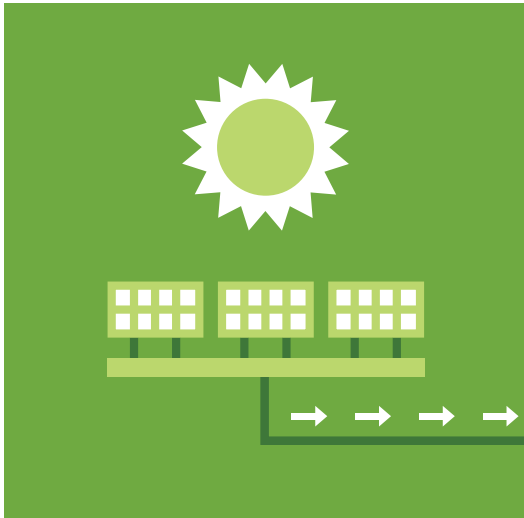
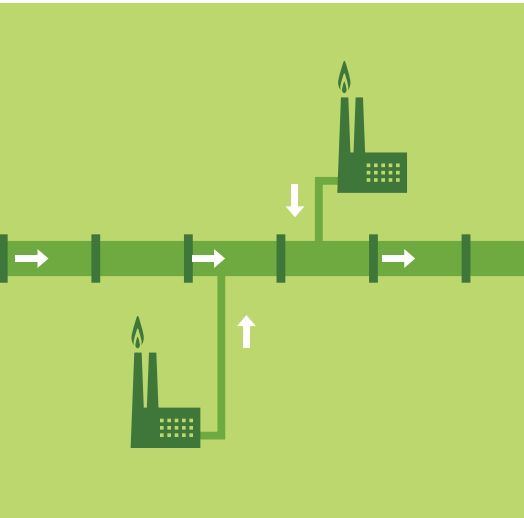
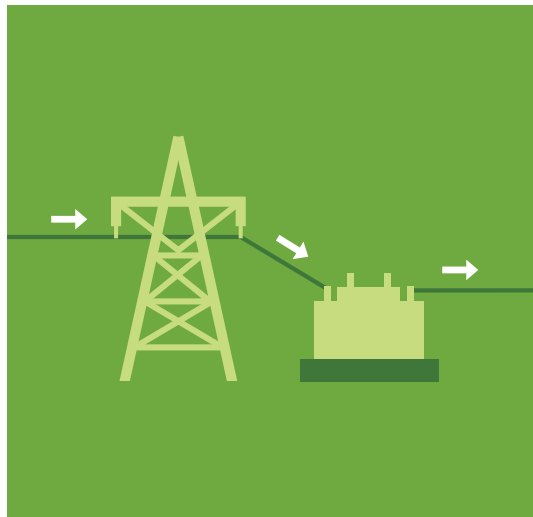
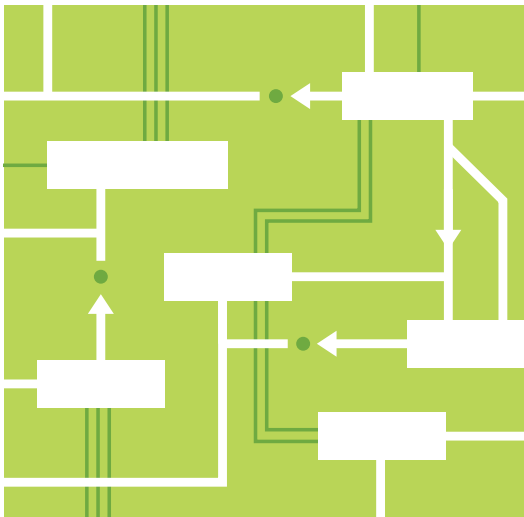
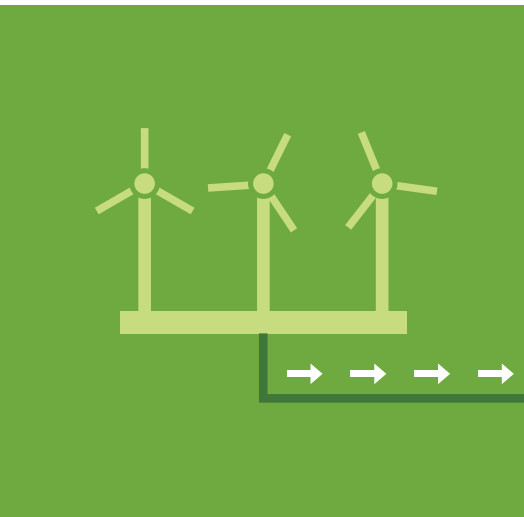
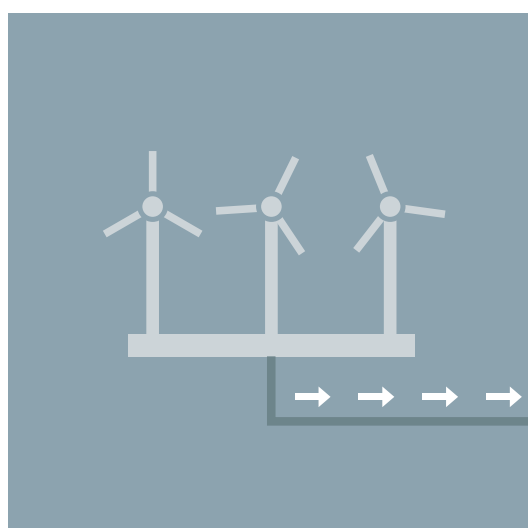
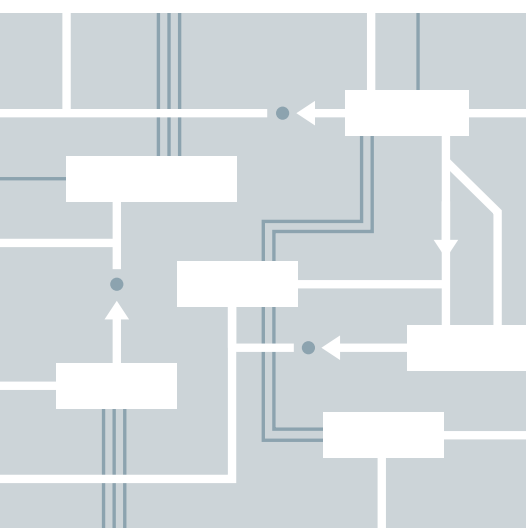
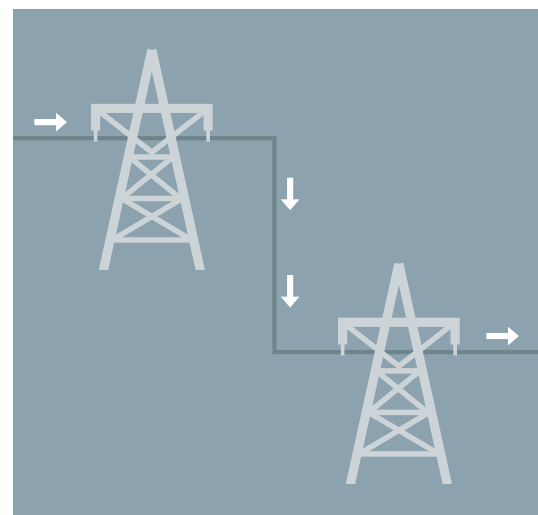
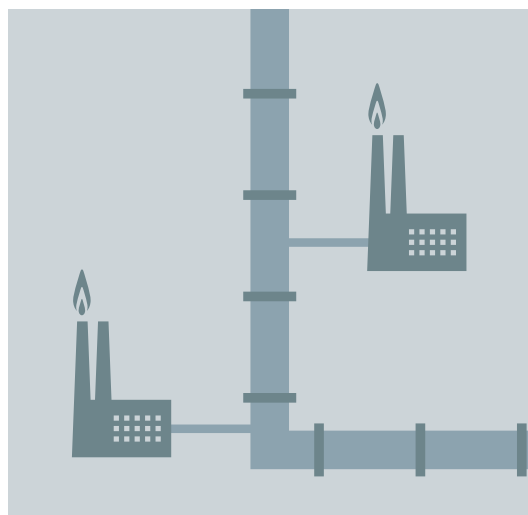
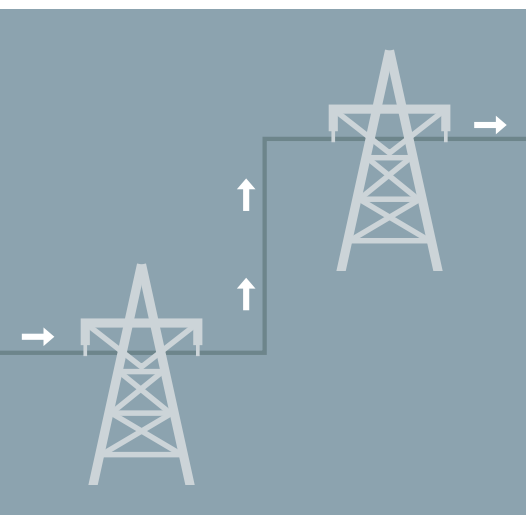
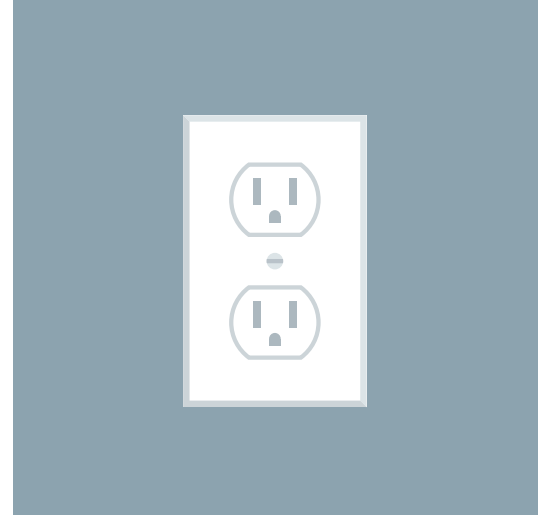
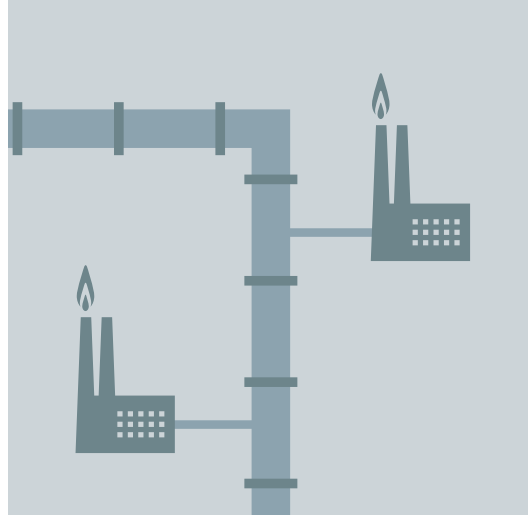
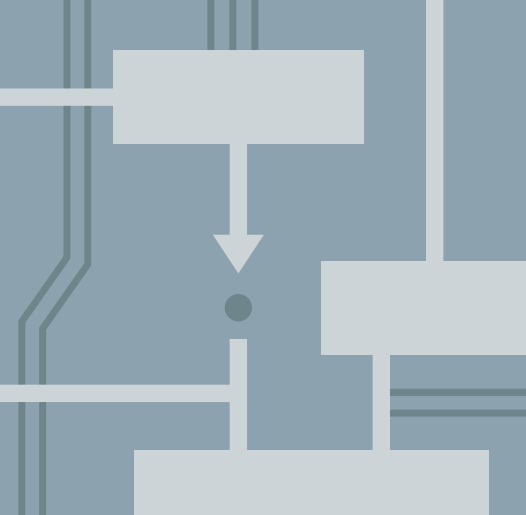


ISO New England

2014 Regional System Plan

EXECUTIVE SUMMARY







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

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

**Managing comprehensive regional
power system planning**

**Developing and administering the
region's competitive wholesale
electricity markets**

Preface

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



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

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

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

The 2014 *Regional System Plan* (RSP14) and the regional system planning process identifies the region’s electricity needs and plans for meeting these needs for 2014 through 2023.

