RSP 2011

REGIONAL SYSTEM PLAN

EXECUTIVE SUMMARY

ISO new england

Preface

ISO New England Inc. is the not-for-profit corporation responsible for the reliable operation of New England's power generation and transmission 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.[1] Regional System Plans meet the tariff requirements by including the following:

- Forecasts of future annual 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 merchant transmission facilities) 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 is updated several times each year and also includes information on project status and cost estimates.[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 system, and information that can be used for improving the design of the regional power 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 can take to meet the needs of the system.[3]

The *2011 Regional System Plan* (RSP11) and the regional system planning process were developed in full accordance with the requirements established in the OATT for the region's 10-year electricity needs from 2011 through 2020. The requirements of the OATT, including Attachment K, the *ISO Information Policy*, interconnection procedures, and requirements for generators and elective upgrades, prescribe how ISO tasks comply with the requirements.[4]

Regional Transmission Planning Results

New England's transmission owners have constructed transmission projects throughout the region on the basis of the needs and solutions identified through the regional

planning process, as detailed in past RSPs and supporting reports.[5] These projects reinforce transmission facilities serving areas that have experienced load growth, such as Vermont, southern Maine, and the New Hampshire seacoast area. The projects also reinforce the system's 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. From 2002 through 2011, 379 projects will have been put into service, totaling approximately $4.6 billion of new infrastructure investment.

In addition to the need for transmission development, the region has responded to the need for electric energy and capacity resources. New generating projects totaling 13,177 megawatts (MW) have been interconnected with the system since generators first submitted requests to the ISO to be interconnected to the New England power system in November 1997. Demand resources currently totaling 2,035 MW are part of the regional power system, and 3,590 MW are planned for 2014.

Past RSPs also have identified risks to the future economical and reliability performance of the system. This information has assisted stakeholders with formulating policies for the region. The information also has been used to identify changes to the markets, which have encouraged the development of resources where and when needed, such as "fast-start" resources in load pockets. These resources can quickly reach rated capability to help meet reliability requirements and reduce the amount of time generators operate out of economic-merit order.

RSP11 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, and draft and final results and other materials appearing in RSP11. From September 2010 through August 2011, the ISO hosted 17 PAC meetings, which were attended by 258 stakeholder representatives from 140 entities. The total stakeholder attendance of 1,004 signifies over 6,900 workforce hours of participation. The ISO also posted to its website PAC presentations, meeting minutes, reports, databases, and other materials.[6] In addition, a public meeting was held on September 8, 2011, to discuss RSP11 and other planning issues facing the New England region.

On October 21, 2011, the ISO New England Board of Directors approved RSP11. The full 210-page document can be downloaded in its entirety from ISO New England's website.

PROGRESS REPORT

TRANSMISSION

The region has completed eight major 345 kilovolt transmission upgrades required for power system reliability, and construction has begun on several more. From 2002 to the end of 2011, a total of 379 transmission projects will have been put into service, representing a $4.6 billion infrastructure investment in all six states. These transmission upgrades maintain system reliability and support market efficiency and have resulted in significant reductions in congestion costs.

GENERATION

Competitive wholesale markets have encouraged the construction of more than 13,100 megawatts (MW) of new generation in the region since 1997.

DEMAND RESOURCES

The Forward Capacity Market has encouraged expansion of demand-side resources, such as energy efficiency and active demand resources, which reduce load only when needed. More than 2,000 MW of demand resources are available in 2011 and more is being planned.

Contents

Introduction

The ISO New England *2011 Regional System Plan* presents the results of load, resource, and transmission analyses of New England's electric power system for the 10-year planning period through 2020. 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 economical system in compliance with federal and state regulations and guidelines. In addition to complying with all applicable sections of the ISO's *Transmission, Markets, and Services Tariff*, approved by the Federal Energy Regulatory Commission (FERC), RSP11 and the system planning process satisfy the relevant criteria and requirements established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the region.[7]

Over the past decade, the system planning process and market design have fostered significant improvements to the region's generation and demand resources and transmission system. Much of the region's generation was built during the last 10 years, and most of the region's electric energy production now comes from efficient, gas-fired combined-cycle generators. Additionally, the amount of demand resources in the region has grown significantly. The transmission system, which for decades saw little investment, has been upgraded to better serve the region's load. Building on the results and recommendations of previous Regional System Plans, RSP11 discusses the results of completed studies and new and planned infrastructure throughout New England. Accounting for the current status of the system, RSP11 discusses ongoing, new, and pending analyses. In addition, RSP11 discusses state and federal policies that affect the planning process, system reliability and economic performance issues, and how the region is addressing these issues.

ISO New England, working closely with its stakeholders, has identified five challenges expected to have an impact on the New England power system in the coming years. The challenges include resource performance and flexibility; increased reliance on natural gas; retirement of generators; integration of variable resources; and alignment of planning and markets. The Strategic Planning Initiative will proactively address these issues to ensure continued reliability and an efficient marketplace in the long term.

Notwithstanding the region's recent improvements, challenges remain for maintaining the reliable and efficient operation of the New England power system, involving the following:

- Resource performance and flexibility
- The region's increased reliance on natural-gas-fired capacity
- The potential retirement of generators
- The integration of a greater level of *variable* (i.e., inter-mittent) resources
- The alignment of wholesale market design and regional transmission planning

To address these challenges and prepare for the changes likely to confront the New England power system, the region has begun a Strategic Planning Initiative.[8] Through the initiative, the region is actively assessing the current tools it has developed to ensure reliability. These tools include market rules that retain resources wishing to leave the capacity market, out-of-merit commitment and dispatch of capacity to maintain system security, the procurement of emergency capacity, and special operator actions during fuel shortages.[9] Given the expected changes and impacts to New England's generation fleet, the region must decide whether these tools should be improved and better integrated or whether new approaches are warranted to preserve and improve the efficiency of reliable system operations.

The region has a long history of cooperation through its open stakeholder processes and is well poised to meet upcoming challenges identified by the Strategic Planning Initiative and other stakeholder efforts.

