities attended. The ISO also posted to its website PAC presentations, meeting minutes, reports, databases, and other materials.[4] In addition, the ISO held a public meeting on September 12, 2013, to discuss RSP13 and other planning issues facing the New England region.

On November 7, 2013, the ISO New England Board of Directors approved RSP13. The full 160-page document can be downloaded in its entirety from www.iso-ne.com.

Progress Report

Transmission

From 2002 through June 2013, 475 transmission projects were put into service, representing a $5.5 billion investment in new infrastructure. These projects have reinforced the transmission facilities serving the entire region with upgrades identified in all six New England states. The projects also have reinforced the system in critical "load pockets," such as Southwest Connecticut and Boston, allowing the import of power from other parts of the system. New interconnections with neighboring power systems also have been placed in service, strengthening the region's ability to interchange power with these systems.

System Resources

Since 1997, nearly 15,000 megawatts of new generation have been interconnected to the New England power system, while approximately 3,400 MW of less efficient, primarily older resources, have retired. Currently, about 1,850 MW of demand resources (both demand-response and energy-efficiency measures) are part of New England's resource mix, and 2,563 MW are expected by 2016.

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Introduction

Over the past decade, ISO New England's regional system planning process and market design have fostered significant improvements to the region's generation and demand resources and transmission system.[5]

Almost 30% of the region's existing generation was built during the last 12 years, and the amount of energy-efficiency performing as demand resources in the Forward Capacity Market (FCM) has increased roughly 200 MW per year over the past four years. The transmission system, which had seen little investment in past decades, has been upgraded to better serve the region's load.

To maintain the reliable and efficient operation of the New England power system, the regional system planning process is continuous and comprehensive, building on the results and recommendations of previous plans. Notwithstanding the region's system improvements, challenges remain across the 10-year planning horizon for maintaining system reliability, including the following:

- Improving resource performance and flexibility
- Maintaining reliability given the region's increased reliance on natural-gas-fired capacity
- Planning for the potential retirement of generators
- Integrating a greater level of intermittent resources (i.e., *variable energy resources*; VERs)

To address these challenges, prepare for changes likely to confront the New England power system, and assess potential system enhancements, the ISO and its stakeholders are conducting a Strategic Planning Initiative and other market development, system operations, and planning activities to support the overall strategic planning of the region.[6] These activities take place through an open stakeholder process that includes input from the Planning Advisory Committee (PAC) and the New England Power Pool (NEPOOL) committee structure.[7]

Historically, the region has responded to system needs through proactive planning, the completion of transmission projects and other improvements that facilitate the reliable operation of the system, the development of resources needed in the region, and the overall competitiveness of the markets. The Federal Energy Regulatory Commission's Order 1000 now requires fundamental changes to the transmission planning process as it has been conducted in New England since 2001 regarding the transmission owners' right to build and the process for developing transmission projects.[8] The order also requires planning to meet public policy objectives. While the effective date of this order is uncertain, implementing these changes could prove challenging for the region.

In addition to revising the planning process to meet Order 1000 requirements, the ISO is conducting its ongoing regional planning activities under the following set of system considerations:

- Low net load growth due to a slow recovery from the recession and the forecast of energy-efficiency resources
- Existing level and types of resources, the development of new resources, and the retirement of others
- $5.7 billion additional transmission improvements planned for the region consistent with federal and regional reliability standards
- The robust interregional coordination and planning studies the ISO performs with neighboring regions, which are consistent with the interregional requirements of Order 1000

Overview of the *2013 Regional System Plan*

The *2013 Regional System Plan* (RSP13) provides information on system and project needs, system improvements, and the results of newly completed load, resource, and transmission analyses of the New England electric power system for reliably serving load throughout the region to 2022. It also discusses ongoing and new analyses based on the current and planned system and describes new and planned infrastructure for all areas of New England. The major factors influencing resource retirements and the development of the electric power system infrastructure for the 10-year planning period, such as existing and pending state and federal environmental and energy policies, also are addressed.

RSP13 and the system planning process throughout the year comply with all applicable sections of the ISO's *Transmission, Markets, and Services Tariff* (ISO tariff), approved by FERC.[9] The plan and planning process also satisfy the relevant criteria and requirements established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), participating transmission owners (PTOs), and the ISO.[10] As part of its compliance with Attachment K of the ISO's *Open Access Transmission Tariff* (OATT), RSP13 specifically provides information on the timing of system needs and the quantity, general locations, and characteristics of the generation and demand resources that could resolve these needs.[11] The results of various system and regional strategic planning studies and other materials, such as the following, provide this information:

- Forecasts of the average electric energy usage annually and at the peak hour for 2013 to 2022—for the entire system, individual states, and smaller areas of the power system
- Forecasts of the long-term energy-efficiency (EE) savings in the six New England states, annually and at the peak hour for 2016 to 2022
- Projections of the systemwide need for capacity and operating reserves, which show the allowable limits of generator retirements and the locations where fast-start resources would be the most beneficial
- Analyses and operating experience that show the vulnerabilities associated with the regional reliance on natural gas and the benefits of having more reliable access to gas supplies, dual-fuel capabilities, and other fuel sources

- Existing and pending environmental regulations, emissions analyses, and economic studies, which show the effects of using efficient, low-emitting resources; greater amounts of renewable resources; and improved energy efficiency on regional air emissions and economic performance
- Economic studies of resource retirement and expansion scenarios, which describe the effects of varying amounts, locations, and types of resources on system performance
- The Strategic Transmission Analysis, which provides insight on beneficial electrical locations for resource development if and when extensive generation retirements occur across the region
- Planning analyses of wind and photovoltaic (PV) resources and the status of tools to address both the interconnection requirements and systemwide needs for successfully implementing the large-scale development and operation of variable resources
- The results of market resource alternative (MRA) studies and plans for improving both the timeliness and usefulness of this type of analysis to stakeholders
- Summaries of regional and interregional transmission planning studies (i.e., needs assessments and solutions studies), which provide detailed information to resource developers and other stakeholders on potential infrastructure additions

Overview of the Results of System and Strategic Planning Studies

Like the RSP12 forecast, the RSP13 regional forecast shows slow growth in the summer peak demand and annual energy use. The energy-efficiency forecast of demand-side resources also is similar to the RSP12 forecast and shows a further slowing of net load growth. Assuming no retirements, resources procured in the seventh Forward Capacity Auction (FCA #7) are sufficient to meet systemwide needs through 2022, and the ISO Generator Interconnection Queue (the queue) indicates that additional resources are seeking to develop in the region.[12]

The region's heavy dependence on natural-gas-fired generation to meet its electricity needs has resulted in recent operating problems similar to those experienced during past events.[13] Adverse interactions between electric power generators and the natural gas system have occurred, and could occur any time of the year, because the natural gas system has been subject to interruptions that reduce the flow of natural gas to generating units requiring fuel. In addition, the scheduling requirements of the natural gas system for providing fuel to generators can be in conflict with the electric power sector's need for flexible operation. Adding to this issue is that the regional dependence on natural-gas-fired generation to provide both electric energy and capacity is expected to grow with the likely retirement of older coal and oil units and their replacement, in whole or in part, with generators in the queue that burn natural gas. Upgrades to the natural gas system infrastructure, some of which have been proposed, would provide some improvements to the deliverability of natural gas. However, additional solutions are required to address fuel-adequacy issues.