Regional Power System Evolution and System Planning Achievements

From 2002 to June 2014, 559 projects were put into service, totaling approximately \$6.6 billion of new transmission investment.

New England's transmission owners have placed in service transmission projects throughout the region to provide solutions to the needs identified through the regional planning process, as detailed in past RSPs and supporting reports.⁴ These projects have reinforced the transmission facilities serving the entire region with upgrades in all six New England states. The projects also have reinforced the system in critical "load pockets," such as Southwest Connecticut (SWCT) and Boston, allowing the import of power from other parts of the system. New interconnections with neighboring power systems also have been placed in service, strengthening the region's ability to interchange power with these systems.

In addition to transmission development, market participants and the states have responded to the need for electric energy and capacity resources. New England states' annual investments in energy-efficiency (EE) programs are expected to exceed \$900 million per year for 2018 through 2023. These EE investments remain a large part of the expansion in passive demand resources, which are projected to grow at approximately 200 MW per year across the 10-year horizon.

From November 1997 through April 2014, new generating projects totaling 14,995 megawatts (MW) have interconnected to the New England power system, and 4,114 MW of primarily older, less efficient resources have retired from the system.⁵ Active and passive demand resources, currently totaling 2,100 MW, are part of the regional power system, and 2,950 MW are expected by 2017.⁶

RSP14 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 entities interested in regional system planning activities in New England.

The ISO and the PAC have discussed study proposals, scopes of work, assumptions, draft and final study results, and other materials appearing in RSP14. From September 2013 through August 2014, the ISO hosted 15 PAC meetings, and 197 stakeholder representatives from 109 entities attended at least one meeting. The ISO also posted to its website PAC presentations, meeting minutes, reports, databases, and other materials.⁷ In addition, the ISO held a public meeting on September 11, 2014, to discuss RSP14 and other planning issues facing the New England region.

On November 7, 2014, the ISO New England Board of Directors approved the *2014 Regional System Plan*.

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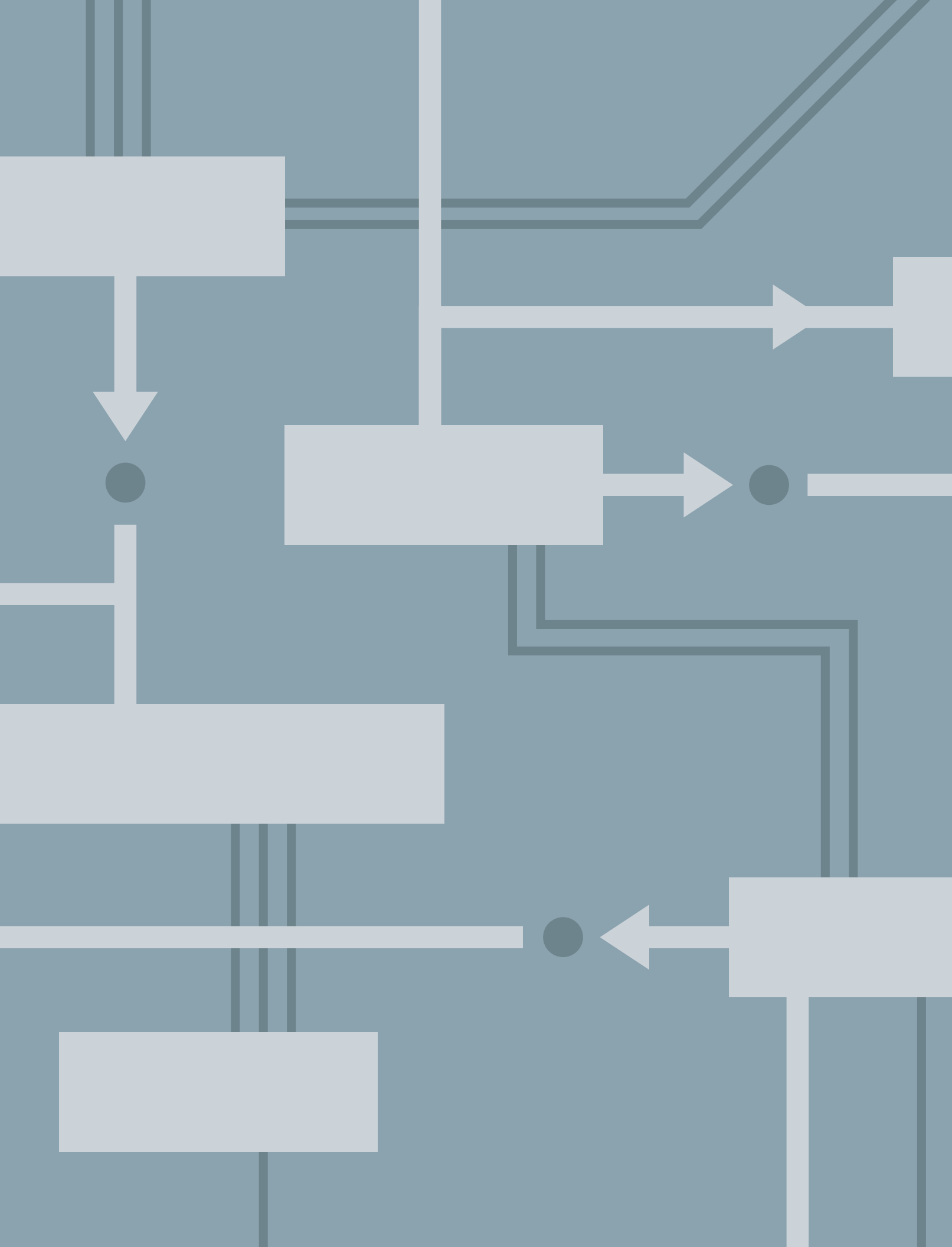
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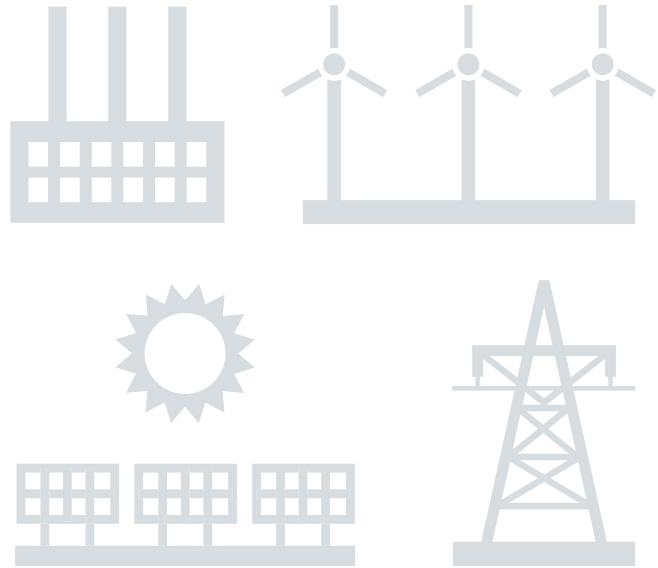
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Introduction

ISO New England's regional system planning process and market design have fostered significant additions to the region's generation and demand resources.⁸



Approximately 10% of the region's existing generation was built during the past 10 years, and the amount of energy efficiency participating as demand resources in the Forward Capacity Market (FCM) has increased roughly 235 megawatts (MW) per year over the past four years. The transmission system, which had seen little investment in past decades, has been upgraded over the past 10 years to reduce congestion and better serve the region's load.

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

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

To address these regional strategic planning issues, prepare for changes likely to confront the New England power system, and assess potential system enhancements, the ISO and its stakeholders are modifying the market design, system operations, and planning activities.⁹ These planning activities, which are designed to ensure a reliable and economical power system, take place through an open stakeholder process that includes input from the Planning Advisory Committee (PAC). Additionally, the ISO receives advisory input through the New England Power Pool (NEPOOL) committee structure on potential changes to the market design, provisions of the *Open Access Transmission Tariff* (OATT), and supporting procedures.¹⁰

Historically, the region has supported the reliable operation of the system through proactive planning, the completion of transmission projects and other improvements, the development of needed resources, and the overall competitiveness of the markets. The ISO anticipates that compliance with the Federal Energy Regulatory Commission's (FERC) final Order No. 1000 will require fundamental changes to the transmission planning process as it has been conducted in New England since 2001. Opening the process to nonincumbent transmission developers and implementing a competitive solicitation process for transmission solutions are key components of this order.¹¹ The order also requires the planning process to address public policy objectives and includes modifying the interregional planning processes, as well. The final scope and substance of the changes to the regional system planning process are still uncertain pending the final FERC order and court decisions.

The ISO is conducting its ongoing regional planning activities under the following set of system considerations:

- **Low net load growth** due to a slow recovery from the recession and the forecast of energy-efficiency resources
- Existing level, types, and locations of **resources**, the development of new resources, and the retirement of others
- \$4.5 billion additional **transmission improvements** planned for the region, consistent with federal and regional reliability standards
- The results from interregional coordination and planning studies the ISO performs with **neighboring regions**

The regional planning process has been robust and able to foster the development of required infrastructure through the ISO's partnership with the states, market participants, transmission owners, and other stakeholders. The ISO is committed to procuring adequate resources and remains hopeful that the region will install the required types of demand and supply resources where and when needed. Transmission projects have been placed in service successfully, and others are under development. The ISO will continue to work through the PAC and NEPOOL processes to meet and implement all requirements as they continue to evolve.

Overview of the 2014 Regional System Plan

The *2014 Regional System Plan* (RSP14) builds on the results of previous regional system plans and analyses. It provides information on electric power system needs; system improvements; and the results of newly completed load, resource, and transmission studies for reliably meeting demand throughout the region to 2023. It also discusses ongoing and new analyses based on the current and planned system and describes new and planned infrastructure for all areas of New England. The report also addresses many of the challenges the region is facing and how the ISO and its stakeholders are addressing key strategic issues. Notably, the report addresses the major factors influencing resource development, the requirements for fuel certainty, and the development of the electric power system infrastructure for the 10-year planning period, such as existing and pending state and federal environmental and energy policies.