Major Findings and Observations

This section presents an overview of the major findings of RSP11 load forecasts; supply and demand resource and transmission planning efforts; market outcomes; economic studies; and other programs, projects, and initiatives that are part of the system planning process. The sections of the report that contain more details of these findings and observations are indicated.

For all RSP11 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 RSP11 results and conclusions and ultimately influence the future development of transmission and generation and demand resources:

- Demand and energy-efficiency (EE) forecasts, which are dependent on the economy, new building and federal appliance-efficiency standards, state EE goals and project 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
- Fuel price forecasts, which change with world markets and infrastructure development
- Market rules and public policies, which can alter the development of market resources
- Technology development and its deployment, which may improve the physical ability and the economic viability of new types of power system equipment and the efficiency of operating the power system
- Timing of planned system improvements, which can be subject to siting and construction delays and changes to the system

The ISO considers these factors for developing a robust plan. While each RSP is a snapshot in time, the planning process is continuous, and results are updated as needed, accounting for the status of ongoing activities and new initiatives, such as the Strategic Planning Initiative.

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

The amount and location of the net system load could affect the need for new resources and the required timing of some transmission projects. RSP11 summarizes the growth of electric energy usage, both annually and at the peak hour—for the entire system, individual states, and smaller areas of the power system. RSP11 also summarizes the state EE goals and the status of the ISO's project to develop a method to forecast energy savings from expected EE implementation.

Annual and Peak Use of Electric Energy and Load Growth

The RSP11 forecast for the annual use of electric energy is slightly higher than the RSP10 forecast, and the peak load forecasts are similar. The forecast is highly dependent on the economic forecast, which reflects (1) the recent recession ending in 2009 followed by weak economic growth in 2010 and (2) a projected rebound in 2013 followed by sustained load growth.

Energy consumption is projected to grow an average 1.1% annually over the next 10 years, while summer peak demand is expected to grow by 1.4% per year.

The RSP11 forecasts incorporate the expected effects of federal EE standards for appliances and commercial equipment that will go into effect in 2013 and the historical energy-efficiency savings (i.e., reductions in past loads resulting from energy-efficiency measures). The forecasts consider demand resources that cleared the Forward Capacity Market (FCM) to be sources of supply and not demand-side measures for reducing the demand forecast. The forecasts of the energy savings attributable to federal appliance standards and FCM passive resources are 1.6% and 4.7%, respectively.[10] These represent a total energy savings of 6.3% of the gross consumption of electric energy projected for 2020.[11]

The 50/50 "reference case" summer peak forecast is 27,550 megawatts (MW) for 2011, which grows to 31,215 MW for 2020.[12] The 90/10 "extreme case" summer peak forecast is 29,695 MW for 2011 and grows to 33,700 MW in 2020. The actual load has been near or above the 50/50 forecast nine times during the last 19 years as a result of weather conditions and has been near or has exceeded the 90/10 forecast five times during the same period. The ISO forecasts the 10-year growth rate to be 1.4% per year for the summer peak load, 0.5% per year for the winter peak load, and 1.1% per year for the annual use of electric energy. The annual *load factor* (i.e., the ratio of the average hourly load during a year to peak hourly load) remains fairly stable and declines slightly from 56.1% in 2011 to 54.5% in 2020.

Energy-Efficiency Forecast

The New England states and members of the Planning Advisory Committee (PAC) have requested that the ISO consider the potential impacts of the states' energy-efficiency programs beyond the EE already considered in the short- and long-term planning of the system. The New England states' EE goals call for a total reduction of approximately 13.6% of the regionwide electric energy consumption projected for 2020, but the goals do not have targets for peak load reductions.[13]

ISO New England is currently developing a methodology to forecast long-term energy-efficiency savings from state-sponsored programs, for years beyond what is currently captured in the Forward Capacity Market.

In response to stakeholder requests, the ISO met with state energy-efficiency program administrators, other ISO/RTOs, and regional stakeholders to identify and discuss issues associated with developing a method of improving EE forecasts and incorporating EE savings from state programs into the ISO's planning process. Major issues include:

- Determining how to accurately calculate the decrease in peak loads resulting from reduced energy use
- Projecting funding levels for state-sponsored energy efficiency, which may be uncertain and may affect the amounts of EE successfully developed

The open stakeholder process with the PAC and other committees, such as the Load Forecast Committee and the Reliability Committee, is expected to be completed by late 2011 and in time to incorporate the EE forecast into RSP12.

Needs for Capacity and Operating Reserves

RSP11 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 current regional development of generation, demand, and import capacity resources is expected to provide the capacity needed to meet resource adequacy requirements (i.e., the minimum amount of capacity the region will require, called the *Installed Capacity Requirement* [ICR]). The net ICR is expected to grow from 32,127 MW in 2013 to an illustrative value of 35,635 MW by 2020.[14]

The results of the latest Forward Capacity Auction (FCA #5) show that New England should have adequate resources to meet demand through 2014/2015. Future FCA auctions will help procure the capacity needed, should generation retirements occur after the 2014/2015 timeframe.

Resources are projected to be sufficient for the 2014/2015 commitment period, but resource retirements may make new resources necessary sooner than otherwise expected.[15] The fifth Forward Capacity Auction (FCA #5) recognized the "nonprice" retirement request of Salem Harbor units #1, #2, #3, and #4, representing nearly 750 MW.[16] In addition, challenges to the continued operation of nuclear plants in the region, particularly Vermont Yankee, which is rated at approximately 600 MW, presents additional potential losses of capacity. Other resource retirements could result from coal and oil resource owners choosing not to invest in required environmental remediation measures. The high likelihood of additional retirements at future auctions would accelerate the expected need for new resources.