The ISO is pursuing market and operational changes, as follows, to address the risks associated with unit performance and gas dependency:

- Coordinating with the gas industry to obtain timely information to fill information gaps and better manage the power system
- Enhancing market mechanics to better enable resource performance
- Improving market incentives for resources to perform
- Procuring sufficient resources to meet the requirements for capacity and electric energy

Economic studies of various system-expansion scenarios have used metrics such as potential production costs, transmission congestion, and a number of others to suggest the most economical locations for resource development and the least economical locations for resource retirements. Other economic studies are showing the effects of possible new imports from Canada.

Environmental and economic incentives provided by governmental policies are encouraging the development of low-emitting, renewable resources, such as wind and solar. These resources could diversify the fuel supply; however, the reliable large-scale integration of intermittent resources would place increased regulation and reserve requirements on the system, presenting challenges for system operations and planning. Hydroelectric units have traditionally been well suited to provide regulation and reserves, but they may lose some of their ability to operate flexibly as part of their relicensing requirements. Additionally, while photovoltaic resources will not likely require the development of new transmission, significant wind development will, as shown by the wind integration study of the Strategic Transmission Analysis. This analysis is developing conceptual additions to the regional transmission system that would enable onshore wind resources to serve load reliably. Elective upgrades and merchant transmission facilities under consideration have the potential to improve access to renewable resources in remote areas of the region and in neighboring areas. In addition, smart grid technologies are being developed to improve the electric power system's performance and operating flexibility.

Another aspect of the Strategic Transmission Analysis evaluated how the retirement of "at-risk" oil- and coal-fired generating units will affect reliability and assessed the most favorable locations for replacing the retired units. The results of the study showed that with the potential retirements, and the assumed completion of planned improvements in the *RSP Project List*, the need for new transmission facilities would be minimized and load could be served reliably, provided new capacity were electrically located near existing generator locations. Developing resources at the region's energy trading hub (the Hub) or deliverable to the Hub also would reduce the need for transmission expansion.[14] Although some local transmission improvements may be required, these locations are favorable even when considering resources needed to compensate for the unit retirements.

Transmission projects are in various stages of development, and many have begun or have completed the siting process. While transmission upgrades continue to progress throughout the region, the required timing and components of certain projects are being modified because of the reduction in net loads indicated by the load and EE forecasts, the retirement of generating resources, and the addition of new market resources. In general, the critical load level identified in all transmission system needs assessments can be used to identify the amount of resources that would relieve transmission system constraints. However, when resources fail to develop in the required amounts and in the needed locations, the proper timing of transmission projects is critical to meet regional reliability requirements and to mitigate risks associated with unit performance and gas dependency.

The ISO supports interregional planning efforts and has coordinated planning activities with the New York Independent System Operator (NYISO), PJM Interconnection, and other interregional organizations, such as the NPCC and NERC, and has actively participated in the Eastern Interconnection Planning Collaborative (EIPC).[15] The ISO has filed with FERC proposed measures required for compliance with FERC Order 1000 to enhance interregional planning and improve interregional transmission cost allocation.[16]

On May 17, 2013, FERC issued its order on the ISO's filing to comply with Order 1000 regional requirements, which will significantly change how transmission planning is conducted in New England and will place additional responsibilities on the ISO.[17] The order includes the following requirements:

- First, the order requires the removal of the participating transmission owners' right to build, which is contained in the Transmission Operating Agreements, and it directs the ISO to implement a competitive process to build transmission.[18]
- Second, the order significantly limits the projects that could be exempted from the competitive process and requires the ISO to establish an effective date for the implementation of this process based on the start of an annual planning cycle.[19]
- Third, FERC rejected the ISO's proposed public policy design it filed in October 2012, which would have had the states select the more efficient or cost-effective transmission solution that would resolve an identified transmission need driven by public policy requirements.[20] FERC requires the ISO, and not the states, to evaluate the solutions offered after a public policy project is identified and select the more cost effective or efficient project for inclusion in the Regional System Plan.

The regional planning process has been robust and able to foster the development of required infrastructure through the partnership of the ISO with the states, market participants, transmission owners, and other stakeholders. The ISO will continue to work with stakeholders through the NEPOOL process to establish a means of complying with and implementing Order 1000 regional requirements, which could pose challenges to the region.[21]

Major Findings and Observations

This section highlights the major findings and observations of the RSP13 load forecast, energy-efficiency forecast, supply and demand resource and transmission planning studies, market outcomes, and economic studies.

Other projects, studies, and initiatives that are part of the system planning process are summarized. The sections of the report that contain more details of these findings and observations are indicated.

For all RSP13 analyses, the ISO used a number of assumptions, which are subject to uncertainty over the course of the planning period. Some factors, as follows, are subject to change, which may vary RSP13 results and conclusions and ultimately influence the future development of transmission and generation and demand resources:

- Demand and energy-efficiency forecasts, which are dependent on the economy, new building and federal appliance-efficiency standards, state EE goals and program implementation, and other considerations
- Resource availability, which is dependent on physical and economic parameters that affect the performance, development, and retirement of resources
- Environmental regulations and compliance strategies, which can vary with changes in public policies, economic parameters, and technology development
- The deployment of new technologies, which may affect the physical ability and the economic viability of new types of power system equipment and the efficiency of operating the power system
- Fuel price forecasts, which change with world markets and infrastructure development
- Market rules and public policies, which can alter the development of market resources
- Timing of planned system improvements, which can be subject to siting and construction delays, uncertainty due to the implementation of the competitive process for transmission development under FERC Order 1000, and changes to the system

The ISO considers these factors for developing a robust plan. While each RSP is a snapshot in time, the ISO updates the results of planning activities as needed, accounting for the status of ongoing projects, studies, and new initiatives.

Forecasts of the Peak Demand and Annual Use of Electric Energy and the Effects of Energy-Efficiency Measures

RSP13 includes forecasts of annual energy use and peak energy use, as well as the peak load reductions and energy savings from energy efficiency. The amount and location of the net system load affect the need for new resources and the required timing of some transmission projects.

Peak Demand, Annual Use of Electric Energy, and Load Growth

The RSP13 forecast of summer peak demand is higher than the RSP12 forecast by 75 MW for 2013 and lower than the RSP12 forecast by 50 MW for 2021 for the 50/50 "reference" case.[22] For RSP13, the 50/50 summer peak forecast is 27,840 MW for 2013, which grows to 31,520 MW for 2022. The 90/10 summer peak forecast, which represents summer heat waves, is 30,135 MW for 2013 and grows to 34,105 MW in 2021.[23] The ISO forecasts the 10-year growth rate to be 1.4% per year for the summer peak demand, 0.6% per year for the winter peak demand, and 1.1% per year for the annual use of electric energy. The annual *load factor* (the ratio of the average hourly load during a year to peak hourly load) continues to decline from 56.2% in 2013 to 54.6% in 2022.

The load forecast is highly dependent on the economic forecast, which reflects economic trends. The RSP13 forecasts also account for reductions based on the energy-efficiency forecast and the expected effects of historical energy-efficiency savings and federal EE standards for appliances and commercial equipment, which will go into effect in 2013 and would save 1.6% of the total gross electric energy consumption in 2022.[24] Another factor for developing the forecasts is that demand resources that cleared the Forward Capacity Market are considered to be sources of supply and not demand-side measures.