RSP14 and the ongoing system planning process comply with all applicable sections of the ISO's *Transmission, Markets, and Services Tariff* (ISO tariff), approved by FERC.¹² The plan and planning process also satisfy the relevant standards, criteria, and other requirements established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), participating transmission owners (PTOs), and the ISO.¹³

As part of its compliance with Attachment K of the ISO's *Open Access Transmission Tariff* (OATT), RSP14 specifically provides information on the timing of system needs and the quantity, general locations, and characteristics of the generation and demand resources that could resolve these needs and defer or eliminate the need for transmission projects.¹⁴ The results of various system and regional strategic planning studies and other materials, as follows, provide this information:

- Forecasts of the average **electric energy usage** annually and at the peak hour for 2014 to 2023— for the entire system, individual states, and smaller areas of the power system
- Planned long-term **energy efficiency (EE) additions** for 2014 through 2017 and forecasts of the EE savings in the six New England states, annually and at the peak hour for 2018 to 2023
- Forecasts of the **growth of photovoltaic (PV) resources** in the region from 2014 through 2023
- Projections of the systemwide need for both capacity and operating reserves and the identification and evaluation of the locations where **fast-start resources** (i.e., those available for service within 10 minutes or within 30 minutes) would be the most beneficial
- Evaluations of **interface transfer capabilities** relevant to capacity zone modeling, which when combined with other RSP14 information, help market participants identify the portions of the system with potential resource surpluses or shortfalls
- Analyses and operating experience that show the vulnerabilities associated with the regional reliance on natural gas and the benefits of having more reliable access to gas supplies, dual-fuel capabilities, and other fuel sources
- Existing and pending **environmental regulations, emissions analyses, and economic studies**, which show the effects of using efficient, low-emitting resources; greater amounts of renewable resources; and increased energy efficiency on regional air emissions and the economic performance of the system
- Economic studies of **resource retirements and expansion**, which describe the effects of varying amounts, locations, and types of resources and imports from neighboring systems on system performance
- The **Strategic Transmission Analysis**, which provides insight on beneficial electrical locations for resource development and the effects of extensive generation retirements across the region
- Planning analyses of **wind and photovoltaic resources**, the status of revisions to the interconnection requirements, tools for developing forecasts, and the identification of systemwide needs for successfully integrating and operating variable resources on a large-scale
- Studies of **market resource alternatives (MRAs)** in the Southeast Massachusetts/Rhode Island load pockets¹⁵
- Summaries of regional and interregional **transmission planning studies** (i.e., needs assessments and solutions studies), which provide detailed information to resource developers and other stakeholders on potential infrastructure additions

Overview of System and Strategic Planning Issues

The New England system requires resources that provide flexible capacity and energy supply and transmission to carry electric energy where needed. Improvements in the markets, the development of new resources, and transmission upgrades are helping meet these regional needs. Interregional planning studies, especially for ensuring reliable infrastructure development, electric power system.

Similar to the RSP13 forecast, the RSP14 regional forecast shows slow growth in both the summer and winter peak demand of 1.3% and 0.6%, respectively, and annual energy use of 1%. The energy-efficiency forecast also is similar to the RSP13 forecast and shows a further slowing of net load growth to about half the growth rate of the summer peak load and essentially no net growth in both the winter peak load and regional annual use of energy. The ISO issued a multistate forecast of photovoltaic resources and is working with stakeholders to expand the forecast to cover all distributed generation (DG) resources.¹⁷

Despite the slow growth in demand, RSP14 shows that the region requires additional reliable capacity, which can be achieved by developing new resources and improving the performance of existing resources. Over 4,000 MW of resource retirements are expected from June 2014 through June 2017, stemming from *nonprice* retirement requests by demand and supply resources, and additional generators are likely to retire as a result of their not being economically competitive.¹⁸ Few new resources cleared the eighth Forward Capacity Auction (FCA #8), and the region is projected to require new resources from 2017 through 2023. To ensure resource adequacy in the region, the ISO expects to procure needed resources through the Forward Capacity Market. Additional market performance incentives are aimed at further encouraging resource owners to improve their performance and develop capacity, including demand resources and new resources listed in the ISO New England Generator Interconnection Queue (the queue).¹⁹ Some of the key market improvements to the day-ahead and real-time markets, as well as changes to the FCM, are as follows:

- **“Pay for performance,”** designed to encourage the operation of resources when most needed, including during scarcity events, by creating stronger financial incentives to produce electric energy and to supply reserves (to be implemented on June 1, 2018)
- **A sloped demand curve for capacity auctions,** designed to reduce the volatility in capacity prices between periods of excess supply and periods when new capacity resources are needed, which may occur as aging plants retire (to be implemented for the FCA #9 primary auction and for the associated reconfiguration auctions)²⁰

ISO New England launched this initiative in 2010 to identify risks to long-term power grid reliability.

The risks include:

- **the region’s growing dependence on natural gas to produce electricity,**
- **declining resource performance,**
- **resource retirements,**
- **and increasing amounts of renewable resources.**

To address these risks and help bolster reliability, the ISO has implemented operational and market enhancements, and more market changes are underway.

- An update of the methodology for **identifying and forming capacity zones** to be used in the FCAs that reflect changing system conditions and encourage the development of capacity resources in needed locations (to be reflected in FCA #9, reconfiguration auctions, and settlements)

To further support the region's need for reliable capacity and because New England has become an energy-constrained system in recent years, New England requires fuel certainty. The need for greater fuel certainty to maintain reliability was evident in 2013 and 2014, when the region's heavy dependence on natural-gas-fired generation to meet its electricity needs resulted in system operating problems similar to those experienced during past extreme weather events.²¹ Both the high demand for natural gas during cold weather periods and interruptions to the natural gas system have reduced the flow of fuel to generating units, and the natural gas units with dual-fuel capability have not always been effective or timely in switching to using oil. More so, LNG supplies, while beneficial, have been subject to competition from growing worldwide demand. Lastly, infrequently operated coal-fired and oil-fired generators have experienced diminished operating performance and constrained energy production due to issues with fuel availability, delivery, and other challenges caused by the sporadic operation of the units.

The results of studies, as well as actual events, demonstrate the need for fuel certainty in the region. The results of an ICF International study show that the region is projected to have shortfalls of natural gas supply during winter periods through 2020, even with the addition of 450 million cubic feet per day (MMcf/d) of new pipeline capacity.²² Planned and forced outages of non-gas-fired generation (e.g., nuclear and coal units) further increase the system's reliance on gas-fired generation and its exposure to potential shortfalls of natural gas for fueling this electric power generation.²³ The retirement of older coal, oil, and nuclear units and their replacement, in whole or in part, with generators that burn natural gas is expected to increase the regional dependence on natural-gas-fired generation to provide electric energy and capacity. Additionally, force majeure events (e.g., caused by weather, equipment failures, fuel embargos, and labor strikes) could interrupt all types of fuel supplies and further complicate the fuel-certainty issue.

To address the fuel-certainty issue, generators and other contracting entities can make firm commitments for procuring natural gas. This would lead to the improved use of existing natural gas infrastructure as well as infrastructure upgrades, such as the addition of natural gas pipelines and LNG terminals, which in turn would improve the deliverability of natural gas. Several infrastructure improvements have been proposed, and the New England states are considering additional means of funding new pipeline capacity into the region. Hydroelectric power can be accessed by building transmission interconnections with Canada, for which the states also are considering a means of funding. Proposed Elective Transmission Upgrades (ETUs), in various stages of development, could improve access to renewable resources in neighboring areas and remote areas of New England.²⁴ The ISO's Strategic Transmission Analysis and economic study results also stated that adding transmission facilities to areas of northern New England could facilitate access to large-scale wind power, if developed in this region, and be extended to support imports of Canadian hydropower.²⁵

Greater fuel diversity would also improve system reliability. This could be achieved through the more effective use of dual-fuel-capability at existing dual-fuel units and incentives that encourage the development of this capability at existing non-dual-fuel units and proposed single-fueled units. During winter 2013/2014, resource performance and fuel-adequacy issues were improved through a winter reliability program and better coordination between electric power and natural gas system operations. FERC has approved an ISO program for winter 2014/2015, revised from the 2013/2014 program.²⁶

Environmental and economic incentives provided by governmental policies are encouraging the development of low-emitting, renewable resources, such as wind and solar. These resources could diversify the fuel supply; however, the reliable large-scale integration of intermittent resources would place increased regulation and reserve requirements on the system, presenting challenges for operating and planning the system. Conventional and pumped-storage

hydroelectric facilities have traditionally been well suited to provide regulation and reserves, but they may lose some of their operating flexibility as part of their relicensing requirements. Natural gas units, which are subject to gas nomination and physical constraints, and baseload units, particularly nuclear units, which are normally dispatched to their maximum output, also are unsuitable for helping meet regulation and reserve requirements. Increasing the availability of operating reserves, enhancing market incentives, and procuring sufficient resources to meet the region's ramping and regulation needs all would improve system flexibility, and several recent and planned market improvements are aimed at addressing these issues.

Although most photovoltaic resources do not require transmission expansion, for these resources to be integrated into the system while maintaining system reliability, their interconnection requirements must be revised and their operational forecast tools improved. Operating procedures may need to be revised, as well, to address unique operating requirements associated with a larger composition of intermittent resources in the capacity mix. In addition, smart grid technologies presently being developed and implemented should improve the electric power system's performance and operating flexibility.

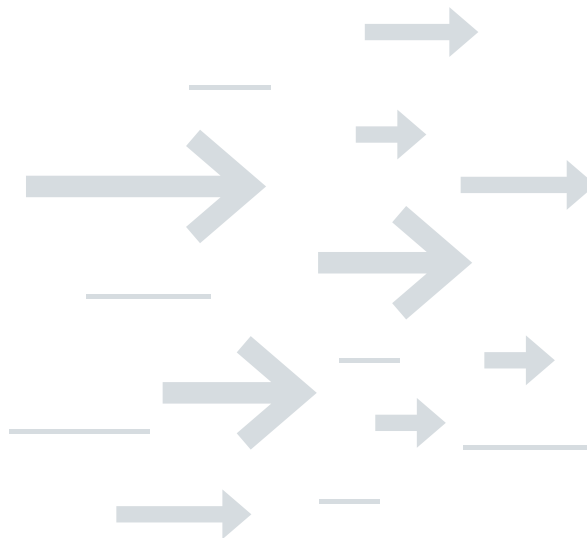
Transmission projects have been placed in service throughout the region, and others are in various stages of development, including siting. The required timing and components of certain projects are being modified, however, because of the reduction in net loads, the retirement of generating resources, and the addition of new market resources. In general, the development of resources in load pockets relieves transmission system constraints. But when resources fail to develop in the required amounts and in the needed locations, properly timed transmission projects that provide access to more remote resources are critical for meeting regional reliability requirements and mitigating the risks associated with resource deficiencies.

The ISO has coordinated interregional planning activities with the New York Independent System Operator (NYISO), PJM Interconnection, neighboring Canadian provinces, and multiregional organizations, such as NPCC and NERC, and has actively participated in the Eastern Interconnection Planning Collaborative (EIPC).²⁷ The ISO has filed with FERC proposed measures required for compliance with Order No. 1000 that will change interregional planning and interregional transmission cost allocation.²⁸



Major Findings and Observations

This section highlights the major findings and observations of the RSP14 load forecast, energy-efficiency forecast, and photovoltaic forecast; supply and demand resource and transmission planning studies; market outcomes; and economic studies.



