2019 Regional System Plan

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OCTOBER 31, 2019

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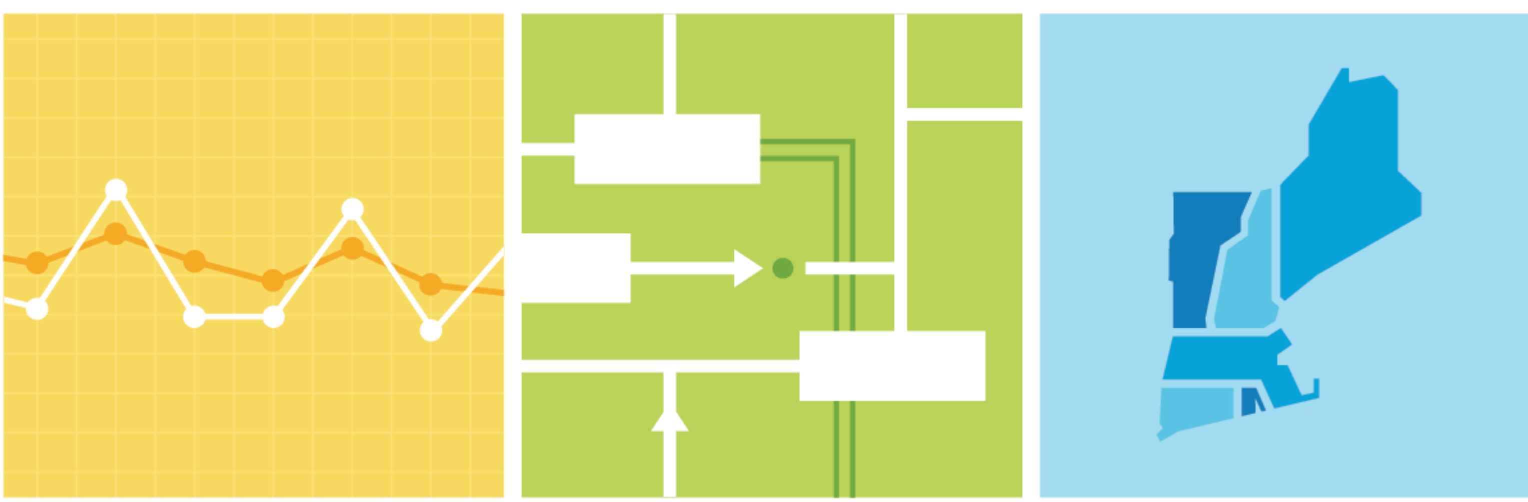

Preface

ISO New England Inc. (ISO) 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 periodic preparation of a 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* (the ISO tariff), approved by the Federal Energy Regulatory Commission (FERC). Regional System Plans meet the tariff requirements by summarizing planning activities that include 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 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.

RSPs also must summarize the ISO's coordination of its 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, RSPs identify 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.

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 appreciates the robust input provided by stakeholders, which makes this report possible.

The *2019 Regional System Plan* (RSP19) and the regional system planning process identify the region's electricity needs and plans for meeting these needs for 2019 through 2028. RSP19 updates the RSP17 report by discussing study proposals, scopes of work, assumptions, draft and final study results, and other materials. RSP19 also identifies key electric power system issues the region faces and how they can be addressed. RSP19 planning activities were reviewed at PAC meetings held from September 2017 through August 2019. The ISO also posted to its website PAC presentations, meeting minutes, reports, study base cases, databases, and other materials for stakeholder review and use. On August 8, 2019, the ISO and the PAC discussed stakeholder comments on an earlier draft of RSP19, and the ISO held a public meeting on September 12, 2019, to discuss RSP19 and other planning issues facing the New England region.

Through the planning process, the ISO demonstrates compliance with all planning criteria and regulatory requirements. As required by the OATT Attachment K, the ISO New England Board of Directors has approved the *2019 Regional System Plan.*

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Section 1
Executive Summary

Over the past 22 years, the ISO New England (ISO) region has benefited from the successful implementation of wholesale electricity markets and transmission planning and development, which have significantly enhanced system reliability and improved overall market efficiency. New England has the resource base and transmission system needed to meet consumer demand for power at competitive prices. However, challenges remain. The region now faces three key issues, which the ISO is addressing through a number of planning, operational, and market measures:

- **Energy security—**Although many projects for resource development have been proposed in the region, energy-security and reliability issues may arise from energy-production limitations associated with "just-in-time" fuel sources (i.e., natural gas); *variable energy resources* (VERs), like intermittent wind and photovoltaics (PV); and compliance with environmental regulations. In response, New England state policies and incentives for developing renewable resources, as well as energy efficiency (EE) and imports from neighboring regions, are helping offset regional natural gas demand. Additionally, the ISO, with stakeholder input, is working on near-term and long-term market improvements to expand the existing suite of energy and ancillary services that will cost effectively address uncertainties and supply limitations and enhance energy security.
- **Transmission development—**Transmission improvements are needed to maintain and enhance the reliability of the regional power system and support state policies to access remotely located sources of clean energy. Transmission plans are in place throughout the region to meet system needs.
- **Grid transformation—**The widespread addition of inverter-based technologies (which use power electronics to convert between alternating current [AC] frequencies or between AC and direct current [DC] frequencies) and distributed energy resources (most which the ISO cannot observe or control like traditional resources) would require transmission upgrades and control system improvements for reliably interconnecting these resources to the grid.[1] Structural changes to the transmission and distribution systems are being analyzed and implemented, and new procedures put in place, to help transform the grid and improve the reliable, economical, and environmental performance of the system overall.

New England is currently energy constrained, which remains the greatest reliability risk to the region. Variable energy resources and natural gas generators with infrastructure and operational limitations on their energy production are replacing nuclear, coal, and oil resources, which have backup fuel storage but are retiring. With its existing fuel infrastructure, New England has at times been challenged to meet electricity demands, particularly in winter. Given the shift in the resource mix, these challenges are likely to extend to all seasons longer term. During extreme cold periods, electricity needs have been met through a combination of generators using natural gas from pipelines and liquefied natural gas (LNG), but also, now-declining uses of nuclear, coal, and oil fuels. Although new incremental natural gas

[1] *Inverter-based technologies* include wind, photovoltaics resources, high-voltage direct-current (HVDC) facilities, battery energy-storage systems, and flexible alternating current transmission system (FACTS) devices, which can help regulate voltages and improve the stability performance of the system. *Distributed energy resources* (DERs) are sources and aggregated sources of electric power not directly connected to a bulk power system. DERs include generators (i.e., distributed generators) and energy-storage technologies capable of exporting active power to an electric power system.

generation is being added, the pipelines continue to have limited availability for electric power generators without firm gas contracts, potentially at any time of the year, for supporting the increased capability. Additionally, LNG deliveries to New England, which are influenced by economics and logistics, can be uncertain, and environmental permitting for new dual-fuel capability (typically, natural gas and oil) is becoming more difficult. Even when these units have permits, their run times for burning oil may be restricted to limit their air emissions, similar to existing oil generation and dual-fuel units.

The ISO has implemented near-term market and operational changes to address the region's energy-security risks, and is discussing long-term market solutions with stakeholders. The development of renewable resources, EE, energy storage, and imports and the continued investment in gas-efficiency measures will help mitigate these risks. Other solutions include enhancing operating procedures for confirming natural gas availability, improving communications and coordination with pipeline operators, and implementing a short-term fuel-security review for winter. Market changes under development could drive additional measures, such as firm contracts with gas suppliers to improve gas availability for power generation, the use of existing and new dual-fuel capability when gas supplies are limited, and adequate on-site storage and replenishment of liquid fuels to enhance dual-fuel power plant reliability.

The future reliable and economic performance of the system is expected to continue to improve as a result of approximately $1.3 billion of planned transmission upgrades over the next 10 years, much of which is in siting or under construction. The ISO has been identifying long-term system needs for the Boston area and plans to solicit competitive solutions for addressing these needs in accordance with FERC Order 1000 requirements.[2] Generator retirements, the integration of many distributed and grid-level resources, the use of inverter-based technologies, and issues rising from minimum-load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades.

The overall system is transforming to a cleaner, hybrid grid, with low system emissions and the widespread development of renewable resources, including onshore and offshore wind generation, energy efficiency, and PV.[3] Over the longer-term planning horizon, additional imports of Canadian hydroelectricity (hydro) and new technologies, such as smart meters, microgrids, and energy storage will likely continue the trend toward a cleaner, albeit more complex, system. The ISO closely monitors policy developments, which include the electrification of the transportation sector as well as heat-pump penetration anticipated to increase demand beyond the 10-year RSP19 forecast period.

The ISO has taken several actions to address the added complexities for real-time operations, regional planning, and the economic performance of the system brought about by grid transformation. State-of-the-art tools and analyses have improved demand, wind, and solar forecasting techniques and system models; methods for measuring the state of the system; system security; and the process for facilities to interconnect to the system. Economic studies have identified key issues with different resource portfolios for the region. For example, with transmission analyses, economic studies have shown that the large-scale development of wind resources in Maine would require considerable transmission expansion to serve demand in southern New England, and southeastern Massachusetts offshore wind resources would

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[2] FERC, *ISO New England Inc. Order on Compliance Filings* (May 17, 2013), https://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.

[3] A *hybrid grid* is a power system where large generators and other power resources connected to the regional transmission system meet electricity needs, in combination with thousands of small resources connected "behind the meter" (BTM) directly to retail customer sites or local distribution utilities.

require less transmission development. In addition, a number of wholesale market improvements promote resource responses, such as system flexibility, that facilitate grid transformation.

The ISO continues to work with stakeholders to improve the system and wholesale electricity markets and to address present and future regional challenges as the system becomes more difficult to forecast; supply resources, less controllable; and system operations, more complicated. For all RSP19 analyses, the ISO used a number of assumptions, discussed with the PAC, which are subject to uncertainty as the system evolves over the planning period and the markets are enhanced to accommodate public policy objectives. Changes in these assumptions could affect the results and conclusions of RSP19 analyses and ultimately influence the development of transmission and generation and demand resources. While each RSP is a snapshot in time, the planning process is continuous. As needed and appropriate, the ISO updates the results of planning activities by accounting for the status of ongoing projects, studies, and new initiatives.

1.1 Highlights and Key Results of the Regional System Plan

This section discusses the highlights of RSP19 and the results of various system and regional strategic planning studies and other materials. The RSP19 sections indicated below contain more details and links to definitions of terms and full citation information.

1.1.1 Forecasts of the Annual and Peak Use of Electric Energy, Energy Efficiency, and Photovoltaic Capacity and Energy (Section 3)

While the forecast methods used in RSP19 are generally similar to those used in RSP17, the ISO incorporated improvements to the models for peak demand and annual energy-use forecasts that better reflect peak-eliciting weather conditions. Historical loads, seasonal weather patterns, and economic and demographic factors drive the RSP19 forecasts of the gross peak and annual electric energy demand regionwide and in individual states and subareas. RSP19 also summarizes nameplate and energy projections of photovoltaic resources participating in the wholesale electricity markets as well as behind-the-meter (BTM) PV. In addition, RSP19 includes forecasts of energy-efficiency resources, which, with behind-the-meter PV forecasts, lower the gross forecasts of peak demand and annual use of electric energy. Although the ISO explicitly develops PV nameplate and energy-efficiency forecasts (see Sections 3.2 and 3.3), it fully considers all other BTM resources when developing its gross demand forecasts. The resultant net demand forecasts are key inputs for determining the region's resource-adequacy requirements for future years, evaluating the reliability and economic performance of the electric power system under various conditions, and planning needed transmission improvements.

Key Section 3 results are as follows:

- The 10-year net energy for load, accounting for both EE and PV, is projected to decrease from 125,823 gigawatt-hours (GWh) in 2019 to 121,336 GWh in 2028, which represents a decline of 0.4% per year. The RSP19 "50/50" net summer peak forecast is 25,323 megawatts (MW) for 2019, which declines to 24,408 MW for 2028.[4] The "90/10" net summer peak forecast, which

[4] A *50/50 peak load* has a 50% chance of being exceeded because of weather conditions, expected to occur in the summer in New England at a weighted New England-wide temperature of 90.2 degrees Fahrenheit (°F), and in the winter, 7.0°F. A *90/10 peak load* has a 10% chance of being exceeded because of weather conditions, expected to occur in the summer in New England at a weighted New England-wide temperature of 94.2°F, and in the winter, 1.6°F.

represents more extreme summer heat waves, is 27,212 MW for 2019 and declines by 0.3% per year to 26,576 MW in 2028.[5]

- The gross winter peak demand from 2019 through 2028 grows at 0.6% per year, but the net annual peak demand decreases by 0.6% per year as a result of EE additions throughout the region.
- Regional summer peak demand savings from energy efficiency are expected to grow from 2,913 MW in 2019 to 5,372 MW in 2028. New England states' annual investments in EE programs are expected to be more than $1 billion per year for 2019 through 2028. These EE investments remain a major factor in the expansion of passive demand resources in the region, which are projected to grow at an average rate of 273 MW per year across the 10-year horizon.
- All photovoltaic resources in the region reached 2,884 MWac in nameplate capacity by the end of 2018 and are expected to grow to 6,744 MWac by 2028. The estimated reductions in summer seasonal peak demand due to behind-the-meter PV resources are 708 MW (2,048 MW nameplate) in 2019 and 1,051 MW in 2028 (4,150 MW nameplate); BTM PV does not reduce winter peaks because they typically occur after the sun sets.
- The ISO is closely watching the preliminary strategic electrification initiatives implemented by the New England states to meet greenhouse gas (GHG) reduction mandates and goals. These initiatives are just beginning but are expected to promote the growth of emerging technologies, such as electric vehicles and air-sourced, cold-climate heat pumps. Depending in part on the timing and rate of their adoption, these new electricity uses will be important considerations in the long-term outlook for annual electric energy use and peak demand in the years beyond the RSP19 forecast period.

1.1.2 Projections of the Systemwide Need for Capacity and Operating Reserves (Section 4)

Sufficient resources are projected for New England through 2028 to meet the resource adequacy planning criterion, assuming no major retirements and the successful completion and operation of all new resources that have cleared the Forward Capacity Market (FCM). The planning analyses account for new resource additions that have responded to wholesale electricity market improvements, state policies, and known resource retirements. The ISO is committed to procuring resources through the FCM and expects the region to install adequate resources to meet the physical capacity needs that the Installed Capacity Requirements (ICRs) will define for future years.[6]

To date, resource-adequacy studies have shown that the most reliable and economic place for developing new resources is in the Northeastern Massachusetts (NEMA)/Boston and Southeastern Massachusetts/ Rhode Island (SEMA/RI) areas. This is due to recent and anticipated retirements of aging fossil generation and the projected load growth in these areas. Transmission improvements are underway in these areas, and new fast-start generation is under construction. This will help meet the regional and local capacity needs and improve system reliability, but delays in the construction or additional

[5] The actual gross demand has been near or above the 50/50 forecast 12 times during the last 27 years because of weather conditions; seven of these 12 times, the load has been near or has exceeded the 90/10 forecast.

[6] *Installed capacity* is the megawatt capability of a generating unit, dispatchable load, external resource or transaction, or demand resource that qualifies as a participant in the FCM according to the market rules.

retirements would make meeting local resource-adequacy requirements less certain.[7] Overall, the region is expected to experience more generating resource additions than retirements, and the ISO projects that adequate resources will be available to meet net ICR for the next 10 years.

Consistent with the resource-adequacy criterion and processes, the use of specific operator actions (e.g., Operating Procedure No. [OP 4], *Actions during a Capacity Deficiency*) may be necessary when resources are unavailable to serve demand.[8] Actual system conditions would affect the frequency and extent of OP 4 actions, in addition to the amount of resources procured to meet capacity needs and resource availability.

RSP19 summarizes operable-capacity analyses using projected systemwide demand forecasts and projected systemwide ICR values. During either extremely hot and humid 90/10 summer peak-load conditions or extremely cold winter conditions, the load and capacity relief to meet system needs could range from 1,150 MW to 2,500 MW during the study period. Although New England has adequate installed capacity to meet the winter peak demands, which are 6,000 MW to 7,000 MW lower than the summer peak demands, OP 4 actions may still be necessary during extreme cold weather. This is because the region relies on natural gas to fuel much of its generation, but sufficient fuel may not be readily available when the weather is cold. (See Section 1.1.5 that discusses the region's immediate concerns about winter energy-security issues, the availability of natural-gas-fired generators to produce energy, and the ISO's efforts to address these challenges over the long term.)

The region is expected to meet future representative operating-reserve requirements through 2023 for the system as currently planned. Fast-start resources with short lead times for project development and generators able to quickly ramp up can satisfy near-term operating-reserve requirements while providing operational flexibility to major load pockets and the system overall. Developers interconnecting and placing well-sized and economical resources within or near major load pockets to replace resource retirements would decrease the amount of reserves required within load pockets and reduce the reliance on transmission facilities. Transmission improvements can continue to help reduce or eliminate operating-reserve needs in the major import areas.

As of April 1, 2019, the ISO's Interconnection Request Queue (the queue) reflected 19,047 MW of proposed projects.[9] This includes an additional 11,316 MW of wind resources, 3,070 MW of large-scale PV, and 1,381 MW of battery storage to be interconnected to the New England power system. Offshore resources are being proposed off the southeastern New England coast, and proposed onshore wind resources are predominantly in northern New England.

The ISO improved the interconnection process and now offers a cluster study approach, which provides the means for considering multiple requests in the same study and allocating the costs of significant upgrades among the cluster participants in the interconnection queue. The first phase of the clustering process involves conducting a transmission planning study that identifies the transmission infrastructure

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[7] A *fast-start resource* can be electrically synchronized to the electric power system and reach its maximum production or output within 10 to 30 minutes to respond to a contingency and serve demand. It also can be a demand resource that helps with recovery from a contingency and assists in serving peak demand.

[8] The analysis showed that even with the region meeting ICR, ISO New England would require the use of Operating Procedure No. 4, *Actions during a Capacity Deficiency,* (May 7, 2019), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

[9] All resources seeking interconnection are unlikely to be built. Some projects will withdraw after receiving the interconnection study results or may chose not to pursue their project for other reasons, such as financing issues, the need for significant transmission reinforcements, or the lack of a state contract. Also, some projects chose to submit multiple interconnection requests because they have not decided on a specific interconnection point, which ultimately will require the withdrawal of the interconnection request not being pursued.

and associated system upgrades necessary to enable the interconnection of up to all proposed resources in a particular geographic area. The second phase specifies transmission facilities required to interconnect the resources showing interest in transmission cost sharing and meeting other requirements. To date, the ISO completed a cluster study for proposed resources in northern and western Maine. A second cluster study for resources in that same area is underway and anticipated to be completed by the fourth quarter of 2019. Even with the cluster approach, remote resources would require considerable transmission improvements, which may be costly to build, to be well integrated with the demand centers in southern New England.

1.1.3 Transmission System Needs, Solutions, and Cost Considerations (Section 5)

In large measure, as a result of transmission expansion in New England, the region has maintained a high level of reliability and resiliency; the dispatch of more efficient generating units, which reduces the need for out-of-merit unit commitment; and lower wholesale market costs. The low growth of net peak demand and changes to the assumptions used in needs assessments has reduced the overall need for major additional reliability-based transmission projects over the planning horizon. The development of FCM resources in appropriate zones also has deferred the need for major new projects. Drivers of needed transmission improvements include the following:

- Resource retirements
- Anticipation of light-load operating conditions
- Integration of inverter-based technologies
- Need to upgrade aging infrastructure
- Compliance with evolving Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Corporation (NERC) requirements

More sophisticated modeling is now under development to better reflect the dynamic characteristics of generators and load and the expansion of distributed resources, which will inform future transmission needs.

1.1.3.1 Transmission Planning Process, Criteria, and Assumptions

The ISO's regulatory requirements continue to change significantly, along with the associated processes, national and regional criteria, and assumptions used in long-term reliability assessments. On April 18, 2018, FERC completed an audit of ISO New England's compliance with Order 1000 as it relates to transmission planning and expansion and interregional coordination for July 10, 2013, through June 30, 2017.[10] The ISO successfully passed this audit, with no findings of noncompliance. ISO system assessments and processes also demonstrate full compliance with NERC and NPCC requirements for meeting resource adequacy and transmission planning criteria and standards.[11] In addition, the planning processes reflect requirements of NPCC's classification of the bulk power system (BPS).[12]

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[10] FERC, *Audit of ISO New England, Inc.'s Compliance with its Transmission, Markets, and Services Tariff; and Commission Accounting, Reporting, and Record Retention Requirements,* final (April 18, 2018), https://www.iso-ne.com/static-assets/documents/2018/04/pa16-6-000_4-18-18_final_audit_report.pdf.

[11] In 2018, ISO New England participated in the NPCC Internal Control Evaluation investigation. On the basis of the ISO's demonstrated internal controls, NERC removed the planning standards from the scope of its June 2018 on-site audit of the ISO.

[12] ISO New England, "Updates to System Studies," memorandum (February 24, 2017), https://www.iso-ne.com/static-assets/documents/2017/02/updates_to_system_study_memo.pdf, and *Updates to System Studies*—

FERC Order 1000 requires the ISO to solicit competitive proposals for reliability projects not needed within or at three years after a system need has been identified; for market-efficiency projects; or if federal, state, and local public policies drive transmission needs.[13] The ISO plans to use the competitive solution process to solve the non-time-sensitive, thermal violations identified for peak load conditions in the Boston area after the preferred solution to solve short-term, minimum-load, voltage violations has been selected.[14] The ISO anticipates issuing its first request for proposals (RFP) to solicit competitive bids from qualified transmission project sponsors by early 2020. The Order 1000 process for planning for public policy was used for the first time in 2017 and is scheduled to begin again in 2020.

The ISO periodically updates the transmission planning processes and assumptions to reflect all requirements. The *Transmission Planning Process Guide* describes the existing regional system planning process and how transmission planning studies are performed, as described in Attachment K of Section II of the *ISO New England Transmission, Markets and Services Tariff* (the tariff), including compliance with FERC Order 1000 requirements.[15] The *Transmission Planning Technical Guide* references the current standards and specifies the criteria and assumptions used in transmission planning studies and new methodologies regarding the study assumptions using probabilistic methods.

In addition, the region meets the ISO's Planning Procedure No. 3 (PP 3), *Reliability Standards for the New England Area Pool Transmission Facilities* and other requirements that ensure the reliability of the New England pool transmission facilities (PTFs) through coordination of system planning, design, and operation.[16]

1.1.3.2 Transmission Upgrades

Reliability transmission upgrades have resulted in significant market-efficiency benefits by reducing congestion and out-of-merit operating costs. Thus, to date, the ISO has not identified the need for separate market-efficiency transmission upgrades (METUs), primarily designed to reduce the total net production cost to supply the system load. Many new elective transmission upgrades (ETUs) have been proposed, which focus on delivering zero- or low-carbon resources to New England. As of June 1, 2019, 17 projects are under study as ETUs, and three have received their proposed plan application approval. Additionally, the development of economic and fast-start resources in response to the ISO's wholesale electricity markets has helped reduce congestion and Net Commitment-Period Compensation (NCPC).[17] The 2018 total for congestion resulting from transmission constraints was $64.5 million, and the total for

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Incorporating Changes in Criteria and Assumptions into Ongoing Assessments, presentation (March 22, 2017), https://www.iso-ne.com/static-assets/documents/2017/03/a4_updates_to_system_studies.pdf.

[13] FERC Order 1000 preserves the status for incumbents of both proposed and planned projects on the ISO's Regional System Plan project list as of May 18, 2015. FERC, "Order No. 1000—Transmission Planning and Cost Allocation," website (October 26, 2016), https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

[14] ISO New England, *Open Access Transmission Tariff*, Attachment K, Section 4.3, "Competitive Solution Process for Reliability Transmission Upgrades and Market-Efficiency Transmission Upgrades" (January 29, 2019), https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

[15] The latest versions of the ISO New England, *Transmission Planning Process Guide* and *Transmission Planning Technical Guide* are available at https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides.

[16] ISO New England, Planning Procedure No. 3, *Reliability Standards for the New England Area Pool Transmission Facilities* (September 15, 2017), https://www.iso-ne.com/static-assets/documents/2017/10/pp3_r8.pdf.

[17] NCPC is a make-whole (i.e., *uplift*) payment to a supply resource that responded to the ISO's dispatch instructions but did not fully recover its start-up and operating costs in either the Day-Ahead or Real-Time Energy Markets.

voltage and second-contingency NCPC was $17.7 million, of the $9.8 billion total wholesale electricity markets in 2018.[18]

In 2019, the ISO received a study request to perform an economic evaluation of the potential benefits of upgrading the Orrington-South export interface in Maine. After discussing the findings with stakeholders, the ISO will determine whether or not the savings in production costs would be sufficient to move forward with a METU needs assessment to evaluate the benefits of improving access to renewable resources in the northern part of that state.

RSP19 does not identify the need for any public policy transmission upgrades, consistent with the planning process and the requests of all six New England states.