New resources could be provided in part by some of the resources in the ISO's Generation Interconnection Queue (the queue), which included over 7,992 MW as of April 1, 2011; new demand resources; and new import capacity from neighboring regions.[17] Changes directed by FERC will improve the market incentives for developing resources when and where needed.[18]

Operating Reserves

Resources participating in the locational Forward Reserve Market and other resources that are committed and on line are helping to satisfy the operating-reserve requirements of the region overall and in major load pockets to cover contingencies.[19] As a result of transmission upgrades and other resource additions, the Greater Southwest Connecticut area is not expected to need any additional local operating reserve for 2011 to 2015.[20] Over the same period, the forecasted need for the Greater Connecticut area is 400 to 1,000 MW, and the need for the BOSTON area is in the range of 0 to 400 MW.[21] The addition of in-merit generation or demand resources within the major import areas, improvements to the transmission system, or some combination of all measures would decrease the need to locate operating reserves within these areas.

Unit retirements and the addition of variable resources, particularly wind, will likely grow with time and increase the need for flexible operations and resources to provide reserves, regulation service, and ramping in the most effective locations. A review of the requirements for operating reserve and an evaluation of potential enhancements to the locational FRM to better meet operational needs and improve the long-term efficiency and reliability of the system are being considered.

Transmission System Needs and Solutions

The transmission system performance must meet reliability requirements in accordance with applicable NERC, NPCC, and ISO criteria and standards. To meet these requirements, RSP11 identifies the need for transmission development in the region and summarizes the status of ongoing transmission studies and projects in various stages of implementation. Transmission projects also have reduced congestion and decreased dependence on generating units located in load pockets. In 2010, systemwide congestion-related costs totaled approximately $37 million, and payments for generators in "must-run" situations that provided second-contingency coverage and voltage support totaled $9 million. These represent significant reductions from 2008 when congestion totaled $273 million and generator payments for "must-run" situations totaled $212 million.

According to the US Department of Energy (DOE) *2009 National Electric Transmission Congestion Study,* which summarized the amounts of congestion throughout the Eastern Interconnection, the New England system currently experiences little system congestion.[22] As a result, DOE has removed New England as an "area of concern" for the identification of National Interest Electric Transmission Corridors.

Transmission Projects

The *RSP Project List* is a summary of transmission projects under various stages of development (i.e., concept, planned, proposed, and under construction), as required under the *Open Access Transmission Tariff* (OATT) to meet regional system needs.[23] It also includes information on project status and cost estimates. The descriptions of transmission projects in RSP11 are based on the June 2011 update, which includes 189 projects at a total cost of approximately $5.3 billion.[24] The ISO updates the *RSP Project List* at least three times per year, as improvements are identified and projects are completed or eliminated from the list. In addition, the ISO makes databases used for simulating the power system available to stakeholders.

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. All transmission projects are coordinated with other regions as well. The ISO is continuing to work with regional participating transmission owners (PTOs) and other stakeholders to improve the timeliness, transparency and quality of transmission project cost estimates provided to stakeholders throughout the development of transmission projects. The ISO also has advised the PAC of the regional network service (RNS) rate and projections developed by the PTOs.[25]

The status of several major projects under development is as follows:

- The Maine Power Reliability Program (MPRP), for which the Maine Public Utilities Commission has approved most of the components, establishes a second 345 kilovolt (kV) path in the north from Surowiec to Orrington and adds new 345 kV lines in southern Maine, creating a third parallel path from Surowiec to Eliot. These new paths will provide basic infrastructure necessary to 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 local load pockets as necessary.[26] The ISO is evaluating the extent to which transfer capability through Maine has been increased as a result of the MPRP project. The MPRP project is scheduled for completion by the end of 2014.

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

  - As a result of the needs assessments and solutions studies conducted by the ISO and the siting proceedings completed by the affected states (Massachusetts, Connecticut, and Rhode Island), the Springfield and Rhode Island components of NEEWS are scheduled for completion by 2014.

  - The Interstate Reliability Project was reevaluated to account for an updated load forecast, system operating constraints, resources acquired and delisted through the Forward Capacity Auctions, the impact of the unavailability of the Salem Harbor facility, and the possibility that the Vermont Yankee plant will not remain operational.

    - Studies that considered these and other factors show that the Interstate Reliability Project continues to be needed to meet national and regional reliability criteria and serve load throughout southern and eastern New England. The project is needed to ensure power flow of FCA-cleared resources between western New England and eastern New England that will improve the ability of the overall transmission system to serve load. The system needs assessment also identified concerns with generator mechanical stress issues, high short-circuit levels at key substations, and system performance following extreme contingencies and the retirement of generating units. The preferred solution for the Interstate Reliability Project has been identified and has an expected in-service date of 2015.

    - The need for the Central Connecticut Reliability component of NEEWS remains under consideration as part of the Greater Hartford–Central Connecticut study.

Several major transmission planning studies have been completed and others are underway throughout all six New England states. Some studies have developed solutions to serve major portions of the system, including Vermont and New Hampshire, the Merrimack Valley, the Pittsfield and Greenfield area, and the Greater Boston area. All studies examine the system comprehensively and account for the electrical characteristics of the tightly integrated New England network.

Some generating units must run to reliably serve area load pockets, which may partially solve system needs. These load pockets include portions of Maine, the Boston area, southeastern Massachusetts (SEMA), western Massachusetts, the Springfield area, and portions of Connecticut. In addition to improving reliability, transmission improvements placed in service have reduced load costs associated with second-contingency and voltage-control payments to generators. The Lower Southeastern Massachusetts (Lower SEMA) short-term upgrades are one example of transmission improvements that have improved reliability, reduced dependencies on generating units, and reduced "make-whole" payments to market participants with resources whose operating costs were 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 accomplish the following actions:

- Preserve the reliability of service to load pockets, which could likely face generator retirements within the planning horizon
- Provide access to renewable resources, some of which are likely to be located remotely from load centers
- Provide access to a diversity of generator types using different fuels and having varying operating characteristics

Transmission upgrades have been identified in all six New England states to meet reliability requirements. Several are currently under construction, have been approved in state-level siting proceedings, or are being prepared for siting. These include the Maine Power Reliability Program, upgrades in Southeastern Massachusetts, and the Interstate Reliability Project in Connecticut, Massachusetts and Rhode Island. In all, more than 189 projects, representing an investment of about $5.3 billion, have been proposed to reinforce the reliability of New England's power system.