Energy-Efficiency Forecast

The EE forecast for 2016 through 2022 shows a regionwide annual average energy savings of approximately 1,358 gigawatt-hours (GWh) and an average reduction in peak loads of 193 MW per year. The EE forecast shows savings of 1,621 megawatt-hours (MWh) in 2016, declining to 1,114 MWh in 2022. Similarly, the peak load savings from EE declines from 231 MW in 2016 to 159 MW in 2022. The EE forecast also shows results for each New England state.

The annual energy use forecast, minus both the FCM passive demand resources projected for 2013–2016 and the 2017–2022 energy-efficiency forecast, shows essentially no net long-run growth in electric energy use and would save 11.4% of the gross energy consumption in 2022.[25] The summer peak 90/10 forecast, when adjusted for both the existing FCM passive resources projected for 2013–2016 and the 2017–2022 energy-efficiency forecast, is projected to increase at a more modest rate, approximately half the projected growth rate of the demand forecast.

Energy consumption is projected to grow an average of 1.1% annually through 2022, while summer peak demand is expected to grow by 1.4% per year. When taking energy efficiency into account, the load growth forecast shows essentially no long-run increase in electric energy use and 0.9% annual growth in annual summer peak demand.

Needs for Capacity and Operating Reserves

RSP13 quantifies the system needs for capacity and operating reserves and the amounts procured through the Forward Capacity Market and the locational Forward Reserve Market (FRM).

Capacity

The minimum amount of capacity the region needs to meet resource adequacy requirements is called the *Installed Capacity Requirement* (ICR). The region's net ICR is expected to grow from 31,552 MW in 2013 to a representative value of 35,300 MW by 2022.[26] This represents a growth of over 400 MW per year (416 MW on average), which is equivalent to 1.25% per year. The current development of generation, demand, and import capacity resources in the region is expected to provide the capacity needed to meet the ICR. Because the ICR calculation accounts for the load-relieving actions of ISO Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*, meeting the ICR level could necessitate the use of specific OP 4 actions.[27] Several factors affect the frequency and extent of OP 4 actions, including the amount of resources procured to meet capacity needs, their availability, actual system loads, and other system conditions.[28] Study results show that the need for load and capacity relief by OP 4 actions will be up to 3,300 MW during extremely hot and humid summer peak-load conditions over the planning horizon.

The seventh Forward Capacity Auction (FCA #7) procured adequate resources to meet demand through 2016/2017.

Resources are projected to be sufficient for the 2016/2017 capacity commitment period.[29] The region would have a surplus of 2,842 MW in 2018/2019, which would decrease to 2,042 MW in 2022/2023, accounting for the load and energy-efficiency forecasts and assuming all resources with capacity supply obligations for FCA #7 remain in service and only known retirements are considered.[30]

The amount of capacity resources in the Northeast Massachusetts (NEMA)/Boston capacity zone is projected to marginally meet the resource adequacy requirements for that area. In FCA #7, the local sourcing requirement (LSR) for NEMA/Boston was 3,209 MW, and the resources in that area, which include over 700 MW of new resources procured in FCA #7, totaled 3,716 MW.[31] Additional load growth, reduced resource availability—possibly resulting from fuel supply issues—or retirements in NEMA/Boston would create the need to develop additional new resources.

Other resources throughout the region, particularly demand resources, have submitted "nonprice" retirement requests, and approximately 1,660 MW of one-year dynamic and static delist bids were approved in FCA #7.[32] The high likelihood of resource retirements at future auctions also will likely accelerate the need for new resources, and the region already is beginning to lose older, relatively inefficient generating facilities. Additionally, coal and oil resource owners could choose not to invest in environmental remediation measures called for in pending or required regulations, which could force these units to shut down.

FERC-approved changes also will improve the market incentives for developing resources when and where needed, and the Strategic Planning Initiative is assessing ways to enhance the efficient development of resources.[33] FCM changes will develop criterion and processes for creating, modifying, or collapsing capacity zones. These changes also will address the relationship between the zonal reconfigurations and the ISO's rejection of resource delist bids. In general, the development of new resources near the system load centers in NEMA/Boston and Connecticut, and in other load pockets throughout the system, mitigates reliability risks associated with resource retirements and resource performance issues, improves system performance, and allows for a more optimal use of the existing infrastructure. Resources in the generator interconnection queue, which included 5,294 MW as of April 1, 2013; new demand resources; and new import capacity from neighboring regions are in various stages of development and could address some of these issues.

Operating Reserves and Resource Flexibility

Operating reserve is the megawatt capability of a power system greater than system demand that is required for preserving system reliability—such as by providing frequency regulation, responding to load forecast errors, and filling the void left by forced outages—when resources or transmission facilities are lost because of a contingency.[34] Some resources are required to be synchronized to the system for immediate use (i.e., *spinning* resources), and some must be available for service within 10 minutes or within 30 minutes (i.e., *fast-start* resources).[35] In New England, resources participating in the locational Forward Reserve Market and other committed and on-line resources help satisfy the operating-reserve requirements of the region overall and in major load pockets.

As a result of transmission upgrades and other resource additions in recent years, the Greater Southwest Connecticut area is not expected to need any additional fast-start capability for 2013 to 2017.[36] Over the same period, the forecasted need for this type of generation in the Greater Connecticut area is up to 900 MW during the summer, and the need in the BOSTON area may be up to 300 MW.[37] The expected increase in import capabilities into Greater Connecticut and BOSTON during the next several years, and the planned additions of economical generation within these areas procured through the FCM, would allow the ISO more flexibility in achieving the best economic outcome for energy production while maintaining adequate amount of operating reserves for these areas to meet operational reliability standards. Further additions of in-merit generation or demand resources within the major import areas, increases in the import capabilities of these areas, or some combination of these outcomes would decrease the need to locate operating reserves within these areas.

Unit retirements; greater dependency on limited-energy generation (LEG) resources that can limit their operation when they have limited fuel; and the addition of intermittent resources, particularly wind and photovoltaics, will increase the need for flexible operations and resources to provide reserves, regulation service, and ramping in the most effective locations. The ISO has reviewed the existing requirements for operating reserves, and potential enhancements to the wholesale electricity markets are nearly final to better meet operational needs and improve the efficiency and reliability of the system as currently configured. The ISO has increased the 10-minute operating-reserve requirement by 25% and will be procuring additional replacement reserves beginning in October 2013.

Transmission System Needs and Solutions

Transmission projects placed in service over the past 10 years have reduced congestion and decreased dependence on generating units located in load pockets. In 2012, systemwide congestion-related costs totaled approximately $29.3 million, and payments for generators in "must-run" situations that provided second-contingency coverage and voltage control totaled just under $23.7 million. These values total approximately 1.1% of the $4.77 billion wholesale electric energy market.

Transmission Projects

The ISO regularly discusses with the PAC the scope of transmission system needs and the progress of transmission system needs assessment studies that drive regional transmission planning for improvements. In response, the PAC provides guidance and comments on study scopes, assumptions, and results. All transmission projects are coordinated with other regions as warranted. The ISO also has advised the PAC of the regional network service (RNS) rate and projections developed by the PTOs.[38]

Approximately $5.7 billion in transmission investment for reliability purposes is planned for the next five years.