1.1.3.3 Project Updates

From 2002 through June 2019, 801 transmission project components have been placed in service across the region; another 67 project components have a status of planned, proposed, or under construction. Overall, the estimated investment in New England to maintain reliability was $10.9 billion from 2002 to June 2019, and another $1.3 billion is planned over the planning horizon. Since the publication of the *2017 Regional System Plan*, the following major projects have been completed or are near completion:[19]

- A +/- 200 MVAR static synchronous compensator (STATCOM)—a flexible alternating current transmission system (FACTS) device—has been added in Maine to provide dynamic voltage control. Other FACTS devices have been added throughout the system associated with wind resource interconnections.
- The Maine Power Reliability Program (MPRP) included the addition of significant new 345 kV and 115 kV transmission lines and new 345 kV autotransformers at key locations in Maine. All upgrades were placed in service by December 2018.
- The New Hampshire/Vermont 2020 Upgrades included the addition of a new 345/115 kV autotransformer, a new 230/115 kV autotransformer, several new 115 kV transmission lines, upgrades and rebuilds of several existing 115 kV lines, and several reactive device additions and substation upgrades. Most of the New Hampshire/Vermont 2020 Upgrades are in service with the exception of a new 115 kV line between Madbury and Portsmouth, NH, which is anticipated to be in service in May 2020.
- The Connecticut River Valley Upgrades in Vermont included the rebuild of a 115 kV transmission line and the rebuild of a 115 kV station. The project also featured a +50/−25 MVAR static VAR compensator (SVC), which is a FACTS device. All upgrades were placed in service by November 2018.
- The Greater Hartford Central Connecticut (GHCC) 2022 Upgrades included the addition of two new autotransformers and 115 kV upgrades, including reconductoring lines, installing new lines, separating double-circuit towers (DCTs), rebuilding two stations, and adding reactive support to maintain voltage. Several of the projects within the GHCC suite of projects are already in service, and all the components of the preferred solutions are expected to be in service by December 2019.

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[18] The negative $64.5 million congestion total for 2018 was due to export-constrained supply areas, predominantly in northern Maine and northern New York, primarily driven by system-outage conditions.

[19] ISO New England, *2017 Regional System Plan* (November 2, 2017), https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

- The Southwest Connecticut (SWCT) 2022 Upgrades included all 115 kV upgrades, such as rebuilding and reconductoring lines, installing new lines, rebuilding two stations, and adding reactive support to maintain voltage. Several of the projects within this suite of projects are already in service, and all the components of the preferred solutions are expected to be in service by September 2020. Due to the addition of several new generators clearing in the FCM, a follow-up to the 2022 needs assessment was performed (2025 Update). These update results showed that three transmission solutions identified in the 2022 Upgrades were no longer required and were subsequently canceled.
- The Pittsfield and Greenfield 2022 Upgrades included adding a new 345/115 kV autotransformer, adding reactive support to control voltage on the 345 kV system, adding a new 115 kV station, rebuilding a 115 kV station, rebuilding and reconductoring 115 kV lines, installing a new 115 kV line, separating 115 kV double-circuit towers, and adding reactive support to maintain voltage on the 115 kV system. All the projects within the Pittsfield and Greenfield suite of projects are already in service with the exception of a 115 kV station at Pochassic (in Westfield, MA), and a new 115 kV line between Pochassic and Buck Pond, also in Westfield, which will be placed in service by June 2020.

Improvements have been identified for both SEMA/RI and Greater Boston, and their associated development and construction are underway. These reliability upgrade projects will bolster the 345 kV and 115 kV facilities of the New England transmission system. A needs assessment has been completed for Boston, which identifies time-sensitive concerns under minimum load and also non-time-sensitive thermal overloads and system restoration concerns due to the retirement of the Mystic generators. The ISO is updating the Maine, New Hampshire, Western and Central Massachusetts, and Eastern Connecticut area studies to reflect the revised study assumptions and processes.

Because of the general age of the transmission system in New England, many assets across the system are reaching their end of life and are requiring replacement or refurbishment. Spending by transmission owners to address these concerns has increased over the past few years.[20] In addition, enhancements to existing substations are needed to meet NERC's physical and cybersecurity standards.[21]

1.1.4 Interregional Planning Requirements and Activities (Section 6)

Interconnections with neighboring systems provide access to capacity and energy and reduce emissions by generators within the New England area. The interconnections continue to support regional reliability and the economic operation of the system. The ISO fully reflects the energy and capacity import capabilities of the interconnections in its planning studies.

Through the Northeastern ISO/RTO Planning Protocol, ISO New England coordinates interregional studies, including interconnection queue studies, and satisfies interregional planning requirements under Order 1000.[22] ISO New England, the New York ISO (NYISO), and PJM presented system needs to the

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[20] A PAC presentation is required for all asset-condition-related work where the cost estimate is greater than or equal to $5 million. The "New England Asset Management Key Study Area" webpage (2019) is a repository to store all asset-condition-related PAC presentations; see https://www.iso-ne.com/system-planning/key-study-areas/new-england-asset-management/.

[21] NERC, *Reliability Standards for the Bulk Electric Systems of North America*, Standard CIP-014-2, *Physical Security*, (updated April 17. 2019), https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf.

[22] PJM (the Regional Transmission Operator 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

Interregional Planning Stakeholder Advisory Committee; none of the entities or their stakeholders identified new interregional transmission facilities that may be more efficient or cost-effective solutions to these regional needs.

Planning activities also occur under the NPCC, NERC, and the Eastern Interconnection Planning Collaborative (EIPC), which identify key issues and coordinate planning studies over wide areas. Several interregional studies quantify some of the reliability risks New England faces resulting from its high dependency on natural-gas-fired generation. Other interregional activities identify key issues that must be addressed to successfully integrate inverter-based resources, such as the frequency response of the system.

1.1.5 Energy-Security-Related Risks to System Reliability and Solutions (Section 7)

While fuel constraints during cold periods initially brought energy-security concerns to light, in the longer term, these risks may emerge whenever fuel constraints or uncertainties limit energy production, regardless of season. Although the region is projected to have sufficient resources to meet capacity requirements and enough transmission facilities to meet reliability criteria, as the region's resource mix evolves, the ISO is concerned that the region's energy security could deteriorate.

The need for the region to take actions, as well as the results of several interregional and ISO studies, show the extent of these top reliability risks to New England. In response, the ISO implemented near-term market and operational improvements and continues developing longer-term solutions to ensure that system reliability can be sustained.

1.1.5.1 Regional Dependence on Natural Gas as the Primary Fuel

New England relies on natural gas as a primary fuel for generating electric energy and is decreasing its reliance on oil and coal. The high regional use of natural-gas-fired generation reflects the addition of new, efficient natural-gas-fired units over the past 20 years; the generally low price of natural gas; and the greater ease with which these new, efficient units can comply with emissions requirements. This change in the fuel mix reduces the economic dispatch of older, less efficient oil- and coal-fired units. The recent retirements of non-natural-gas-fired generation, including nuclear units, further increases the regional dependence on natural-gas-fired generation.

Natural-gas-fired generation's proportion of the system capacity mix is expected to grow from 49.5% in 2019 to approximately 54.4% by 2023 but decrease to 48.6% by 2028. Further retirements of coal and oil generators are expected over the next 10 years due to generally low natural gas prices, renewable energy additions, and pending environmental regulations. The Pilgrim nuclear plant in Massachusetts retired in 2019. Although renewable resources are anticipated to grow over the long term, the ISO expects natural gas resources to continue to set the marginal price for wholesale electricity in most hours over the planning horizon.

1.1.5.2 The Energy-Security Risk

The region's reliance on the natural gas fuel-delivery system, however, exposes the regional electric power system to potential reliability problems, energy-security risks, and an associated increased cost of electricity when natural gas prices are high, even as New England's reliance on natural gas as a primary

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Columbia), ISO New England, and the New York ISO follow the *Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol* (July 13, 2015) to enhance the coordination of their planning activities and address interregional planning issues as part of regional compliance with FERC Order 1000; see https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/othr/ipsac/rto_plan_prot/planning_protocol.pdf.

fuel for generating units is projected to grow. This is the result of limited gas pipeline capacity and transportation infrastructure in New England, largely built to serve natural gas customers other than electric power generators. Pipelines can be constrained any time of the year, but extreme cold-weather conditions and the subsequent heavy demand for residential heating needs fueled by natural gas can exacerbate regional energy-security issues.[23] Fuel must be readily available in adequate amounts, and timely deliveries of fuel replenishments are required, particularly when electric power imports from neighboring regions may not be available.

Liquefied natural gas deliveries are also subject to risk. LNG is a global commodity imported to New England and the Canadian Maritime provinces by ocean tanker that must be contracted for in advance. The arrivals of spot LNG cargoes depend on global prices and vary monthly and from year to year; they also supply the entire Northeast—not just New England generators. Constraints on the regional gas supply (pipeline gas and LNG) also result in higher spot prices for the limited amounts of natural gas capacity available to generators within the New England region.

Renewable resources play a valuable, but limited, role in offsetting natural gas consumption (see Sections 7.6 and 9.3); they may not be available during extreme weather conditions or be able to respond to emergencies on the system. ISO operating experience and the US Department of Energy (DOE)'s National Renewable Energy Laboratory (NREL) data show that wind resources reduce to 0 MW output during very high or low wind speeds, and PV production is considerably reduced during cloudy conditions. Wind speeds are variable, creating a need for natural-gas-fired generators that can ramp up and down quickly to balance fluctuations in supply or demand. The ISO can neither "see" nor dispatch most PV, and none of it helps meet peak winter demand, which happens after the sun has set. Moreover, winter conditions, with snowfall and fewer daylight hours, also dampen solar output.

Limited access to dual-fuel capability across the region and restrictions on oil-fired generation also can exacerbate energy-security issues. Environmental air-emissions permitting for dual-fuel capability is becoming more difficult, and energy production by units burning oil is restricted. These concerns were realized during a cold snap from late December 2017 until early January 2018. During this period, natural gas demand spiked, and in accordance with standard procedures, natural gas pipelines reduced supply to natural-gas-fired generators. Several generators burned oil, and the ISO was actively monitoring the depleting oil inventory to maintain reliability. Fortunately, regional demand was met during the cold snap.

1.1.5.3 Working toward a Solution

NERC has formed an Electric-Gas Working Group to develop guidelines for assessing interdependency concerns between the natural gas sector and electric power system. The group will identify new simulation methods and best practices for dealing with energy-security issues. An NPCC study showed that contingencies on the natural gas pipeline system could result in the loss of natural gas-fired generating units in New England. However, the ISO would have sufficient time to prevent cascading electrical outages because the generators would trip sequentially rather than simultaneously. The study also identified the benefits of increased LNG and oil fuels for generating units, which could be achieved more readily through firm fuel contracts. In 2017, the ISO conducted a fuel-security study that examined the effects of various generating resource and fuel-mix combinations in the 2025 timeframe on reliable winter operations of the power system. The results for this study showed that energy security is

[23] Potential causes for pipeline constraints include high demand, failures and maintenance conditions, and other unexpected system conditions.

enhanced with an increase in the availability of LNG, dual fuels, renewables, and imports from neighboring regions.

For well over a decade, the ISO has worked closely with the natural gas industry to improve coordination between gas and electricity sector operations and communications. Contracts for natural gas and oil are among the options in which generators could invest to satisfy performance requirements in the capacity market. Infrastructure build-out by gas suppliers, including LNG or compressed natural gas (CNG) storage would also benefit the New England system.

The recent expansions of natural gas pipelines were meant to serve local gas distribution company loads but at times can somewhat help the electric power sector. Several minor expansion projects were or are planned to be commercialized in the near term, bringing the total net contracted transportation capacity into New England to 3.59 billion cubic feet/day (Bcf/d) by November 2020. The realization of other pipelines in various stages of planning and siting seems unlikely, although their development would improve the availability of natural gas to generating units.

The ISO improved its situational awareness through surveys of generating units that inform system operations of fuel restrictions and environmental constraints that could limit energy production. The ISO also projects energy market costs and provides them to generating units, which incents them to procure fuel and generate when most needed. Longer term, the energy-security initiative is identifying market improvements directed at three measures: [24]

- Strengthening generation owners' financial incentives to undertake more robust supply arrangements, when cost effective, while not prescribing what form these supply arrangements may take
- Rewarding resources' flexibility that helps manage and prepare for energy-supply uncertainties during the operating day, given the increasingly just-in-time nature of the power system's fuel supply
- Efficiently allocating electricity production across multiple days from resources that have limited stored energy sources

Building on the region's competitive wholesale electricity structure, the ISO is proposing rule changes that will help signal, through transparent market prices, the costs of operating a reliable power system as the profile of resources comprising the New England fleet continues to evolve.

1.1.6 Existing and Pending Environmental Regulations, Emissions Analyses, and Other Studies (Section 8)

Existing and pending federal, regional, and state environmental regulations may require generators to consider adding air pollution control devices; modifying or reducing water use and wastewater discharges; and, in some cases, limiting operations. The actual compliance timelines and costs will depend on the timing and substance of the final regulations and site-specific circumstances of the electric generating facilities, but uncertainty and risks of delay for permitting and operations may effect generators and transmission facilities. The integration of various types and amounts of renewable resources may require operational modifications or retrofits at existing fossil generators to provide flexible operation, resulting in additional environmental compliance costs. Based on these and other

[24] ISO New England, *Energy Security Improvements*, discussion paper (April 2019), https://www.iso-ne.com/static-assets/documents/2019/04/a00_iso_discussion_paper_energy_security_improvements.pdf.

economic factors, some generator owners may determine certain resources are uneconomical and retire their facilities instead of making major investments in environmental compliance measures.

The New England states have targets for developing renewable energy supplies and energy efficiency and reducing carbon emissions, resulting in 14,386 MW of solar and wind resources in the ISO's interconnection queue, as shown in Section 4.5.3.1. To further help meet the region's environmental targets, the southern New England states have individually and collectively contracted for offshore wind resources and a new tie to Hydro-Québec intended to deliver hydro power, as discussed in Section 10.2. The long-term growth of demand resources, energy storage, microgrids, and electrification of demand is also anticipated as a means of lowering carbon emissions to meet state targets.

Regional generator air emissions remain relatively low compared with historical levels, due to the generation fuel mix, including—in order of the percentage share of 2017 annual energy production—natural gas, nuclear, hydro, wind, other fuel type (landfill gas, methane, refuse, solar, steam, and wood), oil, and coal. Higher emissions, however, occur during the winter months because of coal and oil use by generators when natural gas is more expensive or in limited supply. The retirement of nuclear units would tend to increase regional emissions, but the addition of low- or zero-emitting resources would tend to reduce emissions in the long term.

1.1.7 Grid Transformation (Section 9)

Environmental laws, regulations, policies, and targets; economics; and a desire for grid resiliency continue transforming the electric power grid into one that uses increasing amounts of renewable resources, imports from neighboring regions, and FACTS technologies. All the changes to the resource mix and transmission system present physical challenges to planning and operating the electric power system that must be addressed. Energy production's dependence on variable energy resources, coupled with the ISO's reduced ability to observe and control distributed energy resources, increases the need for a flexible system response, including additional voltage regulation, ramping, regulation, and reserves. High amounts of inverter-based technologies present protection and control issues. The growth of DERs means that the distribution system will be operated in new ways, and interactions with the transmission system will become increasingly important. High-voltage, direct current (HVDC) and FACTS applications present opportunities for improving system performance, but technical issues must be addressed to ensure their successful operation and planning.

1.1.7.1 Industry Studies

Studies and whitepapers by the US Department of Energy, Electric Power Research Institute (EPRI), NERC, EIPC, and NPCC have helped frame many of the grid-transformation issues and have suggested how to address them, such as through the following actions:

- Improved coordination of operations and planning between the transmission and distribution grid operators
- Enhanced situational awareness by better forecasting variable energy resource production and demand response, using phasor measurement units and new methods of estimating the state of the system, analyzing operational security, and planning system improvements for reliability
- The addition of flexible resources, including batteries and other types of storage resources, demand response, and specific controls in inverter-based resources
- Modern interconnection standards for wind and distributed energy resources that minimize the adverse effects on transmission system performance by reflecting voltage and frequency ride-

through characteristics and allowing for "smart-inverter" interconnections, which can provide ancillary services[25]

- Adaptive protection and control-system upgrades that perform under variable short-circuit conditions
- Smart-inverter applications can provide ancillary services, increase hosting capacity of DERs, improve power quality, provide voltage regulation, and enhance overall system resiliency and economic performance. Applications of this technology exist, further improvements are underway, and barriers to applications are being overcome.
- Engagement with professional organizations, such as the Institute of Electrical and Electronics Engineers (IEEE), International Council on Large Electric Systems (CIGRE), and the Power Systems Engineering Research Center (PSERC), as well as EPRI, DOE, and other agencies, which provide forums for educating the technical and nontechnical communities

1.1.7.2 ISO Actions

In addition to participating in professional organization activities, the ISO has taken a number of other actions to address technical issues associated with transforming the grid, and it continuously explores new methodologies and tools for analyzing the system and developing solutions to the challenges presented. Regional stakeholder groups have improved the coordination between the transmission and distribution systems, and a special PAC meeting held in May 2019, with presentations by industry leaders, discussed the physical, business, and regulatory issues of grid transformation.[26] Situational awareness, which is vital for the ISO's system security calculations, has improved through the following measures that reflect industry recommendations:

- Periodic surveys of distribution owners that identify the amounts and locations of PV
- Application of phasor measurement units to provide key system information, improve state-estimation calculations, and enhance system models
- Use of state-of-the-art, short-term forecasting tools that provide expected outputs of PV and wind generating units

The ISO has also improved planning processes and study methodologies for assessing the expected impacts of emerging technologies associated with the strategic electrification initiatives of the New England states. The addition of a clustering approach in the ISO's interconnection procedures is facilitating the addition of new resources, including wind generation projects. Improved models of wind and PV are better reflecting anticipated system performance, and the use of high-speed cloud computing facilitates and expedites studies.

The ISO also has adopted a number of practices to ensure the reliable integration of new inverter-based resources, including the use of advanced models that capture device performance and the confirmation of appropriate ride-through and response capabilities of wind generators, large-scale PV, and DERs. The ISO actively participates in developing industry standards, including IEEE 1547—*Standard for the*

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[25] *Ride-through capabilities* greatly improve system reliability by preventing the likelihood of widespread trips of variable and distributed resource interconnections, which could result in unacceptable system performance during contingency events on the transmission and distribution systems.

[26] Presentations made at the ISO's May 23, 2019, Grid Transformation Day are available at https://www.iso-ne.com/committees/planning/planning-advisory/?eventId=137649.

Interconnection of Distributed Resources with Electric Power Systems, which ensures that increased amounts of PV can be reliably and economically interconnected to the distribution system.[27] In 2018, the New England states adopted the voltage and frequency ride-through provisions of the final approved IEEE Standard 1547-2018. The testing standards for inverters are scheduled for revision no earlier than 2020.

Changes in the ISO's administration of the wholesale electricity markets, as follows, have improved operational security and flexibility:

- Do-not-exceed dispatch for VERs, which enhances system reliability and reduces the extent of spilled resources[28]
- Fast-start pricing that encourages increases in generation outputs, which meet ramping requirements that occur later in the afternoon
- Negative pricing in the energy markets, which reduces overgeneration on the system
- Improved models of PV, which are reflected in ICR calculations
- Price-responsive demand resources, which provide price elasticity in the energy market
- Recognition of the physical and operational characteristics of all types of electric-storage resources that better facilitate their participation in the markets and can be coupled with variable energy resources to improve consistency of supply

1.1.7.3 ISO Studies and Results

Economic studies provide a common framework for stakeholder discussions on several issues facing the New England region and the need for physical infrastructure and improvements to the wholesale electricity markets.[29] For example, economic studies inform policymakers of the potential benefits of transmission expansion to support the delivery of wind energy. The ISO participates in many studies and has conducted several that have shown how the large-scale development of renewables in the region affects system performance. The ISO's 2016 Economic Study examined six different scenarios for 2025 and 2030, which showed the following results:[30]

- Natural gas will remain an important source of fuel for electric power generators.
- The development of resources near load centers, such as southern New England, and at retired generation sites generally requires little transmission development. Conversely, significant transmission investment will be required to incorporate large amounts of renewable energy resources well exceeding demand in load centers or areas further from load centers.

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[27] An abstract of *1547-2003—IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems* is available at http://ieeexplore.ieee.org/document/1225051/?reload=true (2017).

[28] *Spilled* renewable resources are those that must reduce output to respect system constraints and can include imports from Canada, hydro, wind, and photovoltaics.

[29] ISO New England economic studies are available at the Planning Advisory Committee webpage using the "Document Type: filter: https://www.iso-ne.com/committees/planning/planning-advisory/?document-type=Economic Studies.

[30] ISO New England, 2*016 Economic Study: NEPOOL Scenario Analysis—Implications of Public Policies on ISO New England Market Design, System Reliability and Operability, Resource Costs and Revenues, and Emissions* (November 20, 2017), https://www.iso-ne.com/static-assets/documents/2017/11/final_2016_phase1_nepool_scenario_analysis_economic_study.docx.

- The large-scale development of renewable resources could increase spillage even with transmission system upgrades, especially during shoulder seasons.
- Meeting carbon-emission targets may prove challenging for the New England region without the widespread development of renewable resources, EE, and interconnections with neighboring systems.

Supplemental studies of the 2016 Economic Study assessed several market and operational issues. For each of the original scenarios, the supplemental analysis examined the following:[31]

- Representative Forward Capacity Auction clearing prices, which showed the need for additional revenue streams outside the wholesale electricity markets for capacity and energy. Scenarios that added renewables resulted in the greatest revenue shortfalls for all resource types given the higher cost of new entry for renewables and depressed energy market revenues.

- The ability of the natural gas system to supply fuel to generators, which showed an inability to satisfy the installed capacity of all natural-gas-fired generating units across the six resource-expansion scenarios
- Changes in the amounts of regulation, ramping, and reserves, which showed the advantages of dispatching more flexible resources, having the ability to dispatch wind and PV resources down, and forecasting accurate quantities of wind generation, PV, and demand

The results of the ISO's 2017 Economic Study, which built upon the 2016 Economic Study, reinforced the above technical results.[32] While the ISO did not conduct an Economic Study in 2018, it did analyze scenarios of offshore wind expansion under conditions experienced during the 2017/2018 cold spell. The results show that wind generation would have reduced production costs, environmental emissions, fossil fuel consumption by generating units, and locational marginal prices. Economic studies for 2019 are currently underway to address issues with offshore wind development and constraints experienced by onshore wind facilities.

1.1.8 Multistate and State Initiatives that Affect System Planning (Section 10)

The ISO continuously works with a wide variety of policymakers and other regional and interregional stakeholders on initiatives that influence electric power system planning. These groups include the New England Conference of Public Utilities Commissioners (NECPUC), the New England States Committee on Electricity (NESCOE), the Coalition of Northeastern Governors, the Consumer Liaison Group (CLG), and others. Each New England state has a unique set of energy policy objectives and goals and continues to implement laws, policies, and initiatives that affect regional system planning in New England.

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[31] Amro Farid, *2016 Economic Study Phase II: Regulation, Ramping, and Reserves—Scenario Results* (Thayer School of Engineering, Dartmouth College, December 20, 2017), https://www.iso-ne.com/static-assets/documents/2017/12/a2_2016_economic_study_phase_2_ramping_regulation_reservers_scenario_results.pdf; Todd Schatzki and Christopher Llop, *Overview of Report: Capacity Market Impacts and Implications of Alternative Resource Expansion Scenarios* (Analysis Group, May 17, 2017), https://www.iso-ne.com/static-assets/documents/2017/05/a4_2016_economic_study_capacity_market_impacts_and_implications_of_alternative_resource_expansion_scenarios.pdf; and ISO New England, *2016 Economic Study Results: Peak-Gas-Day/Hour Capacity and Energy Analysis* (May 25, 2017), https://www.iso-ne.com/static-assets/documents/2017/08/a3_2016_economic_study_natural_gas_capacity_and_energy_analysis_rev1.pdf.

[32] ISO New England, *2017 Economic Study: Exploration of Least-Cost Emissions-Compliant Scenarios* (October 29, 2018), https://www.iso-ne.com/static-assets/documents/2018/10/2017_economic_study_final.docx.