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

For all RSP14 analyses, the ISO used a number of assumptions, which are subject to uncertainty over the course of the planning period. Changes in these assumptions may vary RSP14 results and conclusions of the analyses and ultimately can influence the future development of transmission and generation and demand resources:

- **Fuel availability and fuel-price forecasts**, which change with world markets and infrastructure development
- **Demand and energy-efficiency forecasts**, which are dependent on the economy, new building and federal appliance-efficiency standards, state EE goals and program implementation, and other considerations
- **Resource availability**, which is dependent on physical and economic parameters that affect the performance, development, and retirement of resources
- **Environmental regulations and compliance strategies**, which can vary with changes in public policies, economic parameters, and technology development
- **The deployment of new technologies**, which may affect the physical ability and the economic viability of new and existing resources and the efficiency of operating the power system
- **Market rules and public policies**, which can alter the development of market resources and renewable resources

- **Timing of planned system improvements**, which can be subject to siting and construction delays, and other changes to the system

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

Forecasts of Peak Demand, Annual Use of Electric Energy, Effects of Energy-Efficiency Measures, and Distributed Generation

RSP14 includes forecasts of annual and peak energy use, as well as the peak load reductions and annual energy savings from energy efficiency. The amount and location of the net system load affect the need for new resources and the required timing of some transmission projects.

PEAK DEMAND, ANNUAL USE OF ELECTRIC ENERGY, AND LOAD GROWTH

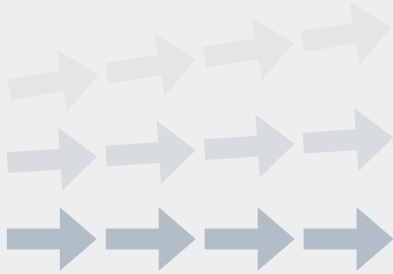
The RSP14 forecast of summer peak demand is lower than the RSP13 forecast by 125 MW for 2014 and by 205 MW for 2022 for the 50/50 “reference” case.²⁹ The RSP14 50/50 summer peak forecast is 28,165 MW for 2014, which grows to 31,620 MW for 2023. The 90/10 summer peak forecast, which represents more extreme summer heat waves, is 30,470 MW for 2014 and increases to 34,195 MW in 2023.³⁰ The ISO forecasts the 10-year growth rate to be 1.3% per year for the summer peak demand, 0.6% per year for the winter peak demand, and 1.0% 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 56.1% in 2014 to 54.7% in 2023.

Load forecasts are highly dependent on the economic forecast, which reflects economic trends. The RSP14 load forecasts also account for reductions based on the historical growth of non-FCM energy-efficiency savings and the expected effects of federal EE standards for appliances and commercial equipment.³¹ The load forecast does not include the energy-efficiency savings of the passive demand resources (PDRs) that participate in the Forward Capacity Market or account for the energy-efficiency forecast. These PDRs and the energy-efficiency forecast are represented as supply-side resources in planning studies.³²

ENERGY-EFFICIENCY FORECAST

RSP14 discusses the annual planned additions of EE in the FCM for 2014 through 2017 and forecasts new EE for each year from 2018 to 2023. The EE forecast (for 2018 through 2023) shows a regionwide annual average energy savings of approximately 1,518 gigawatt-hours (GWh) and an average reduction in peak loads of 205 MW per year.³³ The EE forecast shows savings from new energy-efficiency levels (i.e., not cumulative EE) of 1,764 GWh in 2018, ranging to 1,288 GWh in 2023. Similarly, the peak load savings from new EE ranges from 239 MW in 2018 to 174 MW in 2023. The EE forecast also shows results for each New England state.

The annual energy-use forecast, minus both the FCM passive demand resources projected for 2014–2017 and the 2018–2023 energy-efficiency forecast, shows essentially no net long-run growth in electric energy use and would save 13.8% of the forecasted gross energy consumption in 2023. The summer peak 90/10 forecast, when adjusted for both the existing FCM PDRs projected for 2014–2017 and the 2018–2023 energy-efficiency forecast, is projected to increase at 0.7% compared with the 1.3% projected growth rate of the demand forecast. Transmission planning studies use this adjusted 90/10 forecast, and at 30,873 MW for 2023, is 747 MW lower than the gross



Energy consumption, unadjusted for energy-efficiency measures, is projected to grow an average of 1% annually through 2023, while summer peak demand is expected to grow by 1.3% per year.

Since 2012, ISO New England has used a multistate EE forecast to capture the longer-term effects of EE in its system planning processes.

When the energy-saving effects of EE are included, the forecast shows essentially no growth in total electricity usage and 0.7% annual growth in summer peak demand over the 10-year planning horizon.

50/50 forecast of 31,620 MW.³⁴ After allowing for FCM energy efficiency and the EE forecast, the winter peak demand is expected to slightly decline at a rate of 0.1% over the 10-year forecast.

DISTRIBUTED GENERATION FORECAST

Distributed generation resources have been rapidly growing in New England and are predominantly photovoltaic resources developed as a result of governmental policies (e.g., incentives). To be able to account for the rapid growth of PV resources and their intermittent performance, the ISO, with input from the six New England states and other stakeholders, developed a multistate forecast of PV. The forecast considers the amounts and locations of existing PV resources, state policy objectives for PV development, and uncertainties in future policy and market and price conditions necessary to support the continued development of PV.

By the end of 2013, the installed nameplate of PV was almost 500 MW_{AC}, which was approximately double the amount installed in 2012.³⁵ The PV forecast also shows an increase of PV resources to over 1,800 MW_{AC} by 2023, which has a total estimated summer seasonal claimed capability (SSCC) of approximately 632 MW.³⁶ Almost 70% of PV is projected to be in Massachusetts.

The growth in distributed generation resources, particularly PV resources, poses extraordinary technical challenges for grid operators and planners, some of which are as follows:

- A limited amount of DG resource data for planning studies, including resource size, location, and operational characteristics
- A current inability of system operators to observe and control DG resources in real time
- A need to better understand the impacts of growing DG on system operations, including ramping, reserve, and regulation requirements for the most intermittent resources
- Potential reliability impacts to the regional power system posed by future amounts of DG, resulting from existing state interconnection standards

The challenges are being addressed through advanced research conducted by the US Department of Energy (DOE) and highly technical analysis by ISO staff. Stakeholder discussions have provided vital data and guidance to the ISO.

The ISO is working to improve its operating forecasts to more fully account for PV. The ISO also plans on improving the PV planning forecast, producing a PV energy forecast for RSP15, and more fully addressing the above issues and other challenges presented by the growth of DG resources. Additionally, the ISO and stakeholders are discussing the use of the PV forecast in long-term planning studies, and progress has been evident over the past year; economic studies have already considered the modeling of PV resources, and plans call for using the PV forecast in new transmission planning studies. Stakeholder discussions on the use of the PV forecast in other planning studies, such as resource adequacy studies, will continue in fall 2014, with plans for implementation by FCA #10.

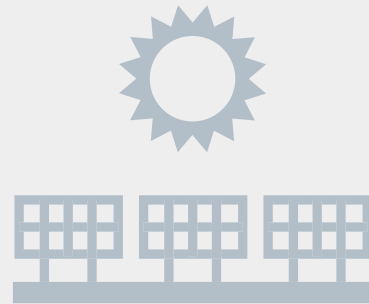
Although the ISO is not directly involved with the interconnection of most distributed generation and traditionally has not been aware of the timing or locations of DG installations, in the planning process, it considers existing DG as resources or as part of the historical load, which is an input into the ISO load forecast. The ISO will continue discussions with stakeholders to develop any needed improvements required to extend the planning forecast from PV to other types of DG as a part of RSP15.

Needs for Capacity and Operating Reserves

RSP14 quantifies the system needs for capacity and operating reserves and the amounts procured through the Forward Capacity Market and the locational Forward Reserve Market (FRM).

CAPACITY

The minimum amount of capacity the region needs to meet resource adequacy requirements is called the *Installed Capacity Requirement (ICR)*. The region's net



In 2014, ISO New England, with help from stakeholders, developed the nation's first multistate forecast of distributed generation (DG) resources to quantify and better understand the impact of increased amounts of DG on both grid operations and future grid planning. Results of the first forecast show that solar photovoltaic (PV) resources will continue to grow in the region, with 1,800 MW (nameplate) forecasted by 2023. By the end of 2013, the installed nameplate of PV in New England was approximately 500 MW.

ICR is expected to grow from 32,588 MW in 2014 to a representative value of 36,100 MW by 2023.³⁷ This represents a growth of approximately 390 MW per year, which is equivalent to 1.14% per year. The development of generation, demand, and import capacity resources for the region is required to provide the capacity needed to meet the ICR. Because the ICR calculation accounts for the load-relieving actions of ISO Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*, meeting the ICR level could necessitate the use of specific OP 4 actions.³⁸ Several factors affect the frequency and extent of OP 4 actions, including the amount of resources procured to meet capacity needs, their availability, actual system loads, and other system conditions.³⁹ Study results show that the need for load and capacity relief by OP 4 actions will be as much as 2,665 MW during extremely hot and humid summer peak-load conditions over the planning horizon.

FCA #8 resulted in the first capacity shortage in a primary auction. As recently as fall 2013, a surplus of capacity resources (both new and existing) was considered likely for the auction, but retirements have since been announced. Resources will be procured for the 2017/2018 capacity commitment period if deemed necessary in upcoming



More than 4,600 MW of capacity is expected to retire over the next three years. Despite the slow load growth forecasted for New England, the pending retirements of large generators and the likelihood of additional retirements mean the region will need new capacity resources to reliably serve demand in the future.



The eighth Forward Capacity Market auction (FCA #8), to secure capacity obligations from resources for the 2018/2019 commitment period, procured slightly less than the capacity requirement, which resulted in higher capacity prices than the seven previous auctions.



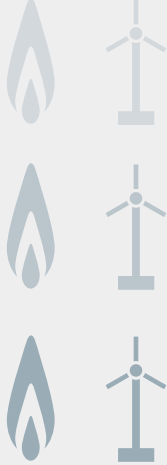
annual reconfiguration auctions.⁴⁰ The region is projected to require 424 MW in 2019/2020, which would increase to a shortage of 1,155 MW in 2023/2024, accounting for the load and energy-efficiency forecasts and only known retirements. This also assumes all resources with capacity supply obligations for FCA #8 remain in service. In August 2013, Entergy announced the retirement of Vermont Yankee (604 MW) and submitted a nonprice retirement request. During fall 2013, the ISO received nonprice retirement requests for an additional 2,531 MW to leave the market. The ISO analyzed 100 “static” delist bids, totaling 4,170 MW, and was not required to reject any for reliability reasons in FCA #8.⁴¹ The probability for resource retirements at future auctions will likely accelerate the need for new resources; the region already is beginning to lose older, relatively inefficient generating facilities. Additionally, generation 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.