The descriptions of transmission projects in RSP13 are based on the June 2013 *RSP Project List* update, which includes 282 projects at a total cost of approximately $5.7 billion.[39] Generally, transmission system upgrades continue to be necessary because new resources are not being installed of sufficient size or in a location that eliminates the need for system upgrades. The ISO updates the *RSP Project List* at least three times per year, identifying improvements and changes in project status. The status of several major projects under development is as follows:

- The Maine Power Reliability Program (MPRP), for which the Maine Public Utilities Commission (MPUC) has approved siting for most of the components, establishes a second 345 kilovolt (kV) path in northern Maine from Surowiec to Orrington and adds new 345 kV lines in southern Maine, creating a third parallel path from Surowiec to Eliot. Many components of these new paths are under construction, and several elements already are in service. When completed, they will provide basic infrastructure needed for increasing the ability to move power into Maine from New Hampshire and will improve the ability of the transmission system within Maine to move power into the local load pockets as necessary.[40] Studies have demonstrated that the MPRP also will provide a modest increase in the transfer capability across major interfaces in Maine, including Maine to New Hampshire. The MPRP project is scheduled for completion by early 2015, with the exception of upgrades around Lewiston.

- The New England East–West Solution (NEEWS) series of projects has been identified to address system reliability needs:

  >> The Rhode Island components of NEEWS are complete, while the final Springfield components are under construction and scheduled to be in service by the end of 2013. The portions of the Springfield components affecting Connecticut import capability are in service.

- The Interstate Reliability Project has been reevaluated to account for updated load and energy-efficiency forecasts; system operating constraints; and resources acquired, delisted, or retired through the Forward Capacity Auctions, such as the impact of the retirement of the Salem Harbor facility. The need for the Interstate Reliability Project has been reconfirmed, and the preferred solution is unchanged. This solution consists of new 345 kV transmission between Millbury, MA; West Farnum, RI; Lake Road, CT; and Card, CT. The siting proceedings in the affected states of Connecticut and Rhode Island have been conducted, and approvals have been issued. Siting proceedings in Massachusetts, the one remaining affected state, are expected to be completed in early 2014.
- The need for the Central Connecticut Reliability component of NEEWS is being reevaluated as part of the Greater Hartford–Central Connecticut (GHCC) study. The GHCC needs assessment has been completed, a report is being drafted, and solution alternatives are being developed.

- The Long-Term Lower Southeastern Massachusetts (Lower SEMA) project addresses system reliability concerns in the lower southeastern Massachusetts (LSM) area, which includes Cape Cod, and is scheduled for completion in September 2013. The project includes adding a new 345 kV transmission line from the Carver substation to a new 345/115 kV substation west of Barnstable on Cape Cod, adding a third 345 kV line serving Cape Cod. The project received siting approval in April 2012.

In addition to the system needs assessments and solutions studies, several major transmission planning studies have been completed and others are underway to address system issues in all six New England states. Some studies have developed preferred solutions to serve major portions of the system, including Vermont and New Hampshire, the Pittsfield and Greenfield area, the southwestern area of Connecticut, and the Greater Boston area. All studies examine the system comprehensively and account for the electrical characteristics of the tightly integrated New England network. The ISO continues to review the timing and components of projects throughout the system to account for system changes in load level, resource development and availability, and other factors.

Generation helps ensure the reliability of area load pockets, which include portions of Maine, the Boston area, southeastern Massachusetts, western Massachusetts, the Springfield area, and portions of Connecticut. In addition to enhancing reliability, transmission improvements placed in service have reduced costs associated with second-contingency and voltage-control payments to generators. The Lower SEMA short-term upgrades are one example of transmission upgrades that have improved reliability, reduced dependencies on generating units, and reduced "make-whole" payments to market participants whose resources had operating costs higher than their energy market revenues over a 24-hour dispatch day.

Transmission expansion may be required to meet future challenges facing the New England region to preserve the reliability of service to those areas of the system that could face generator retirements within the planning horizon and to address reliability needs attributable to load growth and resource integration.

Development of Elective Transmission Upgrades

Several developers have proposed Elective Transmission Upgrades (ETUs), which are in various stages of study and development.[41] These projects could increase New England's tie capability with its neighbors and improve access to renewable sources of energy. For example, certain generators are considering elective upgrades as a way to mitigate curtailment of wind energy resources. The ISO will continue to monitor the outcomes of these upgrades and their impacts on system conditions and needs. The ISO has initiated an effort to improve the existing Elective Transmission Upgrade process.

Regional Strategic Planning

In addition to identifying the need for capacity and operating reserves, the ISO assesses the potential impacts of fuel availability and public policies, including environmental initiatives, on the system's need for certain amounts, types, and locations of resources and transmission improvements. The ISO also is addressing issues concerning the development and integration of renewable resources and smart grid technologies.

Resource Performance and Natural Gas Dependency

The ISO is addressing several strategic planning issues associated with natural gas dependency, resource performance, and natural gas supplies. These problems have been quantified, and solutions are being implemented to improve infrastructure and markets.

Natural Gas Dependency

New England is increasingly dependent on natural gas as a primary fuel for generating electric energy and decreasing its dependence on oil. In 2000, 17.7% of the region's capacity was natural-gas-fired generation, which produced 14.7% of the region's electric energy, whereas in 2012, natural gas plants represented 43.0% of the region's capacity and 51.8% of the system's electric energy production. In 2000, oil units represented 34.0% of the region's capacity and produced 22.0% of the region's electric energy that year, but in 2012, oil units represented 21.6% of the capacity and produced 0.6% of the region's electric energy. Over the same period, the capacity reduction of coal units has been less severe from 11.7% to 7.8%; their energy production decreased from 17.9% to 3.2%.

> In 2012, 52% of the electricity generated in the region was produced by natural-gas-fired power plants, while oil units produced less than 1%, and coal plants generated about 3%. Nuclear produced approximately 31%; hydro and pumped storage produced 7%; and renewable energy resources produced 7% of the electricity generated in the region.

The high regional use of natural gas to generate electricity is the result of the addition of new, efficient natural-gas-fired units over the past decade; the recent low price of natural gas; and the displacement of older, less efficient oil- and coal-fired units in economic dispatch. As the revenues from the wholesale electricity markets decline for these oil and coal units and more units retire, the regional reliance on natural gas for providing capacity and energy will increase. Further dependency on natural-gas-fired generation will likely occur, resulting from the loss of other types of generation subject to risks, such as nuclear and hydro units that may not be relicensed. Many units also do not have effective dual-fuel capability (in terms of the amount of time they need to switch to using oil or the availability of secondary fuel inventory). Accompanying the increased use of natural gas are concerns regarding the adequacy of the region's natural gas pipeline capacity and gas supply in the pipelines to serve electric power generation reliably; at any time of the year, natural and geopolitical events of all types could interrupt supplies of gas and other fuels, such as oil and coal.

Resource Performance

System events that occurred during 2012 and winter 2013 brought into focus the vulnerabilities and limitations of the system when generators have not made adequate arrangements for all types of fuel to support their energy offers, particularly during severe winter or other stressed system conditions. These events also highlighted reliability issues with infrequently operated oil- and coal-fired generators. In light of these resource availability concerns in 2012 and early 2013, the ISO is implementing, with stakeholder input, near-term improvements to the wholesale electricity markets to enhance system reliability. Plans call for the following improvements to be in place by the end of 2014:[42]

- Improve the use of the daily reoffer period, which enables resources to more closely reflect their true cost of fuel in their energy market offers, which is essential for appropriate energy market pricing
- Accelerate the timing of the Day-Ahead Energy Market and associated reliability commitments to align more closely with existing natural gas trading and nomination cycles, which will improve the ability of generators to procure needed natural gas and allow the ISO additional time to activate non-gas-fired generators, if needed
- Allow reserve prices to increase under tight system conditions to better reflect the costs of maintaining these reserves, which will improve energy market pricing and associated incentives for resources to deliver power when needed
- Increase the amount of needed operating reserves, which will more closely reflect system operator action and improve the pricing of reserves and electric energy
- Update the shortage-event trigger in the Forward Capacity Market to improve incentives for resources to make adequate arrangements for fuel during tight system conditions

In addition, the ISO is planning to implement several out-of-market measures to address fuel supply and reliability for the 2013/2014 winter.[43] These include ways of compensating generators that maintain oil inventories, increasing access to demand resources, and verifying the ability of dual-fueled units to switch fuels. These measures are intended to supplement the near-term market changes until the medium- and long-term changes can be implemented.

