ISO New England 2012 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

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 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 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 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 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 market participants and stakeholders can take to meet the needs of the system.[3]

Regional Transmission Planning Results

New England's transmission owners have constructed 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.[4] These projects have reinforced the transmission facilities serving areas that have experienced load growth, such as Vermont, southern Maine, and the New Hampshire seacoast area. 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. From 2002 through June 2012, 400 projects were put into service, totaling approximately $4.8 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 14,432 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 2,106 MW are part of the regional power system, and 3,646 MW are expected by 2015.

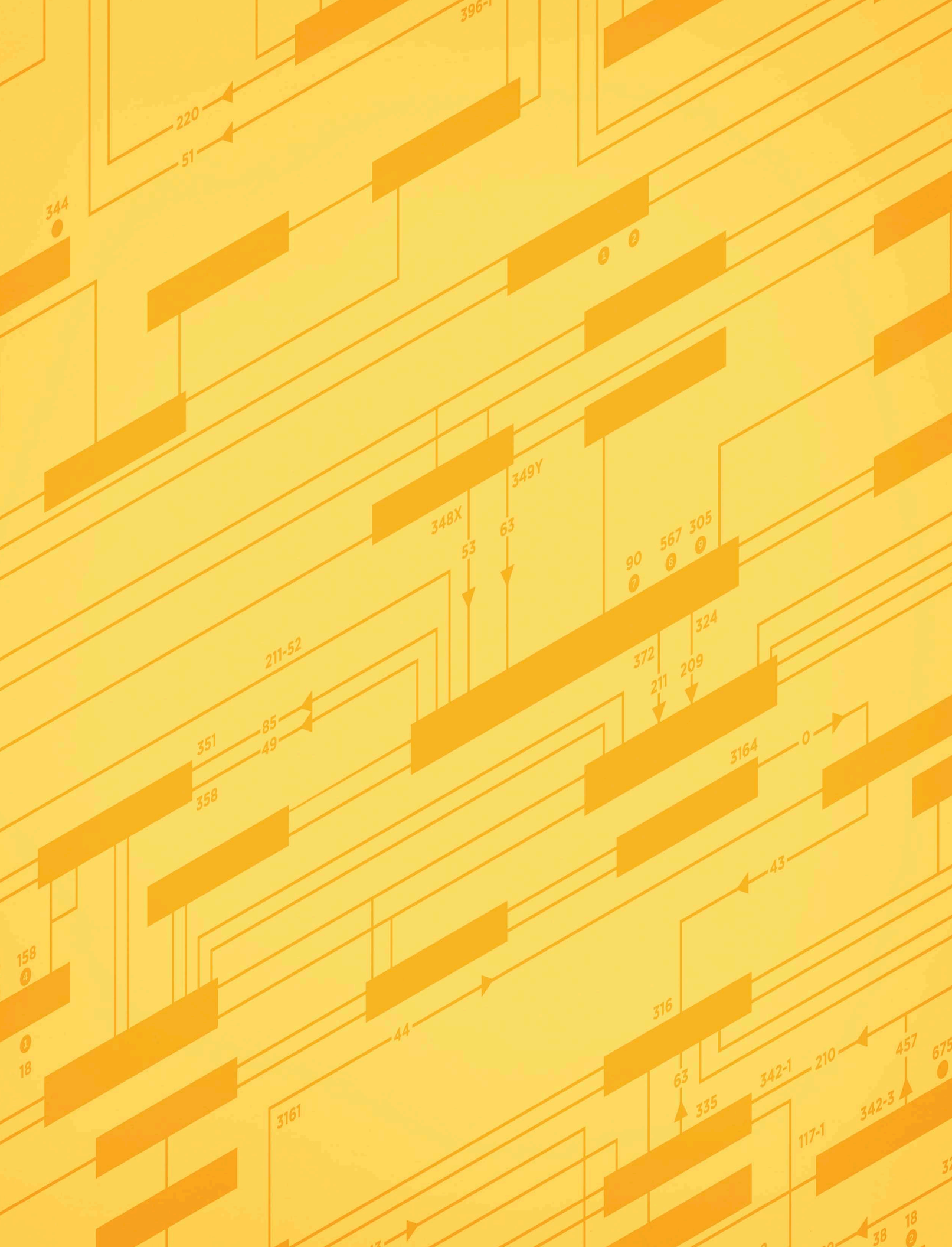
Past RSPs and recent ISO studies also have identified risks to the future economic and reliability performance of the system. This information has continued to assist stakeholders with formulating policies for the region. The information also has been used to identify needed changes to the markets, which must encourage 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.

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, and draft and final results and other materials appearing in RSP12. From September 2011 through August 2012, the ISO hosted 14 PAC meetings, which were attended by 175 stakeholder representatives from 101 entities. The total stakeholder attendance of 714 signifies over 4,400 workforce hours of participation. The ISO also posted to its website PAC presentations, meeting minutes, reports, databases, and other materials.[5] In addition, a public meeting was held on September 13, 2012, to discuss RSP12 and other planning issues facing the New England region.

On November 2, 2012, the ISO New England Board of Directors approved RSP12. The full 200-page document can be downloaded in its entirety from ISO New England's website.


396-1
220
51
344
1
2
348X
349Y
53
63
90
7
567
8
305
9
211-52
324
372
211
209
351
85
49
358
3164
0
43
158
4
1
18
44
316
3161
63
335
342-1
210
457
342-3
675
117-1
38
18
2

Progress Report

Transmission

From 2002 through June 2012, 400 transmission projects required for power system reliability have been put into service, representing $4.8 billion in infrastructure improvement.