The amount of capacity resources located in import-constrained zones is projected to meet the local resource adequacy requirements. Connecticut resources exceed this zone’s local sourcing requirement (LSR) by 1,872 MW.⁴² In FCA #8, the LSR for Northeast Massachusetts (NEMA)/Boston was 3,428 MW, and the resources in this area, including new resources not yet on line, totaled 3,821 MW. Although the NEMA/Boston area is projected to have surplus capacity, the ISO has growing concerns about the lack of timely development of new resources in this area that, if not developed, would result in the area being short of required capacity. Additional load growth or reduced resource availability—possibly resulting from fuel supply issues; a failure to develop new, cleared resources in a timely manner; or retirements—could create the need to develop additional new resources across the region or in constrained zones.⁴³

FERC-approved changes also will improve the market incentives for developing resources when and where needed, and the Strategic Planning Initiative is assessing ways to enhance the efficient development of resources.⁴⁴ The ISO is following a new two-step process for creating, modifying, or collapsing capacity zones. Step one

The new resources proposed for New England are predominantly natural gas or wind plants.

RSP14 reports that, as of April 2014, 6,915 MW of new generation had been proposed. More recent data from November 2014 show that about 8,300 MW of new generation has been proposed: more than 4,500 MW of natural gas resources and nearly 3,700 MW (nameplate) of wind. Not all proposed projects will be built; historically, the proposal queue has had a megawatt attrition rate of 70%.



identifies potential zonal boundaries and associated transfer limits. Step two uses objective criteria to evaluate the portions of the system identified in step one and establish whether any of these areas will be modeled as capacity zones in the capacity auction.⁴⁵ These changes are addressing the relationship between the zonal reconfigurations and the ISO’s rejection of delist bids. A new zone for the Southeast Massachusetts/Rhode Island (SEMA/RI) area will be eligible for modeling in FCA#9. In general, the development of new resources near the system load centers mitigates reliability risks associated with resource retirements and resource performance issues, improves system performance, and allows for improved use of the existing transmission infrastructure. Resources in the generator interconnection queue, which included 6,915 MW as of April 1, 2014; new demand resources; and new import capacity from neighboring regions are in various stages of development and could address some of these issues.

OPERATING RESERVES AND RESOURCE FLEXIBILITY

Operating reserve is the megawatt capability of a power system greater than system demand required for preserving system reliability—such as by providing frequency regulation, responding to load forecast errors, and filling the void left by forced outages—when resources or transmission facilities are lost because of a contingency.⁴⁶ Some resources are required to be synchronized to the system for immediate use (i.e., *spinning* resources), and some must be fast-start resources.⁴⁷ In New England, resources participating in the locational FRM and other committed and on-line resources help satisfy the operating-reserve requirements of the region overall and in major load pockets.

The ISO develops the representative operating-reserve requirements of major import areas as ranges to account for future uncertainties about the availability of resources, load variations due to weather, and other factors. For 2014 through 2018, the representative operating-reserve requirements for Greater Southwest Connecticut is from 0 to 350 MW.⁴⁸ Over the same period, the need for operating reserves in Greater Connecticut is as much as 1,100 MW during the summer, and similarly, the need for the BOSTON area is as much as 350 MW. Although each of these areas currently has sufficient resources to meet its representative reserve requirements, the placement of fast-start, energy-efficiency, and economical baseload resources in these load pockets would improve system performance. Transmission projects that increase the transfer capability into these areas or in other ways improve the electrical access of these areas to economical resources also would enhance the economical and reliable performance of the system.

The need for flexible resources to provide operating reserves as well as other ancillary services, such as regulation and ramping, will likely increase as a result of unit retirements and the addition of variable energy resources, particularly wind and PV. To date, increasing the 10-minute operating-reserve requirement and adding seasonal replacement reserves have improved the systemwide performance for meeting peak load, ramping during changing system conditions, and the resource response to contingencies.

Transmission System Needs and Solutions

Transmission projects placed in service have reduced congestion and decreased dependence on generating units located in load pockets. In 2013, the real-time systemwide congestion-related costs totaled approximately \$175,000, and payments for generators in “must-run” situations that provided second-contingency coverage and voltage control totaled just under \$54.6 million. These values in total represent approximately 0.6% of the \$8.82 billion wholesale electric energy market.

TRANSMISSION PROJECTS

The ISO and the PAC regularly discuss the scope of transmission system needs and the progress of assessments that drive regional transmission planning for improvements. The PAC provides guidance and comments on study scopes, assumptions, and results. All transmission projects are coordinated with other regions as warranted. The ISO also has advised the PAC of the regional network service (RNS) rate and projections developed by the PTOs.⁴⁹

The descriptions of transmission projects in RSP14 are based on the June 2014 RSP Project List update, which includes 222 projects at a total cost of approximately \$4.5 billion.⁵⁰ The ISO updates the RSP Project List at least three times per year, identifying improvements and changes in project status. The status of several major projects under development is as follows:

- **The Maine Power Reliability Program (MPRP)**, for which the Maine Public Utilities Commission (MPUC) has approved siting for most of the components, establishes a second 345 kilovolt (kV) path in northern Maine from Suowiec to Orrington and adds new 345 kV lines in southern Maine, creating a third parallel path from Suowiec to Eliot. Many components of these new paths are under

construction, and several elements already are in service. When completed, they will provide basic infrastructure needed to increase the ability to move power from New Hampshire into Maine and will improve the ability of the transmission system within Maine to move power into the local load pockets as necessary.⁵¹ Studies have demonstrated that the MPRP also will provide a modest increase in the transfer capability across major interfaces in Maine, including an increase from 1,600 to 1,900 MW of the Maine-to-New Hampshire transfer capability. The MPRP project is scheduled for completion by early 2015, with the exception of upgrades around Lewiston expected to be complete by January 2017.

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

- The Rhode Island components and the Springfield components of NEEWS were placed in service in 2013.
- The Interstate Reliability Project (IRP) was reevaluated in light of updated load and energy-efficiency forecasts; system operating constraints; and resources acquired, delisted, or retired through the Forward Capacity Auctions, such as Salem Harbor. Consistent with the original plan, the final plan calls for a new 345 kV transmission between Millbury, MA; West Farnum, RI; Lake Road, CT; and Card, CT. Additional system modifications to the original plan have been identified, which primarily relieve thermal constraints. Other improvements identified in the original plan have been eliminated, including upgrades to 345 kV facilities. The IRP has received siting approval and is under construction.
- A reevaluation of the Central Connecticut Reliability Project (CCRP), a 345 kV line from North Bloomfield to Frost Bridge, has been completed with the Greater Hartford/Central Connecticut study. A number of 115 kV upgrades that address local Hartford concerns and issues associated with imports into western Connecticut have replaced the CCRP project.

- **The Long-Term Lower Southeastern Massachusetts (Lower SEMA)** project addresses system reliability concerns in the lower southeastern Massachusetts (LSM) area, which includes Cape Cod, and went into service in 2014. The project included adding a new 345 kV transmission line from the Carver substation to a new 345/115 kV substation west of Barnstable on Cape Cod, adding a third 345 kV line serving Cape Cod.

- **The Greater Boston study** assessed and identified improvements required to respect revised cable ratings in downtown Boston and the addition of Footprint Power generating plant (674 MW) at the Salem Harbor site. The ISO is reviewing the merits of two alternatives, which include an independent review of the cost of each alternative to ensure that the most cost-effective solution is selected for the Greater Boston area. One alternative includes new 345 kV circuits from Scobie to Tewksbury and from Wakefield to Woburn, and the other alternative plan includes

Substantial upgrades to the high-voltage transmission system to meet federal reliability requirements are under construction, have been approved, or are under development.

Approximately \$4.5 billion in transmission investment for reliability purposes is planned. Additionally, several elective transmission projects that would be funded by private developers have been proposed.

a high-voltage, direct-current (HVDC) submarine cable (SeaLink HVDC Submarine Cable Project) extending from Seabrook, New Hampshire, to Boston, Massachusetts. System improvements common to both alternatives also were identified.

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

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

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

DEVELOPMENT OF ELECTIVE TRANSMISSION UPGRADES

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

Regional Strategic Planning

The ISO is assessing a number of potential reliability effects of the fuel-procurement strategies of natural-gas- and oil-fired generators and the influences of public policies, including environmental initiatives. Fuel availability and certainty for generating electric energy, and the system’s need for specific amounts, types, and locations of resources and transmission improvements, are important elements of system reliability being assessed. The ISO also is addressing issues concerning the development and integration of renewable resources and smart grid technologies.

RESOURCE PERFORMANCE AND FUEL CERTAINTY

Several strategic planning issues associated with fuel certainty and resource performance stem from the region’s dependence on natural gas-fired generation and other constrained-energy resources. These problems have been quantified, and infrastructure and market solutions are being implemented.

To mitigate potential grid reliability issues, ISO New England will implement a second Winter Reliability Program for the upcoming winter.

The program includes incentives...

- **for oil and dual-fuel generators to increase their oil inventories;**
- **for gas-fired generators to contract for liquefied natural gas to augment pipeline gas;**
- **for power plants to become dual-fuel resources;**
- **and for new demand-response resources to participate.**

A similar program in place in winter 2013/2014 was critical in maintaining system reliability. ISO New England is working with stakeholders on wholesale power market changes to address these challenges over the long term.

Natural Gas Dependency: New England is increasingly dependent on natural gas as a primary fuel for generating electric energy and decreasing its dependence on oil. In 2013, the approximate percentages of the region's generation capacity and electric energy production by fuel type were as follows:

- **Natural gas:** 42.8% capacity and 45.1% electric energy
- **Oil:** 22.3% capacity and 0.9% electric energy
- **Coal:** 7.2% capacity and 5.6% electric energy
- **Nuclear:** 14.6% capacity and 33.2% electric energy
- **Hydro, pumped storage, and renewable resources:** 13.1% capacity and 15.3% electric energy

The high regional dependence on natural-gas-fired generation has resulted in natural gas fuel prices typically setting the marginal price for wholesale electricity.

The high regional use of natural gas to generate electricity is the result of the addition of new, efficient natural-gas-fired units over the past 13 years; the generally low price of natural gas; and the displacement of older, less efficient oil- and coal-fired units in economic dispatch.⁵² As the revenues from the wholesale electricity markets decline for these older oil and coal units and more units retire, the regional reliance on natural gas for providing capacity and energy will increase. Natural gas-fired generation's proportion of the system capacity mix is expected to grow to approximately 48% as early as 2017. The region will continue to depend on natural-gas-fired generation because of the risks faced by other types of generation. Nuclear and hydro units have already announced retirements or may not be relicensed. Many units do not have dual-fuel capability. Other units with dual-fuel capability, especially newer combined-cycle generators, are not effective in terms of the amount of time they need to switch to using oil or the availability of secondary fuel inventory.



In 2013,

- **45.1% of the electricity generated in the region was produced by natural-gas-fired power plants;**
- **oil units produced less than 1%;**
- **coal plants generated 5.6%;**
- **nuclear produced 33.2%;**
- **hydro, pumped storage, and renewable energy resources together produced 15.3% of the electricity generated in the region.**

Adding to the concern about the increased use of natural gas are concerns about the capacity of the region's gas pipelines and the adequacy of the gas supply for serving electric power generation reliably; at any time of the year, a natural or geopolitical event could interrupt supplies of gas and other fuels, such as oil and coal. Renewable resources provide some diversity of energy supply but are weather dependent, typically need thermal or hydro resources to accommodate their variability, and pose both interconnection and operational challenges.