1.2 Key Findings and Conclusions

The *2019 Regional System Plan* identifies system needs, and plans for meeting these needs, for 2019 through 2028. RSP19 also discusses risks to the regional electric power system; the likelihood, timing, and potential consequences of these risks; and mitigating actions. Some of the highlights of RSP19, as discussed in Section 11, are as follows:

- Forecasts of the regional net peak and annual energy show negative growth resulting from the additions of PV and EE, along with other BTM resources, which are reflected in the planning processes. Growth of net peak demand, thus, is not a key driver of new infrastructure needs over the 10-year planning horizon. Longer term, the electrification of transportation and heating/cooling load is expected to increase system loads.
- Needed capacity and operating reserves are provided through the wholesale markets. Studies of expected system conditions show that developing new resources near load centers, particularly in NEMA/Boston and SEMA/RI would provide the greatest reliability benefit. To the extent well-sized and placed cost-effective resources were developed to more closely match demand, the system would perform more reliably, require fewer transmission upgrades, and exhibit less congestion.
- Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of inverter-based resources, and changes to mandatory planning criteria promulgated by NERC and NPCC will likely drive the need for longer-term transmission projects.
- Revisions to the ISO planning processes now reflect FERC Order 1000 requirements, probabilistic study assumptions, and changes to national and regional criteria. Coordinated planning activities with other systems will continue growing, particularly to provide access to a greater diversity of resources, including hydro imports and variable energy resources, and to meet environmental compliance obligations.
- The regional reliance on natural-gas-fired generation, coupled with natural gas pipeline constraints and uncertain LNG deliveries can pose reliability issues and lead to price spikes in the wholesale electricity markets any time of the year. The ISO and interregional organizations assessed these risks in a number of energy-security studies, and the ISO took a number of actions to improve the overall reliable and economical operation of the system. Further improvements in the wholesale electricity markets will be required, which will be discussed with stakeholders in 2019 and beyond. The greater development of renewable resources, particularly those with energy storage; energy efficiency; imports from neighboring regions; and continued investment in gas-efficiency measures are also part of the solution.
- Environmental regulations, other public policies, and economic considerations will affect the operation of existing resources and the mix of new regional resources. Existing oil and coal generators are expected to retire and be replaced with more efficient natural-gas-fired generation and renewable resources. Generator environmental compliance depends on final federal regulations and site-specific circumstances, which have been subject to uncertainty and delays that could affect generator permitting and operations. Carbon-emission targets will likely be the key regional environmental constraint on energy production by fossil-fired generating units.
- The region has significant potential for developing renewable resources and is actively addressing several key technical challenges to the successful integration of these resources. New

forecasting methods improve the reliable and economical operation of the system with increasing amounts of wind resources and BTM PV. The ISO conducts cluster analyses that identify the transmission interconnection requirements of multiple resources, which can be used to expeditiously integrate renewable resources. The large-scale development of wind resources in northern New England would require major transmission system improvements, but offshore wind proposals are better situated closer to load centers in southern New England. Coupling energy-storage systems with variable energy resources may improve VERs' consistency of supply and overall system performance.

- New England is transforming to a sustainable, hybrid grid that supports the connection of more renewable energy and the transition to the smart grid, which will allow for the more effective use of distributed energy resources. The lack of observability and controllability of variable and distributed energy resources will need to be addressed to realize the full benefits of energy storage, microgrids, and smart grid technologies. The rapid implementation of revised interconnection standards for distributed resources, including the IEEE 1547 and testing standards, is vital for ensuring overall system reliability and facilitating the economical development of renewable resources, such as PV. The ISO remains a leader in technological innovation, as shown by the widespread use of phasor measurement units, extensive application of flexible alternating-current transmission systems, and the implementation of state-of-the-art forecasting methods for wind resources and PV.
- Federal and state policies and initiatives will continue to affect the planning process, such as those promoting EE, PV, and wind resources.
- In response to the New England electric power system becoming more energy limited, the ISO has improved the forecasting and dispatch of resources, enhanced the markets, and created new systems and tools to improve operational and planning study models, capabilities, and performance. Work is ongoing.

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 reliably and economically. RSP19 complies with the intraregional and interregional planning processes required by the ISO's *Open Access Transmission Tariff*. As shown by RSP19, planning studies also comply with all NERC, NPCC, and regional requirements.

Section 2
Overview of RSP19, the Power System, and Regional System Planning

As the Regional Transmission Organization (RTO) for New England, ISO New England (ISO) operates the region's electric power system, administers the region's competitive wholesale electricity markets, and conducts the regional system planning process, which includes coordinating planning efforts with neighboring areas. The main objectives of the ISO's system planning process are as follows:

- Identify system needs and potential solutions for ensuring the short-term and long-term reliability of the system
- Facilitate the efficient operation of the markets through resource additions and transmission upgrades that serve to reliably move power from various internal and external sources to the region's load centers[33]
- Provide information to regional stakeholders, who can further develop system improvements

To meet these objectives and in compliance with all portions of the ISO's *Transmission, Markets, and Services Tariff* (ISO tariff), including the *Open Access Transmission Tariff* (OATT), the *2019 Regional System Plan* (RSP19) describes the ISO's ongoing system resource and transmission planning activities covering the 10-year period to 2028.[34]

This section provides an overview of RSP19 and the ISO's regional system planning process required by the ISO's tariff. For background, the section also provides highlights of the power system and the wholesale electricity market structure in New England. A summary of the various regional subdivisions the ISO uses in system planning studies is also provided.

Throughout RSP19, italicized terms indicate that a definition for the term is included within the text or footnotes. Links are provided to other documents, including the tariff, that include exact wording and full definitions of the more complex terms. In case of any discrepancies between RSP and tariff definitions, the tariff definition overrules. Links to relevant technical reports; presentations; and other, more detailed materials also are included throughout the report. All website addresses are current as of the time of publication. Appendix A is a list of acronyms and abbreviations used in RSP19.

2.1 Overview of the System Planning Process and RSP19

For maintaining the reliability of the New England power system, while promoting the operation of efficient wholesale electricity markets, the ISO and its stakeholders analyze the system and its components as a whole. They account for the performance of these individual elements and the many

[33] Likewise, the markets and market changes may help meet future system needs by providing incentives for the development of new resources. Market changes are subject to a different stakeholder process and are described in the ISO's Annual Markets Report (AMR) (accessible at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor) and Wholesale Markets Project Plan (WMPP) (https://www.iso-ne.com/markets-operations/markets-development/wholesale-markets-project-plan).

[34] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff) (2019), http://www.iso-ne.com/regulatory/tariff/index.html, including Section II. *ISO New England Open Access Transmission Tariff*, https://www.iso-ne.com/participate/rules-procedures/tariff/oatt.

varied and complex interactions that occur among the components that affect the overall performance of the system.

Using information on defined system needs, a variety of established signals from ISO-administered markets, and other factors, stakeholders responsible for developing needed resources can assess their options for satisfying these needs and commit to developing market resource projects. For example, stakeholders can build a new power plant to provide additional system capacity and produce electric energy. Similarly, market participants can provide *demand resources,* including *active demand resources* and *passive demand resources* (PDRs), to meet capacity needs and reduce the amount of electric energy used.[35] They also can develop, and independently fund transmission upgrades, to interconnect a merchant transmission facility (MTF) to the ISO system.[36] These upgrades and supply and demand resource alternatives could result in modifying, offsetting, or deferring proposed regulated transmission upgrades.

To the extent that stakeholder responses to market or other signals are not forthcoming or adequate to meet identified system needs, the planning process requires the ISO either to acquire transmission solutions through a competitive solicitation or to work with incumbent transmission owners to develop their own transmission solutions, depending on the identified year of need. All transmission upgrades must meet reliability performance requirements.

2.1.1 Types of Transmission Upgrades

Attachment N of the OATT, "Procedures for Regional System Plan Upgrades," defines several categories of transmission upgrades that can be developed to address various types of defined system needs, such as reliability and market efficiency.[37] Transmission upgrades resulting from system changes proposed by individual proponents include, for example, generator-interconnection-related upgrades and elective transmission upgrades (ETUs). Section 5.5 discusses specific transmission upgrades.

2.1.1.1 Reliability Transmission Upgrades

Reliability transmission upgrades (RTUs) are necessary to ensure the continued reliability of the New England transmission system, in compliance with applicable reliability standards. An RTU also may provide market-efficiency benefits. To identify the transmission system facilities required to maintain reliability and system performance, the ISO evaluates the following factors using reasonable assumptions for forecasted load and the availability of generation and transmission facilities:

- Known changes in available supply resources and transmission facilities, such as anticipated transmission enhancements, considering elective transmission upgrades and merchant transmission facilities (see Section 2.1.1.5); the addition of generators and demand resources;

[35] *Demand resources* verifiably reduce their consumption of electricity from the regional power system through installed measures (e.g., products, equipment, systems, services, practices, or strategies) on end-use-customer facilities. *Active demand resources* are dispatchable resources that offer to reduce load quickly in response to price signals in the ISO's markets, such as by powering down machines (i.e., load management) or using electricity from on-site generators instead of the grid. (i.e., distributed generation; see more below). *Passive demand resources* are nondispatchable and may reduce the total amount of electrical energy consumed across many hours during peak times or seasons through the use of energy–efficiency measures, such as energy-efficient appliances and lighting and advanced cooling and heating technologies.

[36] A *merchant transmission facility* is an independently developed and funded facility subject to the operational control of the ISO, pursuant to an operating agreement specific to each facility.

[37] See the OATT, Section II.B, Attachment N, "Procedures for Regional System Plan Upgrades," http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

resource retirements; and maintenance schedules, forced outages, and other unavailability factors

- Forecasted load, which accounts for growth, reductions, and redistribution throughout the grid
- Acceptable stability response
- Acceptable short-circuit performance
- Acceptable voltage levels
- Adequate thermal capability
- Acceptable system operability and responses (e.g., automatic operations, voltage changes)

2.1.1.2 Market Efficiency Transmission Upgrades

Market efficiency transmission upgrades (METUs) are primarily designed to reduce the total net production cost to supply the system load. The ISO categorizes a proposed transmission upgrade as a METU when it determines that the net present value of the net savings in the total cost to supply system load with and without the METU is greater than the net present value of the carrying cost of the identified upgrade. Analyses can include historical information from market reports and special studies, for example, and they report on cumulative net present value annually over the study period.

2.1.1.3 Public Policy Transmission Upgrades

A *public policy transmission upgrade* (PPTU) is an addition or upgrade designed to meet transmission needs driven by public policy requirements. The planning process for PPTUs includes opportunities for input from the New England States Committee on Electricity (NESCOE; see Section 10.1.1) and the Planning Advisory Committee (PAC; see Section 2.1.5). The ISO conducts the public policy planning process, as set out in Attachment K, in accordance with its compliance filing for FERC Order 1000 (see Section 5.3 and Section 6.6).[38]

2.1.1.4 Generator-Interconnection-Related Upgrades

A *generator-interconnection-related upgrade* is an addition or modification to the New England transmission system for interconnecting a new or existing generating unit whose capability to provide energy or capacity is materially changing and increasing, whether or not the interconnection is for meeting the Network-Capability Interconnection Standard or the Capacity-Capability Interconnection Standard.[39] The costs for this upgrade typically are allocated to the generator owner in accordance with the OATT.

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[38] FERC, *ISO New England Inc. Order on Compliance Filings* (May 17, 2013), https://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. Also see "Order No. 1000—Transmission Planning and Cost Allocation," FERC webpage (updated August 2, 2018), http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

[39] The Network-Capability Interconnection Standard is an energy-only standard that includes the minimum criteria required to permit a generator to connect to the transmission system so that it has no adverse impacts on the reliability, stability, or operation of the system, including the degradation of transfer capability for interfaces affected by the generating facility. The Capacity-Capability Interconnection Standard is a capacity and energy standard that includes the same criteria as the Network-Capability Interconnection Standard but also includes criteria to ensure intrazonal deliverability by avoiding the redispatch of other capacity network resources. The OATT, Section 22, defines the standards; http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch22/sch_22_lgip.pdf. Also see Schedule 23 for small generator

2.1.1.5 Elective Transmission Upgrades

An *elective transmission upgrade* is an interconnection or upgrade to the pool transmission facilities (PTFs) that are part of the New England transmission system and subject to the ISO's operational control pursuant to an operating agreement.[40] ETUs are independently developed facilities funded by one or more entities that have agreed to pay for all the costs of the upgrade and thus assume the full market risk of development.

The ETU process is the mechanism available to integrate new merchant transmission facilities into the regional transmission system. The process provides an option for project sponsors to propose, develop, and fund transmission development within New England or connecting to neighboring systems.[41] Such transmission may result in strengthening electrically weak portions of the regional transmission network, enhancing generator deliverability, or facilitating the integration of renewable resources.

The ETU interconnection procedures have requirements and obligations similar to those of generators, so that ETUs can establish and maintain a meaningful position in the ISO Interconnection Request Queue (the queue).[42] The ETU interconnection service allows certain tie lines with neighboring areas to be designed to deliver capacity into New England and have these interconnection service rights preserved as the New England system changes over time. The market rules ensure that these resources can deliver capacity and energy into the wholesale power markets.

2.1.2 Transmission Planning Guides

The ISO developed guides that document both the implementation of the regional planning process described in Attachment K of the OATT and the associated technical assumptions.[43] The *Transmission Planning Process Guide* (Process Guide) contains details on the existing regional system planning process and how transmission planning studies are performed through the open regional stakeholder process.[44] It discusses the development of needs assessments and solution studies, including the opportunities for stakeholder involvement. The guide includes more recent modifications required by FERC Order 1000 for

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interconnections and applications for new interconnections; https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch23/sch_23_sgip.pdf.

[40] *Pool transmission facilities* are the facilities rated 69 kilovolts (kV) or above owned by the participating transmission owners, over which the ISO has operating authority in accordance with the terms set forth in the Transmission Operating Agreements. Refer to the OATT, Section II.49, 109, for additional specifications, http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf. See Schedule 25 of the OATT for additional information on ETUs.

[41] An *internal ETU* is a transmission facility with interconnection points located solely within the New England Control Area; it would receive a right to interconnect to the system subject to meeting all the requirements specified in an Interconnection Agreement (e.g., completing the upgrades required to accommodate the requested interconnection). An *external ETU* is a transmission facility that will interconnect the New England Control Area with another control area. External ETUs can receive Capacity Network Import Interconnection Service (CNI Interconnection Service) for capacity, or Network Import Interconnection Service (NI Interconnection Service) for energy if they complete all the required milestones. For more information, See the OATT, Schedule 25, *Elective Transmission Upgrade Interconnection Procedures* (January 29, 2019), https://www.iso-ne.com/static-assets/documents/2015/02/sch_25.pdf.

[42] The *ISO's Interconnection Request Queue* lists the status of requests for the interconnection of new or *uprated* (i.e., increased capacity) generating facilities to the ISO New England-administered transmission system; see Section 4.5.3 It also includes elective transmission upgrades and transmission service requests.

[43] OATT, Attachment K, http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

[44] ISO New England, *Transmission Planning Process Guide* (September 20, 2018), https://www.iso-ne.com/static-assets/documents/2018/05/transmission_planning_process_guide_1_30_2018.pdf.

the use of qualified transmission project sponsors (QTPSs), planning for public policy, and interregional planning.[45] The *Transmission Planning Technical Guide* (Technical Guide) describes the current standards, criteria, and assumptions used in transmission planning studies of the regional power system.[46] Both guides include stakeholder input.

2.1.3 Planning Studies Conducted for and Summarized in RSP19

The ISO continually conducts numerous regional and local-area studies during all stages of planning for ensuring the reliability of the power system. FERC, interregional entities, the states, and others, also sponsor planning initiatives for improving the power system and interregional coordination. Throughout RSP19, the ISO's major studies and initiatives, as well as those conducted by others, both individually and jointly with the ISO, are summarized consistent with the steps used in the planning process:

- Ten-year load forecasts through 2028 of seasonal gross peak load and annual gross electric energy use
- Distributed generation (DG) forecast for photovoltaic (PV) generation and an energy-efficiency (EE) forecast for 2019 to 2028
- The development of a net forecasts of annual and peak electric energy use
- Analyses of the amount, operating characteristics, and locations of needed energy, capacity and operating reserves
- Analyses of Forward Capacity Market (FCM) results and locational Forward Reserve Market (FRM) resources that meet system needs
- Implications of generator retirements and interconnection of distributed energy resources on the transmission system[47]
- Assessments of systemwide and local-area needs (i.e., needs assessments), and transmission solutions to meet these needs (i.e., solution studies)[48]
- Planning coordination studies and initiatives affecting the planning of the system:
    - Northeastern ISO/RTO planning coordination studies
    - Eastern Interconnection Planning Collaborative (EIPC) activities[49]

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[45] Any entity that intends to submit a proposal in response to an ISO-identified need for a reliability transmission upgrade, market-efficiency transmission upgrade, public policy transmission upgrade, or a backstop transmission solution must first be recognized by the ISO as a *qualified transmission project sponsor*, in accordance with the OATT, Attachment K, Section 4B.

[46] ISO New England, *Transmission Planning Technical Guide*, (April 9, 2019), https://www.iso-ne.com/static-assets/documents/2017/03/transmission_planning_techincal_guide_rev4_1.pdf.

[47] *Distributed energy resources* are sources and aggregated sources of electric power not directly connected to a bulk power system. DERs include generators (i.e., distributed generators) and energy-storage technologies capable of exporting active power to an electric power system.

[48] Refer to the OATT, Attachment K, Section 4.1 and 4.2 for complete definitions for needs assessments and solutions studies; https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

[49] The *Eastern Interconnection* is one of two major AC power grids in North America spanning from central Canada eastward to the Atlantic coast (excluding Québec), south to Florida, and west to the foot of the Rocky Mountains (excluding most of Texas—the portion in the Electric Reliability Corporation of Texas) that, during normal system conditions, interconnects transmission and distribution infrastructure and operates at a synchronized frequency of 60 Hertz (Hz) average. The Eastern Interconnection is tied to the Western Interconnection, the Texas

- Joint planning studies with neighboring regions conducted with the US Department of Energy (DOE), North American Electric Reliability Corporation (NERC), and Northeast Power Coordinating Council (NPCC).[50]

- Discussions of regional strategic planning needs and solutions to resource adequacy and regional energy-security issues
- Effects of compliance with environmental regulations on generator operating requirements and the need for remediation measures
- Operating and planning for the integration of renewable resources, including the need for transmission development for wind generation (e.g. cluster studies) and the identification of interconnection issues
- Studies of the economic and environmental performance of the system for various future resource- and transmission-expansion scenarios
- Federal, state, and regional initiatives and governmental activities and policies affecting the planning process

2.1.4 Accounting for Uncertainty

Regional system planning must account for the uncertainty in assumptions made about the next 10 years stemming from the following:

- Changing demand, fuel availability (i.e., production by generators relying on fuel delivered "just in time," including natural gas) and production by *variable energy resources* (VERs), which are intermittent resources, such as wind and PV, market rules, technologies, planning processes, and environmental requirements[51]
- Development and retirement of resources
- Physical conditions under which the system might be operating
- Other relevant events

The following major factors may vary RSP19 results and conclusions and ultimately affect the development and timing of needed transmission facilities, generation, and demand:

- Forecasts of demand, energy efficiency, and distributed generation, which are dependent on the economy, new building and federal appliance-efficiency standards, state goals for the implementation of EE and DG programs, and other considerations

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Interconnection, and the Québec Interconnection generally through numerous high-voltage direct-current (HVDC) transmission lines.

[50] NERC is a FERC-designated Electric Reliability Organization (ERO) whose mission is to reduce risks to the reliability and security of the grid. The Northeast Power Coordinating Council is one of six regional entities located throughout the United States, Canada, and portions of Mexico responsible for enhancing and promoting the reliable and efficient operation of the interconnected bulk power system. The NPCC region covers nearly 1.2 million square miles populated by more than 55 million people. NPCC in the United States includes the six New England states and the state of New York. NPCC Canada includes the provinces of Ontario and Québec and the Maritime provinces of New Brunswick and Nova Scotia. As full members, New Brunswick and Nova Scotia also ensure that NPCC reliability issues are addressed for Prince Edward Island. More information about NERC and NPCC is available at http://www.nerc.com/ and https://www.npcc.org/, respectively. Also see more in Sections 6.3 and 6.5.

[51] Intermittent or *variable energy resources* produce energy subject to variations in "fuel" determined by weather and, in the case of PV, time of day; see Section 9.2.

- Resource availability, which is dependent on physical and economic parameters, including fuel availability, which 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 economic viability of new types of power system equipment and the efficiency of operating the power system
- Fuel price forecasts, which change with world markets and infrastructure development
- Market rules and public policies, which can alter the development of market resources
- Siting and construction delays for generation and transmission and other changes to the system

While each RSP represents a snapshot in time, the planning process is continuous, adaptive, and successful in meeting planning objectives in an open and transparent manner with interested stakeholders for the 10-year planning horizon; see Figure 2-1. The ISO continually evaluates system needs, responds to changing market conditions, updates inputs and assumptions to studies, and revisits the results as needed when new information becomes available. The ISO has been improving the information provided to stakeholders, especially the required timing of transmission projects.

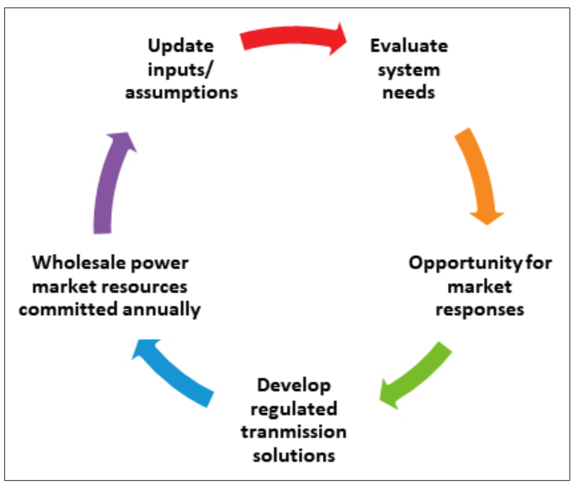

Figure 2-1: ISO New England system planning process.

2.1.5 Working with the Planning Advisory Committee and Other Committees

To conduct the system planning process, the ISO holds an open and transparent stakeholder forum with the Planning Advisory Committee (PAC).[52] Any stakeholder can designate a representative to the PAC by providing written notice to the ISO. PAC membership currently includes representatives from state and federal governmental agencies; participating transmission owners (PTOs); ISO market participants; other New England Power Pool (NEPOOL) members; consulting companies; manufacturers; and other organizations, such as universities and environmental groups.[53] The PAC has met 19 times from fall 2017

[52] PAC materials (2000 to the present), including agendas, minutes, materials, draft reports—with stakeholder questions and ISO responses—and final reports are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html.

[53] NEPOOL members serve as ISO stakeholders and market participants. More information on NEPOOL participants is available at http://www.iso-ne.com/participate/governing-agreements/nepool-agreement.

to summer 2019 to discuss draft scopes of work, assumptions, and draft and final study results on a wide range of issues. In addition, subgroups of the PAC have discussed the energy-efficiency forecast, the distributed generation forecast, environmental issues, and economic studies.

Other committees are involved in the system planning process. The Reliability Committee (RC) provides input on planning procedures, proposed plan applications, regional transmission cost allocation (TCA) applications, and other activities that affect the design and oversight of reliability standards for the power system. The Transmission Committee (TC) provides advisory input on the general tariff provisions of the OATT and amendments to the Transmission Operating Agreement.[54] The Markets Committee provides advisory input on changes proposed by the ISO to *Market Rule 1* and market procedures.[55] Stakeholders who advise ISO New England or its neighboring ISO/RTOs on system planning matters have the opportunity to meet as a unified group through the Interregional Planning Stakeholder Advisory Committee (IPSAC; see Section 6.6).

2.1.6 Providing Information to Stakeholders

In addition to publishing the Regional System Plan and specific needs assessments and solutions studies to provide information to stakeholders, the ISO issues the *RSP Project List* and *Asset-Condition Update* (see Sections 5.7 and 5.9).[56] The *RSP Project List* includes the status of transmission upgrades during a project's lifecycle, and the *Asset-Condition List* captures the transmission asset conditions reported to the PAC.[57] Both lists are updated several times per year; RSP19 incorporates information from the June 2019 lists.

Additionally, the ISO posts on its website detailed information supplemental to the RSP process, such as the Regional Electricity Outlook (REO), Annual Markets Report (AMR), Wholesale Markets Project Plan (WMPP), presentations, and other reports.[58] The ISO also makes available databases used in its analyses and related information required to perform simulations consistent with FERC policies and the ISO Information Policy requirements pertaining to both confidential information and critical energy infrastructure information (CEII) requirements.[59] Stakeholders can use this information and data to conduct their own independent studies.

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[54] A *Transmission Operating Agreement* is an agreement between a Regional Transmission Organization and a transmission-providing utility whereby the RTO pays the utility for its transmission system costs in exchange for control of the transmission.

[55] *Market Rule 1* (ISO tariff, Section III) (2019), http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[56] The *RSP Project List* is available at http://www.iso-ne.com/system-planning/system-plans-studies/rsp (filters: Regional System Plan document type; XLS file type). The latest *Asset-Condition List* is the "June 2019 ISO New England Asset Condition Update," spreadsheet (June 2019), https://www.iso-ne.com/static-assets/documents/2019/06/final_asset_condition_list_june_2019.xls.

[57] Stakeholder presentations to the PAC on the condition and management of key assets are available at the ISO's "New England Asset Management Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/new-england-asset-management/?load.more=1.

[58] Recent and archived RSP materials are available at http://www.iso-ne.com/trans/rsp/index.html. The latest and archived editions of the REO, AMR, and WMPP are available at https://www.iso-ne.com/about/regional-electricity-outlook, http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/, and http://www.iso-ne.com/markets-operations/markets-development/wholesale-markets-project-plan. The needs assessments and solutions studies presented to the PAC and posted on the ISO website can be obtained by contacting ISO Customer Service at 413-540-4220.