Of those 400, eight are major 345 kilovolt transmission projects. These transmission upgrades reinforce critical areas of the grid where demand is highest, such as in Southwest Connecticut and Boston, as well as areas that have experienced significant load growth, such as Northwest Vermont.

These and other projects help maintain system reliability and enhance the region's ability to support competitive wholesale electricity markets.

Generation

More than 14,400 MW of new generation have been constructed in New England since 1997.

Demand resources

More than 2,000 MW of demand resources currently are part of New England's resource mix, and more than 3,600 MW are expected to be available by 2015.

Contents

2 **Preface**

7 **Introduction**

9 Overview of the Current System and Planning Process

12 **Major Findings and Observations**

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

15 Needs for Capacity and Operating Reserves

17 Transmission System Needs and Solutions

20 Development and Integration of Resources

26 Interregional Planning

27 State, Regional, and Federal Initiatives that Affect System Planning

28 **Conclusions**

29 **Notes**

Introduction

The ISO New England 2012 *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 2021. 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), RSP12 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), participating transmission owners (PTOs), and the ISO.[6]

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. Almost one-third of the region's existing generation was built during the last 11 years, and more than half 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, RSP12 presents the results of newly completed studies and summarizes the new and planned infrastructure for all areas of New England. RSP12 also discusses ongoing, new, and pending analyses based on the current system. In addition, RSP12 discusses state and federal policies that affect the planning process, system reliability, and the economic performance of the system.

Notwithstanding the region's recent improvements, challenges remain across the 10-year planning horizon for maintaining the reliable and efficient operation of the New England power system. These challenges include 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)
- Aligning wholesale market design with regional transmission planning

To address these challenges and prepare for changes likely to confront the New England power system, the region is conducting a Strategic Planning Initiative.[7] Through the initiative, the ISO and regional stakeholders have defined the region's key issues and risks and currently are assessing potential enhancements to the planning process and wholesale markets to help ensure a reliable system and efficient marketplace in the long term. As part of this process, the region is assessing the tools available to ensure system reliability, such as various market mechanisms and system operating procedures, and is determining whether to improve and better integrate these tools, develop and implement new approaches, or undertake a combination of both approaches. The region is well poised to meet the upcoming challenges identified by the Strategic Planning Initiative and through other stakeholder efforts, such as the Planning Advisory Committee and the New England Power Pool (NEPOOL) committee structure.

ISO New England, working closely with stakeholders, has identified five challenges expected to affect the New England power system in the coming years. These challenges are associated with resource performance and flexibility, increased reliance on natural gas, retirement of generators, integration of variable resources, and alignment of markets with planning. The Strategic Planning Initiative is addressing these issues to ensure continued reliability and an efficient marketplace in the long term.

Overview of the Current System and Planning Process

The regional planning process, as summarized in the *Regional System Plan*, is comprehensive, providing information to stakeholders on the load and energy-efficiency (EE) forecasts, resource and transmission development needs, infrastructure improvements, interregional coordination, and the results of economic studies and other initiatives, as highlighted below.

The regional energy forecasts show modest growth in peak demand and annual use of electric energy during a gradual recovery from the widespread recession. The newly developed energy-efficiency forecast of demand-side resources shows that state efficiency programs slow load growth further.

Historically, supply and demand resources have responded to the wholesale electricity markets and public policies, and the region has considerable potential for developing new resources where and when needed. The ISO New England Generation Interconnection Queue (the queue) and energy-efficiency forecast indicate this potential for the future development of resources.[8] However, the region is at risk of losing resources to retirements and, as identified in a study of the region's natural gas supply, of becoming increasingly reliant on natural gas to generate electric energy.[9] To begin to address these issues, the region is examining modifications to the markets that would improve resource performance and development. The region also is revising operating procedures that address the reliability issues. Improved communications between the electric power and natural gas system operators are in place and have improved operational coordination. Additional efforts are underway to better coordinate electricity and gas markets and develop and provide incentives for generators to have reliable fuel arrangements that would, for example, encourage investment in oil inventory or the commitment to firm pipeline transportation contracts.

RSP assessments, including those on resource adequacy, operating reserves, and transmission security, have shown the amounts, locations, and types of resources and transmission infrastructure the system requires for complying with criteria and standards. While transmission upgrades continue to progress throughout the region, certain projects are being deferred or modified because of the reduction in net loads indicated by the load and EE forecasts and the addition of new market resources. However, additional infrastructure improvements may be required in the long term to accommodate the likely resource retirements, integrate remote renewable resources, and continue meeting reliability needs. Evolving system conditions may require updates to the planning process and identified needs. For example, the efficient and cost-effective development of needed system infrastructure could be improved by better aligning the market resource procurement process with the system planning process.

Under the Strategic Planning Initiative, the ISO and regional stakeholders currently are examining ways to better coordinate the market structure and planning processes. The initiative also has defined other current and potential tools for preserving reliable and efficient system operations and maintaining system security. The current tools include committing and dispatching resources out-of-merit, procuring more reserves, issuing "gap" requests for proposals to meet short-term reliability needs, procuring emergency capacity through operating procedures, and conducting other special operator actions during fuel shortages.[10]

Potential new tools for improving reliable operations and system security include market rules that can achieve the following:

- Increase economic incentives for resource performance, assess penalties for failing to perform, and more fully value needed operating resource characteristics
- Coordinate the ISO's Day-Ahead Energy Market schedule with the natural gas industry's intraday nomination schedules, which would allow gas-fired generators to submit energy supply offers in the wholesale energy market with more information about their fuel procurements for generating electric energy
- Allow resources to update their electric energy offers hourly to reflect changing fuel prices
- Provide supplemental compensation for needed resources
- Incent dual-fuel capability
- Improve the process for coordinating the timing of developing market resource alternatives to transmission development (i.e., *market resource alternatives*; MRAs)
- Facilitate the integration of intermittent resources

The ISO also is conducting studies to support the Strategic Planning Initiative's longer-term vision of the system. Current analyses are identifying possible changes in the performance characteristics, obligations, and flexibility of the region's resources. Additional studies are more fully identifying the exposure to potential regional and interregional natural gas shortfalls that could limit electric energy production.