Elective and Merchant Transmission Development

Several developers have proposed elective and merchant transmission upgrades, which are in various stages of study and development.[27] These projects could increase New England's tie capability with its neighbors and improve access to renewable sources of energy. The ISO will continue to monitor projected system conditions and needs based on the outcomes of these upgrades.

Analysis of Market Resources as an Alternative to Transmission Investment

Regional System Plans have provided considerable information on the amounts, types, locations, and performance requirements of resources that could meet system needs. In response to stakeholder requests for more detailed information, the ISO recently conducted a pilot study analyzing how various market resources could solve reliability needs in Vermont and New Hampshire. The ISO intends to conduct more such analyses for other areas in the region.

Past Regional System Plans have provided considerable information on the amounts, types, locations, and performance requirements of resources that could meet system needs. Market resources can include disparate types of end-use efficiency, generation including distributed generation, and storage technology options, which makes assessing their suitability during the planning process challenging.

In response to PAC requests for more detailed information 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.[28] The analysis identified the critical load levels and hypothetical supply-side units of 10 MW, 50 MW, and 500 MW, which eliminate thermal overloads for normal and contingency conditions. ISO staff and members of the PAC currently are evaluating the benefits of this type of analysis and will provide input and feedback to the ISO before additional studies are performed.

As part of the Strategic Planning Initiative, the region will consider market design changes to better align system planning requirements and wholesale market design.

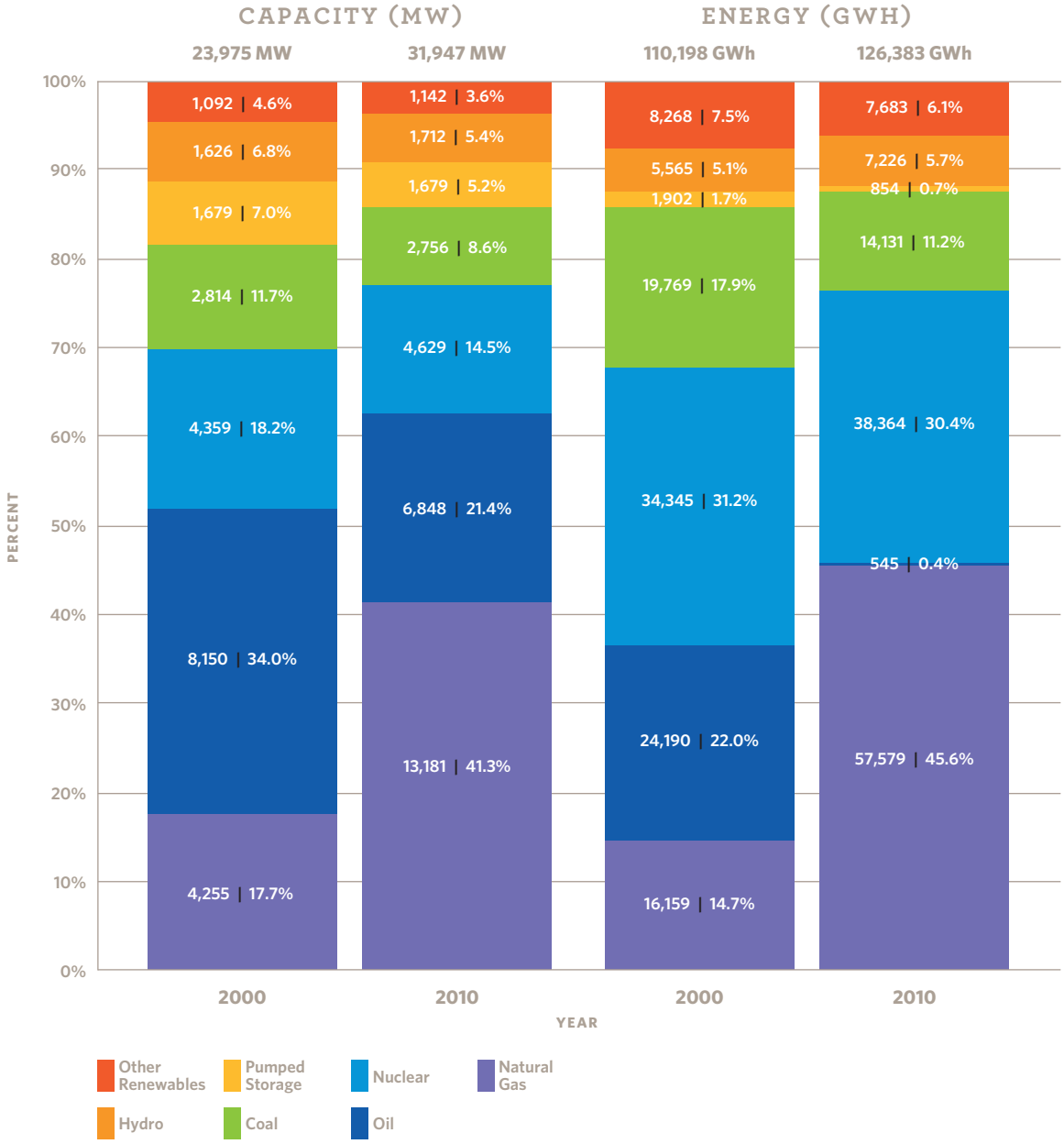
Development and Integration of Resources

In addition to identifying the need for capacity and operating reserves, the ISO's system planning process assesses the impacts that fuel diversity and environmental initiatives can have on future system needs and regional solutions to meet those needs. It also identifies and resolves issues concerning the development and integration of renewable resources and smart grid technologies.

Fuel Diversity and Natural Gas

While New England remains heavily dependent on natural gas as a primary fuel for generating electric energy, improvements to the region's natural gas infrastructure and coordination between the gas and electric power system operators have

mitigated concerns about fuel diversity and reliability. However, the region's dependency on natural gas is expected to increase with time. As shown in chart, 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 2010, natural gas plants represented 41.3% of the region's capacity and provided about 45.6% of the system's electrical energy. At 34.0% of the region's capacity in 2000, oil units produced 22.0% of the region's electric energy that year, but in 2010, at 21.4% of the capacity, oil units produced 0.4% of the region's electric energy. Almost 90% of the summer capacity of these units (MW) is over 20 years old.