The ISO is working with stakeholders over the medium and long terms on additional improvements to the wholesale electricity markets. These improvements, expected to be implemented over the next few years, include the following:

- More fully integrating demand resources into the energy market, which will broaden the conditions under which demand resources could be called on to help meet the region's energy needs
- Further modifying the FCM shortage-event trigger and replacing the shortage-event penalty structure with a pay-for-performance model so that resources will have even stronger incentives to perform when system needs are greatest

Natural Gas Supplies

Recent improvements to the interregional natural gas infrastructure have helped improve the supply of natural gas from the Marcellus Shale production areas to the Northeast. Additional enhancements to the regional pipeline network would allow New England to access the larger quantities of natural gas for the region's power generators. Unlike the electric power industry, which proactively plans the expansion of the transmission network, natural gas transportation requires firm contractual arrangements before natural gas pipeline facilities can be constructed.

A planning study of regional natural gas issues quantified the regional need for additional natural gas system supply or the use of non-gas-fired resources under a number of scenarios. The analysis considered several scenarios, including the replacement of older oil- and coal-fired generating units with natural-gas-fired generators and natural gas infrastructure outages affecting reliable electric power operation.[44] Additionally, a follow-up natural gas study has begun for determining the potential risks of energy shortfalls for the region under a variety of scenarios. The ISO also is coordinating an interregional study of the natural gas system with the NYISO, PJM, the Midcontinent Independent System Operator (MISO), the Independent Electricity System Operator (of Ontario) (IESO), and the Tennessee Valley Authority (TVA).

The Potential Impacts of Environmental Regulations on the Power System

Existing and pending state, regional, and federal environmental requirements addressing air pollution, greenhouse gas emissions, cooling water drawn from rivers and bays, and wastewater discharges that flow back into these water bodies as well as public treatment works will affect many New England generators in the 2015 to 2022 timeframe. Many generators in the region already have installed needed control technologies because of state environmental rules requiring earlier compliance, and new transmission upgrades have reduced the dependence on older, less efficient oil- and coal-fired units previously needed to address more local reliability concerns. These changes and the greater reliance on natural gas for power generation have lessened air pollution emissions and thermal pollution into rivers and bays in the region.

Between 2001 and 2011, systemwide emissions of nitrogen oxides (NO_X) declined by 58%, sulfur dioxide (SO_2) emissions by 71%, and carbon dioxide (CO_2) emissions by 11%. The decrease appears attributable to a nearly 50% decline in both oil- and coal-fired generation in 2011, combined with a significant increase in natural gas generation, which has a substantially lower SO2 emission rate.[45] In addition to required compliance with regulations, the future regional emissions could vary because of a number of factors; regional emissions would increase with production by oil-fired generating units during periods of natural gas shortages and could decrease through the greater use of energy efficiency and wind and photovoltaic resources.

Using assessments of the potential impact of existing and proposed state and EPA regulations on identified fossil steam units in the region, the ISO is identifying existing generation across New England affected by these environmental requirements. Uncertainty remains over the extent to which the final regulations will require generator owners to make capital investments in environmental remediation measures and potentially increase plant operating costs. These factors could require long-term generator outages for implementing required remediation measures. They also could trigger unit retirements as an alternative to accepting higher capital and operating costs. Alternatively, generators may comply with some of the environmental requirements by reducing capacity or energy production.

ISO analyses for the Strategic Planning Initiative and other planning efforts will continue to update stakeholders regarding the generators at risk for retirement and generators that already have environmental remediation measures in place or may require relatively minor upgrades.[46] The actual compliance timelines will depend on the timing and substance of the final regulations and site-specific circumstances of the electric generating facilities.

Renewable Portfolio Standards and the Integration of Renewable Resources

Renewable Portfolio Standards (RPSs) and similar state goals are stimulating the need for, and the development of, renewable resources and energy efficiency in the region. Other regional and industry efforts are assisting in integrating renewable resources, demand resources, and smart grid technologies into the system.

Meeting State Targets for Renewable Energy

The New England states have targets for the proportion of electric energy that load-serving entities (LSEs) must serve using renewable resources, such as wind, solar, and energy efficiency. Because the states are revising these targets to reflect different amounts and types of resources that qualify for RPSs, the ISO cannot project the precise amount of regional renewable energy goals. However, the state goals for EE and renewable resources are estimated to total approximately one-third of the region's projected electric energy consumption by 2022. The region's RPSs can be met by developing the renewable resources already in the ISO queue; importing renewable resources from adjacent balancing authority areas; building new renewable resources in New England not yet in the queue; and using "behind-the-meter" projects and eligible renewable fuels at existing generators, such as biomass. If the development of renewable resources falls short of providing sufficient Renewable Energy Certificates (RECs) to meet the RPSs, load-serving entities can make state-established alternative compliance payments (ACPs).[47] ACPs also can serve as a price cap on the cost of Renewable Energy Certificates.

Integrating Intermittent Renewable Resources

The ISO has made progress implementing the recommendations from the New England Wind Integration Study, which analyzed various planning, operating, and market aspects of wind integration for up to a 12-gigawatt (GW) addition of wind resources to the system. By late 2013, the ISO will have implemented a wind power forecast. The ISO also is facilitating wind integration by modifying operating procedures, data acquisition, and, over the longer-term, dispatch rules.

A number of wind projects have interconnected to electrically remote and weak portions of the regional power system, and additional wind projects are proposed for these areas. These facilities pose operational and planning challenges due to issues with voltage and stability performance, modeling, and differences between actual system operation and interconnection studies.[48] As a result, the ISO is examining potential improvements to the interconnection process, including the use of Elective Transmission Upgrades to strengthen electrically weak portions of the regional transmission network.

Photovoltaic resources are rapidly developing in New England, predominantly situated close to load centers. However, the ISO cannot observe or control most of these resources, which may respond differently to grid disturbances than larger, conventional generators. New ISO initiatives will be addressing these highly complex issues with stakeholders.

Developing New England's Smart Grid

In general, smart grid technologies can improve the ability of the transmission system to operate reliably under a wide variety of system conditions. They can improve the ability of system operators to observe and control the system, increase the transfer capability of the transmission system while adding less new infrastructure, and facilitate end-user response to the power system. Specific applications of smart grid technologies use demand resources to provide ancillary services, such as operating reserves, and help integrate variable renewable resources, such as wind and photovoltaic power, as well as hydroelectric power from neighboring Canadian regions. Smart grid technologies also can facilitate dynamic pricing. This smart grid equipment helps implement both customers' load response and the use of behind-the-meter resources, such as rooftop solar installations.