An examination of possible generator retirements shows that the units most likely to retire have poor economic performance and could require major capital improvements for complying with pending and final US Environmental Protection Agency (EPA) and state environmental regulations. A Strategic Transmission Analysis is evaluating how the retirement of "at-risk" units will affect reliability. This analysis also is developing a conceptual system buildout that would be necessary for combinations of unit retirements, repowering, and integrating remote wind generators.

The integration of intermittent resources, however, presents challenges for operating the system and developing transmission. Economic studies of various system-expansion scenarios have shown potential production costs, transmission congestion, and a number of other metrics. Other analyses have identified operational issues and solutions to facilitate the integration and large-scale use of intermittent resources. Additional studies are evaluating the ability of merchant and elective transmission projects to access renewable energy sources within New England and in neighboring regions.

The ISO is implementing many of the recommendations of a prior study, the *New England Wind Integration Study* (NEWIS), such as the development of a centralized wind power forecast of the region's wind generation.[11] Solar photovoltaic resources have grown in the region, and their continued growth is anticipated. The ISO will continue to track these resources and resolve any potential operational and planning issues that may emerge as the use of these resources expands.

Interregional planning and environmental assessments have become increasingly important for the ISO and stakeholders, who together are addressing issues raised within the region and with neighboring regions. New England is positioning itself to integrate clean and renewable resources and import additional hydroelectric and wind energy from neighboring Canadian provinces. The *Northeast Coordinated System Plan 2011* (NCSP11) demonstrates coordinated planning with the New York ISO (NYISO), PJM Interconnection (PJM), and other interregional organizations, such as the NPCC and NERC.[12] Compliance with FERC Order 1000 on transmission planning and cost allocation, however, will require improvements in the regional planning process.[13] These improvements must consider public policies, enhance interregional planning, and allocate transmission project costs for public-policy projects and interregional projects. The ISO supports other interregional planning efforts, such as the Eastern Interconnection Planning Collaborative (EIPC) and the US Department of Energy (DOE) congestion studies.[14]

To address the issues raised during the regional system planning process and the results of studies and initiatives underway, the region is considering updating the regional planning process; improving the wholesale electricity markets for energy, capacity, and ancillary services; and revising operating procedures.

Major Findings and Observations

This section presents an overview of the major findings of the RSP12. For all RSP12 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 RSP12 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
- 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.

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

The amount and location of the net system load may affect the need for new resources and the required timing of some transmission projects. For the 10-year planning period, RSP12 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. RSP12 also summarizes a new method to forecast the long-term annual and peak energy-efficiency savings for 2015 to 2021.

Peak Demand and Annual Use of Electric Energy and Load Growth

For RSP12, the 50/50 "reference case" summer peak forecast is 27,440 megawatts (MW) for 2012, which grows to 31,255 MW for 2021.[15] The 90/10 "extreme case" summer peak forecast, which represents summer heat waves, is 29,620 MW for 2012 and grows to 33,765 MW in 2021. 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. The ISO forecasts the 10-year growth rate to be 1.5% per year for the summer peak demand, 0.6% per year for the winter peak demand, and 0.9% 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) continues to decline from 57.5% in 2012 to 54.9% in 2021.

The RSP12 forecasts for the annual use of electric energy and winter peaks are not materially different from the RSP11 forecast. The RSP12 forecast of summer peak demand is lower than the RSP11 forecast by approximately 660 MW in 2012 and 290 MW by 2021.

The load forecast is highly dependent on the economic forecast, which reflects (1) the recent recession ending in 2009, followed by weak economic growth beginning in 2010, and (2) a projected moderate rebound in 2014 through 2016, followed by sustained economic growth. The RSP12 forecasts also incorporate the expected effects of federal EE standards for appliances and commercial equipment, which will go into effect in 2013, and the historical energy-efficiency savings (i.e., reductions in past loads resulting from energy-efficiency measures). Another factor for developing

Energy consumption is projected to grow an average 0.9% annually over the next 10 years, while summer peak demand is expected to grow by 1.5% per year.

the forecasts is that demand resources that cleared the Forward Capacity Market (FCM) are considered to be sources of supply and not demand-side measures. The forecast of the energy savings attributable to federal appliance standards is 1.6% of the total gross electric energy consumption for 2021; the forecasted energy-efficiency savings from FCM passive demand resources is 11.4% for 2021.[16] These represent a total energy savings of 13.0% of the gross consumption of electric energy projected for 2021.[17]

Energy-Efficiency Forecast

In response to stakeholder requests, an EE forecast was developed for estimating long-term energy savings and reductions in peak demand not otherwise attributed to savings from FCM passive demand resource or reflected in the ISO load forecast. The EE forecast will be used in conjunction with the passive demand resources that cleared the Forward Capacity Market for 2012 through 2014.

The ISO, with stakeholders, developed a methodology to forecast long-term energy-efficiency savings from state-sponsored programs in all six New England states. The region's EE forecast shows substantial energy savings resulting from energy-efficiency initiatives, and these results are being incorporated into the system planning process and in regional transmission needs assessments and solutions studies. The EE forecast already is having an effect on power system planning. Recently, the reliability need for proposed transmission projects in New Hampshire and Vermont was reexamined, and several projects could be deferred, in part because of the EE forecast.