Natural Gas Infrastructure: Recent improvements to the interregional natural gas infrastructure have helped increase the supply of natural gas from the Marcellus Shale production areas, displacing the Northeast's traditional supply sources, such as the Gulf of Mexico. Additional enhancements to the regional pipeline network are planned and would allow New England to access the larger quantities of natural gas for the region's power generators. Further expansion, however, is likely required, which would improve fuel certainty for the electric power system and provide access to more economical natural gas supply. Unlike the electric power industry, which proactively plans the expansion of the transmission network, natural gas transportation requires firm contractual arrangements before natural gas pipeline facilities can be constructed. The New England states are considering the means of funding pipeline expansion into the region, including possible modifications to the ISO tariff. The increased use of existing LNG storage capability or the expansion of this capability also could improve fuel certainty.

Resource Performance: Operational experience during winter 2013/2014 showed the need for the ISO to manage the limitations of energy production by electric power generators. The vulnerabilities and limitations of the system were evident during severe winter weather and other stressed system conditions because natural gas was not available to generators at desired levels. Several oil-fired generators, which operated periodically and were exposed to equipment failure, fuel interruptions, and supply limitations, further highlighted reliability issues. Market rules that allow resources to constrain their operation when they have limited fuel, such as when the capacity of the natural gas pipeline is lacking, added to operating concerns.⁵³

The ISO has taken a number of actions to address fuel-certainty issues in the short and longer terms. Regional

load was reliably served during winter 2013/2014 as a result of improved communication between electric power and natural gas system operators and the successful implementation of a winter reliability program, which proved vital in maintaining required fuel supplies.⁵⁴ The ISO has filed and FERC has approved an update to this program for winter 2014/2015.⁵⁵ In addition, the ISO is actively collaborating with stakeholders to improve the Day-Ahead Energy Market, Real-Time Energy Market, and Forward Capacity Market. By the end of 2014, the ISO plans on implementing rule changes that allow generators to better reflect the real-time price of fuel in their supply offers.⁵⁶ Longer-term, an FCM pay-for-performance mechanism should create stronger financial incentives for capacity supplies to produce electricity and supply reserves when needed the most. This planned market improvement is designed to encourage generator owners to invest in dual-fuel capability or new fast-start assets, enter into firmer fuel arrangements, and have more reliable operating and maintenance practices, which all should in turn reduce the need for stop-gap measures like a winter reliability program.

More fully integrating demand resources into the energy market also is planned to broaden the conditions under which demand resources could be called on to help meet the region's energy needs.

Studies of Natural Gas Supply Issues: Planning studies of regional natural gas issues quantified the need to bolster the region's natural gas system supply or the use of non-gas-fired resources under a number of scenarios. The scenarios included outages of non-gas-fired generating units, the replacement of older oil- and coal-fired generating units with natural-gas-fired generators, and outages of natural gas infrastructure affecting reliable electric power operation.⁵⁷ The studies examined the potential natural gas available to the region from pipelines, peak-shaving capabilities of the local distribution companies (LDCs) that serve retail customers, and LNG storage. The natural gas supply was compared with the natural gas demand of firm contract holders, including LDCs. The scenarios considered the demands of natural gas customers upstream of New England, and some modeled the low levels of LNG stored and available to the region during winter 2013/2014. The studies, which used 20 years of weather data, show that electric power generators would likely have a gas supply deficit on 24 to 34 days per winter by 2019/2020. Under 2013/2014 winter conditions, the supply deficit would be even more severe.

The ISO also is coordinating an interregional study of the natural gas system with the NYISO, PJM, the Midcontinent Independent System Operator (MISO), the Independent Electricity System Operator (of Ontario) (IESO), and the Tennessee Valley Authority (TVA).

THE POTENTIAL IMPACTS OF ENVIRONMENTAL REGULATIONS ON THE POWER SYSTEM

Existing and pending state, regional, and federal environmental requirements addressing air pollution, greenhouse gas emissions, cooling water drawn from rivers and bays, and wastewater discharges that flow back into these bodies of water as well as public treatment works will affect many New England generators in the 2015 to 2023 timeframe. Many generators in the region already have installed the needed controls to comply with existing state environmental rules, and new transmission upgrades have reduced the need to use older, less efficient oil- and coal-fired units to address more local reliability concerns. These changes, and the greater reliance on natural gas for power generation, have reduced regional air pollution emissions and thermal discharges into the region's waterways.

Between 2001 and 2012, the annual average emission rate of nitrogen oxides (NO_x) declined by 67%; sulfur dioxide (SO₂), by 92%; and carbon dioxide (CO₂), by 23%. The decrease appears attributable to declines in both oil- and coal-fired generation combined with a significant increase in natural gas generation, which has a substantially lower SO₂ emission rate.⁵⁸ Future regional emissions could increase however, even with more stringent regulations, if oil-fired generating units need to operate during periods of natural gas shortages or because nuclear units have retired or are on outages. Emissions could decrease with the use of lower-emitting fuels, additional environmental controls, and the greater use of energy efficiency and wind and photovoltaic resources.

The ISO has been assessing the potential impact of existing and proposed US Environmental Protection Agency (EPA) and state regulations on the operation of existing fossil steam units and other types of generation in the region. Uncertainty remains over the extent to which the final regulations will require generator owners to make capital investments in environmental remediation measures and potentially increase plant operating costs. These factors could require long-term generator outages for implementing required remediation measures. They also could trigger unit retirements as an alternative to accepting higher capital and operating costs. Alternatively, generators may comply with some of the environmental requirements by reducing capacity or energy production.

ISO analyses will continue to update stakeholders regarding the generators at risk for retirement and generators that already have environmental remediation measures in place or may require relatively minor upgrades.⁵⁹ The actual compliance timelines will depend on the timing and substance of the final regulations and site-specific circumstances of the electric generating facilities, such as their economic performance.

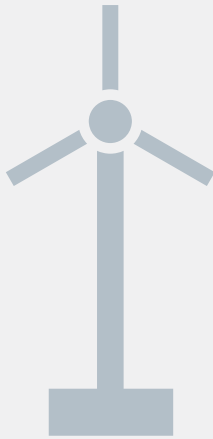
RENEWABLE PORTFOLIO STANDARDS AND THE INTEGRATION OF RENEWABLE RESOURCES

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

Meeting State Targets for Renewable Energy: The New England states have targets for the proportion of electric energy that load-serving entities (LSEs) must serve using renewable resources, such as wind, solar, and energy efficiency. Because the states are revising these targets to reflect different amounts and types of resources that qualify for RPSs, the ISO cannot project the precise amount of regional renewable energy goals. The region's RPSs can be met by developing the renewable resources already in the ISO queue; importing renewable resources from adjacent balancing authority areas; building new renewable resources in New England not yet in the queue; and using "behind-the-meter" projects and eligible renewable fuels, such as biomass, at existing generators. 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).⁶⁰ ACPs also can serve as a price cap on the cost of the RECs.

Integrating Intermittent Renewable Resources: A number of wind projects have interconnected to electrically remote and weak portions of the regional power system, and additional wind projects are proposed for these areas. These facilities pose operational and planning challenges due to issues with voltage and stability performance.⁶¹ In addition, the basic assumptions in interconnection studies may be different from the typical operation of the system, which may further constrain wind output under stressed system conditions, such as during maintenance outages. The ISO is considering ways of improving the Elective Transmission Upgrade process to more readily support the means to strengthen electrically weak portions of the regional transmission network, enhance generator deliverability, and facilitate the integration of renewable resources.

The ISO continues to analyze wind-integration issues and has made progress implementing wind forecasting and dispatch. The wind-integration component of the Strategic Transmission Analysis is exploring conceptual modifications to the transmission system that would enable onshore wind resources to more reliably provide energy. This analysis of approximately 1,100 MW of installed and proposed wind resources examined the proposed transmission system as of October 2013. The study identified the need for local area improvements to accommodate the wind resource interconnections and the need for regional transmission improvements to accommodate the total development of wind resources in several regions of Maine.



In January 2014, ISO New England incorporated a new wind power forecast into its processes and control room dispatch services. The forecast provides ISO system operators with information about where, when, and approximately how much electricity may be produced by each of the large wind facilities in New England.

Wind resource owners can download the forecast for their individual units, which in turn may help them more effectively plan how much energy to offer into the Day-Ahead Energy Market. The ISO is continuing its work to fully integrate wind resources into system dispatch.

The results show that local transmission upgrades could likely accommodate additional wind resource interconnections planned for the Wyman Hydro and Rumford regions in Maine but without major transmission improvements to those local areas. However, additional wind capacity cannot be well integrated into the Keene Road and Bangor regions, also in Maine, without major transmission improvements to these areas. The addition of generation to the Aroostook region of Maine also would require new major transmission facilities to successfully interconnect these resources and integrate them with the rest of the New England system. Regional improvements would be needed to accommodate resources remote from the New England load centers, such as the total wind resources in all the northern New England regions. These transmission improvements could include a major dynamic voltage device, 345 kV dynamically acting series-compensating devices, and 115 kV capacitors.

The 2011 Economic Study quantified the amounts of congestion associated with different wind-penetration scenarios.⁶² The results of the study show the effects of integrating varying amounts of wind on production cost, load-serving energy expense, and congestion, as well as the need for transmission development to enable wind resources to serve the region's load centers. The ISO will continue to engage stakeholders on the issues challenging the wind-interconnection process and the performance of the system with wind resources in locally constrained areas.

While existing amounts of PV have yet to have a significant impact on system operations, the regional goal is to have over 2,000 MW of distributed generation by 2023, approximately 1,800 MW of which is expected to be PV. The ISO and stakeholders are working on several initiatives aimed at facilitating the reliable and efficient integration of PV, including improving the long-term forecast of the amounts and locations of PV resources and the amount of electric energy PV resources produce; developing a short-term solar forecast for use by system operators; and addressing other potential reliability risks posed by growing penetrations of PV, such as interconnection requirements.

Developing New England's Smart Grid: In general, smart grid technologies can improve the ability of the transmission system to operate reliably under a wide variety of system conditions. They can improve the ability of system operators to observe and control the system, increase the transfer capability of the transmission system while adding less new infrastructure, and facilitate end-user response to the power system. Specific applications of smart grid technologies in New England use demand resources to provide ancillary services, such as operating reserves, and help integrate variable renewable resources, such as wind and photovoltaic power and hydroelectric

power from neighboring Canadian regions. Smart grid technologies also can facilitate the reduction in demand when electricity prices are high. This smart grid equipment helps implement both customers' load response and the use of behind-the-meter resources, such as rooftop solar installations.

The region is a leader in the smart grid application of HVDC facilities and flexible alternating-current transmission systems (FACTS), which improve the use of system infrastructure. The ISO and the New England transmission owners installed phasor measurement units (PMUs) and associated equipment at 40 substations to upgrade the monitoring and operation of the system. The ISO and stakeholders have also supported research and development efforts and the establishment of industry standards for integrating smart grid technologies, including dispatching active demand resources, which are affected by the installation of smart meters and changes in retail rate structures. Alternative technology regulation resources and active demand resources may be used to provide regulation and reserve services, which would facilitate the reliable integration of intermittent renewable resources. The ISO will continue to monitor the development of and will support the implementation of these and other advanced technologies.