Comparison of the 2000 and 2010 capacity and electric energy production in New England.

New England's dependency on natural gas is expected to continue to increase. In 2000, natural gas-fired power plants produced about 15% of the region's electricity. By 2010, that had increased to 45.6%. At the same time, electric energy produced by oil units declined from 22% in 2000 to 0.4% in 2010.

Many of the old coal, oil, and nuclear units could likely be replaced by natural-gas-fired generating units, which could be built in locations requiring relatively little additional transmission system infrastructure.

Although the addition of renewable resources would provide some diversity of the fuel supply, the increased regulation and reserve requirements needed to reliably integrate new variable resources into the system could place new stresses on the natural gas system that would need to flexibly provide fuel to generators on short notice. Exacerbating the problem is that many natural-gas-fired units lack the physical ability to provide flexible operation and economical or effective dual-fuel capability (in terms of the amount of time it takes to switch to using oil, ramping rates, or the availability of secondary fuel inventory). All these issues have been identified as part of the Strategic Planning Initiative.

Recent and planned improvements to the regional and interregional natural gas infrastructure have helped and will expand and diversify natural gas sources to meet New England's increasing demand for natural gas to produce electric power. Also, the implementation of operating procedures and improved communications between electric power and natural gas system operators have decreased operational risks and improved the reliability and diversity of natural gas supply and transportation. However, more work needs to be done.

To understand the emerging vulnerabilities, particularly in severe winter or other stressed system conditions, the ISO has issued a request for proposals to study regional natural gas issues.[29] This study will aim to assess the effects of generator retirements on fuel diversity concerns; determine the quantities of gas-fired megawatts available after all firm, priority deliveries are accounted for; review natural gas infrastructure contingencies affecting reliable electric power operation; and determine the need for additional natural gas system supply to reliably serve New England generating resources.

The Potential Impacts of Water and Environmental Emissions Regulations on the Power System

For more than 10 years, the region's average and marginal emission rates for sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) have been declining. This is a result of natural-gas-fired generators in the region having lower emissions than the generating units they displaced in economic dispatch and coal-fired units adding emission controls.[30] New transmission upgrades have facilitated the dispatch

of natural gas units, which overall has significantly reduced the reliance on older, less efficient oil units. Compared with 1999, the 2009 average emission rate for SO_2 has declined by 71%; the rate for NO_X, by 66%; and the rate for CO_2, by 18%. Total emissions for SO_2 and NO_X have also decreased from 2001 levels by 62% and 54%, respectively.

Emission rates for New England generators continue to decline. Compared with 1999, the 2009 average emission rate for sulfur dioxide has declined by 71%, nitrogen oxide by 66%, and carbon dioxide by 18%. Proceeds from Regional Greenhouse Gas Initiative auctions have provided nearly $263 million to the six New England states, and 86% has been targeted to state energy-efficiency programs.

However, the region and neighboring areas face extensive and stricter state and federal environmental regulations to protect public health and the environment that address air emissions, including air toxics; cooling water intake requirements; and the handling of coal combustion waste products.[31] When promulgated, these regulations will increase the operating costs for affected generating plants that require emission allowances, add capital costs for environmental controls, and require the use of low-emitting fuels.[32] These regulations may lead to the retirement of some aging units before 2020 (the last year of this 10-year plan) and limit energy production and generation capacity. Because this could lead to new generation dispatch and commitment patterns and shifting costs, the ISO will monitor and evaluate environmental initiatives as they occur or are proposed and reflect them in system planning studies.

The ISO reviewed several modeling assessments and reports that evaluated the impact of upcoming EPA regulations and identified fossil and steam thermal units that would need to comply with these regulations. Drawing on these studies and conducting an independent analysis, the ISO identified the amount of generation across New England that could be affected by the environmental requirements:

- A total of 12.1 gigawatts (GW) of fossil fuel and nuclear capacity could be subject to cooling water intake requirements, of which 5.6 GW could be subject to more restrictive requirements associated with adding control options to protect aquatic life, with full compliance likely by 2020.

- A total of 7.9 GW of existing coal steam or oil/gas steam units could be subject to the proposed US *Air Toxics Rule,* with full compliance likely by 2016.

- Additional amounts of installed capacity in New England may be subject to future required reductions in the interstate transport of emissions after EPA removed generators in Connecticut and Massachusetts from the final *Cross-State Air Pollution Rule*.[33]

The Regional Greenhouse Gas Initiative and impending changes to federal air and water regulations are likely to affect some New England generators. The ISO has initiated a study to better quantify the resource implications of existing and upcoming EPA regulations and will continue to monitor how federal and state policy changes may affect the region.

As part of the Strategic Planning Initiative, ISO analysis also will continue to identify generators that already have environmental remediation measures in place or may require relatively minor upgrades. The actual compliance timelines will depend on the timing and substance of the final regulations and site-specific circumstances of the electric generating facilities. Peak compliance construction activity is expected in the 2012 to 2016 timeframe. The study also will identify generators at risk for retirement.

The Regional Greenhouse Gas Initiative (RGGI) is a cap-and-trade program designed to reduce CO_2 emissions in 10 states throughout the Northeast by 2018. The initial compliance period (2009 to 2011) ends in December 2011, and in 2012, RGGI participants will complete a comprehensive assessment of the program's design, its impacts, the need for additional CO_2 reductions, and the issue of imports and emissions "leakage."[34] The March 9, 2011, RGGI auction cleared at $1.86/ton of CO_2 and raised $205 million for New England energy-efficiency programs, energy-assistance programs, and renewable resource development.