The ISO first met with state energy-efficiency program administrators, other Independent System Operators and Regional Transmission Organizations (ISO/RTOs), various state agencies, 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.[18] Through an open stakeholder process, the ISO developed a methodology for forecasting the amount of energy and peak load savings that can be obtained from energy-efficiency programs.[19] This methodology is based on projections of funding levels for state-sponsored energy efficiency, the amount of energy savings per dollar spent, and the amount of peak load savings per megawatt-hour of energy saved. The EE forecast accounts for uncertainty factors, such as the amounts and spend rates of future budgets and decreases in the energy savings per dollar spent, which may affect the amounts of EE successfully developed. The methodology developed was the first of its kind nationally because it captures and compiles data for six states to create a regional EE forecast. The EE investment is expected to be approximately $8 billion from 2012 through 2021.

The EE forecast for 2015 through 2021 shows an annual average regionwide energy savings of approximately 1,343 gigawatt-hours (GWh), an average reduction in peak loads of 206 MW per year. The EE forecast shows savings of 1,619 MWh in 2015, declining to 1,092 MWh in 2021. Similarly, the peak load savings from EE declines from 249 MW in 2015 to 168 MW in 2021. The EE forecast also shows results for each New England state.

Needs for Capacity and Operating Reserves

RSP12 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). The RSP also discusses pilot analyses of market resource alternatives.

Capacity

The current development of generation, demand, and import capacity resources in the region is expected to provide the capacity needed to meet the requirements for resource adequacy (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 32,010 MW in 2012 to a representative value of 35,600 MW by 2021.[20]

Resources are projected to be sufficient for the 2015/2016 capacity commitment period.[21] The region would have a surplus of 2,660 MW in 2017/2018, which would decrease to 1,903 MW in 2021/2022, accounting for the load and energy-efficiency forecasts and assuming all resources with capacity supply obligations for FCA #6 remain in service.

The sixth Forward Capacity Market auction (FCA #6, which was conducted in April 2012) shows that the New England region should have adequate resources to meet consumer demand through 2015/2016. However, the capacity resources in the Northeast Massachusetts/Boston area are projected to marginally meet demand for that area for the 2015/2016 timeframe, with a projected 59 MW surplus for that load zone.

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. The fifth Forward Capacity Auction (FCA #5) recognized the "nonprice" retirement request of Salem Harbor units #1, #2, #3, and #4 (near Boston), representing nearly 750 MW.[22] In FCA #6, the local sourcing requirement (LSR) for NEMA/Boston was 3,289 MW, and the resources in that area totaled 3,348 MW.[23] Additional load growth or retirements in NEMA/Boston would create the need to develop new resources. Recent developments in NEMA/Boston associated with reduced liquefied natural gas (LNG) supplies further highlighted reliability concerns in this zone.

Other resources throughout the region, particularly demand resources, have submitted nonprice retirement requests, and approximately 1,662 MW of one-year dynamic and static delist bids were approved in FCA #6. 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 old, 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.

Changes directed by FERC 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.[24] 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, improves system performance, and allows for a more optimal use of the existing infrastructure. Resources in the ISO queue, which included 6,600 MW as of April 1, 2012; new demand resources; and new import capacity from neighboring regions are in various stages of development and could address these issues.

Operating Reserves and Resource Flexibility

Operating reserve is the megawatt capability of a power system greater than system demand, which the system requires to preserve system reliability—such as by providing frequency regulation, correcting errors in load forecasting, and handling forced outages—when resources or transmission facilities are lost because of a contingency.[25] The need for operating reserves is a performance-based requirement. Resources participating in the locational Forward Reserve Market and other committed and on-line resources are helping satisfy the operating-reserve requirements of the region overall and in major load pockets to cover contingencies.

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 2013 to 2016.[26] Over the same period, the forecasted need for the Greater Connecticut area is 400 to 1,100 MW during the summer, and the need for the BOSTON area ranges from 0 to 200 MW.[27] 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, limited energy resources, and the addition of intermittent resources, particularly wind, will likely increase the need for flexible operations and resources to provide reserves, regulation service, and ramping in the most effective locations. The ISO is considering a review of the requirements for operating reserve and an evaluation of potential enhancements to the wholesale electricity markets to better meet operational needs and improve the long-term efficiency and reliability of the system.

Analysis of Market Resources as an Alternative to Transmission Investment

Regional System Plans provide considerable information on the desired amounts, types, locations, and performance requirements of resources for meeting system needs. In general, developing resources in load pockets is beneficial, especially the load pockets with exposure

to potential generator retirements. However, assessing the suitability of 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.[28] 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 next pilot study of the Greater Hartford and Central Connecticut area and has updated the PAC on this pilot. Under the scope of the Strategic Planning Initiative, the region will consider modifying the wholesale electricity market design to better align the process for identifying market resource alternatives with the planning process that identifies transmission solutions.

Transmission System Needs and Solutions

The performance of the transmission system must meet reliability requirements in accordance with applicable NERC, NPCC, and ISO criteria and standards. To meet these requirements, RSP12 identifies the transmission development needed in the region and summarizes the status of ongoing transmission studies and projects in various stages of implementation. Transmission projects placed in service over the past 10 years have reduced congestion and decreased dependence on generating units located in load pockets. In 2011, systemwide congestion-related costs totaled approximately $18 million, and payments for generators in "must-run" situations that provided second-contingency coverage and voltage control totaled just under $12 million.