[59] Stakeholders also can obtain publicly available models of the transmission system network through the FERC 715 process, which requires transmitting utilities that operate facilities rated at or above 100 kV to submit information to FERC annually; see http://www.ferc.gov/docs-filing/forms/form-715/overview.asp. *ISO New England Information*

2.1.7 Meeting All Requirements

In addition to complying with the ISO tariff, which reflects the requirements of FERC orders, RSP19 complies with NERC and NPCC criteria and standards, as well as ISO planning and operating procedures.[60] RSP19 also conforms to transmission owner criteria, rules, standards, guides, and policies consistent with NERC, NPCC, and ISO criteria, standards, and procedures.[61]

2.2 Overview of the New England Electric Power System

New England's electric power grid is planned and operated as a unified system of its participating transmission owners and market participants.[62] The New England system integrates resources with the transmission system to serve all regional load regardless of state boundaries. Most of the transmission lines are relatively short and networked as a grid. Therefore, the electrical performance in one part of the system affects all areas of the system. Figure 2-2 shows key facts about the New England regional electric power system.

Policy (ISO tariff, Attachment D) (2019) contains the requirements for controlling the disclosure of CEII and confidential information; see http://www.iso-ne.com/static-assets/documents/regulatory/tariff/attach_d/attachment_d.pdf.

[60] ISO New England, "Rules and Procedures" webpage, http://www.iso-ne.com/participate/rules-procedures. FERC, *Preventing Undue Discrimination and Preference in Transmission Service*, 18 CFR Parts 35 and 37, Order No. 890 (February 16, 2007), http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf. NERC Reliability Standards (2019), http://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx. NPCC Regional Standards (2017), https://www.npcc.org/Standards/default.aspx.

[61] ISO New England, "Transmission Operating Agreements," webpage, http://www.iso-ne.com/regulatory/toa/index.html.

[62] The ISO is not responsible for portions of northern and eastern Maine. The Northern Maine Independent System Administrator, Inc. (NMISA) is a nonprofit entity responsible for the administration of the northern Maine transmission system and electric power markets in Aroostook and Washington counties. The 2019 peak load forecast for NMISA is approximately 139 MW. NMISA, *Seven-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities on the Northern Maine Transmission System* (April 2018), p. 3, http://www.nmisa.com/wp-content/uploads/2018/04/2018-Seven-Year-Outlook-Final.pdf.

- 7.2 million households and businesses; population 14.8 million
- More than 1,900 generating resources:
  - Approximately 350 resources modeled in the Energy Management System
  - More than 1,600 settlement-only generating resources
  - More than 150,000 grid-connected and behind-the-meter solar PV installations, totaling about 2,900 MW (nameplate)
- More than 500 participants in the marketplace (those who generate, buy, sell, transport, and use wholesale electricity and implement demand resources)

- About 9,000 miles of transmission lines
- 13 interconnections to electricity systems in New York and Canada
- 136,355 gigawatt-hours (GWh), all-time annual energy served, set during 2005
- All-time peak demand of 28,130 megawatts (MW), set on August 2, 2006
- 22,818 MW all-time winter peak demand, set on January 15, 2004
- Approximately 31,000 MW of total generating capability for 2018 (summer seasonal claimed capability; SSCC) and 33,000 MW for 2018/2019 (winter seasonal claimed capability; WSCC)
- Over 3,000 MW of active demand resources and energy efficiency and other passive demand resources for 2019 (active demand response and energy efficiency)

- Market value in 2018—$9.8 billion total; $6.0 billion energy market; $3.6 billion capacity market; $0.1 billion ancillary services market
- Approximately $10.9 billion in transmission investment since 2002; approximately $1.3 billion planned

Figure 2-2: Key facts about New England's electric power system and wholesale electricity markets.

Sources: The *2019–2028 Forecast Report of Capacity, Energy, Loads, and Transmission* (2019 CELT Report) (April 30, 2019), http://www.iso-ne.com/system-planning/system-plans-studies/celt#; the *RSP Project List* for June 2019; and ISO market analysis and settlements data. ISO-NE Internal Market Monitor, *2019 Annual Markets Report* (May 23, 2019), https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf; "Key Grid and Market Stats," website (2019), https://www.iso-ne.com/about/key-stats.

Notes: *Settlement-only resources* (SORs) are less than 5 MW but not centrally dispatched by the ISO control room and not monitored in real time. The over 3,000 MW of ISO demand resources do not include behind-the-meter photovoltaic resources (BTM PV) and energy efficiency provided by other customer-based programs outside the ISO markets or are otherwise unknown to the ISO. The total load on August 2, 2006, would have been 28,770 MW had it not been reduced by approximately 640 MW, which included a 490 MW demand reduction in response to ISO Operating Procedure No. 4 (OP 4), *Action during a Capacity Deficiency*; a 45 MW reduction of other interruptible OP 4 loads; and a 107 MW reduction of load as a result of price-response programs, which are outside of OP 4 actions. (OP 4 guidelines contain 11 actions in total that can be implemented individually or in groups, depending on the severity of the situation.) More information on OP 4 is available at http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

RSP19 includes both a NERC and an NPCC term to describe the electric power system. The NERC term, *bulk electric system* (BES), includes transmission elements operated at 100 kilovolts (kV) or higher and real power and reactive power resources connected at 100 kV or higher.[63] The BES does not include

[63] *Real power* or active power is the rate at which energy is expended to do work, measured in kilowatts or megawatts. Reactive power supports the magnetic and electric fields necessary to operate power system equipment in an alternating current power system. It is measured in volt-ampere reactive (VAR) and megavolt-ampere reactive (MVAR) units.

facilities used in the local distribution of electric energy. The NPCC term, *bulk power system*, refers to the interconnected electrical system within northeastern North America comprising system elements on which faults or disturbances can have a significant adverse impact outside of the local area. RSP19 describes how the ISO meets NERC and NPCC requirements to ensure compliance with planning and operating standards and criteria.

2.3 Overview of the New England Wholesale Electricity Market Structure

New England's wholesale electricity markets facilitate the buying, selling, and transporting of wholesale electricity, as well as ensure proper system frequency and voltage, sufficient future capacity, seasonal and real-time reserve capacity, and system restoration capability after a blackout. Stakeholders also have the opportunity to hedge against the costs associated with transmission congestion. As shown in Figure 2-2, in 2018, more than 500 market participants completed transactions in New England's wholesale electricity markets totaling $9.8 billion. The wholesale electricity markets and market products in New England are as follows:[64]

- **Day-Ahead Energy Market—**allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that can occur in real time.
- **Real-Time Energy Market—**coordinates the dispatch of generation and demand resources, to meet the instantaneous demand for electricity.
- **Forward Capacity Market—**through a primary and substitution auction (SA) during each Forward Capacity Auction (FCA) (see Section 4.1.3), ensures the sufficiency of installed capacity, which includes demand resources, to meet the future demand for electricity by sending appropriate price signals to attract new investment, maintain existing investment, and encourage capacity to perform both where and when needed, including during shortage events.[65]
- **Financial Transmission Rights (FTRs)—**allows participants to hedge against the economic impacts associated with transmission congestion and provides a financial instrument to arbitrage differences between expected and actual day-ahead congestion.
- **Ancillary services**
    - **Regulation Market—**compensates resources that the ISO instructs to increase or decrease output moment by moment to balance the variations in demand and system frequency to meet industry standards.[66]
    - **Forward Reserve Market—**compensates generators for the availability of their operational capacity not generating electric energy but able to be converted into electric

[64] For more information on New England wholesale electricity markets, see the ISO's *2018 Annual Markets Report* (AMR18) (May 23, 2019), https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf.

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

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

energy within 10 or 30 minutes when needed to respond to system contingencies, such as unexpected outages.[67]

- **Real-time reserve pricing—**compensates participants with on-line and fast-start generators for the increased values of their electric energy when the system or portions of the system are short of reserves.[68] It also provides efficient price signals to generators when redispatch is needed to provide additional reserves to meet requirements.
- **Voltage support—**compensates resources for maintaining voltage-control capability, which allows system operators to maintain transmission voltages within acceptable limits.

One key feature of the region's wholesale electricity markets is locational marginal pricing for electric energy, which reflects the variations in supply, demand, and transmission system limitations effectively at every location where electric energy enters or exits the wholesale power network. In New England, wholesale electricity prices are set at more than 1,100 pricing points (i.e., *pnodes*) on the power grid. If the system were entirely unconstrained and had no losses, all *locational marginal prices* (LMPs) would be the same, reflecting only the cost of serving the next megawatt increment of load by the generator with the lowest-cost electric energy available, which would be able to flow to any point on the transmission system. LMPs would differ among the pnodes if each location's marginal cost of congestion and marginal cost of line losses differed.

Transmission system constraints, which limit the flow of the least-cost generation and create the need to dispatch costlier generation, give rise to the congestion component of an LMP. Line losses are caused by physical resistance and subsequent heat loss in the transmission system as electricity travels through transformers, reactors, and other types of equipment, resulting in less power being withdrawn from the system than was injected. Line losses and their associated marginal costs are inherent to transmission lines and other grid infrastructure as electric energy flows from generators to loads. As with the marginal cost of congestion, the marginal cost of losses affects the amount of generation that must be dispatched. The ISO operates the system to minimize total system costs, while recognizing physical limitations of the system.

The ISO annually assesses the wholesale electricity markets to better understand problems to be addressed and to determine whether the market design or other measures warrant any changes. The ISO uses this information and the results of RSP studies to develop market design changes through an open stakeholder process.[69]

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[67] According to NERC, NPCC, and ISO criteria, a *contingency* is the sudden loss of a generation or transmission resource. 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. A *forced outage* is a type of unplanned outage or unexpected removal from service of a generating unit, transmission facility, or other facility or portion of a facility because of an emergency failure or the discovery of a problem that needs to be repaired as soon as crews, equipment, or corrective dispatch actions can perform the work.

[68] *Fast-start resources* can be electrically synchronized to the system quickly and reach *claimed capability* (i.e., a generator's maximum production or output) within 10 to 30 minutes to respond to a contingency and serve demand.

[69] See the ISO's Wholesale Markets Project Plans at https://www.iso-ne.com/markets-operations/markets-development/wholesale-markets-project-plan.

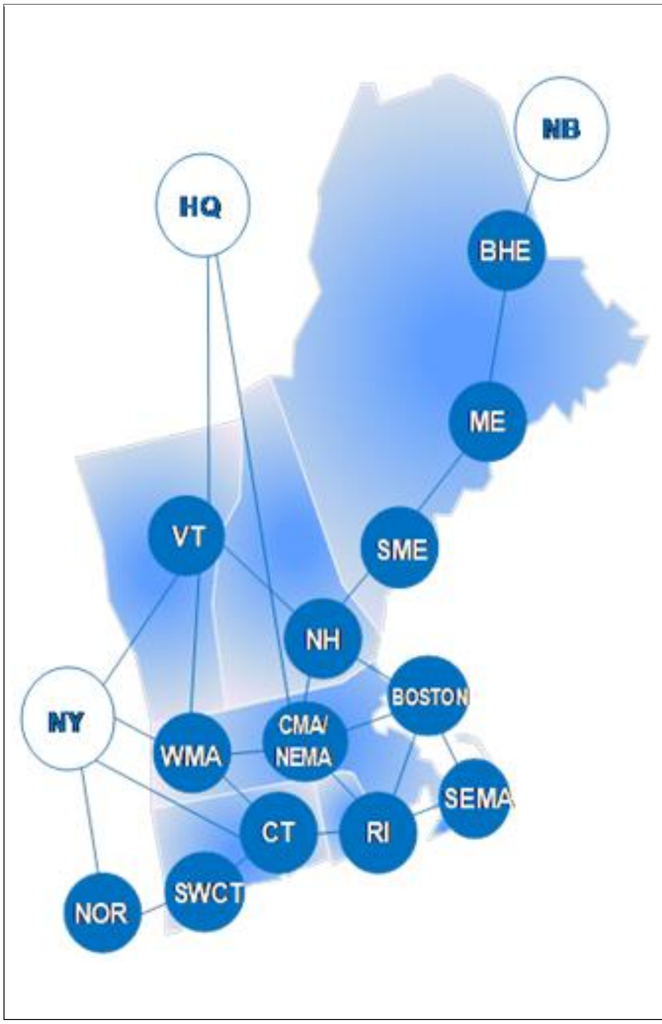
2.4 Overview of System Subdivisions Used for Analyzing and Planning the System

To assist in modeling, analyzing, and planning electricity resources in New England, the region and the system have been subdivided in various ways, including subareas, load zones, reserve zones, demand-resource dispatch zones, and capacity zones. These categories are included in the discussions throughout the RSP and are summarized below.[70]

The ISO has established 13 *subareas* of the region's electric power system. These subareas form a simplified model of load areas connected by the major transmission interfaces across the system. The simplified model illustrates possible physical limitations to the reliable and economic flow of power that can evolve over time as the system changes.

Figure 2-3 shows the ISO subareas and three external balancing authority areas. While transmission planning studies and the real-time operation of the system use more detailed models, the subarea representation shown in Figure 2-3 is suitable for some RSP19 studies of resource adequacy, operating-reserve requirements, production cost, and environmental emissions.

[70] Also see the ISO's "Maps and Diagrams," webpage at https://www.iso-ne.com/about/key-stats/maps-and-diagrams/.



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

Figure 2-3: RSP19 geographic scope of the New England electric power system.

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

The system's pricing points include individual generating units, load nodes, *load zones* (i.e., aggregations of load pnodes within a specific area), and the Hub. The *Hub* is a collection of 32 locations in central New England where little congestion is evident. It typically has a price intended to represent an uncongested price for electric energy, which is used as a price index and point of exchange for bilateral transactions in the energy market. The Hub also facilitates energy trading and enhances transparency and liquidity in the marketplace. In New England, generators are paid the LMP for electric energy at their respective nodes, and participants serving demand pay the price at their respective load zones.[71]

New England is divided into eight electric energy load zones used for wholesale energy market settlement: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA) (see Figure 2-4). *Import-constrained* load zones are areas within New England

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

that do not have enough local resources and transmission-import capability to serve local demand reliably or economically. *Export-constrained* load zones are areas within New England where the available resources, after serving local load, exceed the areas' transmission capability to export the excess electric energy. *Reliability regions*, which reflect the operating characteristics of, and the major constraints on, the New England transmission system, can have the same boundaries as load zones.[72]

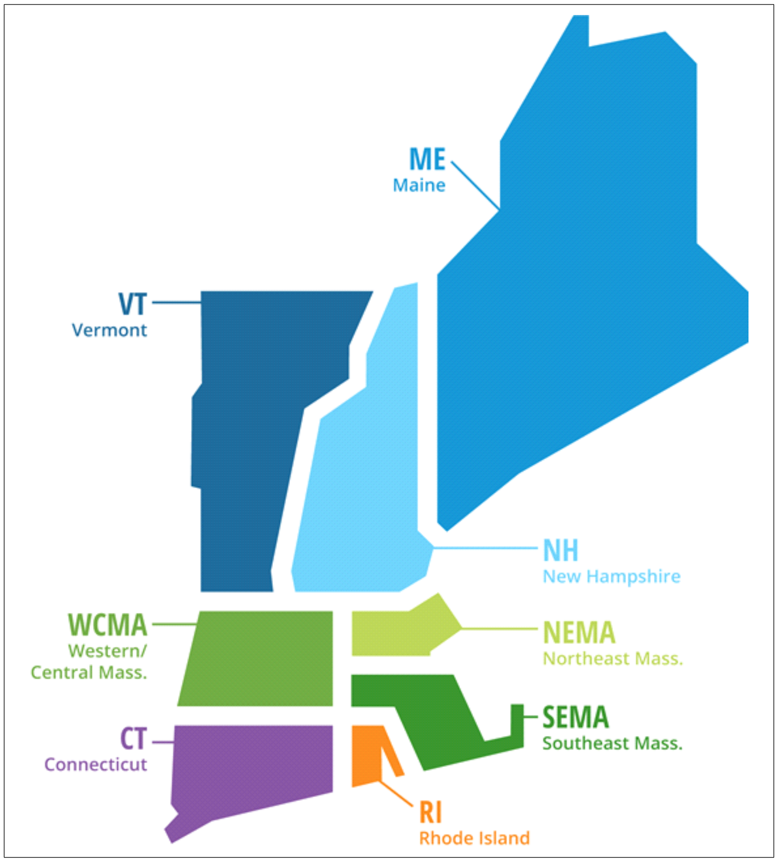


Figure 2-4: Wholesale load zones in New England.

The region also currently has four *reserve zones*—Greater Connecticut; Greater Southwest Connecticut (SWCT); NEMA/Boston; and the rest of the system (Rest-of-System, ROS), which excludes the other, local reserve zones.

Additionally, the region is divided into 19 *demand-resource dispatch zones*, which are groups of pricing nodes used to dispatch active demand resources. These zones allow for a more granular aggregation of active demand resources at times, locations, and quantities needed to address potential system problems. Figure 2-5 shows the dispatch zones the ISO uses to dispatch active demand resources.

[72] See *Market Rule 1*, Section III.2.7, of the ISO tariff, http://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1.

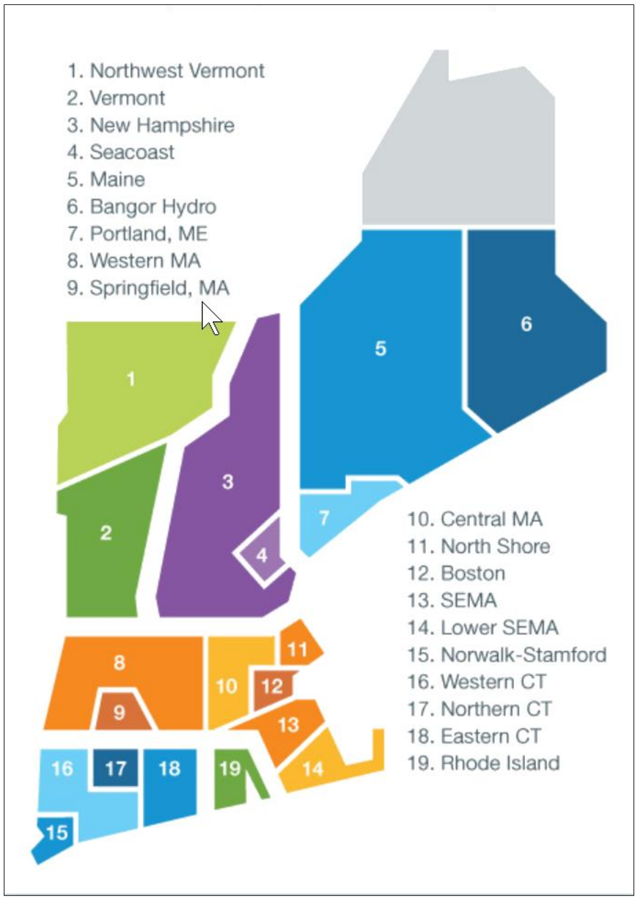


Figure 2-5: Dispatch zones for active demand capacity resources in the ISO New England system.

A *capacity zone* is a specific geographic subregion of the New England Balancing Authority Area designated before each Forward Capacity Auction (FCA) that may represent load zones that are export constrained, import constrained, or contiguous—neither export nor import constrained. The FCAs and subsequent reconfiguration auctions use capacity zones because the amount of capacity purchased in each auction is based on these boundaries. The ISO establishes capacity zones annually and evaluates all transmission interface limits that could be relevant to capacity zone modeling. For Forward Capacity Auctions 12 and 13 (FCA 12 and FCA 13), three capacity zones were modeled (see Section 4.2):

- Southeastern New England (SENE) as an import-constrained zone, which includes the area within the Southeast New England interface, comprising the RSP "bubbles" (as shown in Figure 2-3) for SEMA, RI, and BOSTON
- Northern New England (NNE) as an export-constrained zone, which includes the area north of the North–South interface, comprising the RSP bubbles for BHE, ME, SME, NH, and VT
- Rest-of-Pool (ROP)

As shown in Figure 2-6, four capacity zones will be modeled for FCA 14: Southeastern New England, Northern New England with the Maine capacity zone nested inside the NNE zone, and Rest-of-Pool. The nested Maine capacity zone includes the area north of the ME-NH interface, comprising the RSP bubbles for BHE, ME, and SME.

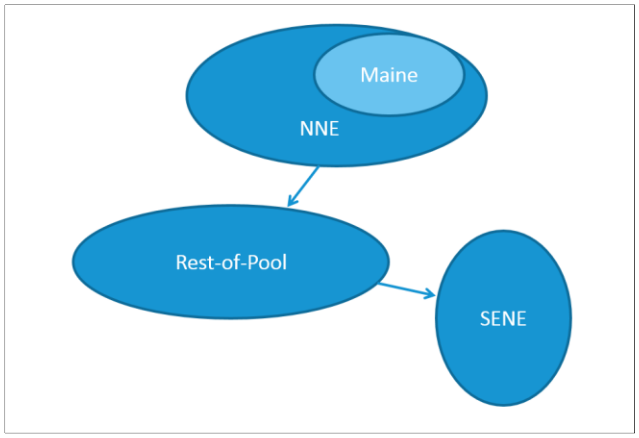


Figure 2-6: Capacity zones to be modeled for FCA 14.

Other capacity zones the ISO considers to represent import- and export-constrained areas or contiguous areas are as follows:

- CT—the area within the Connecticut import interface, including the RSP bubbles for CT, SWCT, and NOR plus the Scitico substation served from western Massachusetts
- NEMA/Boston—the area within the Boston import interface, comprising the RSP bubble for BOSTON
- SEMA/RI—the area within the SEMA/RI import interface, comprising the RSP bubbles for SEMA and RI

Section 3
Forecasts of New England's Peak Demand, Annual Use of Electric Energy, Energy Efficiency, and Distributed Generation

This section discusses the individual forecasts of gross demand, energy efficiency, and photovoltaics for 2019 through 2028. Energy efficiency is considered a resource, and all types of behind-the-meter (BTM) distributed generation are considered a reduction in demand, but for study purposes, their combined growth reduces the forecasts of peak demand and the annual use of energy. These resultant net demand forecasts provide key inputs for determining the region's resource-adequacy requirements for future years (see Section 4.1.3.3), evaluating the reliability and economic performance of the electric power system under various conditions (Section 4.3 and 9.3, respectively), and planning needed transmission improvements (Section 5). This section also discusses the application of the net peak demand and the net annual energy forecasts to planning studies.

A top priority of many New England states is combatting climate change, and the policies in place have a significant impact on regional electric energy demand and consumption. These policies serve as key inputs to the growth of energy-efficiency and photovoltaic resources for the 10-year RSP planning horizon, and ongoing investments in state-sponsored EE programs and the adoption of BTM PV continue to show demand-reducing effects.[73] Strategic electrification initiatives also are taking shape across the region, targeting economywide mandates and goals for reducing greenhouse gases. These initiatives are expected to encourage consumers to adopt emerging technologies (e.g., electric vehicles and electric heat pumps) over the next several decades, resulting in the electrification of the heating and transportation sectors. By midcentury, these efforts likely will have introduced considerable new demand for electricity across the region. Although electrification is still in its infancy, the timing and scale of its growth in the coming years will become important considerations in the region's long-term electricity outlook. Accordingly, working with stakeholders, the ISO is closely monitoring related policy developments and technological advancements to better understand their relevance in the development of long-term demand and energy forecasts for the region.[74]

The methodology for forecasting the gross demand, energy efficiency, and photovoltaic installations in RSP19 are generally similar to RSP17's methodology. However, the ISO incorporated changes to its 2019 gross energy and demand forecast modeling, as described below, to improve overall forecast performance.[75]

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[73] State-sponsored EE programs consist of various efforts designed to reduce energy consumption. These efforts generally are funded by multiple sources, including a system benefits charge (SBC) that electricity providers apply to customer bills, the Regional Greenhouse Gas Initiative (RGGI) auction revenues (see Section 8.2.1.2), and state EE policy funds.

[74] ISO New England, *Discussion of Electrification/Decarbonization,* Load Forecast Committee presentation, July 27, 2018, https://www.iso-ne.com/static-assets/documents/2018/07/iso_presentation_lfc_27_july2018.pdf.

[75] Details of the ISO's gross load forecast methodology and resulting forecasts are located on the ISO's website, as follows, published annually on the "Load Forecast" webpage (2019), https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/. The energy and demand modeling methodology is described in the *Forecast Modeling Procedure for the 2019 CELT Report: ISO New England Long-Run Energy and Seasonal Peak Forecasts* (e.g., 2019 Forecast Modeling Procedure) (April 30, 2019), https://www.iso-ne.com/static-

3.1 ISO New England Gross Demand Forecasts

The ISO's gross demand forecasts are estimates of the amount of electric energy the New England states will need annually and during seasonal peak hours. RSP19's gross demand forecast horizon runs from 2019 through winter 2028/2029. Historical loads and economic and demographic factors drive the forecasts of the gross annual demand for electric energy and gross peak, regionwide and in individual states and subareas. Each forecast cycle updates the historical data for the region's annual use and peak loads, incorporating the most recent economic and demographic forecasts, and making adjustments for resettlement that include meter corrections.