Renewable Portfolio Standards and the Integration of Renewable Resources

Environmental regulations and policies mentioned above, Renewable Portfolio Standards (RPSs), and related state goals are stimulating the need for and development of renewable resources and energy efficiency in the region. Other regional and industry efforts are assisting in integrating renewables, 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 provided by renewable resources, such as wind, solar, and energy efficiency. These state targets will increase to approximately 31.2% of New England's total projected electric energy use by 2020. This goal of 31.2% consists of 13.6% energy-efficiency and combined heat and power programs and 17.6% Renewable Portfolio Standards and policies addressing renewable supply goals.[35] Possible solutions for meeting or exceeding the region's RPSs include developing the renewable resources 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 small "behind-the-meter" projects, and using eligible renewable fuels in existing generators. If the development of renewable resources falls short of providing sufficient Renewable

Energy Certificates (RECs) to meet the RPSs, load-serving entities (LSEs) can make state-established alternative compliance payments (ACPs).[36] ACPs can also serve as a price cap on the cost of Renewable Energy Certificates.

Analysis of the ISO queue shows that 77% of the electric energy produced from these resources alone would meet the growth of RPS requirements through 2020, assuming all state EE goals are met. Even if only 40% of the renewable resources in the queue were developed, they would meet the RPS goal through 2015. The New England States Committee on Electricity (NESCOE) issued a request for information (RFI) to identify the potential amounts and locations of renewable resources the New England region readily could access.[37] The responses to the RFI showed interest by 4,700 MW of renewable resource developers but did not include all projects in the ISO queue. According to NESCOE, the development of all the RFI projects could produce approximately 15,000 gigawatt-hours annually, which would meet the 2020 RPS goal. Transmission developers also responded to the RFI, showing interest in interconnecting load centers with major potential sources of renewables, including those from neighboring Canadian provinces.

Renewable Portfolio Standards and related goals call for renewable resources and energy efficiency to comprise 31.2% of New England's total projected energy use by 2020, with state energy-efficiency and combined heat and power programs making up about 13.6% of these goals.

Integrating Renewable Resources. The ISO completed the *New England Wind Integration Study* (NEWIS), a major study of integrating wind resources into the New England system.[38] This study analyzed various planning, operating, and market aspects of wind integration; simulations that add wind resources up to 12,000 MW; and the conceptual development of a transmission system that can integrate large amounts of wind generation resources. The completed study developed models of generation output for a hypothesized fleet of wind plants suitable for ISO studies. The large-scale integration of wind resources is feasible in the New England region, but the region will need to continue addressing a number of issues, as shown by the following results:

The addition of large-scale wind generation, with its characteristic low operating costs, would reduce wholesale electric energy market revenues for all resources but would reduce revenues for some more than others. The results of a scenario analysis showed a large decrease in net energy market revenues for natural-gas-fired resources, which could make these units uneconomical and not available to supply system needs if they retired. Additional sources of revenue would be needed, possibly by modifying the markets, to preserve these units for providing reliability services as required.

- Increased system flexibility is required to integrate large amounts of wind generation, and the market design would need to evolve to provide incentives for dispatchable resources to add this flexibility.
- The need for operating reserve and regulation would increase.
- Existing methods for calculating capacity values would need to be monitored and possibly modified to improve the accuracy of the estimated capacity values for large increases in wind generation.
- Transmission development would be needed to interconnect the wind resources and to bring the energy to load centers in New England.
- An accurate means of forecasting wind generation outputs is required to support reliable and efficient system operation.
- Interconnection requirements for wind generators should be updated and implemented, as recommended by the NEWIS Task 2 Report.

Connecticut and Massachusetts have goals for developing photovoltaic solar power capacity. Integrating a large amount of megawatts from small-scale solar developments across the system is challenging because these resources are intermittent and present issues similar to those for wind resources. The effects on the overall power system, however, would likely be less significant because the expected amount of solar resource development is much smaller than the planned wind development in the region.

Developing New England's Smart Grid. Smart grid technologies represent the next stage in the evolution of the power system to improve data acquisition, analysis, control, and efficiency of the electric power grid. The smart grid also will facilitate the integration of variable resources. In 2010, the DOE approved funding for the ISO and the New England transmission owners to add over 35 new phasor measurement units, which will be used to improve the monitoring and operation of the system. The ISO and stakeholders also have supported research and development efforts and the establishment of industry standards for integrating smart grid technologies, such as active demand resources. The region is a leader in the application of high-voltage direct-current facilities and flexible alternating-current transmission systems.

Economic Studies of Resource Integration and Interregional Coordination

In 2010, NESCOE requested the ISO to conduct a study of the economic impacts of replacing aging coal- and oil-fired generating units with efficient, low-pollution-emitting, natural gas combined-cycle units; wind resources within New England;

and renewable imports from Canada. This study was conducted to further inform government officials as they establish policies that affect the future planning and development of the system. As a complement to the 2010 economic studies, the ISO is studying units expected to face significant capital investments to meet compliance with environmental regulatory requirements and the impact of their potential retirement on the transmission system.

The New York ISO (NYISO), PJM Interconnection (PJM), and ISO New England coordinated an economic study to identify where major interfaces are constraining interregional transfers. The study analyzed a series of scenarios for the 2015 timeframe to account for planned load, resource expansion and retirements, and transmission configurations that could affect these regions. The study assessed the joint production cost performance and includes the effects of relaxing various combinations of constrained transmission interfaces. Follow-up studies will be fully coordinated with stakeholders.

In response to stakeholder requests received in 2011, the ISO is conducting studies to examine various wind development scenarios, particularly in northern New England, including the Wyman–Bigelow area in Maine. The studies will quantify the near-term economic performance of the system for 2016, assuming the realization of renewable resources in the interconnection queue. The study also will identify the need for transmission development.

ISO New England has completed a number of economic studies that address future system performance for various scenarios. Completed studies and follow-up analyses are being conducted to show the effects of generator retirements, the integration of wind generation, and interregional transfers with neighboring power systems, such as New York ISO, PJM Interconnection, and the Canadian regions.

The economic studies identified several of the strategic issues the region is considering. Accessing the renewable wind energy located in northern New England, remote from the load centers along the southern coast, 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 infrastructure. The addition of resources with low energy costs decreases electric energy expenses for LSEs but also decreases energy market revenues to resources that may require other revenue sources to remain economical. The successful coordination of interregional production cost studies has been demonstrated but requires considerable effort by ISO/RTO personnel and stakeholders.