Transmission Projects

The ISO regularly discusses system needs and the justification for transmission improvements with the PAC, which 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.[29]

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.[30] It also includes information on

project status and cost estimates. The descriptions of transmission projects in RSP12 are based on the June 2012 update, which includes 256 projects at a total cost of approximately $6 billion.[31] The ISO updates the *RSP Project List* at least three times per year, capturing improvements identified and changes in project status. In addition, the ISO makes available to stakeholders the databases used for simulating the power system. 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 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. 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.[32] The ISO is conducting an analysis of the extent to which transfer capability through Maine has been changed because of the MPRP project. The MPRP project is scheduled for completion by early 2015.

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

  >> The ISO conducted the needs assessments and solutions studies, and the affected states (Massachusetts, Connecticut, and Rhode Island) completed the siting proceedings; the Springfield and Rhode Island components of NEEWS are scheduled for service by 2014.

  >> 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 unavailability of the Salem Harbor facility. The need for the Interstate Reliability Project has been reconfirmed, and the preferred solution is unchanged.

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

Transmission upgrades across the region identified for meeting reliability requirements are under construction, have been approved in state-level siting proceedings, or are being prepared for state siting proceedings. These include the Maine Power Reliability Program (MPRP), upgrades in southeastern Massachusetts, and the New England East-West Solution (NEEWS), which comprises several transmission projects in Massachusetts, Connecticut, and Rhode Island. Additional projects have been proposed to reinforce the reliability of New England's power system.

- The Long-Term 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. The project received siting approval in May 2012.

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 Merrimack Valley, the Pittsfield and Greenfield area, and the Greater Boston area. However, certain projects are being deferred because the RSP12 load forecast is lower than the RSP11 forecast and because the new energy-efficiency forecast reduces load further. All studies examine the system comprehensively and account for the electrical characteristics of the tightly integrated New England network.

Generation helps ensure the reliability of area load pockets. 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 enhancing 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 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 accomplish the following actions:

- Preserve the reliability of service to those areas of the system that could 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

The regional planning process is robust, and the New England region stands ready to develop any required infrastructure through the partnership of the ISO with the states, market participants, and other stakeholders.

Elective and Merchant Transmission Development

Several developers have proposed elective or merchant transmission upgrades, which are in various stages of study and development.[33] 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 the outcomes of these upgrades and their impacts on system conditions and needs.

Development and Integration of Resources

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 identifies possible regional solutions to meet these needs and resolves issues concerning the development and integration of renewable resources and smart grid technologies.

Natural Gas Supply and Fuel Diversity Issues

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 2011, natural gas plants represented 42.6% of the region's capacity and provided 51.3% of the system's electrical energy. 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 2011, oil units represented 22.0% of the capacity and produced 0.6% of the region's electric energy.

New England is increasingly dependent on natural gas as the primary fuel for generating electricity, while the use of oil- and coal-fired generation is declining. Between 2000 and 2011, electricity generated by natural-gas-fired power plants grew from about 15% to more than 50%. At the same time, electric energy produced by oil units declined from 22% in 2000 to less than 1% in 2011, and energy from coal plants fell from 18% in 2000 to about 6% in 2011. The rising environmental and economic costs associated with oil and coal have made it difficult for some of these power plants to compete against generators that use lower-cost, lower-emitting fuel sources, such as natural gas.

The overall use of natural gas has been increasing because of increased residential and commercial consumption, international demand, and use by electric power generators. The increase in the 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 relatively low price of natural gas; and the displacement of old, less efficient oil and coal units in economic dispatch.

The reliance on natural gas could be increased by the loss of other types of generation subject to risks, such as nuclear and hydro units that may not be relicensed. Accompanying the increased use of natural gas are concerns regarding the region's need for sufficient natural gas pipeline capacity and gas supply in the pipelines—summer and winter and during all types of natural and geopolitical events that could interrupt supplies of gas and other fuels, such as oil and coal.

Several actual and possible operational circumstances have shown the need for market and planning improvements to enhance the reliability and security of the region's gas- and oil-fuel supplies for generating electricity. To understand the potential vulnerabilities to the disruption in natural gas supply, particularly in severe winter or other stressed system conditions, the ISO completed a study of regional natural gas issues, which accomplished a number of tasks:[34]

- Assessed the effects of generator retirements on fuel supply and diversity concerns
- Determined the quantities of gas-fired capacity available after all firm, priority deliveries are accounted for
- Reviewed natural gas infrastructure contingencies affecting reliable electric power operation
- Determined the need for additional natural gas system supply to reliably serve New England generating resources
- Identified the required amounts of resources that could be used in lieu of natural-gas-fired generation, such as dual-fuel and oil-fired generation
- Considered the effects of several natural gas pipeline infrastructure outages

Recent improvements to the regional and interregional natural gas infrastructure have helped address the increased demand for natural gas. Additional planned enhancements will continue to expand the sources of natural gas for the region's power generators. For example, six regional pipeline projects became commercially available during 2011. Spectra Energy's Algonquin Incremental Market (AIM) project is under consideration, with a tentative schedule for completion by 2016. If fully developed, this project could bring up to an additional 350 thousand dekatherms of natural gas per day from the Marcellus gas fields. Also, the implementation of operating procedures and improved communications between electric power and natural gas system operators has decreased certain near-term operational risks.