ECONOMIC STUDIES OF RESOURCE INTEGRATION AND INTERREGIONAL COORDINATION

Both the *2011 Economic Study* and the *2012 Economic Study* analyzed several of the strategic issues the region is addressing.⁶³ The *2011 Economic Study*, summarized above, examined the economic and environmental impacts of wind integration. The *2012 Economic Study* highlighted the least suitable locations for unit retirements and the most suitable locations for developing different resources without causing congestion. The study showed the effects of using various amounts of energy efficiency and low-emitting resources, including renewable energy.

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

The ISO conducted an economic study in response to a stakeholder request received in 2013. This study examined the effects of increasing the acceptable loss-of-source limits in New England, which currently is limited by constraints in New York and PJM. The study considered changes in required operating reserves and varying profiles and prices of imported energy. As with other economic studies, the results show changes in the production cost, LSE expenses, and environmental emissions. In general, importing more-economical energy from Canada could lower system energy locational marginal prices (LMPs) and emissions but would increase the cost of operating reserves.

ANALYSIS OF MARKET RESOURCES IN LOAD POCKETS AS AN ALTERNATIVE TO TRANSMISSION INVESTMENT

Results of the Strategic Transmission Analysis show that developing resources integrated into or interconnected to the buses in the Hub or in load pockets is beneficial, especially the load pockets with exposure to potential generator retirements.⁶⁴ However, assessing the suitability of developing individual resources can be challenging during the planning process because of the wide variability of the characteristics, locations, and possible combinations of resources that could be developed, such as central station and DG resources, end-use efficiency, and storage technologies. In response to PAC requests for more details about resources that could meet system needs, the ISO applied the lessons learned from studies of the Vermont/New Hampshire area and the Greater Hartford/Central Connecticut area to a study of Southeast Massachusetts/Rhode Island (SEMA/RI).⁶⁵ The study respected the contingency loss of power system elements (N-1 criteria contingencies) but did not address constraints respecting

subsequent criteria contingencies (N-1-1 criteria contingencies) and FCM deliverability requirements. The analysis considered large generators (greater than or equal to 20 MW), small generators (less than 20 MW), and demand resources (less than 40% of the load at a given location). The results show that a minimum of 941 MW of total new generation and load reductions ranging from 5 MW to 590 MW at specific locations, as well as some minor transmission upgrades, can mitigate the thermal and voltage needs for the area.

Interregional Planning

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

The ISO has developed coordinated system plans and has proactively initiated planning studies with other regions. The ISO has worked with both NYISO and PJM through the Northeastern ISO/RTO Planning Coordination Protocol and issued the *2013 Northeast Coordinated System Plan* (NCSP13) that addresses several key interregional issues and summarizes key activities.⁶⁶ The ISO/RTOs have coordinated databases and models of their systems and conducted production cost analyses and transmission analyses of planned system improvements and interconnections. The three planning authorities have discussed these studies and key planning issues affecting the Northeast with stakeholders. Some of these issues include environmental regulations and their potential effect on the power system, challenges and solutions facilitating the integration of renewable resources, the need for fuel diversity, and the results of coordinated studies of the natural gas system.

Sharing more supply and demand resources with other systems most likely will be needed, particularly to meet environmental regulations and successfully integrate intermittent resources. The ISO has worked with stakeholders to establish a means of complying with FERC Order No. 1000, which includes changing the interregional planning process and interregional cost allocation. ISO New England will continue conducting joint studies with NYISO and PJM to identify transmission constraints limiting interregional power transfers and to show the effects of relieving these constraints throughout the ISO/RTO regions. The ISO also will continue to coordinate other efforts with neighboring systems to explore the ability to import power from, and export power to, the eastern Canadian provinces and New York and participate in national and regional planning activities.

ISO New England and other planning authorities throughout the Eastern Interconnection are members of the Eastern Interconnection Planning Collaborative. The EIPC addresses its portion of North American planning issues, coordinates plans, and conducts studies for the entire Eastern Interconnection through a transparent and collaborative process involving input from a broad base of interested stakeholders. ISO New England also serves as

FERC Order 1000 requires changes to grid operators' interregional and regional transmission planning processes.

ISO New England is awaiting final FERC orders on its compliance filings and has requested rehearing on aspects of Order 1000 that would require changes to the regional planning process.

a principal investigator for a project funded as part of DOE grant work. At DOE's request, EIPC is studying how the interface between the natural gas and electric power systems affects operations and planning. In a separate effort, the EIPC is also coordinating planning databases and conducting scenario analyses of electric power transmission systems for the entire Eastern Interconnection.

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

State, Regional, and Federal Initiatives that Affect System Planning

The ISO continuously works with a wide variety of state policymakers and other regional and interregional stakeholders on initiatives such as the Strategic Planning Initiative. Regional initiatives continue for improving the wholesale electricity markets, integrating new technologies, and documenting the regional transmission planning process and technical requirements for planning studies. The draft *Transmission Planning Process Guide* and the draft *Transmission Planning Technical Guide* will be revisited to align with final Order No. 1000 requirements.⁶⁷ In response to stakeholder requests, the ISO is also continuing to work with stakeholders to examine suitable assumptions for use in planning studies, which may more fully consider the probability of resources outages, system transfers, and system load levels.

The ISO has continued to provide technical support to a number of state agencies and groups as they formulate policies for the region. These groups include the New England Conference of Public Utilities Commissioners (NECPUC), the New England States Committee on Electricity (NESCOE), the New England governors, the Consumer Liaison Group (CLG), and others. The planning process will continue to evolve in response to FERC orders and other policy developments. The *Quadrennial Energy Review* by DOE, which will conclude in 2015, is a comprehensive analysis of energy and electricity production and delivery systems that addresses the challenges of cyber- and physical security of critical infrastructure.



Conclusions

The 2014 *Regional System Plan* identifies system needs and plans for meeting these needs. RSP14 also discusses risks to the regional electric power system; the likelihood, timing, and potential consequences of these risks; and mitigating actions. Through an open process, regional stakeholders and the ISO are addressing these issues, which could include further infrastructure development as well as changes to the wholesale electricity market design and the system planning process. Through current and planned activities, the region is working toward meeting all challenges for planning and operating the system in accordance with all requirements.

Notes

- 1 The requirements of the OATT, which include Attachment K, the ISO Information Policy, and interconnection procedures, address generator and elective upgrades. *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section II, Open Access Transmission Tariff, Attachment K, “Regional System Planning Process,” http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf. ISO tariff, Attachment D, “ISO New England Information Policy,” http://www.iso-ne.com/static-assets/documents/regulatory/tariff/attach_d/attachment_d.pdf.
- 2 RSP14 is based on the June 2014 *RSP Project List* (XLS file), <http://www.iso-ne.com/system-planning/system-plans-studies/rsp>.
- 3 The NEPOOL stakeholder process provides advisory input on market, reliability, tariff, and OATT matters; however, the primary forum for regional system planning is the ISO’s Planning Advisory Committee (PAC). More information is available at <http://www.iso-ne.com/committees/participants/participants-committee> and <http://www.iso-ne.com/committees/planning/planning-advisory>.
- 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 Supporting information and some supplements to the RSP statistics, such as import and export figures, are available at *New England 2014 Regional System Plan (RSP14) Load, Energy and Capacity Resource Overview* (April 29, 2014), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/apr292014/a4_rsp14_load_and_capacity_resource_overview.pdf.
- 6 The mix of capacity resources could change. Updates are included in the ISO’s monthly chief operating officer (COO) report to the NEPOOL Participants Committee; http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/index.html.
- 7 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/participate/support/request-information> 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.
- 8 A *demand resource* is a capacity product, type of equipment, system, service, practice, or strategy that verifiably reduces end-use demand for electricity from the power system.
- 9 Meeting materials, 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.
- 10 *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section II, *Open Access Transmission Tariff*, http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf. More information on NEPOOL is available at <http://www.iso-ne.com/committees/participants/participants-committee>.
- 11 FERC, *Order on Compliance Filings* (May 17, 2013), http://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2013/may/er13_193_er13_196_5_17_13_order_on_order_1000_compliance_filings.pdf. “Transmission Operating Agreements,” webpage, http://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2013/may/er13_193_er13_196_5_17_13_order_on_order_1000_compliance_filings.pdf.

- 12** ISO tariff (2014), <http://www.iso-ne.com/regulatory/tariff/index.html>.
- 13** 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.
- 14** ISO tariff Section II, *Open Access Transmission Tariff*, Attachment K, “Regional System Planning Process” (January 1, 2014), http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf.
- 15** A *load pocket* is an area of the system that requires local generation to meet demand because the transfer capability of the transmission system is insufficient to serve the load in that area.
- 16** 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), Newfoundland, Labrador, and Québec.
- 17** A *distributed generation* resource is generation provided by a relatively small, on-site installation directly connected to a distribution facility or retail customer facility and not the regional power system (i.e., it is “behind the meter”), which can alleviate or prevent regional power system transmission or distribution constraints or reduce or eliminate the need to install new transmission or distribution facilities. A small (24 kilowatt) solar photovoltaic system installed by a retail customer is an example of distributed generation.
- 18** “Status of Nonprice Retirement Requests,” webpage, http://www.iso-ne.com/genrtion_resrcs/reports/sts_non_retrmnt_rqst/. An existing resource can submit a *delist bid* for opting out of the capacity market for one year or permanently if the Forward Capacity Auction were to fall below a certain price. Several types of delist bids exist. A *nonprice retirement request* is an irrevocable request to retire all or a portion of a resource. This type of request, which supersedes any delist bids submitted, is subject to a review for reliability impacts. If the ISO notifies a resource owner of a reliability need for the resource, the resource owner has the option to retire the resource as requested or continue to operate it until the reliability need has been met, after which the resource must retire. For more information on delist bids and nonprice retirement requests, refer to the ISO’s *Overview of New England’s Wholesale Electricity Markets and Market Oversight* (May 6, 2014), http://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2014/2014_market_overview_050614.pdf.
- 19** The ISO’s *Generator Interconnection Queue* includes the requests that generators submit to ISO New England to interconnect to the ISO-administered transmission system.
- 20** The FCM reconfiguration auctions take place before and during the capacity commitment period (i.e., June 1 through May 31 of the following year) to allow participants to buy and sell capacity obligations and adjust their positions.
- 21** Information on the January 2004 cold snap is available in the *2005 Regional System Plan*, Section 5.1.2, at https://smd.iso-ne.com/trans/sys_studies/rsp_docs/rpts/2005/102005_RSP05_Final.pdf. Section 6.2.2. of this report contains additional details on 2013/2014 winter natural gas supply constraints. Also refer to the ISO’s *2013 Annual Markets Report* (AMR13), Section 2.1.3.4 (May 6, 2014), http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf.
- 22** ICF International, *Assessment of New England’s Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II*, PAC presentation (December 18, 2013), http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/dec182013/a3_draft_icf_phase_2_gas_study_report_without_appendices.pdf.
- 23** A *planned outage* is the scheduled inoperability of a generator, generally to perform maintenance. A *forced outage* is a type of unplanned outage that involves the unexpected removal from service of a generating unit, transmission facility, or other facility or portion of a facility due to an emergency failure or the discovery of a problem that needs to be repaired as soon as any combination of crews, equipment, or corrective dispatch actions can be put in place to allow the work to be performed.