It is anticipated that more than 2,000 MW of distributed generation (DG), mostly solar photovoltaic (PV) facilities, will be installed regionwide by the end of 2021, up from about 250 MW at the end of 2012. The ISO recently convened a Distributed Generation Forecast Working Group to gather information about DG resources in New England and eventually develop a forecast of future DG growth to be incorporated into the long-term planning process.

The region is a leader in the smart grid application of high-voltage direct-current (HVDC) facilities and flexible alternating-current transmission systems (FACTS), which improve the use of system infrastructure. The ISO and the New England transmission owners installed phasor measurement units (PMUs) and associated equipment at 40 substations to upgrade the monitoring and operation of the system. The ISO and stakeholders have also supported research and development efforts and the establishment of industry standards for integrating smart grid technologies, including dispatching active demand resources, which are affected by the installation of smart meters and changes in retail rate structures. The ISO will continue to monitor the development of these technologies.

Economic Studies of Resource Integration and Interregional Coordination

Both the 2011 and 2012 economic studies analyzed several of the strategic issues the region is addressing.[49] The 2011 economic study examined the effects of integrating varying amounts of wind on production costs, load-serving energy expenses, and emissions, as well as the need for transmission development, to enable wind resources to serve the region's load centers. The 2012 economic study highlighted the least suitable locations for unit retirements and the most suitable locations for developing different resources without causing congestion. The study showed the effects of using various amounts of energy efficiency and low-emitting resources, including renewable energy.

These studies showed several key results. Accessing the onshore wind energy located in northern New England remote from load centers will require transmission expansion. Replacing older high-emitting coal- and oil-fired units with cleaner-burning natural gas generation will decrease environmental emissions but increase New England's dependence on natural gas and potentially require the expansion of the natural gas system infrastructure. The addition of resources with low energy costs decreases electric energy expenses for LSEs but also decreases energy market revenues to resources, which may then require increases in other revenue sources to remain economically viable.

The ISO is currently conducting an economic study in response to a stakeholder request received in 2013. This study, expected to be completed by the end of 2013, will examine the effects of increasing the acceptable loss-of-source limits in New England. As with other economic studies, the results will show changes in the production of electric energy by different types of generators using various types of fuels.

Analysis of Market Resources as an Alternative to Transmission Investment

In general, developing resources in load pockets is beneficial, especially the load pockets with exposure to potential generator retirements. However, assessing the suitability of individual resources during the planning process can be challenging because of the wide variability of the characteristics, locations, and possible combinations of resources, such as central station and distributed generation resources, end-use efficiency, and storage technologies. In response to PAC requests for more details about resources that could meet system needs, the ISO performed a pilot study for the Vermont/New Hampshire (VT/NH) area, which demonstrated how resources of various sizes and at various locations could meet thermal system performance requirements for 2020.[50] The analysis identified the critical load levels and hypothetical supply-side units, which could eliminate thermal overloads for normal and contingency conditions. The ISO has applied the lessons learned from the VT/NH study to the study of the Greater Hartford and Central Connecticut area and has updated the PAC on the results.[51]

> In late 2013, the ISO implemented a wind power forecast. The ISO is also facilitating wind integration by modifying operating procedures and data requirements for wind resources; integrating wind resources into scheduling and dispatch services over the longer term; considering changes to its generator interconnection study process; and identifying elective upgrades to the transmission system in the remote areas where most wind farms are built.

The ISO is examining ways of improving the efficiency of producing analyses on market resource alternatives and a means of summarizing results that would be more useful to stakeholders. Plans call for implementing these enhancements in 2014.

Interregional Planning

ISO New England's planning activities are closely coordinated at the state, regional, interregional, and federal levels. Identifying interregional system needs and the potential impacts that proposed generating units and transmission projects could have on neighboring systems is beneficial to support interregional reliability and economic performance.

The ISO has developed coordinated system plans and has proactively initiated planning studies with other regions.[52] The ISO has worked with both NYISO and PJM through the Northeastern ISO/RTO Planning Coordination Protocol to build on the Northeast Coordinated System Plan and address several key interregional issues and activities:

- Market-efficiency analyses, including the development of coordinated production cost models of the three ISO/RTOs and neighboring regions, which will serve as guidance for future interregional transmission studies

- The effects of environmental regulations and the integration of wind and other renewable resources
- The current and future dependency on natural gas and how the interregional electric power system provides access to a wider variety of types and locations of resources that can improve the overall reliability of the system
- The effects of demand-side resources on the system and how each of the ISOs/RTOs reflects these resources in its respective system operations and planning processes
- Coordinated tracking and discussion of compliance with FERC Order 1000 requirements for interregional planning[53]

Sharing more supply and demand resources with other systems most likely will be needed, particularly to meet environmental regulations and successfully integrate variable energy resources. The ISO has worked with stakeholders to establish a means of complying with FERC Order 1000, which includes improving the interregional planning process and interregional cost allocation. ISO New England will continue conducting joint studies with NYISO and PJM to identify transmission constraints limiting interregional power transfers and to show the effects of relieving these constraints throughout the ISO/RTO regions. The ISO also will continue to coordinate other efforts with neighboring systems to explore the ability to import power from, and export power to, the eastern Canadian provinces and New York and participate in national and regional planning activities.

ISO New England and other planning authorities throughout the Eastern Interconnection are members of the Eastern Interconnection Planning Collaborative. The EIPC addresses its portion of North American planning issues, coordinates plans, and conducts studies for the entire Eastern Interconnection through a transparent and collaborative process involving input from a broad base of interested stakeholders. ISO New England also serves as a principal investigator for a project funded as part of US Department of Energy (DOE) grant work. During Phase I of this project, the EIPC analyzed eight macroeconomic futures and 72 associated sensitivities based on input variables of each future.[54] Phase II commenced in 2011. This phase involves more detailed analysis of three final scenarios selected from the Phase I results and resource-expansion options and summarizes the results of production cost analyses for the transmission buildouts specified in the three final scenarios. At DOE's request, EIPC is further studying how the interface between the natural gas and electric power systems affects operations and planning. The draft EIPC Phase II report will be revised to account for the findings of the EIPC Gas-Electric System Interface Study, targeted for completion in mid-2015.