The ISO is considering several additional actions to improve the reliability of the region's fuel supply to generating units, which will be reviewed through the stakeholder process, such as Markets Committee meetings:

- Obtaining additional information on the fuel arrangements of gas and oil generators
- Coordinating the timing of day-ahead electricity markets with the nomination times of the natural gas industry

- Requiring supplementary fuel procurements to ensure that gas and oil generators have a secure fuel supply
- Making longer-term changes to the product definition and obligations in the Forward Capacity Market

Adding renewable resources would help diversify the region's fuel supply, but the reliable integration of intermittent renewable resources could stress natural gas generators, which would face increased regulation and reserve requirements. Many natural-gas-fired units lack the electrical (physical) ability to provide this flexible operation, and potential adverse interactions with the natural gas system must be addressed. Many units also do not have economical or 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).

Many of these natural gas supply and fuel diversity issues have been identified under the Strategic Planning Initiative. Additionally, the scoping of 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 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 emitting fewer pollutants than the generating units they displaced in economic dispatch and of oil- and coal-fired units adding emission controls.[35] New transmission upgrades have reduced the dependence on older, less efficient oil and coal units, which had been needed to address reliability concerns. Compared with 2001, the 2010 average emission rate for SO_2 has declined by 64%; the rate for NO_X, by 54%; and the rate for CO_2, by 11%. Total emissions for SO_2 and NO_X also have decreased from 2001 levels, by 60% and 52%, respectively.

In the past decade, New England's emission rates for sulfur dioxide, nitrogen oxide, and carbon dioxide have declined, primarily as a result of natural-gas-fired generators with lower emissions producing a larger percentage of the region's electricity than other fossil-fuel-fired generators with higher emissions. In addition, oil- and coal-fired power plants have added emissions controls, further contributing to a decline in emissions. Compared with 2001, the 2010 average emission rate for SO_2 declined by 64%, NO_X by 54%, and CO_2 by 11%.

However, the region and neighboring areas face extensive and stricter state and federal environmental regulations to protect public health and the environment. These regulations address air emissions, including air toxics; cooling water intake requirements; wastewater discharges; and the handling of coal combustion waste products.[36] When promulgated, these regulations will increase the operating costs for affected generating plants, add capital costs for environmental controls, and require the use of low-emitting fuels. These regulations may lead to the

retirement of some aging units before 2021 (the last year of this 10-year plan) and may 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 are proposed and implemented for incorporating valid assumptions in system planning studies.

The ISO reviewed several modeling assessments and reports that evaluated the impact of existing and proposed EPA regulations and identified fossil and steam thermal units in the region 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 potential 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 no later than 2021. Owners of most of the at-risk capacity would face compliance or retirement decisions—and FCM positioning decisions—starting late in this decade.
- A total of 7.9 GW of existing coal steam or oil/gas steam units could be subject to the proposed final Mercury and Air Toxics Standards (MATS), with full compliance likely by 2015. Because infrequently operated units would be exempt from MATS, less than 1 GW of retirements are anticipated as a direct result of these regulations, but the long-term, economic viability of these units remains doubtful.

ISO analyses for the Strategic Planning Initiative and other planning efforts also will continue to identify generators at risk for retirement and 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.

Renewable Portfolio Standards and the Integration of Renewable Resources

Environmental regulations and policies mentioned above, Renewable Portfolio Standards (RPSs), and similar 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 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 with renewable resources, such as wind, solar, and energy efficiency. By 2021, EE and renewable resources would supply 31.8% of the region's projected electric energy. This percentage includes an 11.6% reduction in the region's projected electric energy consumption in 2021 resulting from passive demand

Five New England states have adopted Renewable Portfolio Standards, and Vermont has a similar goal for increasing total generation from renewable resources. Taken together, the states' RPSs and Vermont's similar goals call for renewable resources and energy efficiency to supply 31.8% of New England's projected electric energy by 2021.

resources and the forecasted energy-efficiency savings, as reported in the *2012–2021 Forecast Report of Capacity, Energy, Loads, and Transmission* (2012 CELT Report).[37] It also includes 20.2% of Renewable Portfolio Standards and policies addressing renewable supply goals.[38] 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; "behind-the-meter" projects; and using eligible renewable fuels in existing generators, such as biomass. Further, achievements in energy efficiency in the region that exceed the levels in the EE forecast could reduce the amount of new renewable resources required to meet state RPSs. 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).[39] ACPs also can serve as a price cap on the cost of Renewable Energy Certificates.

Analysis of the ISO queue shows that the electric energy these resources could produce alone would exceed the increase of the RPS requirements through 2018. For example, the development of 40% of the renewable resources in the queue would meet the RPS goals through 2014.

Integrating Intermittent Renewable Resources. The ISO completed the *New England Wind Integration Study*, a major study of integrating wind resources into the New England system.[40] This study analyzed various planning, operating, and market aspects of wind integration and the conceptual development of a transmission system that would be able to integrate large amounts of wind generation resources (i.e., up to 12,000 MW). The study found that New England would be able to accommodate the large-scale integration of wind resources but identified a number of issues if this were to occur. These issues include the need for conducting detailed transmission analyses to maintain reliable system performance; the need for increased system flexibility, operating reserves, and regulation service; and reduced net energy market revenues for natural-gas-fired resources. The study also identified the need for improved methods for calculating capacity values and forecasting wind generation, transmission development for interconnecting new wind resources, and updated interconnection requirements for voltage control and operating data.

New England states have a combination of goals, policies, and funding that promote the development of distributed resources, such as combined heat and power (CHP) systems and photovoltaic solar power capacity. Because solar resources are intermittent, integrating a large amount of megawatts from small-scale solar developments across the system could 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 currently is much smaller than the planned wind development in the region.