- 24** An *Elective Transmission Upgrade* is an upgrade or interconnection to the pool transmission facilities that are part of the New England transmission system, voluntarily funded by an entity or entities that have agreed to pay for all the costs of the upgrade.
- 25** *Strategic Transmission Analysis: Wind Integration Study—Stage 1—Maine, Regional Constraints*, PAC presentation (May 21, 2014), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2014/may212014/a4_strategic_transmission_analysis_wind_power_update.pdf (*STA Wind Integration Study*, 2014). ISO New England, *2011 Economic Study* (March 31, 2014), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2014/2011_eco_study_final.pdf. *2012 Economic Study* (April 2014), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2014/a9_2012_economic_study_final.pdf.
- 26** FERC, *Order Accepting Tariff Revisions*, (September 9, 2014), http://www.iso-ne.com/static-assets/documents/2014/09/er14-2407-000_9-9-14_order_accept_winter_reliability.pdf.
- 27** 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, West Virginia, and the District of Columbia. Additional information on the EIPC is available at <http://www.eipconline.com/>.
- 28** ISO New England, *Order No. 1000 Interregional Compliance Filing of ISO New England Inc. and the Participating Transmission Owners Administrative Committee, Supported by the New England Power Pool Participants Committee*, FERC filing (July 10, 2013), http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13_1960_000_7_10_2013_order_1000.pdf.
- 29** The 50/50 “reference-case” peak loads have a 50% chance of being exceeded because of weather conditions. For the reference case, the summer peak load is expected to occur at a weighted New England-wide temperature of 90.2°F, and the winter peak load is expected to occur at 7.0°F. The 90/10 peak loads have a 10% chance of being exceeded because of weather. For the 90/10 case, the summer peak is expected to occur at a temperature of 94.2°F, and the winter peak is expected to occur at a temperature of 1.6°F.
- 30** The actual load has been near or above the 50/50 forecast 11 times during the last 21 years because of weather conditions; six of these 11 times, the load has been near or has exceeded the 90/10 forecast.
- 31** The ISO’s *Forecast Data 2014* (April 30, 2014), XLS file, worksheet 9 (http://www.iso-ne.com/static-assets/documents/trans/celt/fsct_detail/2014/isone_fcst_data_2014.xls) shows that the gross consumption of electric energy for 2023 is 151,525, gigawatt-hours (GWh). The savings attributable to federal appliance standards is 2,506 GWh for 2023. In addition, passive demand resources are projected to save 20,967 GWh for 2023 (see worksheet 2).
- 32** *Passive demand* resources reduce electric energy consumption that otherwise would have been served by generation resources and include such resources as energy efficiency and distributed generation in locations that have net metering. *Active demand resources* (i.e., demand response) reduce load in response to a request from the ISO for system reliability reasons or in response to a price signal. *Net metering* allows power customers who generate their own electricity, such as from wind or solar power, to feed their unused electricity back into the grid.
- 33** *ISO New England Energy-Efficiency Forecast Report for 2018 to 2023* (June 3, 2014), http://www.iso-ne.com/static-assets/documents/2014/08/eef_report_2018_2023_final.pdf.
- 34** The 34,195 MW 90/10 gross load for 2023 minus the 3,322 MW peak EE savings for 2023 equals the 30,873 MW net for 2023, which is 747 MW less than the 31,620 MW 50/50 gross forecast for 2023.
- 35** The *nameplate* value of a PV installation is the maximum rated output of the equipment. In general, the nameplate rating is a measure of a piece of equipment’s ability to produce or transmit electricity.
- 36** *Seasonal claimed capability* is a generator’s maximum production or output during a particular season, adjusted for physical and regulatory limitations. The actual value that the ISO uses in studies and the markets may vary from this number.

- 37** The net ICR values for 2014/2015 to 2017/2018 are the latest values approved by FERC and are available at <http://www.iso-ne.com/system-planning/resource-planning/installed-capacity-requirements>. *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.
- 38** OP 4 actions include allowing the depletion of the 30-minute and partial depletion of the 10-minute reserves (1,000 MW), scheduling market participants' submitted emergency transactions and arranging emergency purchases between balancing authority areas (1,600 to 2,000 MW), and implementing 5% voltage reductions (400 to 450 MW). Operating Procedure No. 4, *Action during a Capacity Deficiency* (December 9, 2011), http://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op4/op4_rto_final.pdf.
- 39** Higher tie-reliability benefits and reductions in the net ICR would increase the frequency and depth of OP 4 actions.
- 40** FCA #8 covers June 1, 2017, through May 31, 2018. 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.
- 41** Of this total, 2,431 MW consisted of five resources representing 1,535 MW from the Brayton Point Station, three resources representing 342 MW from Norwalk Harbor Station, and 554 MW of demand-response resources. *Static delist bids* for a resource must be submitted before the existing capacity qualification deadline, which occurs approximately eight months before an FCA. These delist bids are for resources opting to remove all or part of their total capacity from the market for a single commitment period at a price greater than or equal to \$1.00/kW-month.
- 42** 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.
- 43** The Capacity Carry Forward Rule addresses situations where a large resource meets a zonal need but eliminates any need for new resources in the subsequent auction (*Market Rule 1*, Section III.13.2.7.9). In the NEMA/Boston capacity zone, the Capacity Carry Forward Rule was triggered when a new source cleared in FCA #7, such that other new resources were not needed in subsequent FCAs.
- 44** FERC, *Order on Compliance Filing* (May 31, 2013), http://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2013/may/er12_953_002_5_31_13_order_accept_fcm_compliance.pdf.
- 45** The retirement of Brayton Point Station (1,535 MW) could trigger the need for modeling a Southeast Massachusetts/Rhode Island capacity zone in FCA #9.
- 46** 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.
- 47** *Spinning* operating reserves are on-line resources that can increase output. Nonsynchronized (i.e., *nonspinning*) operating reserves are off-line resources that can be electrically synchronized to the system quickly, reaching maximum output within 10 to 30 minutes.
- 48** 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.
- 49** *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.

- 50** Cost estimates without transmission cost allocation approval are subject to established variations as projects progress through various stages of implementation. The \$4.5 billion cost estimate has a range of \$3.7 to \$5.3 billion based on projects proposed, planned, and under construction. See the *Regional System Plan Transmission Projects June 2014 Update*, PAC presentation (June 19, 2014), slide 12, at http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/jun192014/a5_rsp14_project_list_update_final.zip.
- 51** The results of a study of the changes in transfer limits across major interactions in Maine, including Maine to New Hampshire, is available at *Maine Power Reliability Program (MPRP): Transfer Capability Study Results*, PAC presentation (December 13, 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/dec132012/mprp_transfer_limits.pdf. Also see *MPRP North to South Steady State Transfer Limits and Incremental Stability Performance Study*, final draft report (November 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/mprp_transfer_limits.pdf.
- 52** While natural gas units are generally in merit, the price of natural gas can spike relative to other fuels, as happened during the winter 2013/2014.
- 53** *Market Rule 1*, http://www.iso-ne.com/regulatory/tariff/sect_3/index.html. The ISO's AMR13, Section 2.1.4, contains additional information on the limited-energy generation provisions; http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf.
- 54** FERC, *Order Conditionally Accepting Tariff Revisions* (September 16, 2013), http://www.iso-ne.com/regulatory/ferc/orders/2013/sep/er13-1851-000_9-16-2013_winter_rel.pdf.
- 55** ISO New England Inc., *Docket No. ER14-___-000, Winter 2014-15 Reliability Program* (Parts 1 and 2), FERC filing (July 11, 2014), http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2407_000_win_rel_pro_7_11_2014.pdf and http://www.iso-ne.com/regulatory/ferc/filings/2014/jul/er14-2407-001_winter_rel_7-11-2014.pdf. Also see above footnote for FERC's September 10, 2014, order.
- 56** The Energy Market Offer Flexibility Rule will allow power supply offers to vary by hour in the Day-Ahead Energy Market, changes in Real-Time Energy Market bids until 30 minutes before the hour in which the offer applies, and negative offers in both markets as low as -\$150/MWh. For additional information on these market improvements, see the ISO's "Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency" (2013), http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf. Also, *ISO New England Inc. and New England Power Pool, Energy Market Offer Flexibility Changes*, FERC filing (July 1, 2013), http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13_1877_000_mkt_offer_flex_7_1_2013.pdf.
- 57** ICF International, *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short- and Near-Term Electric Generation Needs*, final report (June 15, 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/gas_study_ceii.pdf.
- 58** *2012 ISO New England Electric Generator Air Emissions Report* (January 2014), http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/emission/2012_emissions_report_final_v2.pdf. These changes in generation are consistent with New England fuel consumption in 2011 and 2012, as reported by the US Energy Information Administration (EIA). Coal consumption for electric generators fell from 3.0 million short tons in 2011 to 1.8 million short tons in 2012, and residual fuel oil consumption fell from 0.7 million barrels in 2011 to 0.3 million barrels in 2012.
- 59** In all communications, the ISO must adhere to the requirements of its Information Policy regarding the disclosure of confidential information. *ISO New England Information Policy* (ISO tariff, Attachment D) (2014), http://www.iso-ne.com/static-assets/documents/regulatory/tariff/attach_d/attachment_d.pdf.
- 60** *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.

- 61 ISO New England, *Wind Development in Constrained Areas*, PAC presentation (March 21, 2013), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2013/mar212013/a5_wind_development_in_constrained_areas_new.pdf, and the *STA Wind Integration Study* (2014).
- 62 *2011 Economic Study*, http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2014/2011_eco_study_final.pdf.
- 63 *2012 Economic Study*, http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2014/a9_2012_economic_study_final.pdf.
- 64 *The Hub* is a collection of 32 electric energy pricing locations in central New England where little congestion is evident.
- 65 *Market Resource Alternative Analysis—Demand-Side Results Greater Hartford and Central Connecticut Area*, PAC presentation (November 14, 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/nov142012/ghcc_mra_november.pdf, and *Market Resource Alternative Analysis—Final Supply-Side Results Greater Hartford and Central Connecticut Area*, PAC presentation (December 13, 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/dec132012/ghcc_mra.pdf.
- 66 ISO New England, NYISO, PJM, *2013 Northeast Coordinated System Plan* (April 16, 2014), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/othr/ipsac/mtrls/2014/mar282014/2013_ncsp.pdf. The protocol and supplemental materials and reports are available at <http://www.iso-ne.com/committees/planning/ipsac>.
- 67 ISO New England, *Transmission Planning Process Guide*, draft (February 5, 2013), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_process_guide/planning_process_guide_for_february_pac_2_5_2013_3_docx; *Transmission Planning Technical Guide*, draft (December 6, 2013), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/plan_guides/plan_tech_guide/planning_technical_guide_clean_12_06_2013.pdf.