Interregional Planning

ISO New England's planning activities are closely coordinated at several levels:

- Among the six New England states
- With neighboring systems through a Planning Coordination Protocol and the NPCC
- Across the interconnection through the Eastern Interconnection Planning Collaborative (EIPC)[39]
- Nationally through NERC

The ISO has developed coordinated system plans and proactively initiated planning studies with other regions.[40] Sharing more supply and demand resources with other systems will likely become necessary, particularly, to meet environmental regulations and to successfully integrate variable resources. 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.

In August 2009, a coalition of the regional planning authorities within the Eastern Interconnection formed the Eastern Interconnection Planning Collaborative. The EIPC is a first-of-its-kind effort to address its portion of North American planning issues, coordinate plans, and conduct studies for the entire Eastern Interconnection through a transparent and collaborative process with input from a broad base of interested stakeholders. Participants include federal and state policymakers; Canadian provincial officials; consumer and environmental advocates; transmission owners and developers; generation owners; other suppliers; and representatives from transmission-dependent utilities, public power companies, and electric cooperatives within the Eastern Interconnection. ISO New England and other planning authorities throughout the Eastern Interconnection are principal investigators in the EIPC process.

The EIPC has established study assumptions and is on schedule to complete eight macroeconomic futures and 72 associated sensitivities for input variables of each future. A report will be issued late in 2011. By December 2012, for three of the resource scenarios as selected by the Stakeholder Steering Committee, the EIPC will identify interregional transmission expansion options that meet reliability requirements.

The ISO participates in several other national and regional system planning forums, such as the Electric Reliability Organization, the ISO/RTO Council, and the Northeast Power Coordinating Council. The ISO will continue conducting joint studies with NYISO and PJM to identify transmission constraints limiting

interregional power transfers and show the effects of relaxing these constraints throughout the ISO/RTO regions. ISO New England will continue to coordinate efforts with neighboring systems to plan projects jointly, 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. Through the NPCC and NERC, the ISO has participated in interregional assessments, which coordinate planning activities 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 stakeholders through its planning process. Regional initiatives have improved the transparency of transmission cost estimates, provided critical load levels and other information in needs assessments, and demonstrated progress in improving forecasts of energy efficiency. The ISO has continued to provide technical support to a number of state agencies and groups, such as the New England Conference of Public Utilities Commissioners , the New England Governors' Conference, the Consumer Liaison Group, NESCOE, and others. The planning process will continue to evolve in response to FERC and other policy developments.

Through the Strategic Planning Initiative, the ISO is studying the economic and reliability effects of retiring aging, environmentally challenged generating units and their likely replacement with natural-gas-fired generation, variable renewable resources, and imports from the neighboring Canadian regions. The studies will include production cost simulations, analyses of the natural gas system requirements, and transmission planning studies for some of these scenarios. Plans call for continuing discussions of these issues with the region's stakeholders and providing an update on these studies in RSP12.

Active involvement and participation by all stakeholders, including public officials, state agencies, NESCOE, market participants, and other PAC members, are key elements of an open, transparent, and successful planning process. As needed, the ISO will work with these groups, as well as NEPOOL members and other interested parties, to support regional and federal policy initiatives, such as FERC Order No. 1000 on transmission planning and cost allocation.[41] The ISO will continue to provide required technical support to the New England states and the federal government as they formulate policies for the region.

Conclusions

The ISO's *2011 Regional System Plan* provides information on the timing, location, and type of system resources as well as transmission projects necessary to serve load reliably throughout the region through 2020. The economic recession has slowed the growth in summer peak demand, while wholesale electricity markets and other factors have stimulated the successful development of supply and demand resources and transmission infrastructure to meet the needs of the New England region. However, the likelihood of power plant retirements and the expected realization of the region's renewable resource potential will require additional consideration during the planning process to meet future system needs.

The region's heavy dependence on natural-gas-fired generation to supply its electricity needs is expected to grow. At the same time, environmental and economic incentives provided by governmental policies and the wholesale electricity markets are encouraging the development of low-emitting, renewable resources, such as wind and solar. In addition, demand resources are expected to increase. Economic studies have shown the effects of these types of resources and possible new imports from Canada, providing useful information to guide the decisions of policymakers and resource developers. Also, smart grid technologies are being developed to improve the electric power system's performance and operating flexibility.

RSP11 and its complementary *RSP Project List*, needs assessments, and solution studies provide detailed information about the system changes required for serving load reliably in New England for the next 10 years. Transmission projects are in various stages of development, and many have begun or have completed the siting process. Elective and merchant transmission facilities, in various stages of development, have the potential to provide access to renewable resources in remote areas of the region and in neighboring areas.

In its Strategic Planning Initiative, the ISO has identified risks to the regional electric power system; the likelihood, timing, and potential consequences of these risks; and possible mitigating actions. Through an open process, regional stakeholders and the ISO are developing an approach to address these issues, which could include further infrastructure development as well as changes to the wholesale electric market design and the system planning process.

Notes

1 *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/oatt.pdf. *ISO New England Inc. Transmission, Markets, and Services Tariff,* Part II, Section 48 (2010), http://www.iso-ne.com/regulatory/tariff/index.html.

2 RSP11 is based on the June 2011 *RSP Project List,* http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html.

3 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 is available at http://www.iso-ne.com/committees/nepool_part/index.html.

4 ISO tariff, Attachment D, "ISO New England Information Policy" (August 30, 2010), http://www.iso-ne.com/regulatory/tariff/attach_d/index.html. OATT, Schedules 22 and 23, "Standard Large Generator Interconnection Procedures" (January 31, 2011) and "Standard Small Generator Interconnection Procedures" (January 31, 2011), http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

5 Past RSPs are archived at http://www.iso-ne.com/trans/rsp/index.html. For access to supporting reports, contact ISO Customer Service at 413-540-4220.

6 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 PDF file to custserv@iso-ne.com.