Developing New England's Smart Grid. Smart grid technologies can improve data acquisition, analysis, control, and efficiency of the electric power grid and distribution systems. In 2010, DOE approved funding for the ISO and the New England transmission owners to install phasor measurement units (PMUs) at 40 substations, which will be used to upgrade the monitoring and operation of the system. The region is a leader in the smart grid application of high-voltage direct-current (HVDC) facilities and flexible alternating-current transmission systems (FACTS). Smart grid technologies also can facilitate dynamic pricing, if implemented by the states, and the integration of variable energy resources. The ISO and stakeholders also have supported research and development efforts and the establishment of industry standards for integrating smart grid technologies, such as dispatching active demand resources. The ISO will monitor the development of these resources, which are affected by the installation of smart meters and changes in retail rate structures.

Economic Studies of Resource Integration and Interregional Coordination

In response to stakeholder requests received in 2011, the ISO completed economic studies to examine various wind development scenarios, particularly in northern New England. The studies quantify the near-term economic performance of the system for 2016, assuming the realization of renewable resources in the interconnection queue. While the study showed that transmission development could enable different combinations of wind resources, it also recommended further analysis of operational issues.

The economic studies analyzed several of the strategic issues the region is considering. Accessing the onshore wind energy located in northern New England, which is 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 economical.

The ISO presently is conducting economic studies in response to stakeholder requests received in 2012. These studies will examine the effects of adding and retiring resources at various locations. These effects include congestion costs, locations where resource or transmission development could be needed, and resources' potential energy revenues and capital costs based on run times. The studies also will quantify several system metrics for the expansion of renewable resources and energy efficiency, various amounts of price-responsive demand, and the addition of load.[41]

The ISO also is preparing a transmission system study of integrating wind resources within New England and renewable resource imports from Canada. This Strategic Transmission Analysis includes a number of retirement scenarios for aging coal- and oil-fired generating units. The study is developing conceptual transmission buildouts to inform stakeholders and government officials as they establish policies that affect the future planning and development of the system.

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 Northeastern ISO/RTO Planning Coordination Protocol and the NPCC
- Across the interconnection through the Eastern Interconnection Planning Collaborative (EIPC)[42]
- Nationally through NERC and DOE

The ISO has developed coordinated system plans and has proactively initiated planning studies with other regions.[43] The Northeast Coordinated System Plan summarizes 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
- Fuel diversity issues, including the current and future dependency on natural gas and how the interregional electric power system provides "fuel diversity by wire"
- The effects of demand-side resources on the system and how each of the ISO/RTOs reflects these resources in its respective system operations and planning
- Coordinated tracking and discussion of FERC's *Notice of Proposed Rulemaking (NOPR) on Transmission Planning and Cost Allocation,* which became a final rule (FERC Order 1000) in 2011

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. 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. ISO New England will continue conducting joint studies with NYISO and PJM to identify transmission constraints limiting interregional power transfers and 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.

In August 2009, a coalition of the regional planning authorities within the Eastern Interconnection formed the Eastern Interconnection Planning Collaborative, a first-of-its-kind effort. 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 with input from a broad base of interested stakeholders. ISO New England and other planning authorities throughout the Eastern Interconnection are principal investigators in the EIPC process.

During Phase I, the EIPC analyzed eight macroeconomic futures and 72 associated sensitivities based on input variables of each future.[44] This phase resulted in the selection of three final scenarios and the identification of resource-expansion options for these scenarios, which will be analyzed in more detail during a second phase. Phase II, scheduled for completion by December 2012, also will summarize the results of production cost analyses for the transmission buildouts.

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. 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 through its planning process. Regional initiatives have improved the transparency of transmission cost estimates, provided critical load levels and other information included in needs assessments, and developed an energy-efficiency forecasting methodology for the region. 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 (NECPUC), the New England Governors' Conference (NEGC), the New England Governors and Eastern Canadian Premiers (NEG/ECP), the Consumer Liaison Group (CLG), the New England States Committee on Electricity (NESCOE), and others. The planning process will continue to evolve in response to FERC orders and other policy developments.

Active involvement and participation by all stake-holders, including public officials, state agencies, NESCOE, participating transmission owners, 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 to support regional and federal policy initiatives, such as the Strategic Planning Initiative and FERC Order No. 1000 on transmission planning and cost allocation. 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 2012 *Regional System Plan* provides information on the timing, location, and type of system resources and the transmission projects needed for reliably serving load throughout the region through 2021. The economic recession has slowed the growth of the summer peak demand, while wholesale electricity markets and other factors have stimulated the development of supply and demand resources and transmission infrastructure to meet the needs of the New England region. Operational challenges, such as LNG supply issues to NEMA/Boston, are being addressed, and the issues for further analysis are being incorporated into the planning process. To meet future system needs, the planning process will need to consider the likelihood of power plant retirements, the expected development and integration of the region's renewable resources, the impact of public policies, and the close interaction between the natural gas and electric power system infrastructure.

The region's heavy dependence on natural-gas-fired generation to meet its electricity needs is expected to grow, with the likely retirement of old coal and oil units and their replacement, in whole or in part, with generators in the queue, and with the possibility of nuclear outages or retirements. At the same time, environmental and economic incentives provided by governmental policies are encouraging the development of low-emitting, renewable resources, such as wind and solar. Passive demand resources are expected to increase as well, as shown by the ISO's energy-efficiency forecast for this planning period. Economic studies are showing the effects of these types of resources and possible new imports from Canada, providing useful information for policymakers and resource developers. Also, smart grid technologies are being developed to improve the electric power system's performance and operating flexibility and its potential to grow active demand resources.

RSP12 and its associated *RSP Project List*, needs assessments, and solutions studies provide detailed information about the system changes needed to reliably serve load 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 electricity market design and the system planning process. Through current and planned activities, the region is well positioned to meet all challenges to reliable and economic system performance.