The seasonal gross peak load and gross energy-use forecast, as published in the *2019–2028 Forecast Report of Capacity, Energy, Loads, and Transmission* (2019 CELT Report) and used for planning studies, accounts for historical energy efficiency not part of the EE forecast and future federal appliance and lighting standards.[76] The gross forecast does not reflect reductions in peak demand and energy use that will result from the passive demand resources (PDRs) that clear the Forward Capacity Auctions, the energy-efficiency forecast (described in Section 3.2), or the behind-the-meter PV forecast (see Section 3.3). Load reductions stemming from other types of behind-the-meter distributed resources not participating in the FCM, however, are reflected as reductions in the historical loads used in the development of the gross load forecast, which tend to lower the forecast.[77]

Macroeconomic and demographic factors drive the annual consumption of electric energy and the growth of the seasonal peak. Compared with the economic forecast in RSP17, the forecast in RSP19 shows slightly more growth throughout the forecast horizon. The RSP19 forecast continues to use real gross state product (GSP) for energy forecasting.

For the first time since summer 2013, New England experienced several nonholiday weekdays with peak-eliciting weather during the 2018 summer season, which the ISO used to evaluate the performance of its peak demand model. Analysis showed that observed peak loads were lower than ISO forecasts given the weather conditions, helping identify a high bias in the forecast that generally increased with the extremity of weather. To correct this bias, the ISO incorporated changes to the summer demand model

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assets/documents/2019/04/modeling_procedure_2019.pdf. All final forecast values are published in "ISONE 2019 Forecast Data File," spreadsheet containing a number of worksheets (e.g., 2019 Forecast Data) (June 19, 2019), https://www.iso-ne.com/static-assets/documents/2019/04/forecast_data_2019.xlsx. All resulting energy and peak models are documented in a "Energy Models" spreadsheet (e.g., 2019 Energy & Peak Model Details) (April 30, 2019), https://www.iso-ne.com/static-assets/documents/2019/04/model_details_2019.xlsx. The "Load Forecast Materials" webpage also includes the 10-year hourly forecasts in electronic export information (EEI) format (e.g., hourly 2019 forecasts for the region, RSP subareas, and SMD load zones). The "Load Forecast Committee" webpage (2019) also contains materials on relevant stakeholder discussions; https://www.iso-ne.com/committees/reliability/load-forecast/.

[76] The ISO's Capacity, Energy, Load, and Transmission (CELT) Reports and associated documentation contain more details on the long-run forecast methodologies, models, and inputs; weather normalization; regional, state, subarea, and load-zone forecasts of annual electric energy use and peak loads; high- and low-forecast bandwidths; and retail electricity prices. See the 2019 CELT Report at the "CELT Reports," webpage, https://www.iso-ne.com/system-planning/system-plans-studies/celt. Also see the 2019 Forecast Data spreadsheet and other associated 2019 documentation, as listed in the above footnote, at https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/, and the *ISO NE Seasonal Peaks since 1980* (April 25, 2017), which can be accessed at https://www.iso-ne.com/static-assets/documents/2018/06/seasonal_peak_data_summary.xls.

[77] Compared with distributed PV, non-PV distributed generation has been growing much more modestly and somewhat consistently with its historical growth trend. *August 2018 Distributed Generation Survey Results* (see *Non-PV DG Survey Results* section), Distributed Generation Forecast Working Group (DGFWG) presentation (December 10, 2018), https://www.iso-ne.com/static-assets/documents/2018/12/3_dgsurvey_results_aug18.121018.pdf.

specification, including the addition of a second weather variable, that better captures the load response given a variety of weather conditions. A validation analysis demonstrated that the new model significantly improves forecast performance during peak-eliciting weather conditions.[78] The ISO also made improvements to its energy and winter peak demand models for the 2019 forecast.[79]

Table 3-1 summarizes the ISO's forecasts of gross annual electric energy use and gross seasonal peak load (50/50 and 90/10) for New England overall and for each state.[80] RSP19 forecasts of gross annual energy use, and both summer and winter gross seasonal peak conditions, are lower than those published in RSP17. Compared with the RSP17 forecast, the RSP19 50/50 load forecast for gross summer peak demand is 810 megawatts (MW) lower in 2019 and 1,414 MW lower in 2026. The RSP19 90/10 load forecast for gross summer peak demand is 1,377 MW lower in 2019 and 2,019 MW lower in 2026. These greater changes reflected in the RSP19 90/10 forecast are attributed primarily to the modeling changes incorporated to correct the previous tendency to overforecast during extreme weather.

Table 3-1
Summary of Annual Gross Electric Energy Use and Gross Peak Demand Forecast for New England and the States, 2019/2020 and 2028/2029

State[a]	Net Energy for Load (1,000 MWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50		90/10[b]		CAGR[c]	50/50		90/10[b]		CAGR[c]
	2019	2028	CAGR[c]	2019	2028	2019	2028		2019/20	2028/29	2019/20	2028/29	
CT	34,372	36,779	0.8	7,305	7,438	7,719	7,866	0.2	5,647	5,714	5,805	5,879	0.1
ME	13,240	15,260	1.6	2,116	2,318	2,217	2,437	1.0	2,067	2,280	2,105	2,325	1.1
MA	68,831	76,990	1.3	13,864	14,998	14,888	16,209	0.9	10,787	11,533	11,142	11,938	0.7
NH	12,920	14,390	1.2	2,445	2,587	2,568	2,720	0.6	2,025	2,073	2,093	2,146	0.3
RI	9,395	10,614	1.4	2,118	2,342	2,313	2,583	1.1	1,500	1,595	1,540	1,643	0.7
VT	6,852	7,279	0.7	1,095	1,148	1,128	1,184	0.5	1,118	1,180	1,155	1,207	0.6
ISO	145,610	161,312	1.1	28,943	30,831	30,832	32,999	0.7	23,144	24,376	23,841	25,138	0.6

(a) A variety of factors cause state growth rates to differ from the overall growth rate for New England.

(b) The 90/10 gross forecast is used in the development of Installed Capacity Requirements (ICRs).

(c) "CAGR" stands for compound annual growth rate. CAGR values shown for the summer and winter peak loads are for the 50/50 forecasts.

[78] ISO New England, *Draft 2019 ISO-NE Annual Energy and Summer Peak Forecast*, PAC presentation (March 21, 2019), https://www.iso-ne.com/static-assets/documents/2019/03/a4_draft_2019_isone_annual_energy_and_summer_peak_forecast.pdf.

[79] ISO New England, Final *Draft 2019 CELT ISO-NE and States Annual Energy and Seasonal Peak Forecasts,* Load Forecast Committee presentation (March 29, 2019), https://www.iso-ne.com/static-assets/documents/2019/03/lfc_29mar2019_final.pdf.

[80] The *50/50 "reference" case peak loads* have a 50% chance of being exceeded in any peak season because of weather conditions. The *90/10 "extreme" case peak loads* have a 10% chance of being exceeded in any peak season because of weather.

Net energy for load (NEL) is the generation output within an area, accounting for electric energy imports from other areas and electric energy exports to other areas.[81] It also accounts for system losses and excludes the electric energy used to operate pumped-storage hydroelectric plants. The compound annual growth rate (CAGR) for the ISO's electric energy use is 1.1% for 2019 through 2028, 0.7% for the summer peak, and 0.6% for the winter peak.[82]

Figure 3-1 shows the ISO's historical gross summer peak demand (i.e., the load reconstituted to include the megawatt reduction attributable to active demand resources and FCM passive demand resources), the 50/50 gross load forecast, and the 90/10 gross load forecast.[83] The actual gross load has been near or has exceeded the 90/10 forecast seven times over the past 27 years because of hot and humid weather conditions, and it has been near or above the 50/50 gross forecast 12 times during the same period.[84]

[81] The generation output includes output from *settlement-only resources* (SORs), which are less than 5 MW but not centrally dispatched by the ISO control room and not monitored in real time. NEL = Total ISO generator energy production + imports – exports – pumped storage load.

[82] The compound annual growth rate is calculated as follows:

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

[83] OP 4 actions implemented during a capacity deficiency include the dispatch of active demand resources. Operating Procedure No. 4, *Action during a Capacity Deficiency* (June 1, 2018), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

[84] Weather conditions during the actual peak summer loads were slightly below the expected 90/10 weather conditions for 1994, 1999, 2001, and 2002, and weather conditions were at or slightly above the expected 90/10 weather during the 2006, 2011, 2013, and 2018 peaks. A spreadsheet containing historical annual peak loads and associated weather conditions since 1980 is available at https://www.iso-ne.com/static-assets/documents/2014/10/seasonal_peak_data_summary.xls.

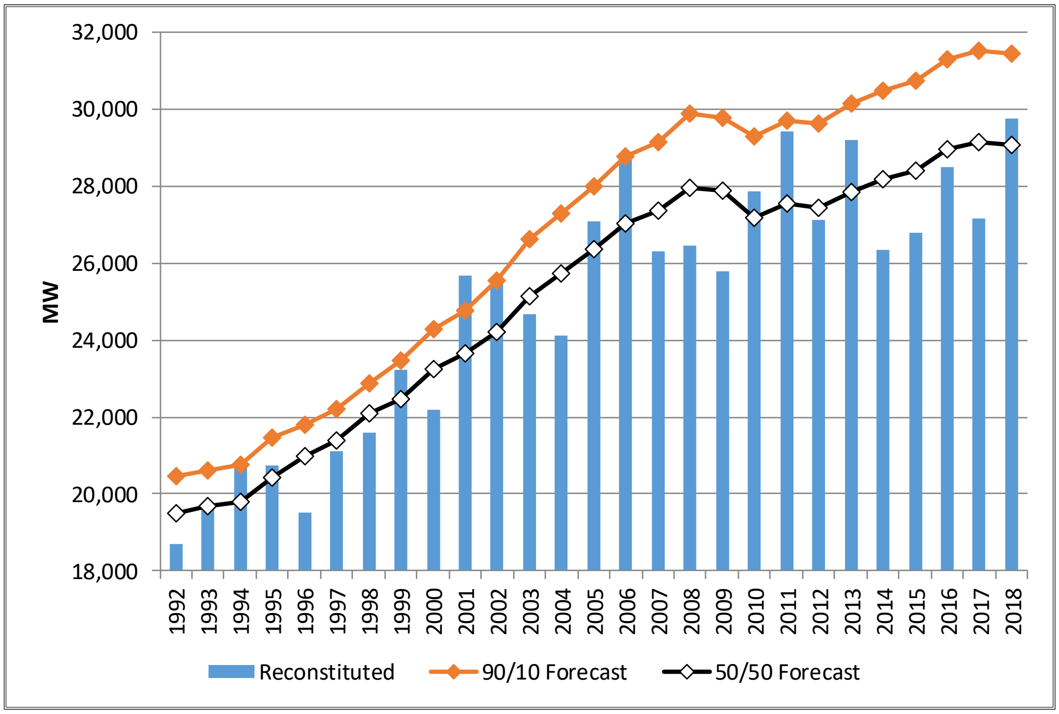

Figure 3-1: The ISO's historical summer gross peak loads (reconstituted to include the megawatt reductions from active demand resources, EE, and BTM PV) and the 50/50 and 90/10 forecasts, 1992 to 2018 (MW).

Note: The forecasted load values are the first-year values of the CELT forecast for each year. For example, the forecasted loads for 2018 are the loads for the first year of the 2018 CELT Report.

3.2 Energy-Efficiency Forecast for New England

The EE forecast reflects participation in the ISO's Forward Capacity Market, which provides the ISO with an understanding of the savings in energy use over the FCM horizon. RSP19 uses FCM-qualified EE resources as a short-term projection of EE development for 2019 (see Section 4.1.3).[85] The ISO's regional energy-efficiency forecast for 2020 through 2028, as summarized in this section, is part of ongoing efforts to collect and analyze data in support of the long-term impacts of state-sponsored energy-efficiency programs on future demand.[86] Individual program administrators and state regulatory agencies provide the ISO with the EE program performance and budget data used to create the forecast for 2020 to 2028. The ISO's Energy-Efficiency Forecast Working Group assesses the forecast assumptions and offers input.

[85] The FCM-qualified EE value is based on the third annual reconfiguration auction (ARA 3) for the first year (2019), and the remaining nine years are forecasted values.

[86] More information on the methodology used to develop the EE forecast is available at the ISO's "Energy-Efficiency Forecast Working Group," webpage, http://www.iso-ne.com/committees/planning/energy-efficiency-forecast. ISO New England, *Final 2019 Energy-Efficiency Forecast* (May 1, 2019), https://www.iso-ne.com/static-assets/documents/2019/04/eef2019_final_fcst.pdf.

The final EE forecast projects the growth of annual savings in the average, total, and peak energy use for the region and each state. The results, which are based on an average annual program spending rate among the six states of $1.177 billion per year, show that the regional annual average savings in energy use attributable to new energy-efficiency measures (i.e., not cumulative from EE savings before 2019) is 1,940 gigawatt-hours (GWh). The forecast for the total savings in energy use from increased EE projected for 2019 to 2028 is 17,457 GWh. The states' increased annual average savings in energy use ranges from 94 GWh in New Hampshire to 1,172 GWh in Massachusetts.

Table 3-2 shows the growth of regional passive demand resources and EE for 2019 through 2028. Over the entire forecast period, the regional annual peak demand is estimated to decrease by an average of 273 MW as a result of passive demand resources and energy efficiency. The forecast for the total decrease in summer peak demand attributable to EE is 2,459 MW from 2019 to 2028. The states' increase in the annual average savings in peak demand ranges from 11 MW in Vermont to 167 MW in Massachusetts.

Table 3-2
Summary of EE Forecast Annual Electric Energy Savings and Peak Demand Reductions for New England and the States, 2019 and 2028 (GWh, MW)

State	Annual Energy Savings (GWh)			Summer Peak Demand Reductions (MW)			Winter Peak Demand Reductions (MW)		
	2019	2028	CAGR[(a)]	2019	2028	CAGR[(a)]	2019	2028	CAGR[(a)]
CT	3,600	6,259	6.3	662	1,045	5.2	560	930	5.8
ME	1,257	2,148	6.1	192	338	6.5	170	307	6.8
MA	9,435	19,982	8.7	1,573	3,073	7.7	1,479	2,904	7.8
NH	682	1,532	9.4	120	240	8.0	96	197	8.3
RI	1,465	3,062	8.5	241	450	7.2	221	428	7.6
VT	857	1,771	8.4	125	226	6.8	143	242	6.0
ISO	**17,297**	**34,754**	**8.1**	**2,913**	**5,372**	**7.0**	**2,668**	**5,008**	**7.2**

(a) "CAGR" stands for compound annual growth rate.

3.3 Distributed Photovoltaic Generation Forecast for New England

Small-scale, distributed photovoltaic generation resources have been growing significantly in New England since 2012 and has already significantly altered the region's seasonal load profiles. BTM PV distributed generation reduces regional annual energy use and summer peak demand, as accounted for in the ISO's PV nameplate capacity forecast and PV energy forecast. As BTM PV penetrations increase, the need for resource ramping will also increase to serve the increasing fluctuations in net demand, as well as the more severe light-load conditions experienced in the shoulder seasons.[87] Because PV facilities constitute the largest segment of DG resources throughout New England and have been growing rapidly in recent years, the ISO's analysis of DG and the DG forecast focuses exclusively on the growth of

[87] *Ramping up* and *ramping down* refer to generators' increasing or decreasing output to meet changing load levels, such as in the early morning, which typically involves ramping up, and in the late evening, which typically involves ramping down. ISO New England, *ISO-NE Net Loads with Increasing Behind-the-Meter PV*, PAC presentation (June 10, 2016), available at https://www.iso-ne.com/static-assets/documents/2016/06/a8_isone_net_loads_with_increasing_behind_the_meter_pv.pdf.

photovoltaics. However, the ISO continues to monitor the growth of non-PV DG, including behind-the-meter energy-storage facilities, to determine whether separate forecasts of these resources may be warranted.

3.3.1 PV Nameplate Capacity Forecast

The ISO's RSP19 nameplate PV forecast is based on recent historical installation trends and updated state and federal policy information and reflects PV participation in the wholesale markets.[88] Table 3-3 lists the state-by-state forecast of annual and cumulative PV nameplate capacities (MW_{AC} [alternating current] ratings), after applying discount factors, through the 10-year planning horizon. These projections include all existing and future PV in the FCM, as well as PV that does and does not participate in the ISO's wholesale energy markets and that reduces the load the ISO observes.[89] To ensure proper accounting, the ISO classifies the forecast into three different types of PV, each of which receives a different treatment in system planning studies:

- FCM resources with capacity supply obligations
- *Energy-only resources* (EORs), which are generation resources that participate in the wholesale energy markets and receive energy market revenues but choose to not participate in the FCM[90]
- Behind-the-meter resources (BTM PV)

System planning studies treat PV resources participating in the ISO wholesale markets as resources with sizes and locations visible to the ISO. PV resources with FCM capacity supply obligations are considered either generators or demand resources. Energy-only resources are registered in the ISO's Customer Asset Management System (CAMS) and collect energy payments, but they do not necessarily supply the ISO with generator characteristics. Both FCM and energy-only resources are market resources that do not reduce the gross demand forecast.

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[88] A full explanation of the methodology used for the PV forecast is available in the file "Final 2019 PV Forecast" (April 29, 2019), https://www.iso-ne.com/static-assets/documents/2019/04/final-2019-pv-forecast.pdf.

[89] The forecast reflects distributed generation PV, which includes projects typically 5 MW or less in nameplate capacity; therefore, the forecast does not include policy drivers for larger-scale projects, which are generally accounted for as part of ISO's interconnection process and participate in wholesale markets.

[90] Settlement-only resources and non-FCM generators, as defined in Operating Procedure No. 14 (OP 14), *Technical Requirements for Generators, Demand-Response Resources, Asset-Related Demands, and Alternative Technology Regulation Resources*, are included in this market type. Refer to OP 14 (April 1, 2019), at http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op14/op14_rto_final.pdf.

Table 3-3
New England States' Annual and Cumulative PV Nameplate Capacities, 2019 to 2028 (MW_{AC})

Year	Annual Sum of States	Annual Total Capacities (MW_{AC} nameplate ratings)					
		CT	MA	ME	NH	RI	VT
Through 2018	2,883.8	464.3	1871.3	41.4	83.8	116.7	306.3
2019	463.1	68.4	292.0	7.1	12.7	51.3	31.5
2020	472.8	91.1	288.0	7.1	12.7	51.3	22.5
2021	458.0	97.5	272.0	6.7	12.0	48.5	21.3
2022	451.9	97.5	272.0	6.7	12.0	42.4	21.3
2023	426.0	71.6	272.0	6.7	12.0	42.4	21.3
2024	358.0	71.6	204.0	6.7	12.0	42.4	21.3
2025	330.0	71.6	176.0	6.7	12.0	42.4	21.3
2026	324.7	71.6	170.7	6.7	12.0	42.4	21.3
2027	291.3	43.5	165.3	6.7	12.0	42.4	21.3
2028	284.6	42.1	160.0	6.7	12.0	42.4	21.3
Total	**6,744.4**	**1,190.9**	**4,143.2**	**109.7**	**205.6**	**564.6**	**530.3**

System planning studies, including Installed Capacity Requirement (ICR) calculations (see Section 4.1.1), consider behind-the-meter PV as part of the demand forecast. Figure 3-2 illustrates the classification of the 2019 PV forecast into FCM, non-FCM energy-only resources, and BTM PV. Table 3-4 shows the data for this figure.

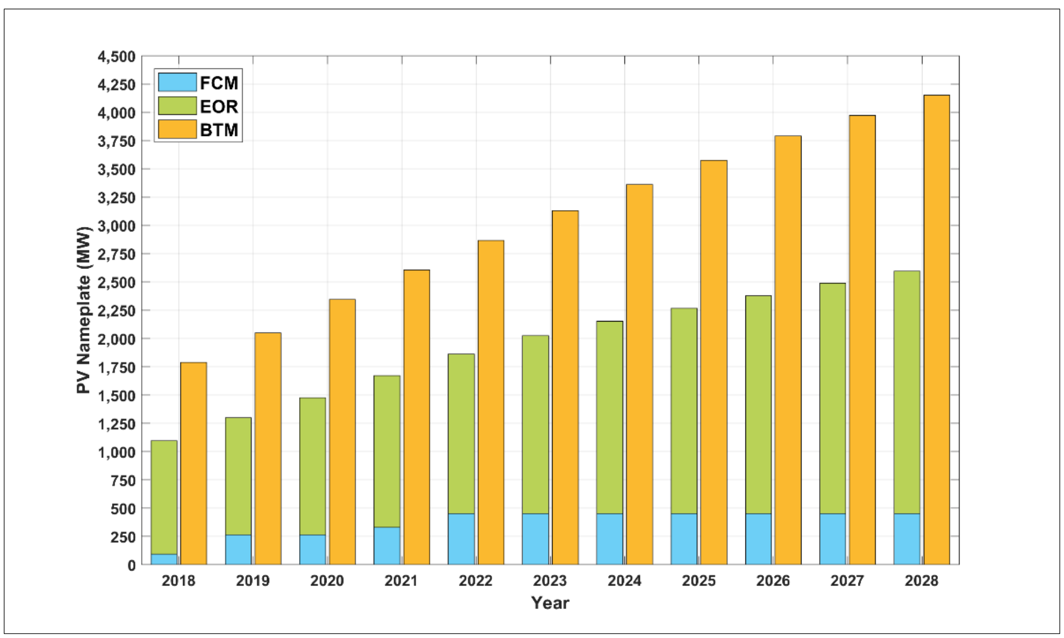

Figure 3-2: Cumulative New England PV forecast for each classification of PV, 2019 to 2028 (MW).

Notes: The FCM category reflects the PV nameplate of all or portions of the FCM-qualified resources. The FCM value is held constant for the summer of 2022 and beyond. PV has no value in the FCM during the winter months; see Section 4.1.3. The net load forecast reflects reductions of BTM PV.

Table 3-4
Cumulative New England PV Forecast for Each Classification of PV, 2019 to 2028 (MW)

PV Category	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
FCM PV	92.4	264.4	264.4	331.1	452.9	452.9	452.9	452.9	452.9	452.9	452.9
Non-FCM, Energy-Only PV	1,003.1	1,034.8	1,210.6	1,340.0	1,409.3	1,571.6	1,700.0	1,814.4	1,926.1	2,035.1	2,141.3
Behind-the Meter PV	1,788.3	2,047.7	2,344.8	2,606.6	2,867.5	3,131.2	3,360.9	3,576.5	3,789.5	3,971.9	4,150.2

3.3.2 PV Energy Forecast

Using the nameplate PV forecast, historical installation rates, and performance based on a statistical sample of PV production data, the ISO estimates a PV energy forecast. Beginning with the 2019 nameplate forecast, the ISO has estimated BTM PV's summer peak load reductions along with the growth of PV penetrations. Higher PV penetrations account for diminishing PV production overall because they cause peak loads to occur later in the afternoon when PV is less effective at reducing the load.[91] Table 3-5 shows the values of regional annual energy savings and summer peak demand reductions from the 2019 forecast of BTM PV.

Table 3-5
Summary of BTM PV Forecast Annual Electric Energy Savings and Peak Demand Reductions for New England and the States, 2019 and 2028 (GWh, MW)

State	Annual Energy Savings (GWh)			Summer Peak Demand Reductions (MW)		
	2019	2028	CAGR[(a)]	2019	2028	CAGR[(a)]
CT	623	1,441	9.8	173	285	5.7
ME	57	133	9.9	16	27	5.8
MA	1,218	2,538	8.5	345	509	4.4
NH	107	229	8.8	31	47	4.8
RI	84	253	13.1	23	50	8.8
VT	402	628	5.1	119	133	1.2
ISO	**2,490**	**5,222**	**8.6**	**708**	**1,051**	**4.5**

(a) "CAGR" stands for compound annual growth rate.

3.4 The Net Demand Forecast

The net forecast is the gross demand forecast lowered by the forecasted BTM PV load reductions and the energy-efficiency forecast. The net forecast is detailed in Figure 3-3:, Figure 3-4, and Figure 3-5 and Table **3-6** to Table 3-8. Figure 3-3: shows the gross annual energy-use forecast (NEL), minus the BTM PV and EE forecasts. The results show declining long-run growth in electric energy use. Similarly,

[91] ISO's detailed analysis and resulting methodology for estimated summer peak load reductions is available as an appendix in "Final 2016 PV Forecast Details," at https://www.iso-ne.com/static-assets/documents/2016/09/2016_solar_forecast_details_final.pdf.

Figure 3-4 shows the amounts that BTM PV and EE reduce the gross summer peak load. Figure 3-5 shows the amount that EE reduces the gross winter peak load. Table 3-6 compares the gross energy and peak demand forecasts with the net forecasts. The net summer peak is projected to remain relatively flat over the forecast horizon. The net winter peak is flat (i.e., negative 0.6%) over the 10-year forecast. The BTM PV does not reduce the winter peak because the winter peak occurs after the sun has set. Table 3-7 shows the net load forecast for each of the New England states (megawatt-hours [MWh] and MW), and Table 3-8 shows the net load forecast for each of the RSP subareas. The net systemwide *load factor* (i.e., the ratio of the average hourly load during a year to peak hourly load) based on the net 50/50 and annual energy forecasts remains relatively consistent over the forecast horizon, ranging from 56.1% to 56.7%.