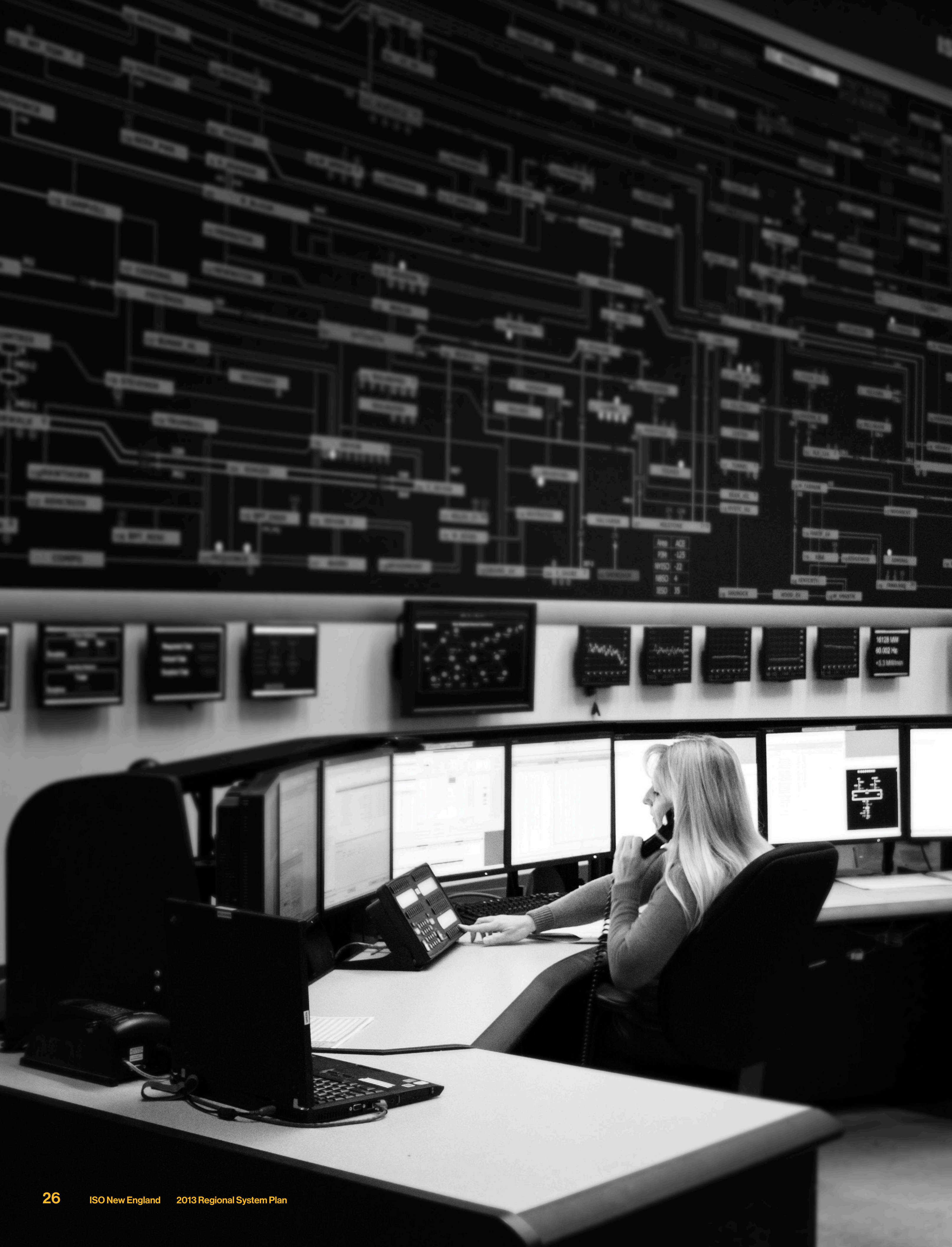
In June 2013, the ISO, in partnership with several transmission owners, completed the installation of 40 phasor measurement units (PMUs, or synchrophasors) on the high-voltage transmission system throughout New England. These PMUs are now streaming data that the ISO and transmission owners can use to analyze system disturbances and to develop tools for system operators. The project was funded by a 2009 grant from the US Department of Energy.

The ISO participates in several other national and regional system planning forums, such as NERC, the ISO/RTO Council, and the Northeast Power Coordinating Council. Through the NPCC and NERC, the ISO has participated in interregional assessments, which coordinate planning studies and demonstrate compliance with all required planning standards, criteria, and procedures.

State, Regional, and Federal Initiatives that Affect System Planning

The ISO continuously works with a wide variety of state policymakers and other regional and interregional stakeholders on initiatives such as the Strategic Planning Initiative and FERC Order 1000. Regional initiatives continue for improving the wholesale electricity markets, integrating new technologies, and documenting the regional transmission planning process and technical requirements for planning studies. The draft *Transmission Planning Process Guide* describes the process for developing the draft scopes of work, study assumptions, needs assessment studies, and solutions studies and how stakeholders can provide inputs.[55] The draft *Transmission Planning Technical Guide* describes the standards, criteria, and assumptions used in transmission planning studies.[56] Both these documents will be revisited to align with final Order 1000 requirements.

The ISO has continued to provide technical support to a number of state agencies and groups as they formulate policies for the region. These groups include the New England Conference of Public Utilities Commissioners (NECPUC), the New England States Committee on Electricity (NESCOE), the New England governors, the Consumer Liaison Group (CLG), and others. The planning process will continue to evolve in response to FERC orders and other policy developments.



Conclusions

The *2013 Regional System Plan* identifies system needs and plans for meeting these needs. RSP13 also discusses risks to the regional electric power system; the likelihood, timing, and potential consequences of these risks; and mitigating actions. Through an open process, regional stakeholders and the ISO are addressing these issues, which could include further infrastructure development as well as changes to the wholesale electricity market design and the system planning process. Through current and planned activities, the region is working toward meeting all challenges for planning and operating the system.

Notes

1 *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section II, *Open Access Transmission Tariff*, Attachment K, "Regional System Planning Process" (January 1, 2013), http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf. ISO tariff, Attachment D, "ISO New England Information Policy" (August 30, 2013), http://www.iso-ne.com/regulatory/tariff/attach_d/index.html. OATT, Schedules 22 and 23, "Standard Large Generator Interconnection Procedures" (February 12, 2013) and "Standard Small Generator Interconnection Procedures" (July 25, 2012), http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

2 RSP13 is based on the June 2013 *RSP Project List*, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html.

3 The region's private and municipal utilities formed NEPOOL 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. The NEPOOL stakeholder process provides advisory input on market, reliability, and OATT matters. More information is available at http://www.iso-ne.com/committees/nepool_part/index.html.

4 PAC materials and meeting minutes are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html. For access to PAC critical energy infrastructure information (CEII), complete the PAC Access Request Form at http://www.iso-ne.com/support/custsvc/forms/index.html and mail to ISO New England Inc., Attn: Customer Support, One Sullivan Road, Holyoke, MA 01040-2841, or email the PDF file to custserv@iso-ne.com.

5 A *demand resource* is a capacity product, type of equipment, system, service, practice, or strategy that verifiably reduces end-use demand for electricity from the power system.

6 Meeting materials, notes, and dates for discussing the Strategic Planning Initiative are available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html.

7 See notes 3 and 4.

8 FERC, *Order on Compliance Filings,* 143 FERC ¶ 61,150 (May 17, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/may/index.html. "Transmission Operating Agreements," web page, http://www.iso-ne.com/regulatory/toa/index.html.

9 *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff) (2013), http://www.iso-ne.com/regulatory/tariff/index.html.

10 Information on NERC requirements is available at http://www.nerc.com/. Information on NPCC is available at http://www.npcc.org/. An NPCC compliance audit conducted from March 12 through March 15, 2012, showed no ISO violations of any standards and requirements.

11 ISO tariff, Section II, *Open Access Transmission Tariff*, Attachment K, "Regional System Planning Process" (January 1, 2013), http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

12 The ISO's *Generator Interconnection Queue* includes the requests that generators submit to ISO New England to interconnect to the ISO-administered transmission system.

13 Information on the January 2004 cold snap is available at http://www.iso-ne.com/pubs/spcl_rpts/2005/index.html.

14 The *RSP Project List* summarizes transmission projects under various stages of development (i.e., concept, planned, proposed, and under construction), as required under the OATT to meet regional system needs. It also includes information on project status and cost estimates. The current update of the *RSP Project List* is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html. The system's pricing points for electric energy include individual generating units, load nodes, *load zones* (aggregations of load pnodes within a specific area), and the Hub. The *Hub* is a collection of energy pricing locations that has a price intended to represent an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace.