Notes

1 The requirements of the OATT include Attachment K, the *ISO Information Policy*, and interconnection procedures and address generator and elective upgrades. *ISO New England Open Access Transmission Tariff,* Section II, Attachment K, "Regional System Planning Process" (March 1, 2012), http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf. *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Part II, Section 48 (2010), http://www.iso-ne.com/regulatory/tariff/index.html. ISO tariff, Attachment D, "ISO New England Information Policy" (March 12, 2012), 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.

2 RSP12 is based on the June 2012 *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 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.

5 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.

6 *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/. An NPCC compliance audit conducted from March 12 through March 15, 2012, showed no ISO violations of any standards and requirements.

7 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.

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

9 ICF International, *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*, draft report (June 15, 2012) (ICF Natural Gas Study), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/gas_study_ceii.pdf. Also see the ISO's memo to the PAC regarding this study (June 15, 2012), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_ltr.pdf.

10 *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.

11 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.

12 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.

13 FERC, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 18 CFR Part 35, Docket No. RM10-23-000, Order 1000, 136 FERC ¶ 61,051 (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.

14 *National Interest Electric Transmission Corridors and Congestion Study* documents are available at http://nietc.anl.gov/documents/index.cfm. DOE's 2012 congestion study is scheduled to be released by the end of 2012. See the DOE website, "2012 National Electric Transmission Congestion Study," http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/2012-national.

15 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.

16 *Passive* demand resources principally are 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. The total gross load forecast is the load forecast in the ISO's *2012–2021 Forecast Report of Capacity, Energy, Loads, and Transmission* (2012 CELT Report) before applying the reductions attributable to federal energy-efficiency standards. See http://www.iso-ne.com/trans/celt/report/index.html. Copies of all CELT reports are located at http://www.iso-ne.com/trans/celt/index.html (May 2012).

17 The ISO's *Forecast Data 2012* (May 4, 2012), sheet 9 (http://www.iso-ne.com/trans/celt/fsct_detail/index.html) shows that the gross consumption of electric energy for 2021 is 152,770 gigawatt-hours (GWh). The savings attributable to federal appliance standards is 2,395 GWh for 2021. In addition, passive demand resources are projected to save 17,409 GWh for 2021.

18 The open stakeholder process included communications with the newly formed Energy-Efficiency Forecast Working Group (EEFWG), the PAC, and other committees, such as the Load Forecast Committee, the Reliability Committee, and the Interarea Planning Stakeholder Advisory Committee (IPSAC).

19 The ISO analyzed approximately 130 unique EE programs.

20 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/summary_of_icr_values.pdf. *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.

21 A *capacity commitment period* runs from June 1 through May 31 of the following year. FCA #6 covers June 1, 2015, through May 31, 2016. 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.

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

23 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.

24 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. FERC, *Order on Rehearing and Clarification and Order Accepting Compliance Filings*, Docket Nos. Er10-787-005, EL10-50-003, EL10-57-003,ER10-787-006, EL10-50-004, EL10-57-004, ER10-787-007, EL10-50-005, EL10-57-005, 138 FERC ¶ 61,027 (January 19, 2012), http://www.iso-ne.com/regulatory/ferc/orders/2012/jan/er10-787_1-19-12_order_fcm_redesign.pdf. FERC, *Order on Tariff Revisions to the Forward Capacity Market*, Docket Nos. ER12-953-000, 138 FERC ¶ 61,238 (March 30, 2012), http://www.iso-ne.com/regulatory/ferc/orders/2012/mar/er12-953-000_3-30-12_order_fcm_redesign_ext.pdf.

25 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.

26 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. (See Section 2.4.)

27 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.

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

29 *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.

30 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* (August 1, 2012), http://www.iso-ne.com/regulatory/tariff/sect_2/index.html.

31 Cost estimates without transmission cost allocation approval are subject to established variations as projects progress through various stages of implementation. The $6.0 billion cost estimate has a range of $4.9 to $7.1 billion based on projects proposed, planned, and under construction. See the *Regional System Plan Transmission Projects June 2012 Update*, PAC presentation (June 19, 2012), slide 16, at. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/jun192012/june2012_project_list.pdf.

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

33 An *Elective Transmission Upgrade* (ETU) 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.

34 ICF Natural Gas Study, https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/gas_study_ceii.pdf.

35 *2010 ISO New England Electric Generator Air Emissions Report* (April 2012), http://www.iso-ne.com/genrtion_resrcs/reports/emission/final_2010_emissions_report_v2.pdf.

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

37 The 11.6% is the reduction from the CELT forecast after accounting for the energy savings attributable to federal appliance standards. 2012 CELT Report, http://www.iso-ne.com/trans/celt/report/index.html.

38 RPSs apply only to competitive retail suppliers, which excludes municipal utilities.

39 *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.

40 PAC archives of NEWIS materials are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/index.html.

41 The metrics include production costs, LSE energy expenses, congestion, environmental emissions, average LMPs, fuel consumption and energy production by fuel type, revenues from the energy market, and the capital investment supported by simulated energy revenues.

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

43 The *2011 Northeast Coordinated System Plan* (NCSP11) (ISO New England, NYISO, and PJM; May 31, 2012) and supplemental materials and reports are available at http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/index.html and http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/index.html.

44 EIPC, *Phase I Report: Formation of Stakeholder Process, Regional Plan Integration, and Macroeconomic Analysis* (December 2011), http://www.eipconline.com/Phase_I.html.

www.iso-ne.com

ISO new england

1 Sullivan Road Holyoke, Massachusetts 01040