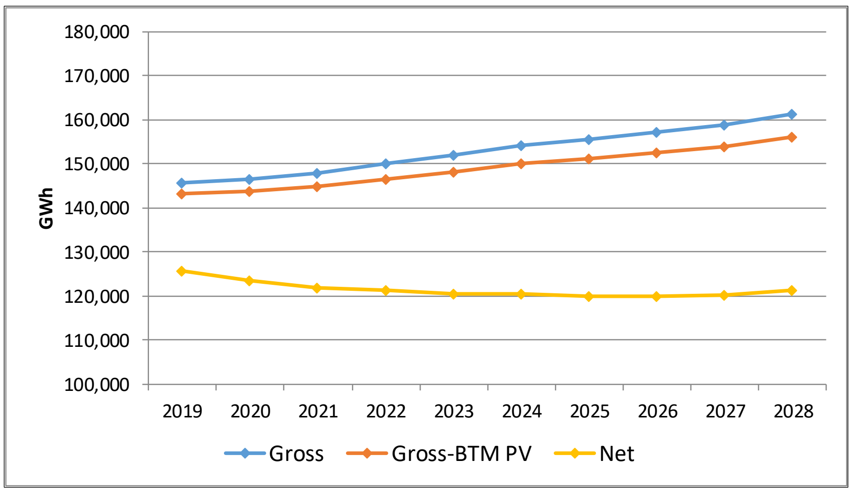

Figure 3-3: RSP19 gross annual energy-use forecast (blue); gross energy forecast minus BTM PV (orange); gross energy forecast net of EE and BTM PV (yellow) for 2019 to 2028 (MW).

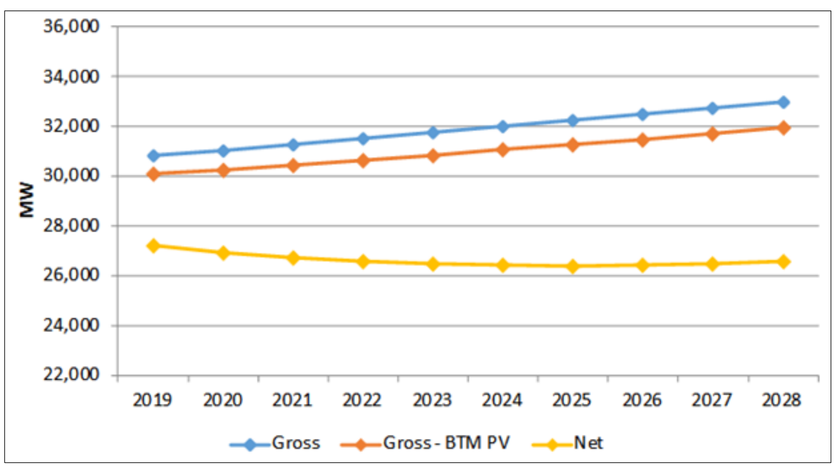

Figure 3-4: RSP19 gross summer peak demand forecast (90/10) (blue); gross demand forecast minus BTM PV (orange); and net of EE and BTM PV demand forecast (yellow) for 2019 to 2028 (MW).

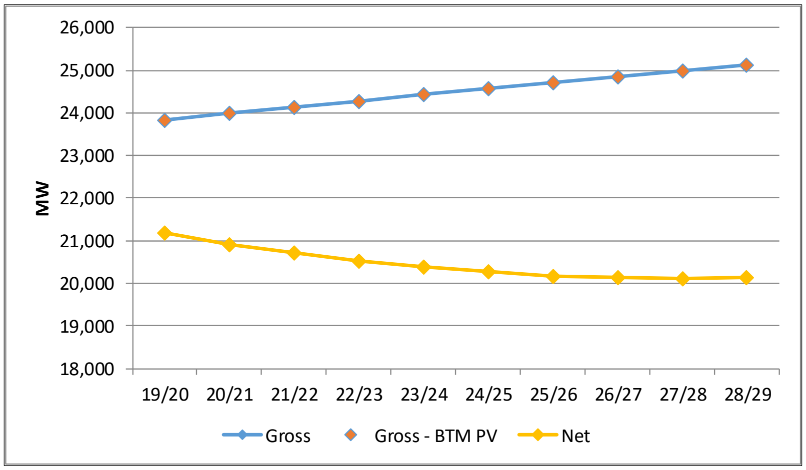

Figure 3-5: RSP19 gross winter peak demand forecast (90/10) (blue); gross demand forecast minus BTM PV (red diamonds); and net of EE and BTM PV demand forecast (yellow) for 2019 to 2028 (MW).

Table 3-6
Percentage Growth Rates of the Gross and Net Forecasts of Annual and Peak Electric Energy Use, 2019 to 2028

	Gross	Net[(a)]
Annual Energy	1.1	−0.4
50/50 Summer	0.7	−0.4
90/10 Summer	0.8	−0.3
50/50 Winter	0.6	−0.6
90/10 Winter	0.6	−0.6

(a) The net forecast is the gross forecast minus BTM PV and the energy-efficiency forecast.

Table 3-7
State and Systemwide Net Forecasts of Annual and Peak Electric Energy Use, 2019 to 2028 (MWh, MW)[(a)]

Area	Energy (1,000 MWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50 Load		90/10 Load		CAGR[(b)]	50/50 Load		90/10 Load		CAGR[(b)]
	2019	2028	CAGR[(b)]	2019	2028	2019	2028		2019/20	2028/29	2019/20	2028/29	
CT	30,149	29,079	−0.4	6,471	6,108	6,885	6,536	−0.6	5,087	4,784	5,245	4,949	−0.7
ME	11,926	12,979	0.9	1,908	1,953	2,009	2,072	0.3	1,898	1,973	1,936	2,018	0.4
MA	58,178	53,470	−0.7	11,946	11,416	12,970	12,627	−0.5	9,308	8,629	9,663	9,034	−0.8
NH	12,131	12,629	0.4	2,294	2,300	2,417	2,433	0	1,929	1,876	1,997	1,949	−0.3
RI	7,846	7,299	−0.8	1,854	1,842	2,049	2,083	-0.1	1,279	1,167	1,319	1,215	−1.0
VT	5,593	4,880	−1.5	851	789	884	825	−0.8	975	938	1,012	965	−0.4
ISO[(c, d)]	**125,823**	**121,336**	**−0.4**	**25,323**	**24,408**	**27,212**	**26,576**	**-0.4**	**20,476**	**19,368**	**21,173**	**20,130**	**−0.6**

(a) The total load-zone projections are similar to the state load projections and are available at the ISO's "2019 Forecast Data File" (April 23, 2019), https://www.iso-ne.com/static-assets/documents/2019/04/forecast_data_2019.xlsx; tabs #2A-2C, "ISO-NE Control Area, States, RSP Subareas, and Standard Market Design (SMD) Load Zones Energy and Seasonal Peak Load Forecast."

(b) CAGR values shown for the summer and winter peak loads are for the 50/50 forecasts.

(c) The net forecasts are not used in the development of the Installed Capacity Requirement.

(d) Totals may not equal the sum because of rounding and may not exactly match the results for other tables in this section.

Table 3-8
Forecast of Net Demand in RSP Subareas, 2019 to 2028 (GWh, MW)[a]

Area	Energy (1,000 MWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50 Load		90/10 Load		CAGR[b]	50/50 Load		90/10 Load		CAGR[b]
	2019	2028	CAGR[b]	2019	2028	2019	2028		2019/20	2028/29	2019/20	2028/29	
BHE	1,682	1,831	0.9	269	275	283	292	0.3	269	279	274	286	0.4
ME	5,621	6,118	0.9	900	923	948	979	0.3	927	965	946	988	0.5
SME	4,263	4,642	0.0	680	696	716	739	0.3	648	672	661	688	0.4
NH	10,301	10,788	0.5	1,929	1,949	2,032	2,061	0.1	1,645	1,615	1,702	1,677	−0.2
VT	6,668	6,111	−1.0	1,075	1,022	1,121	1,072	−0.6	1,127	1,088	1,169	1,122	−0.4
BOSTON	27,411	26,134	−0.5	5,640	5,445	6,113	6,005	−0.4	4,237	3,934	4,399	4,118	−0.8
CMA/NEMA	7,376	6,997	−0.6	1,509	1,455	1,636	1,606	−0.4	1,200	1,106	1,246	1,157	−0.9
WMA	8,850	8,008	−1.1	1,798	1,692	1,953	1,875	−0.7	1,593	1,471	1,654	1,538	−0.9
SEMA	12,971	11,863	−1.0	2,672	2,514	2,907	2,789	−0.7	2,069	1,921	2,147	2,011	−0.8
RI	10,893	10,113	−0.8	2,458	2,402	2,701	2,700	−0.3	1,736	1,589	1,794	1,657	−1.0
CT	14,336	13,632	−0.6	3,073	2,865	3,270	3,068	−0.8	2,429	2,268	2,505	2,347	−0.8
SWCT	9,717	9,370	−0.4	2,086	1,969	2,219	2,106	−0.8	1,641	1,544	1,692	1,597	−0.7
NOR	5,735	5,729	0.0	1,235	1,201	1,313	1,283	−0.3	955	914	985	946	−0.5
ISO total[c, d]	**125,478**	**120,613**	**−0.4**	**25,323**	**24,408**	**27,212**	**26,576**	**−0.4**	**20,476**	**19,368**	**21,173**	**20,130**	**−0.6**

(a) The total load-zone projections are similar to the state load projections and are available at the ISO's "2019 Forecast Data File;" https://www.iso-ne.com/static-assets/documents/2019/04/forecast_data_2019.xlsx, tabs #2A-2C, "ISO-NE Control Area, States, RSP Subareas, and SMD Load Zones."

(b) CAGR values shown for the summer and winter peak loads are for the 50/50 forecasts.

(c) The net forecasts are not used in the development of the Installed Capacity Requirement

(d) Totals may not equal the sum because of rounding and may not exactly match the results for other tables in this section.

3.5 Summary of Key Findings of the Demand, Energy-Efficiency, and PV Forecasts

The RSP19 forecasts of annual energy use and peak loads are key inputs in establishing the system needs discussed in Section 4 through Section 9. The key points of the forecast are as follows:

- The 10-year net energy for load, accounting for both EE and PV, is projected to decrease from 125,823 GWh in 2019 to 121,336 GWh in 2028, which represents a decline of 0.4% per year. The RSP19 50/50 net summer peak forecast is 25,323 MW for 2019, which declines to 24,408 MW for 2028. The 90/10 net summer peak forecast, which represents more extreme summer heat waves, is 27,212 MW for 2019 and declines by 0.3% per year to 26,576 MW in 2028.
- The EE forecast drives the reduction of the growth rate of the 10-year gross winter peak demand from 0.6% to a net annual value of −0.6%. The projected decline of the net peak load may help mitigate winter reliability concerns.
- Regional summer demand savings from energy efficiency are expected to grow from 2,913 MW in 2019 to 5,372 MW in 2028. New England states' annual investments in EE programs are expected to be more than $1 billion per year for 2019 through 2028. These EE investments

remain a major factor in the expansion of passive demand resources in the region, which are projected to grow at an average rate of 273 MW per year across the 10-year horizon.

- Photovoltaic resources reached 2,884 MWac in nameplate capacity by the end of 2018 and are expected to grow to 6,744 MWac by 2028. The estimated reductions in summer seasonal peak loads due to BTM PV resources are 708 MW in 2019 and 1,051 MW in 2028; BTM PV does not reduce winter peaks because they typically occur after the sun has set.
- The ISO is closely monitoring the preliminary strategic electrification initiatives implemented by the New England states to meet mandates and goals for reducing greenhouse gases (see Section 8.2.2). These initiatives are just beginning but are expected to promote the growth of emerging technologies, such as electric vehicles and air-sourced cold-climate heat pumps. Depending in part on the timing and rate of their adoption, these new electric uses will be important considerations in the long-term outlook for electric energy and peak demand in the coming years.

Section 4
Resource Adequacy—Resources, Capacity, and Reserves

The ISO's system planning process identifies the amounts and locations of capacity resources the system needs for ensuring resource adequacy and how the region is meeting these needs through the Forward Capacity Market (FCM) and the locational Forward Reserve Market (FRM). The amount of capacity the system requires in a given year is determined through the Installed Capacity Requirement (ICR) calculation, which accounts for uncertainties, contingencies, and resource performance under a wide range of existing and future system conditions. The procurement of resources providing operating reserves for the system and local areas addresses contingencies, such as unplanned outages. Collectively, the forecasts of future electricity demand (as discussed in Section 3), the ICR calculation, the procurement of resources providing capacity and reserves, and the operable-capacity analyses that consider future scenarios of load forecasts and operating conditions are referred to as the resource-adequacy process.

This section discusses the following topics:

- Requirements for resource adequacy over the 10-year planning period
- Analyses conducted to determine the systemwide and local-area needs for ensuring resource adequacy
- The region's efforts to meet the need for resources through market initiatives, such as the FCM and FRM
- Energy efficiency (EE) and renewable resources being developed by initiatives prompted through policy changes by the six New England states

This section also discusses the results of the net operable-capacity assessments of the system under a variety of deterministic stressed-system conditions.[92] Also addressed are existing and future generating resources, including the capacity supply obligations (CSOs) to the markets and the seasonal claimed capability (SCC) of existing resources and projects proposed through the ISO's interconnection queue that can help meet the long-term needs of the system.[93]

4.1 Determining Systemwide and Local-Area Capacity Needs

The Installed Capacity Requirement forms the basis for determining the future systemwide capacity needs. The planning process also determines the need for localized capacity, accounting for export and import transmission capabilities (or limitations) of these capacity zones (see Section 2.4). The annual Forward Capacity Auctions (FCAs) and annual and monthly reconfiguration auctions are intended to

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

[93] Pursuant to Schedules 22, 23, and 25 of ISO's *Open Access Transmission Tariff*: Schedule 22, *Large Generator Interconnection Procedures* (January 29, 2019), https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch22/sch_22_lgip.pdf; Schedule 23, *Small Generator Interconnection Procedures* (January 29, 2019, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch22/sch_22_lgip.pdf; and Schedule 25, *Elective Transmission Upgrade Interconnection Procedures* (January 29, 2019), https://www.iso-ne.com/static-assets/documents/2015/02/sch_25.pdf.

procure the needed capacity, systemwide and for identified capacity zones. This section provides the results of the systemwide and local-area analyses for the planning period.

4.1.1 Systemwide Installed Capacity Requirements

The ISO develops the ICR in consultation with NEPOOL and other interested parties through an extensive stakeholder process. The ISO vets the assumptions used to develop the ICR with the New England stakeholders, and the Power Supply Planning Committee (PSPC) reviews the values developed by the ISO. They are then reviewed, discussed, and voted on by the Reliability Committee (RC) and the Participants Committee (PC) before they are filed with FERC.

As part of a stakeholder process conducted in 2018, the methodologies used to develop various assumptions associated with the development of the ICRs have been changed to better reflect modeling of the system conditions. The changes were implemented over a two-year period. The development of the ICR calculations performed for 2018 captured the modeling of the load-reduction uncertainty associated with BTM PV and the increase in the minimum system operating reserve (from 200 MW to 700 MW) needed for reliable system operations. An equivalent demand forced-outage rate (EFORd) was used instead of an assumed 20% derate to model fast-start generator performance in the Transmission Security Analysis (TSA) calculations, and the load relief due to a 5% voltage reduction was decreased from 1.5% to 1.0%.[94] These changes were effective starting with ICR calculations performed in 2019.

This section of RSP19 discusses the established net ICR values for the 2019/2020 through 2022/2023 capacity commitment periods (CCPs) and illustrates representative net ICR values for the 2024/2025 through 2028/2029 periods.[95] The established net ICR values for the 2019/2020 through 2022/2023 CCPs reflect the latest ICR values approved by FERC and were developed using the 2018 CELT Report load data.[96] The representative net ICR values for 2024/2025 through 2028/2029 are calculated using the same assumptions used to develop the net ICR for 2022/2023 except for the demand forecast net of BTM PV.[97] The net demand forecast used to calculate the representative net ICR values are based on the 2019 CELT forecast.[98]

The representative net ICR values do not indicate the definitive amount of capacity the region will purchase for that period but provides stakeholders with a general forecast of the likely capacity needs of the region into the future. The actual amount of capacity the region will purchase in an FCA and

[94] The EFORd is the portion of time a unit is in demand but is unavailable because of forced (i.e., unplanned) outages.

[95] Established ICR values refer to the FERC-approved values. Representative net ICR values are the representative ICRs for the region, minus the tie-reliability benefits associated with the Hydro-Québec Interconnection Capability Credits (HQICCs). (As defined in the ISO's tariff, the HQICC is a monthly value that reflects the annual installed capacity benefits of the HQ Interconnection, as determined by the ISO using a standard methodology on file with FERC.) The ISO calculates representative net ICR values solely to inform New England stakeholders; it does not file these values with FERC for approval. The values for FCA 14 for the 2023/2024 CCP are scheduled to be filed with FERC in November 2019. For additional information about ICRs, see the ISO's "Installed Capacity Requirements," webpage at http://www.iso-ne.com/system-planning/resource-planning/installed-capacity-requirements/.

[96] ISO New England, *2018–2027 Forecast Report of Capacity, Energy, Loads, and Transmission* (May 2018), https://www.iso-ne.com/static-assets/documents/2018/04/2018_celt_report.xls.

[97] ISO New England, *Net Installed Capacity Requirements, Representative Future Net ICRs, and Operable Capacity Analysis for 2019 Regional System Plan*, PAC presentation (May 21, 2019), https://www.iso-ne.com/event-details?eventId=138765.

[98] ISO New England, *2019–2028 Forecast Report of Capacity, Energy, Loads, and Transmission* (May 2019), http://www.iso-ne.com/system-planning/system-plans-studies/celt.

subsequent reconfiguration auctions will be based on the net ICR and the resource offers resulting from the use of demand curves. Specifically, beginning with FCA 11 for capacity commitment period 2020/2021, the ISO has developed systemwide and zonal demand curves using a marginal-reliability-impact (MRI)-based methodology to procure capacity.[99]

Table 4-1 shows the actual and representative New England net ICRs for 2019/2020 to 2028/2029 and the resulting reserves expressed as a percentage of the 2019 CELT Report forecast of the 50/50 peak demands.[100] The percentage resulting reserves associated with the actual net ICRs would be approximately 1.6% lower if these requirements were expressed as a percentage of the 2018 CELT 50/50 peak demands. The 2018 CELT 50/50 peak demands are approximately 340 MW to 420 MW higher than the corresponding forecast in the 2019 CELT Report. The 50/50 peak forecast for the years shown in Table 4-1 is equal to the gross demand forecast minus reductions for BTM PV (see Section 3.3).

Table 4-1
Actual and Representative New England Net Installed Capacity Requirements and Resulting Reserves (MW, %)

Commitment Periods	2019 CELT Forecast 50/50 Peak (MW)[(a)]	Actual and Representative Future Net ICR (MW)[(b)]	Resulting Reserves (%)[(c)]
2019/2020	28,236	33,390	18.3
2020/2021	28,353	33,520	18.2
2021/2022	28,499	33,550	17.7
2022/2023	28,670	33,750	17.7
2023/2024	28,838	TBD[(d)]	—
2024/2025	29,014	32,950	13.6
2025/2026	29,196	33,165	13.6
2026/2027	29,382	33,390	13.6
2027/2028	29,576	33,625	13.7
2028/2029	29,781	33,870	13.7

(a) The 2019 relevant CELT forecast 50/50 peak loads reflect the BTM load reductions from the PV forecast as described in Section 3.

(b) Net ICR values for 2019/2020 to 2022/2023 are the latest values approved by FERC. These net ICR values were developed using 2018 CELT Report loads.

(c) The resulting reserves percentage is calculated using the 2019 CELT Report loads. The resulting reserves percentage for 2019/2020 to 2022/2023, when calculated using their respective 2018 CELT Report loads, ranged from 16.1 % to 16.8% (These values are not shown in the above table).

(d) As of the RSP19 publication date, the net ICR for 2023/2024 was under development and scheduled to be filed with FERC in November 2019.

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99 FERC, ISO New England Inc. and New England Power Pool Participants Committee letter order accepting filing, 155 FERC ¶ 61,319, Docket No, ER16-1434-000 (June 28, 2016). In its order, FERC accepted the new demand curve design as well as a transition mechanism for the systemwide capacity demand curve. The transition curve is a hybrid of the previous linear demand-curve design and the new MRI-based design. While systemwide capacity demand curves were developed for FCA 9 and FCA 10, a linear methodology was used to develop the demand curves for these auctions.

100 Resulting reserves are the amount of capacity in excess of the forecast 50/50 peak load. Percentage resulting reserves = [{(Net ICR − 50/50 peak load) ÷ 50/50 peak load} × 100].

As shown in Table 4-1, the region's net ICR is expected to grow from 33,390 MW in 2019 to a representative value of 33,870 MW by 2028. This represents an average growth of approximately 53 MW per year, which is equivalent to approximately an annual compound growth rate (CAGR) of 0.16% per year compared with the 0.59% CAGR of the net 50/50 peak demand after reflecting the BTM PV.

4.1.2 Local Resource Requirements and Limits

While the ICR addresses New England's total capacity requirement assuming the system overall has no transmission constraints, certain subareas are limited in their ability to import or export power. To address the impacts of these constraints on subarea reliability, before each FCM auction, the ISO determines the *local sourcing requirement* (LSR) and *maximum capacity limit* (MCL) for certain subareas within New England. An LSR is the minimum amount of capacity that must be electrically located within an import-constrained capacity zone to meet the net ICR. An MCL is the maximum amount of capacity electrically connected in an export-constrained capacity zone used to meet the net ICR for the New England region. Before each FCA, areas that meet certain objective criteria for zonal modeling are designated as capacity zones and assigned an LSR or MCL.[101] Establishing capacity zones is a mechanism to ensure that the appropriate amount of capacity is procured within each capacity zone and contributes effectively to meet total system reliability. (See Section 4.2 for further discussion of capacity zones.)

The latest LSR and MCL values for the last five capacity commitment periods, as approved by FERC, are tabulated in Table 4-2.[102] Future LSR and MCL values have not been developed because insufficient information exists for the ISO to determine whether future import and export capacity zones, if any, will be established.

[101] LSRs and MCLs are based on network models using transmission facilities that will be in service no later than the first day of the relevant capacity commitment period. Capacity zones are developed pursuant to ISO tariff, Section III.12.4. Annually, in the November timeframe, potential capacity zones are reviewed with stakeholders. For the 2023/2024 CCP, this review was performed on November 15, 2018, and is available at the ISO's PAC presentation, *Forward Capacity Auction 14 Capacity Zone Development Preview* (November 15, 2018), https://www.iso-ne.com/static-assets/documents/2018/11/a4_fca14_zonal_development_presentation.pdf.

[102] The ICR requirements for 2018/2019, 2019/2020 through 2021/2022, and 2022/2023 are available in the FERC filings at https://www.iso-ne.com/static-assets/documents/2017/12/icr_related_values_2018_aras.pdf, https://www.iso-ne.com/static-assets/documents/2018/11/icr_for_aras_2019.pdf, and https://www.iso-ne.com/static-assets/documents/2018/11/icr_filing_fca_13.pdf.

Table 4-2
Actual LSRs and MCLs (MW)[a]

Capacity Commitment Period		LSR (MW)[b]				MCL (MW)[b]
		CT	NEMA/ Boston	SEMA/RI	SENE[c]	NNE[c]
2018/2019	FCA 9	7,020	3,391	7,479	N/A	N/A
2019/2020	FCA 10	N/A	N/A	N/A	10,083	N/A
2020/2021	FCA 11	N/A	N/A	N/A	10,182	8,660
2021/2022	FCA 12	N/A	N/A	N/A	9,973	8,670
2022/2023	FCA 13	N/A	N/A	N/A	10,141	8,545

(a) Source: "Summary of Historical Installed Capacity Requirements and Related Values Tables" in "Summary of the ICR and Related Values and Associated Assumptions" spreadsheet, https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx. These are the latest values filed with FERC.

(b) LSR and MCL values were calculated only for capacity zones triggered to be modeled (see Section 4.2) in that capacity commitment period.

(c) The SENE capacity zone is the aggregation of the NEMA/Boston and SEMA/RI load zones. The NNE capacity zone is the aggregation of the Maine, New Hampshire, and Vermont load zones.

4.1.3 Capacity Supply Obligations from the Forward Capacity Auctions

This section presents the results of FCA 9 through FCA 13, including the amount of capacity that generation, import, and demand resources in the region will supply.

4.1.3.1 Competitive Auctions with Sponsored Policy Resources

In FCA 13, an additional market mechanism was added to the Forward Capacity Market to accommodate state sponsored, out-of-market renewable resources. The Competitive Auctions with Sponsored Policy Resources (CASPR) framework is designed to maintain competitively based, forward capacity price signals while, over time, accommodating the entry into the FCM of new resources sponsored by public entities.[103] CASPR includes a new two-stage, two-settlement process where a secondary market known as a substitution auction (SA) would be held immediately after the primary capacity auction is completed. The primary auction and SA together are the FCA.