7 *ISO New England Inc. Transmission, Markets, and Services Tariff*, Part II, (2011), http://www.iso-ne.com/regulatory/tariff/index.html. Information on NERC requirements is available at http://www.nerc.com. Information on NPCC is available at http://www.npcc.org/.

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

9 *In-merit generation* is when the generators with the lowest-price offers are committed and dispatched first, and increasingly higher-priced generators are brought on line as demand increases. *Out-of-merit dispatch* is when higher-priced generators are committed and dispatched before lower-priced resources to respect system reliability requirements, which results in increased costs to load.

10 *Passive* demand resources are principally designed to save electric energy use and are in place at all times without requiring direction from the ISO. *Active* demand resources reduce load in response to a request from the ISO to do so for system reliability reasons or in response to a price signal.

11 The ISO's *Forecast Data 2011* (May 5, 2011), sheet 9 (http://www.iso-ne.com/trans/celt/fsct_detail/index.html) shows that the gross consumption of electric energy for 2020 is 151,498 GWh. The savings attributable to federal appliance standards is 2,253 GWh for 2020. In addition, passive demand resources are projected to save 7,194 GWh.

12 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 "extreme-case" peak loads have a 10% chance of being exceeded because of weather. For the extreme 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.

13 The 13.6% includes the energy-efficiency goals for Massachusetts, Maine, and Rhode Island, plus the Connecticut Renewable Portfolio Standards Class III goals, which include energy-efficiency and combined heat and power. The state EE goals do not take credit for federal appliance standards.

14 The FERC-approved 32,127 MW value is based on the RSP10 load forecast and appears in the ISO's *2011–2020 Forecast Report of Capacity, Energy, Loads, and Transmission* (CELT) (May 2011), http://www.iso-ne.com/trans/celt/report/. *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.

15 A *capacity commitment period* runs from June 1 through May 31 of the following year. FCA #5 covers June 1, 2014, through May 31, 2015. 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.

16 A *nonprice retirement request* is a binding request to retire the entire capacity of a generating resource.

17 The *ISO Generator Interconnection Queue* includes those generators that have submitted requests to interconnect to the ISO New England transmission system.

18 FERC, *Order on Paper Hearing and Order on Rehearing*, Docket Nos. ER10-787-000, EL10-50-000, EL10-57-000, ER10-787-004, EL10-50-002, and EL10-57-002, 135 FERC ¶ 61,029 (April 13, 2011), http://www.iso-ne.com/regulatory/ferc/orders/2011/apr/err10-787-000_4-13-11_fcm_redesign_order.pdf.

19 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.

20 To conduct some RSP studies, the region is divided into various areas related to 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.

21 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. The need for the BOSTON area is expected to grow from a range of 0 to 250 MW for 2011 through 2014 to a range of 0 to 400 MW for 2015 as a result of the retirement of the Salem Harbor units.

22 DOE, *2009 National Electric Transmission Congestion Study* (December 2009), http://www.congestion09.anl.gov/documents/docs/Congestion_Study_2009.pdf. 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.

23 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. *ISO New England Open Access Transmission Tariff* (December 7, 2007), http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

24 Cost estimates without transmission cost allocation approval are subject to wide ranges of accuracy and change as projects progress through various stages of implementation. The $5.3 billion cost estimate has a range of $4.3 to $6.3 billion based on projects that are proposed, planned, and under construction. See the June 2011 *RSP Project List* PAC presentation (June 30, 2011), slide 7, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2011/june_project_list_slides.pdf.

25 *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. As of 2011, the existing RNS rate is $0.012/kWh and is estimated to increase to $0.021/kWh in 2015.

26 The ISO is studying the amount of export-transfer capability from Maine to New Hampshire.

27 An *elective transmission upgrade* is an upgrade to the New England transmission system that is 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.

28 See the materials presented at the May 26 PAC meeting at https://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2011/may262011/nta_analysis.pdf.

29 *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short- and Near-Term Power Generation Needs*, public version scope of work (May 17, 2011), http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/2011/pv_final_sow_isone_2011_natural_gas_study_5_17_11.pdf.

30 *2009 ISO New England Electric Generator Air Emissions Report* (March 2011), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/eag/mtrls/2011/apr82011/final_2009_emissions.pdf.

31 Air emission regulations cover nitrogen oxides, particulates, sulfur dioxide, mercury, other air toxics, and greenhouse gases, such as carbon dioxide.

32 The purchase of an *emission allowance* authorizes a source to emit one ton of a pollutant during a given year or any year thereafter. At the end of each year, the source must hold an amount of allowances at least equal to its annual emissions.

33 Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone in 27 States; Correction of SIP Approvals for 22 States (*Cross-State Air Pollution Rule*), 40 CFR Parts 51, 52, 72, 78, and 97 (July 6, 2011), http://www.epa.gov/airtransport/pdfs/TR_070611_WEB.pdf.

34 *Leakage* refers to an increase in lower-cost, imported power from non-RGGI areas. 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, offsetting, to some degree, the intended CO_2 reductions within the RGGI states.

35 RPSs apply only to competitive retail suppliers, which excludes load served by municipal utilities.

36 *Renewable energy certificates* are tradable, nontangible commodities, each representing the eligible renewable generation attributes of 1 MWh of actual generation from a grid-connected renewable resource.

37 NESCOE, "Request for Information in Support of Meeting New England's Renewable Energy Goals Cost Effectively" (December 30, 2010), http://www.nescoe.com/Coordinated_Procurement.html.

38 GE Applications and Systems Engineering. *New England Wind Integration Study* (December 5, 2010), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf. PAC archives of NEWIS materials are available at http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/index.html.

39 Additional information on the EIPC is available at http://www.eipconline.com/.

40 The *2009 Northeast Coordinated System Plan* (ISO New England, NYISO, and PJM; May 24, 2010) and supplemental materials and reports are available at http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/index.html, http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/reports/index.html, and http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/index.html.

41 Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 18 CFR Part 35 (136 FERC ¶ 61,051, Docket No. RM10-23-000, Order 1000) (July 21, 2011), http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp and http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

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