15 PJM Interconnection LLC 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. Additional information on the EIPC is available at http://www.eipconline.com/.

16 ISO New England, *Order No. 1000 Interregional Compliance Filing of ISO New England Inc. and the Participating Transmission Owners Administrative Committee, Supported by the New England Power Pool Participants Committee*, FERC filing (July 10, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/jul/index.html.

17 FERC, *Order on Compliance Filings*, 143 FERC ¶ 61,150 (May 17, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/may/index.html.

18 "Transmission Operating Agreements," http://www.iso-ne.com/regulatory/toa/index.html.

19 FERC stated that the ISO could grandfather existing projects no longer subject to either evaluation or reevaluation as of the effective date, which would not be subject to the competitive process.

20 *Order No. 1000 Compliance Filing of ISO New England Inc. and the Participating Transmission Owners Administrative Committee*, parts 1 and 2 (October 25, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2012/oct/index.html.

21 The ISO is scheduled to make its Order 1000 compliance filing to FERC on November 15, 2013.

22 The 50/50 "reference-case" peak loads have a 50% chance of being exceeded because of weather conditions. For the reference case, the summer peak load is expected to occur at a weighted New England-wide temperature of 90.2°F, and the winter peak load is expected to occur at 7.0°F. The 90/10 peak loads have a 10% chance of being exceeded because of weather. For the 90/10 case, the summer peak is expected to occur at a temperature of 94.2°F, and the winter peak is expected to occur at a temperature of 1.6°F.

23 The actual load has been near or above the 50/50 forecast 10 times during the last 20 years because of weather conditions; six of these 10 times, the load has been near or has exceeded the 90/10 forecast.

24 The ISO's *Forecast Data 2013* (May 3, 2013), worksheet 9 (http://www.iso-ne.com/trans/celt/fsct_detail/index.html) shows that the gross consumption of electric energy for 2022 is 151,005 gigawatt-hours (GWh). The savings attributable to federal appliance standards is 2,450 GWh for 2022. In addition, passive demand resources are projected to save 17,406 GWh for 2022 (see worksheet 2).

25 *Passive demand resources* reduce electric energy consumption that otherwise would have been served by generation resources and include such resources as energy efficiency and "behind-the meter" distributed generation (DG) in locations that have net metering. *Active demand resources* (i.e., demand response) reduce load in response to a request from the ISO for system reliability reasons or in response to a price signal. *Net metering* allows power customers who generate their own electricity, such as from wind or solar power, to feed their unused electricity back into the grid.

26 The net ICR values for 2012/2013 to 2015/2016 are the latest values approved by FERC and are available at http://www.iso-ne.com/markets/othrmkts_data/fcm/doc/. *Representative net* ICR values are illustrative future ICRs for the region, minus a monthly value that reflects the annual installed capacity benefits of the Hydro Québec Phase II Interconnection.

27 OP 4 actions include allowing the depletion of the 30-minute and partial depletion of the 10-minute reserves (1,000 MW), scheduling market participants' submitted emergency transactions and arranging emergency purchases between balancing authority areas (1,600 to 2,000 MW), and implementing 5% voltage reductions (400 to 450 MW). Operating Procedure No. 4, *Action during a Capacity Deficiency* (December 9, 2011), http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

28 Higher tie-reliability benefits and reductions in the net ICR would increase the frequency and depth of OP 4 actions.

29 A *capacity commitment period* runs from June 1 through May 31 of the following year. FCA #7 covers June 1, 2016, through May 31, 2017. Existing capacity resources are required to participate in the FCA and automatically are 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.

30 These totals do not account for the announced shutdown of Norwalk Harbor Station (349 MW nameplate capacity).

31 A *local sourcing requirement* is the minimum amount of capacity that must be electrically located within an import-constrained capacity zone to meet the ICR.

32 For more information on delist bids, refer to the ISO's *Overview of New England's Wholesale Electricity Markets; Market Oversight* (May 15, 2013), http://www.iso-ne.com/pubs/spcl_rpts/index.html.

33 FERC, *Order on Compliance Filing*, 143 FERC ¶ 61,198 (May 31, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/may/index.html.

34 According to NERC, NPCC, and ISO criteria, a *contingency* is the loss of one or more generation, transmission, or both types of facilities or power system elements. A system's *first contingency* (N-1) is when the power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that time has the largest impact on the system.

35 *Spinning* operating reserves are on-line resources that can increase output. Nonsynchronized (i.e., *nonspinning*) operating reserves are off-line resources that can be electrically synchronized to the system quickly, reaching maximum output within 10 to 30 minutes.

36 To conduct some RSP studies, the region is divided into various areas associated with their electrical system characteristics. *Greater Connecticut* is an area that has boundaries similar to the State of Connecticut but is slightly smaller because of electrical system limitations near Connecticut's borders with western Massachusetts and Rhode Island. *Greater Southwest Connecticut* includes southwestern and western portions of Connecticut. The *BOSTON* area (all capitalized) includes the city of Boston and northeast Massachusetts.

37 The ISO develops the representative operating-reserve requirements 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.

38 *Regional network service* is the transmission service over the pool transmission facilities (PTFs), including services used for network resources or regional network load not physically interconnected with a PTF.

39 Cost estimates without transmission cost allocation approval are subject to established variations as projects progress through various stages of implementation. The $5.7 billion cost estimate has a range of $4.4 to $6.9 billion based on projects proposed, planned, and under construction. See the *Regional System Plan Transmission Projects June 2013 Update*, PAC presentation (June 14, 2012), slide 9, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/jun192013/index.html.

40 For the results of a study of the changes in transfer limits across major interactions in Maine, including Maine to New Hampshire, see *Maine Power Reliability Program (MPRP): Transfer Capability Study Results*, PAC presentation (December 13, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/dec132012/index.html. Also see *MPRP North to South Steady State Transfer Limits and Incremental Stability Performance Study*, final draft report (November 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/mprp_transfer_limits.pdf.

41 An *Elective Transmission Upgrade* is an upgrade to the New England transmission system voluntarily funded by one or more participants that have agreed to pay for all the costs of the upgrade. *Merchant transmission facilities* are independently developed and funded and subject to the operational control of the ISO, pursuant to an operating agreement specific to each of these facilities.

42 For additional information on the near-, medium-, and long-term measures, see *Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency*, ISO white paper (2013), http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf. *ISO New England Inc. and New England Power Pool, Docket No. ER13-1877-000, Energy Market Offer Flexibility Changes*, FERC filing (July 1, 2013), http://www.iso-ne.com/regulatory/ferc/filings/2013/jul/index.html.

43 FERC, *Order Conditionally Accepting Tariff Revisions*, 144 FERC ¶ 61,204 (September 16, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/sep/index.html.

44 ICF International, *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short- and Near-Term Electric Generation Needs*, final report (June 15, 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/gas_study_ceii.pdf.

45 *2011 ISO New England Electric Generator Air Emissions Report* (February 2013), http://www.iso-ne.com/genrtion_resrcs/reports/emission/2011_emissions_report.pdf. These changes in generation are consistent with New England fuel consumption in 2010 and 2011, as reported by the US Energy Information Administration (EIA). Coal consumption for electric generators fell from 6.2 million short tons in 2010 to 3.0 million short tons in 2011, and residual fuel oil consumption fell from 1.5 million barrels in 2010 to 0.7 million barrels in 2011.

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