The CASPR market design maintains competitively based primary auction prices by minimizing the price-suppressive effect of out-of-market subsidies on competitive (unsubsidized) resources, thereby accommodating the entry of subsidized resources into the FCM over time. CASPR is intended to be a sustainable, market-based approach that extends, rather than upends, the existing capacity market framework. Existing resources awarded capacity supply obligations in the primary auction may subsequently transfer their obligations to new, subsidized resources that do not have CSOs. Transferring resources must then permanently retire (they have no CSOs or interconnection rights) and pay the

[103] *Sponsored policy resources* (SPRs) are new generators, demand, or import capacity resources located in a New England state that receive from that state or applicable local government out-of-market revenues under a renewable, clean, or alternative energy standard in place as of January 1, 2018. State sponsorships available to renewable technologies but not to other types of resources include state Renewable Portfolio Standards and similar renewable energy goals (see Sections 8.3 and 8.4); state initiatives to reduce greenhouse gas emissions (e.g., the Massachusetts *Global Warming Solutions Act*; see Section 8.5.3); and regional carbon cap-and-trade programs, such as the Regional Greenhouse Gas Initiative, state-sponsored, long-term contracts to develop renewable resources, and federal production and investment tax credits (see Section 8.5.3). See the ISO's "New England's Capacity Markets and Renewable Energy Future," discussion paper (June 3, 2015), https://www.iso-ne.com/static-assets/documents/2015/06/iso_ne_capacity_mkt_discussion_paper_06_03_2015.pdf.

subsidized resources for fulfilling their supply obligations. This is arranged, at a clearing price that makes both parties better off, using the two-settlement substitution auction. CASPR does not directly affect the capacity payments by loads or to the other (nonretiring) resources awarded CSOs.[104]

4.1.3.2 Capacity Supply Obligations for the Past Five FCAs

Table 4-3 illustrates the results of the past five FCAs for capacity commitment periods 2018/2019 (FCA 9) through 2022/2023 (FCA 13) and provides the CSO totals at the conclusion of each auction. This table also includes some details on the types of CSOs procured, including self-supply obligation values that reflect bilateral capacity arrangements as well as import CSOs from neighboring balancing authority areas.

Table 4-3
Summary of the FCA Obligations at the Conclusion of Each Auction (MW)[(a)]

Commitment Period	FCA	ICR	HQICC	Net ICR[(b)]	Capacity Supply Obligation[(c)]	Self-Supply Obligation	Import Capacity Supply Obligation
2018/2019	9	35,142	953	34,189	34,695	1,287	1,449
2019/2020	10	35,126	975	34,151	35,567	1,586	1,450
2020/2021	11	35,034	959	34,075	35,835	1,550	1,235
2021/2022	12	34,683	958	33,725	34,828	1,644	1,217
2022/2023	13	34,719	969	33,750	34,839	1,696	1,188

(a) Information regarding the results of annual reconfiguration auctions is available at https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-auction-bilateral-results.

(b) The net ICR equals the ICR minus the Hydro-Québec Interconnection Capability Credits (HQICCs). The ICR applies to the FCA, not the reconfiguration auction.

(c) For FCA 13, the CSO represents obligations received in both the primary auction (34,785 MW) and SA (54 MW)

Table 4-4 illustrates, by resource type, the amounts of new capacity procured during the last five FCAs. Since RSP17, two FCM auctions were conducted: FCA 12 for capacity commitment period 2021/2022 and FCA 13 for CCP 2022/2023.

[104] See FERC, *ISO New England, Inc. Order on Tariff Filing* (accepting CASPR), Docket No. ER18-619, 162¶ 61,205 (March 9, 2018), https://www.iso-ne.com/static-assets/documents/2018/03/er18-619-000_3-9-18_order_accept_caspr.pdf.

Table 4-4
Capacity Supply Obligation for New Capacity
Procured during the Forward Capacity Auctions (MW)[a, b, c]

Capacity Resource	FCA 9	FCA 10	FCA 11	FCA 12	FCA 13
Generation resources	1,060	1,459	264	167	837
Demand-resource total	367	371	640	514	654
Active demand resources	*81*	*20*	*85*	*144*	*87*
Passive demand resources[d]	*286*	*350*	*554*	*371*	*566*
Import resources	1,360	1,361	1,153	1,136	1,108

(a) A full listing of all new and existing resources that qualified to participate in each of the FCAs is available in the "Forward Capacity Obligations" spreadsheets at https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fca-results. In addition, updated summaries of CSOs by resource type for each commitment period are provided monthly in the NEPOOL Participants Committee COO Reports at https://www.iso-ne.com/committees/participants/participants-committee.

(b) Totals may not sum due to rounding.

(c) Totals do not include new capacity uprates from existing generating resources.

(d) Passive demand resources include EE and distributed generation.

4.1.3.3 Capacity Commitment Period 2021/2022

FCA 12 was conducted in February 2018 and procured 34,828 MW of capacity for 2021/2022 capacity commitment period. The auction acquired 30,011 MW of generation, including 167 MW of new generation and 7 MW of new capacity uprates from existing generating resources. The auction also procured 514 MW of demand resources, which includes 358 MW of EE and 13 MW of distributed generation, for a total of 371 MW of passive demand resources.

Approximately 34,828 MW of new and existing resources cleared the auction, which was approximately 1,103 MW above the net ICR of 33,725 MW. While the auction closed with enough resources to meet demand, the ISO rejected two bids to dynamically delist or withdraw capacity from the market for the one-year capacity commitment period.[105] Exelon Generation Co. sought to delist its Mystic 7, 8, and 9 generating facilities in Everett, Massachusetts. When a resource seeks to delist, the ISO evaluates whether the transmission system could be operated securely without the resource; for FCA 12, the ISO's tariff did not allow consideration of other factors (e.g., fuel security; see Section 7). The ISO's mandatory transmission reliability review showed that transmission lines in Boston could be overloaded if Mystic 7 and Mystic 8 were not available during 2021/2022, so these dynamic delist bids were rejected and the generators retained. Mystic 7 is a 575 MW generator that can burn either oil or natural gas, and Mystic 8

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[105] A *delist bid* is a submission in an FCA for an existing FCM resource indicating that the resource wants to opt of the auction before the deadline for qualifying its existing capacity and does not want a CSO below a certain price. The ISO reviews all delist bids for reliability impacts. A *dynamic delist bid* is submitted during the auction and indicates that a resource wants to opt out of receiving a CSO below a certain price. *Static delist bids, retirement delist bids*, and *permanent delist bids* are submitted for a resource before an FCA and cannot be changed during the auction. A *static delist bid* requests that a resource opt out of receiving a CSO at a certain price and reflects either the cost of the resource or a reduction in ratings as a result of ambient air conditions. If a *retirement delist bid* clears, the resource is prohibited from participating in any New England markets and cannot obtain a CSO unless it qualifies for and clears as a new resource in a subsequent FCA. If a *permanent delist bid* clears, the resource is prohibited from participating in any future FCM auctions or assuming any CSO unless it qualifies for and clears as a new resource in a subsequent FCA. A permanently delisted resource may participate in the energy market.

is a 703 MW natural-gas-fired generator. The reliability review found that Mystic 9 was not needed, and it was allowed to leave the capacity market for one year.

Approximately 34.5 MW of resources received obligations under the renewable technology resource (RTR) designation in FCA 12.[106] The RTR designation allows a limited amount of renewable resources to participate in the auction without being subject to the Minimum Offer Price Rule.[107] The RTR eligibility rules are different from the CASPR eligibility rules, meaning a resource that qualifies as a sponsored-policy resource for SA participation may not qualify as a RTR resource for primary auction participation.

4.1.3.4 Capacity Commitment Period 2022/2023

In February 2019, the ISO conducted FCA 13 where 34,839 MW of capacity was procured for the 2022/2023 capacity commitment period, which was approximately 1,089 MW above the net ICR of 33,750 MW. The auction rules allow the region to acquire more or less than the capacity target, providing flexibility to acquire additional capacity and enhanced reliability at a cost-effective price. FCA 13 was the first auction run under CASPR; see Section 4.1.3.1. The substitution auction closed with Vineyard Wind, an offshore wind project (800 MW nameplate) in development off the coast of Massachusetts, assuming an obligation of 54 MW from Pawtucket Power, an existing resource that will retire June 1, 2022.

FCA 13 secured 29,611 MW of generation, including 837 MW of new generation that included renewable resources, such as wind (62 MW) and solar (141 MW), and one large combined-cycle (CC) natural gas plant, Killingly Energy Center (632 MW), under development in Connecticut. The auction also procured 654 MW of demand resources, which includes 434 MW of EE. Overall, interest in the FCM by EE resources continues to be strong, as demonstrated in Figure 4-1, and growth is likely to continue until the standards change.[108] Approximately 145 MW of resources received obligations under the RTR designation in FCA 13. Approximately 336 MW remain in the RTR exemption cap and will be carried over to FCA 14 unless the tariff is changed.

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[106] *Renewable technology resources* are generators or on-peak demand resources located in a New England state that receive from that state or the federal government out-of-market revenues under that state's renewable or alternative energy resource standard in place as of January 1, 2014.

[107] The *Minimum Offer Price Rule* establishes a benchmark price called an offer-review trigger price, which forms the lower limit on offer prices to prevent new resources from entering the FCM at prices below their costs, presuming that new supply offers below the threshold are not attempts to suppress the clearing price.

[108] For example, Section 321 of the US *Energy Independence and Security Act of 2007* (EISA) prohibits the sale of any general service lamp that does not meet a minimum efficiency standard of 45 lumens/watt, effective January 1, 2020. While the implementation of the EISA standards faces some uncertainties, until the current EISA standards go into effect, are modified or revoked, they constitute current law. Therefore, as required by ISO New England's *Manual for Measurement and Verification of On-Peak Demand Resources and Seasonal Peak Demand Resources* (Manual M-MVDR), the ISO will require that the Measurement and Verification Plans submitted during the FCM qualification process reflect the minimum efficiency standards set out by EISA. Standard changes like this may limit growth of EE. See the manual (October 4, 2018) at https://www.iso-ne.com/static-assets/documents/2018/10/manual_mvdr_measurement_and_verification_of_onpeak_and_seasonal_peak_demand_resources_rev07_20181004.pdf.

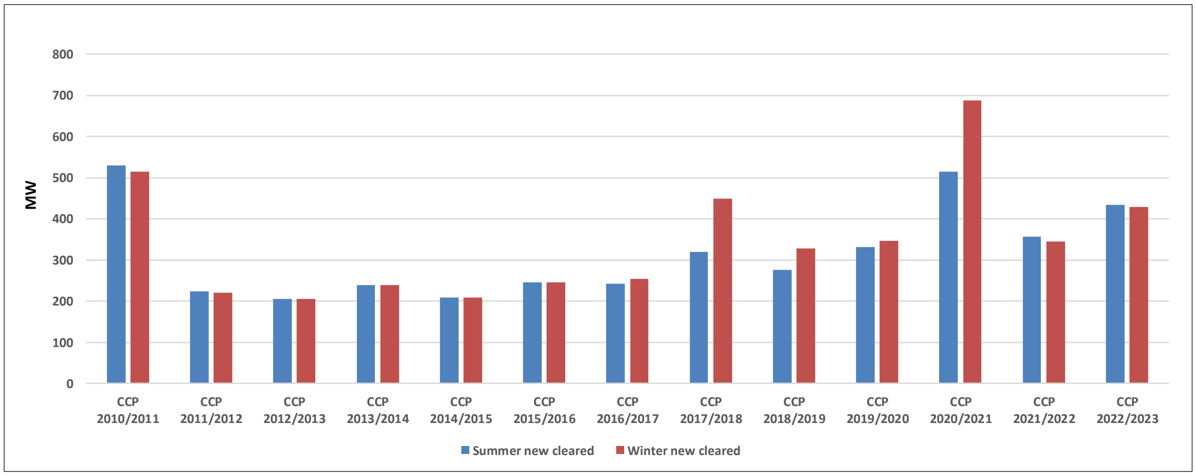

Figure 4-1: Comparison of cleared new summer and winter energy-efficiency resources by capacity commitment period, CCP 2010/2011 to CCP 2022/2023 (MW).

As a temporary solution to address regional energy-security concerns that predominate in the winter and are sparked by limited availability of fuel for gas-fired generators (see Section 7), the ISO incorporated a fuel-security reliability review into the FCM beginning with FCA 13.[109] The new rules, applicable through FCA 15, established a process and criteria for evaluating the reliability impacts of retirement delist bids, substitution auction demand bids, and all annual reconfiguration auction demand bids on system fuel security, as required by the ISO tariff, Section III.13.2.5.2.5A, *Fuel Security Reliability Review*.[110] The fuel-security review consists of an hour-by-hour chronological simulation of the New England electricity supply system for a winter period from the beginning of December through the end of February. One of the key assumptions driving the results of the review is the amount of natural gas available for electricity generation. The process for this fuel security reliability review is detailed in Planning Procedure No. 10 (PP10), *Planning Procedure to Support the Forward Capacity Market*, Appendix I.[111] (Refer to Section 7.7.2 for further discussion on solutions for addressing the region's energy-security risks.)

In FCA 13, the ISO retained two resources, Mystic 8 and 9, for fuel security. Both resources are located in the NEMA/Boston load zone and sought to retire but elected to continue to operate for the 2022/2023 CCP (CCP 13) and possibly the 2023/2024 CCP (CCP 14). (See Section 5.5.4 for information regarding the Boston 2028 needs assessment.)

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[109] ISO New England, "Forward Capacity Market: Retain Resources for Fuel Security Key Project," webpage (2019), https://www.iso-ne.com/committees/key-projects/forward-capacity-market--retain-resources-for-fuel.

[110] A *demand bid* is a request to purchase an amount of energy, at a specified location, or an amount of energy at a specified price associated with a physical load. Like a retirement delist bid in a primary auction, an *SA demand bid* is submitted for a resource before an FCA—and cannot be changed during the auction—if it clears, the resource is prohibited from participating in any New England markets and cannot obtain a CSO unless it qualifies for and clears as a new resource in a subsequent FCA. A *reconfiguration auction demand bid* is submitted days in advance of the annual reconfiguration auction and indicates that a resource wants to opt out of receiving a CSO for a single CCP below a certain price.

[111] ISO New England, Planning Procedure No. 10 (PP 10), *Planning Procedure to Support the Forward Capacity Market*, (May 31, 2019), https://www.iso-ne.com/static-assets/documents/2019/05/pp-10-r23-053119.pdf.

4.1.3.5 Representative Systemwide Resource Needs

The representative net ICR values for future years (Section 4.1.1) indicate the systemwide capacity needs. Table 4-5 compares these systemwide needs with the resources procured in FCA 13, accounting for the future levels of BTM PV (Section 3.3), and the future levels of energy-efficiency resources (Section 3.2). The projection of systemwide capacity needs assumes that all resources with CSOs through FCA 13 are in commercial operation by June 1, 2022, and that they remain in service through the 2028/2029 commitment period.

As shown in Table 4-5, New England will be approximately 2,300 MW to 2,500 MW above net ICR during the 2024/2025 through 2028/2029 capacity commitment periods. This assumes that the projected load and capacity assumptions materialize, no additional retirements occur, and newly proposed resources are in service in accordance with their projected construction schedules. Even if additional resources were to retire, such as Mystic 8 and 9 totaling 1,413 MW, the ISO anticipates meeting the net ICR requirement because sufficient resources exist, EE resources have been forecasted, and additional resources have been proposed in the interconnection queue. The ISO monitors closely the build out of all new, noncommercial resources in anticipation that some may be early or others late. To date, the tendency has been toward new demand resources and renewables being available as much as a year in advance of their expected in-service date, while large-sized generation (e.g., CC generators) has been delayed due to permitting issues and construction delays.

Table 4-5
Future Systemwide Needs (MW)

Year	50/50 Peak Load[(a)]	Representative Net ICR (Need)	FCA 13 (Known Resources)[(b)]	EE Forecast (New Resources)[(c)]	Resource Surplus/Shortage[(d)]
2024/2025	29,014	32,950	34,839	581	2,470
2025/2026	29,196	33,165	34,839	817	2,491
2026/2027	29,382	33,390	34,839	1,018	2,467
2027/2028	29,576	33,625	34,839	1,185	2,399
2028/2029	29,781	33,870	34,839	1,322	2,291

(a) The 50/50 peak loads reflect forecasted BTM PV resources.

(b) FCA 13 resource numbers are based on FCA 13 auction results, assuming no additional retirements, Mystic 8 and 9 resources continue to operate (with a CSO of 1,413 MW), and the same level of imports (i.e., most imports need to requalify for every auction). Details are available at https://www.iso-ne.com/static-assets/documents/2018/11/public_er19-___-000_11-6-18_fca_13_info_filing.pdf.

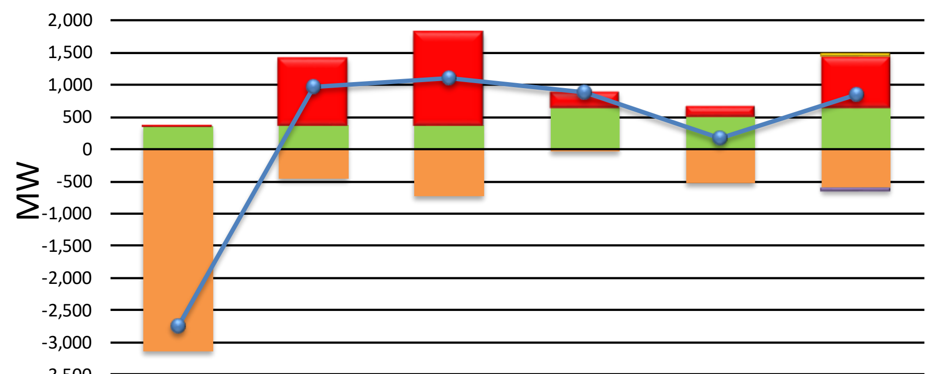
(c) EE cumulative forecast values are based on the 2019 EE forecast. Details are available at the ISO's "Energy-Efficiency Forecast," webpage (2019), https://www.iso-ne.com/system-planning/system-forecasting/energy-efficiency-forecast.

(d) Additional resources would be required if additional resources retired or less capacity imports obtained CSOs.

4.1.3.6 Summary of New Capacity and Delist Bids

As part of the FCM rules, the ISO reviews each primary auction delist bid, SA demand bid, and reconfiguration auction demand bids to determine whether the capacity associated with the request to shed a CSO is needed for the reliability of the New England electric power system. All reviews are performed in accordance with ISO tariff, Section III.13.2.5.2.5 and PP 10, Beginning in 2018, a reliability review will also include a fuel-security assessment.

As shown in Figure 4-2, more than 5,400 MW of generation and demand-response capacity have retired or will retire by 2022/2023.[112] The ISO evaluates the effect of potential retirements on the system as well as the potential impact to the Forward Capacity Market. During the 2018/2019 through 2022/2023 period, over 3,700 MW of generating resources and 2,900 MW of demand resources have been or are expected to be installed. In general, new generation resources typically have been clearing within one or two auctions in response to major retirements on the system, while new demand resources have been clearing at relatively the same levels regardless of retirements. In recent FCAs, fast-start generation, such as gas-fired combined-cycle generators and large gas-fired combustion turbines, are clearing. Renewables such as solar, solar combined with batteries, and wind have also cleared more often.



	FCA 8	FCA 9	FCA 10	FCA 11	FCA 12	FCA 13
SA Retirement Demand Bids						-54
Retirements	-3,135	-464	-728	-25	-519	-596
SA New Supply Generation						54
Cleared New Generation	27	1,060	1,459	264	167	783
Cleared New Demand Response	355	367	379	640	514	654
Net (Additions - Retirements)	-2,753	963	1,110	879	162	841

Figure 4-2: Summary of new capacity additions and retirements clearing in each FCA, for FCA 8 to FCA 13 (MW).

4.2 Determining FCM Capacity Zones

For developing FCM capacity zones, the ISO annually identifies and evaluates all the boundaries and interface transfer capabilities that could be relevant to FCA capacity zone modeling. The review must focus on the actual constraints observed and expected on the New England system and directly considers submitted retirements and rejected delist bids. This review is designed to be responsive to system changes, such as new transmission facilities and new capacity resources.

Determining capacity zones is a two-step process. Step one identifies potential zonal boundaries and associated transfer limits to be tested for modeling in the auction. Step two uses objective criteria to determine whether or not a zone should be modeled for the pertinent capacity commitment period. With respect to step two, the trigger to model an import-constrained zone is based on the quantity of existing resources in the zone, whereas the trigger to model an export-constrained zone is based on the quantity of existing and proposed new resources that could qualify in the zone. Zones neither import- or export-constrained are merged into the Rest-of-Pool (ROP) capacity zone. Once a capacity zone is

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[112] Capacity retirements to date and future retirements include Salem Harbor Station (749 MW); Vermont Yankee (604 MW); Norwalk Harbor Station (342 MW); Brayton Point Station (1,535 MW); Mount Tom Station (143 MW); Pilgrim Nuclear Power Station (677 MW); Bridgeport Harbor 3 (383 MW); Mystic 7 (575 MW); Mystic Jet (9 MW); Pawtucket Power (54 MW) and over 1,200 MW of demand-response resources.

established for an FCA, it will not be modified for reconfiguration auctions. This FERC-approved methodology for determining capacity zones focuses on the review of system conditions for the capacity commitment period associated with the upcoming FCA. Generally, zone determinations are made in the spring of each year and presented to the RC, PSPC, and the PAC.

For FCA 14, it was determined that the following capacity zones will be modeled: Southeastern New England (SENE), Northern New England (NNE) with the Maine capacity zone nested inside the NNE zone, and Rest-of-Pool.[113] The SENE zone was modeled because constraints continue to be observed in the transfer of power into the SENE area. These constraints were observed for the contingency loss of either generating resources or other transmission elements on or near the boundary formed by the combination of the load zones. The NNE zone and the Maine zone were modeled for FCA 14 because a significant amount of new capacity additions were proposed in the northern part of the system during the qualification process, making the area more likely to be export constrained. Similar to previous FCAs, Connecticut was evaluated as a potential import-constrained zone but was merged with the ROP capacity zone because the transmission system has been improved significantly and the markets have responded for building new generation in the area. The Western Massachusetts load zone will continue to form the basis of the ROP capacity zone. The final set of capacity zones for FCA 14 will be filed with FERC in November 2019.

4.3 Analyzing Operable Capacity

The ISO performs systemwide operable-capacity analyses to estimate the net capacity and determine the operable-capacity margin available under summer and winter seasonal peak load conditions for two scenarios (i.e., using the 50/50 and 90/10 forecasts of peak load). The analysis assumes that peak load conditions are reduced to fully reflect BTM PV (see Section 3.3). It also assumes that to meet the assumed peak demand plus operating-reserve requirements, the capacity in New England will only be equal to the net ICR, which relies on load and capacity relief from the implementation of ISO Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4) actions to meet the one-day-in-10 years loss-of-load expectation (LOLE).[114] A negative margin for a specific scenario indicates the extent that possible mitigation actions would be required through predefined protocols, as prescribed in OP 4 or Operating Procedure No. 7 (OP 7), *Action in an Emergency*.[115]

4.3.1 Summer Operable Capacity

Table 4-6 shows the results of the ISO's systemwide operable-capacity analysis during the summer for the 2020/2021 to 2028/2029 commitment periods. The results show that if the loads associated with the 50/50 forecast occurred, the system's operable capacity margin would range from approximately 650 MW to 760 MW before summer 2023. New England could experience operable-capacity margin shortfalls beginning summer 2024 due to the lower reserve margins used for the later years. (As discussed in Section 4.1.1, the ICR calculations for 2019 through 2022 were based on the CELT 2018

113 ISO New England, Forward Capacity Auction 14 Transmission Transfer Capabilities and Capacity Zone Development, presentation (March 20, 2019), https://www.iso-ne.com/static-assets/documents/2019/03/a7_fca_14_transmission_transfer_capabilities_and_capacity_zone_development.pdf.

114 A *loss-of-load expectation analysis* is a probabilistic analysis used to identify the amount of installed capacity (in megawatts) the bulk electric power system needs to meet the NPCC and ISO resource adequacy planning criterion to not disconnect firm load more than one time in 10 years. ISO New England, Operating Procedure No. 4, *Action during a Capacity Deficiency* (May 7, 2019), http://www.iso-ne.com/participate/rules-procedures/operating-procedures.

115 ISO New England, Operating Procedure No. 7, *Action in an Emergency* (January 1, 2019), http://www.iso-ne.com/participate/rules-procedures/operating-procedures.

forecast, which resulted in a reserve margin of 18%. But the calculation for 2024 through 2028 used the CELT 2019 forecast, which resulted in a reserve margin of 13.7% beginning in 2024.) The extent of potentially required OP 4 actions decreases from 2024 to 2028 because the ICR (i.e., the required capacity) grows faster than the projected peak loads, which results in a higher reserve margin in the later years.

Table 4-6
Projected New England Operable-Capacity Analysis for Summer 2020 to 2028, Assuming 50/50 and 90/10 Loads (MW)

Capacity Situation (Summer MW)		2020	2021	2022	2023	2024	2025	2026	2027	2028
50/50 forecast	Load net of BTM PV[(a)]	28,353	28,499	28,670	28,838	29,014	29,196	29382	29,576	29,781
	Operating reserves[(b)]	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
	Total requirement	**30,658**	**30,804**	**30,975**	**31,143**	**31,319**	**31,501**	**31,687**	**31,881**	**32,086**
	Installed capacity (net ICR)[(c)]	33,520	33,550	33,750	N/A	32,950	33,165	33,390	33,625	33,870
	Assumed unavailable capacity	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100
	Total net capacity[(d)]	**31,420**	**31,450**	**31,650**	**N/A**	**30,850**	**31,065**	**31,290**	**31,525**	**31,770**
	Operable capacity margin[(e)]— 50/50 forecast	**762**	**646**	**675**	**N/A**	**−469**	**−436**	**−397**	**−356**	**−316**
90/10 forecast	Load net of BTM PV	30,273	30,449	30,652	30,851	31,058	31,270	31,488	31,713	31,948
	Operating reserves[(b)]	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
	Total requirement	**32,578**	**32,754**	**32,957**	**33,156**	**33,363**	**33,575**	**33,793**	**34,018**	**34,253**
	Installed capacity (net ICR)[(c)]	33,520	33,550	33,750	N/A	32,950	33,165	33,390	33,625	33,870
	Assumed unavailable capacity	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100	−2,100
	Total net capacity[(d)]	**31,420**	**31,450**	**31,650**	**N/A**	**30,850**	**31,065**	**31,290**	**31,525**	**31,770**
	Operable capacity margin[(e)]— 90/10 forecast	**−1,158**	**−1,304**	**−1,307**	**N/A**	**−2,513**	**−2,510**	**−2,503**	**−2,493**	**−2,483**

(a) These values are net of BTM PV, consistent with the other projections in this section. Because this table uses net ICR, the ISO does not subtract the EE forecast; EE is considered part of the resource mix meeting the ICR.

(b) The 2,305 MW value of operating reserves is based on the following assumptions: a first contingency of 1,400 MW plus a 20% increase in the 10-minute operating reserve to compensate for nonperformance of the reserve generators (as discussed in Section 4.4.1) equal to 280 MW, and 30-minute reserves of 625 MW (one half of 1,250 MW).

(c) Net ICR values for 2020/2021 to 2022/2023 are the latest values approved by FERC. These net ICR values were developed using 2018 CELT Report loads. The net ICR values for other years are consistent with the representative future net ICR values in Table 4-5.

(d) The net capacity values are equal to the net ICR minus the assumed unavailable capacity.

(e) “Operable capacity margin” equals “total net capacity” minus “total requirement.”

Table 4-6 also shows that if the projected 90/10 peak loads occurred, New England could experience a large negative operable-capacity margin ranging from approximately −1,150 MW to −1,300 MW before summer 2023 and approximately −2,500 MW for summer 2024 through 2028. Thus, throughout the study period, New England would rely on additional imports or load and capacity relief from OP 4 actions to meet the 90/10 peak demand.

4.3.2 Winter Operable Capacity

Table 4-7 shows the results of the operable-capacity analysis during the winter covering the 2020/2021 through 2028/2029 study period. The results show that if the loads associated with the 50/50 forecast occurred, New England could expect a negative operable-capacity margin ranging from approximately −160 MW to −275 MW before 2023/2024. This negative margin becomes −1,300 MW by the winter of 2024/2025 and approximately −900 MW by the end of the study period. Under the 90/10 peak load, the negative operable-capacity margin ranges from approximately −1,370 MW to −1,440 MW for the CCPs in which the FCA has occurred, and it becomes approximately −2,525 MW by 2024/2025 before reaching the −2,170 level in 2028. The change in the operable-capacity margin beyond 2024/2025 results from the assumption that future capacity additions consist of generating resources without fuel constraints and the extent of unavailable capacity stays constant over the study period.

Table 4-7
Projected New England Operable Capacity Analysis for Winter, 2020/2021 to 2028/2029
Assuming 50/50 and 90/10 Loads (MW)

Capacity Situation (Winter MW)		2020/ 2021	2021/ 2022	2022/ 2023	2023/ 2024	2024/ 2025	2025/ 2026	2026/ 2027	2027/2 028	2028/ 2029
50/50 forecast	Load net of BTM PV[(a)]	23,278	23,420	23,558	23698	23,831	23,964	24,098	24,237	24,376
	Operating reserves[(b)]	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
	Total requirement	**25,583**	**25,725**	**25,863**	**26,003**	**26,136**	**26,269**	**26,403**	**26,542**	**26,681**
	Installed capacity (net ICR)[(c)]	33,520	33,550	33,750	N/A	32,950	33,165	33,390	33,625	33,870
	Assumed unavailable capacity[(d)]	−8,100	−8,100	−8,100	−8,100	−8,100	−8,100	−8,100	-8,100	−8,100
	Total net capacity[(e)]	**25,420**	**25,450**	**25,650**	**N/A**	**24,840**	**25,065**	**25,290**	**25,525**	**25,770**
	Operable capacity margin[(f)]— 50/50 forecast	**−163**	**−275**	**−213**	**N/A**	**−1,286**	**−1,204**	**−1,113**	**−1,017**	**-911**
90/10 forecast	Load net of BTM PV	23,983	24,138	24,283	24428	24,568	24,707	24,847	24,993	25,138
	Operating reserves[(b)]	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
	Total requirement	**26,288**	**26,443**	**26,588**	**26733**	**26,873**	**27,012**	**27,152**	**27,298**	**27,443**
	Installed capacity (net ICR)[(c)]	33,520	33,550	33,750	N/A	32,950	33,165	33,390	33,625	33,870
	Assumed unavailable capacity	−8,600	−8,600	−8,600	−8,600	−8,600	−8,600	−8,600	−8,600	−8,600
	Total net capacity[(e)]	**24,920**	**24,950**	**25,150**	**N/A**	**24,350**	**24,565**	**24,790**	**25,025**	**25,270**
	Operable capacity margin[(f)]— 90/10 forecast	**−1,368**	**−1,493**	**−1,438**	**N/A**	**−2,523**	**−2,447**	**−2,362**	**−2,273**	**−2,173**

(a) These values are net of BTM PV, which are zeros during the winter. Because this table uses net ICR, the ISO does not subtract the EE forecast; EE is considered part of the resource mix meeting the ICR.

(b) The 2,305 MW value of operating reserves is based on the following assumptions: a first contingency of 1,400 MW plus a 20% increase in the 10-minute operating reserve to compensate for nonperformance of the reserve generators (as discussed in Section 4.4.1) equal to 280 MW, and 30-minute reserves of 625 MW (one half of 1,250 MW).

(c) Net ICR values for 2020/2021 to 2022/2023 are the latest values approved by FERC. These net ICR values were developed using 2018 CELT Report loads. The net ICR values for other years are consistent with the representative future net ICR values in Table 4-5.

(d) Assumed unavailable capacity during the winter peak is based on the highest historical planned and unplanned outages during the past 5 years plus the highest amount of historical assumed gas-fired generation at risk rounded to the nearest 100 MW.

(e) The net capacity values are equal to the net ICR minus the assumed unavailable capacity.

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

New England could expect to rely on load and capacity relief from OP 4 during peak loads. The possibility that New England could experience negative operable-capacity margins during the winter peaks, when these peaks are approximately 6,000 MW to 7,000 lower than their corresponding summer peaks, is attributable to the possibility of New England's fossil fuel generators (e.g., natural gas) not having adequate fuel, as discussed in Section 7. The amount of the ICR should be more than adequate to meet the winter peaks if all the capacity resources had adequate fuel. However, New England gas-fired generators rely on surplus natural gas pipeline capability to fuel their generation, but historically, surplus capacity has not been available to power all the generators in the region during the coldest days of winter. The past five years of historical records indicate that generator outages during 50/50 peak weather conditions have been in the 8,100 MW range, and during 90/10 peak weather conditions, outages have been in the 8,600 MW range. Of this amount, due to a lack of natural gas, generator outages during 50/50 peak weather conditions have been in the 4,000 MW range, and during 90/10 peak weather conditions, outages have been in the 4,700 MW range. The ISO is working with stakeholders to develop market-based and other solutions to address energy security (see Sections 7.5.1 and 7.7).

4.4 Determining Operating Reserves and Regulation

In addition to capacity resources being available to meet the region's actual demand for electricity, as discussed in Section 4.1, the system needs a certain amount of resources that can provide operating reserves and system regulation. The overall mix of resources providing operating reserves must be able to respond quickly to system contingencies stemming from equipment outages. The ISO may also call on these resources to provide regulation service for maintaining system frequency and external transactions with neighboring balancing authority areas or to serve load during peak demand conditions. A suboptimal mix of resources overall, with limited amounts of flexible operating characteristics, could result in the system's dependence on higher energy cost resources to provide these services. In the worst case, reliability would be degraded.

Several types of resources in New England have the operating characteristics to respond to contingencies, provide regulation service, and serve peak demand. The generators that provide operating reserves can respond to contingencies within 10 or 30 minutes and can either be synchronized or not synchronized to the power system. Synchronized (i.e., *spinning*) operating reserves are on-line resources that can increase output. Nonsynchronized (i.e., *nonspinning*) operating reserves are off-line, fast-start resources that can be electrically synchronized to the system quickly, reaching maximum output within 10 minutes or within 30 minutes. During real-time daily operations, the ISO determines operating-reserve requirements for the system as a whole and for major import-constrained areas.

This section discusses the need for operating reserves, both systemwide and in major import areas, and the use of specific types of fast-start resources to fill these needs. An overview of the Forward Reserve Market and a forecast of representative future operating-reserve requirements for Greater Southwest Connecticut, Greater Connecticut, and BOSTON are provided. This section also discusses the likely need for additional flexible resources identified by the studies and other actions supporting the region's changing power grid, as discussed in Section 9.

4.4.1 Systemwide Operating-Reserve Requirements

The ISO's operating-reserve requirements, as established in Operating Procedure No. 8, *Operating Reserve and Regulation* (OP 8), are used to protect the system from the impacts associated with a loss of generating or transmission equipment within New England.[116] A certain amount of the power system's resources must be available to provide operating reserves to assist in addressing systemwide contingencies.

To comply with OP 8, *Operating Reserve and Regulation,* the ISO must maintain sufficient reserves in its balancing authority area during normal conditions to be able to replace within 10 minutes the first-contingency loss (N−1) in the New England Reliability Balancing Authority Area multiplied by the contingency-reserve adjustment (CRA) factor for the most recent completed quarter. The current total 10-minute operating-reserve requirement reflecting the CRA factor is 1.2 multiplied by 100% of the first-contingency loss. In addition, OP 8 requires the ISO to maintain sufficient reserves to address the

[116] ISO New England, Operating Procedure No. 8, *Operating Reserve and Regulation* (August 2, 2019), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

uncertainties associated with resource nonperformance, as well as load-forecast error. To meet this need, the ISO must be able to replace at least 50% of the next-largest contingency loss (N–1–1) within 30 minutes plus an additional quantity of replacement reserve for the purposes of meeting NERC requirements to restore 10-minute reserve.

Typically, the largest first-contingency loss is between 1,300 and 1,900 MW, and 50% of the next-largest contingency loss is between 600 and 850 MW. Currently, the expected first-largest contingency is the loss of Phase II interconnection with Hydro-Québec (HQ), while the expected next-largest contingency is the loss of the Mystic 8 and 9 generators.[117]

In accordance with NERC and NPCC criteria for power system operation, ISO Operating Procedure No. 19 (OP 19), *Transmission Operations*, requires system power flows to stay within applicable emergency limits of the power system elements that remain after the loss of any other power system element (N−1).[118] This N−1 limit may be a thermal, voltage, or stability limit of the transmission system. OP 19 further stipulates that within 30 minutes of the loss of the first-contingency element, the system must be able to return to a normal state that can withstand a second contingency. To implement these OP 19 requirements, and as set forth in OP 8, operating reserves must be distributed throughout the system. This requirement is designed to ensure that the ISO can activate all reserves without exceeding transmission system limitations and that the operation of the system remains in accordance with NERC, NPCC, and ISO New England criteria and guidelines.

4.4.2 Locational Reserve Needs for Major Import Areas

To maintain system reliability further, the ISO maintains certain reserve levels within major importing subareas of the system. The amount and type of operating reserves needed within these subareas depend on many factors, including load levels, the projected peak load of the subarea, and the economic and physical operating characteristics of the generators within the subarea. The systemwide commitment and economic dispatch of generation, system topology, system reliability constraints, special operational considerations, possible resource outages, and other system conditions are additional factors that can affect the required levels of reserve within subareas.

The ISO analyzes and determines how the generating resources within the subareas must be committed to meet the following day's operational requirements and withstand possible contingencies, including the most critical contingencies that determine the transmission import capability into the subarea. If maximizing the use of transmission import capability to meet demand is more economical, the subarea will require more local operating reserves to protect for contingencies. If using import capability to meet demand is less economical, generation located outside the subarea could provide operating reserves, thus reducing operating-reserve support needed within the subarea.

Table 4-8 shows representative future operating-reserve requirements for Greater Southwest Connecticut, Greater Connecticut, and NEMA/Boston areas. These estimated requirements are based on

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[117] The Hydro-Québec Phase II interconnection is a direct current (DC) tie with equipment ratings of 2,000 MW. Because of the need to protect for the loss of this line at the full import level in the PJM and NY systems, ISO New England has assumed its transfer capability to be 1,400 MW for calculating capacity and reliability. This assumption is based on the results of loss-of-source analyses conducted by PJM and NY. The procedure and daily limits are shown at the ISO's "Operations Report: Single-Source Contingency," webpage (2019), http://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/single-src-cont.

[118] ISO New England, Operating Procedure No. 19, *Transmission Operations* (February 1, 2019), http://www.iso-ne.com/rules_proceds/operating/isone/op19/op19_rto_final.pdf.

the same methodology used to calculate the requirements for the locational FRM.[119] The estimates account for representative future system conditions for load, economic generation, generation availability, N−1 and N−1−1 transfer limits, and expected contingencies for generation and transmission in each subarea. The analysis accounts for transmission upgrades consistent with the transmission-transfer capabilities presented to the PAC.[120]

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[119] While the estimates for operating-reserve requirements are based on expected future operating conditions, annual market requirements are based on historical data that reflect the actual previous seasonal system conditions, as adjusted for transmission topology changes and resource retirements and additions. The ISO calculates market requirements immediately before each locational FRM procurement period.

[120] ISO New England, *Forward Capacity Auction 14 Transmission Transfer Capabilities and Capacity Zone Development,* presentation (March 21, 2019), https://www.iso-ne.com/static-assets/documents/2019/03/a8_fca14_transmission_transfer_capabilities_and_capacity_zone_development.pdf.

Table 4-8
Representative Future Operating-Reserve Needs in Major New England Import Areas (MW)

Area/Improvement	Market Period[(a)]	Range of Fast-Start Resources Offered into the Past Five Forward-Reserve Auctions (MW)[(b)]	Representative Future Locational Forward Reserve Market Requirements (MW)	
			Summer[(c)] (Jun to Sep)	Winter[(c)] (Oct to May)
Greater Southwest Connecticut[(d)]	2019	188–227	0[(e)]	0
Reflecting impact of Bridgeport Harbor 5	2020		0	0
	2021		0	0
Reflecting impact of Bridgeport Harbor 3 and SWCT upgrades	2022		0	0
	2023		0	0
Greater Connecticut[(f, g)]	2019	613–848[(h)]	0[(e)]	0
Reflecting impact of Bridgeport Harbor 5	2020		0	0
Reflecting impact of Greater Hartford/Central Connecticut upgrades	2021		0	0
Reflecting impact of Bridgeport Harbor 3	2022		0	0
	2023		0	0
NEMA/Boston[(g, i)]	2019	21–208	0[(e)]	0
Reflecting impact of Greater Boston upgrades	2020		50–400 (0 w/ Grt Bos upgrades)	0
	2021		0	0
	2022		0	0
Reflecting impact of Mystic 7	2023		0	0

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

(b) These values are the range of the megawatts of resources offered into the past forward-reserve auctions. A summary of the forward-reserve offers for the past auctions is available at http://www.iso-ne.com/markets-operations/markets/reserves.

(c) "Summer" means June through September of a capacity commitment period; "winter" means October of the associated year through May of the following year (e.g., the 2019 winter values are for October 2019 through May 2020). The representative values show a range to reflect uncertainties associated with the future system conditions. The operating limits shown below reflect those assumed at the time of the analysis.

(d) The assumed N−1 and N−1−1 values that reflect transmission import limits into Greater SWCT are 2,500 MW and 1,750 MW, respectively. These limits will increase to 2,800 MW and 1,900 MW in 2021 when the expected the Southwest Connecticut upgrades are complete.

(e) These values are actual locational forward-reserve requirements. The projections of the requirements for future years are based on assumed contingencies.

(f) For Greater Connecticut, the assumed import limits reflect an N−1 value of 2,950 MW and an N−1−1 value of 1,750 MW. With the Greater Hartford/Central Connecticut upgrades assumed in service in 2020, the N−1 and N−1−1 import limits will increase to 3,400 and 2,200 MW, respectively.

(g) In some circumstances when transmission contingencies are more severe than generation contingencies, shedding some nonconsequential load (i.e., load shed not directly resulting from the contingency) may be acceptable.

(h) These values include resources in Greater Southwest Connecticut.

(i) The assumed N−1 and N−1−1 values reflecting the transmission import limits into Boston are 5,700 MW and 4,600 MW, respectively, reflecting components of the Greater Boston Project in service by June 2019. The operating-reserve values for BOSTON NEMA/Boston would be lower with transmission upgrades or without consideration of the common-mode failure of the Mystic 8 and 9 generators assumed to trip up to 1,400 MW because of exposure to a common-mode failure of the fuel supply.

The representative values show a range to reflect the load and resource uncertainties associated with future system conditions. Table 4-8 also shows the existing amount of fast-start capability located in each subarea resulting from the fast-start resources offered into past FRM auctions. The total 10-minute operating-reserve values associated with the FRM reflect the contingency-reserve adjustment, but this adjustment does not affect the amount of reserves distributed to locations (i.e., the reserve values for Greater Southwest Connecticut, Greater Connecticut, and NEMA/Boston did not increase).

Because the local contingency needs in Greater Southwest Connecticut are nested within Connecticut, resources installed in the Greater Southwest Connecticut area also would satisfy the operating reserve need for resources located anywhere in Greater Connecticut.[121]

4.4.2.1 Greater Southwest Connecticut

Greater Southwest Connecticut does not need to maintain local reserve for the entire study period. The 2018 addition of the efficient gas-fired generator, CPV Towantic, helps the local generation serve a larger portion of the local energy needs, freeing up the import interface for importing reserve when the contingencies occur. The expected addition of Bridgeport Harbor 5 in 2019 and the Southwest Connecticut transmission upgrades in 2021 are expected to further improve the capability of the Southwest Connecticut subsystem to meet its local energy and reserve needs reliably. The scheduled retirement of Bridgeport Harbor 3 generator in 2021 is expected to have little impact on the local reserve needs.

4.4.2.2 Greater Connecticut

As a result of the development of efficient gas-fired generators, and fast-start resources over the past years, the Greater Connecticut subsystem has been able to reliably meet its local energy and reserve needs. Local operating reserves are not expected to be needed because the capability of the import interface is adequate to support the transfers of economic energy and reserve into the area from the rest of the system. Having the Bridgeport 5 and the Greater Hartford/Central Connecticut transmission upgrades in service will further help eliminate locational reserve needs in Greater Connecticut during the study period.

4.4.2.3 NEMA/Boston

The operating-reserve needs for the NEMA/Boston subarea shown in Table 4-8 reflect the possible simultaneous contingency loss of Mystic generators 8 and 9. The addition of Footprint generation in 2018 has allowed more loads in NEMA/Boston subarea to be served by the local economical generation resources. Several of the transmission facilities associated with the Greater Boston project are already in service, and the remaining components are expected to be in service by May 2021 (see Section 5.5.4). The Greater Boston project will increase the import capability into the subarea, thus permitting a higher level of economical transfers and reserves. Therefore, maintaining operating reserve locally is not expected to be required for the study period. The retirement of Mystic 7 will have little impact on the local reserve needs. The impacts from the potential retirements of Mystic 8 and 9 are not evaluated because the timeline of the retirement is beyond the study period of this analysis.

4.4.2.4 Summary of Operating-Reserve Needs in Major Import Areas

The need for maintaining operating reserves in major import areas has been decreasing, and the reduction is expected to continue. Future requirements may be completely eliminated starting as early as 2019, with the completion of proposed transmission upgrades, additional lower-cost generating resources in service in the major import areas, and the expected lower net load-growth forecast.

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[121] *Market Rule 1*, Standard Market Design (ISO tariff, Section III) (2019), defines the types of reserves that can meet these requirements; http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

However unforeseen reductions in economical generation resources (e.g., traditional baseload resources) in these subareas may increase the operating-reserve need.

Longer term, the region might need additional operating reserve as a result of the addition of variable energy resources. For example, wind generating units cannot generate when the wind does not blow or when wind speeds increase above the cutout limits, which reduces the wind generation output to zero (refer to Section 9.2).[122]

4.5 Existing and Future Resource Development in Areas of Need

The development of resources can help meet the long-term needs of the system. This section reviews existing and future generating resources, including the capacity and claimed capability of existing resources, projects proposed through the ISO's interconnection queue, and generator retirements.

4.5.1 Existing Generating Capacity by Load Zone, and State

Generators located close to load centers typically lessen the need for transmission system improvements. Table 4-9 tabulates the existing generating amounts and locations by load zone and state.

Table 4-9
2019 Generating Capacity by State and Load Zone (MW, %)[a, b]

State	Load Zone	Summer			Winter		
		Capacity Rating (MW)[b]	% of State	% of Load Zone	Capacity Rating (MW)[b]	% of State	% of Load Zone
Maine	ME	3,067	100	100	3,703	100	100
	NH	<1	<1	<1	<1	<1	<1
		3,067	*100*		*3,703*	*100*	
New Hampshire	ME	0	0	0	1	0	0
	NH	4,153	100	98	4,398	100	98
	VT	1	<1	1	4	<1	1
		4,155	*100*		*4,403*	*100*	
Vermont	NH	88	21	2	88	17	2
	VT	260	61	99	362	69	99
	WCMA	77	18	2	76	14	2
		426	*100*		*527*	*100*	
Massachusetts	NEMA	3,335	28	100	3,720	29	100
	RI	2	<1	<1	<1	<1	<1
	SEMA	4,673	39	100	5,019	39	100
	WCMA	966	33	98	4,036	32	98
		11,976	*100*		*12,775*	*100*	
Rhode Island	RI	*1,959*	*100*	*100*	*2,170*	*100*	*100*
Connecticut	CT	*9,659*	*100*	*100*	*9,859*	*100*	*100*
Total		**31,242**			**33,437**		

(a) Totals may vary because of rounding.

(b) The values shown are seasonal claimed capability based on the 2019 CELT Report.

[122] *Cutout* is when wind units must reduce to 0 MW during very high wind conditions to protect the physical integrity of the wind generating unit and prevent damage to its blades or other components.

4.5.2 Summer and Winter Seasonal Claimed Capabilities of New England's Generating Resources

Table 4-10 shows the megawatt amount of summer and winter seasonal claimed capabilities of the generating resources, both systemwide and for each load zone, categorized by the assumed operating classification of the resource design.

Table 4-10
Summer and Winter Seasonal Claimed Capabilities for ISO New England Generating Resources, by Assumed Operating Classification, Systemwide and by Load Zone, 2019 to 2020 (MW)[(a)]

Load Zone	Baseload[(b)]	Intermediate[(c)]	Peaking[(d)]	Variable Energy[(e)]
Summer				
CT	4,307	3,761	1,570	21
ME	1,285	1,440	169	173
NEMA	674	2,353	277	31
NH	2,868	1,240	81	52
RI	26	1,889	0	46
SEMA	1,222	2,585	714	152
VT	101	0	132	28
WCMA	286	1,440	2,056	261
Total[(f)]	**10,770**	**14,709**	**5,000**	**763**
Winter				
CT	4,434	3,594	1,808	23
ME	1,432	1,605	213	454
NEMA	662	2,683	374	1
NH	2,895	1,371	101	119
RI	25	2,121	0	24
SEMA	1,893	2,909	211	6
VT	103	0	167	96
WCMA	280	1,609	2,126	97
Total[(f)]	**11,725**	**15,892**	**5,001**	**820**

(a) The values shown are seasonal claimed capability based on the 2019 CELT Report.

(b) *Baseload generators* are assumed to run for long continuous hours at a constant output and have little flexibility. For operating classification purposes, bio/refuse, coal, fuel cell, pondage hydro, weekly hydro, nuclear, and thermal steam generators are assumed in the baseload category.

(c) *Intermediate generators* have the ability to dispatch flexibly and can follow variations in the system load. Combined-cycle generators are assumed in the intermediate category.

(d) *Peaking generators* can be dispatched to meet peak demand for relatively short periods. Internal combustion, gas turbine, and pumped-storage generators, as well as battery storage facilities, are assumed in the peaking category.

(e) *Variable energy resources*, such as wind and PV, produce energy subject to variations in "fuel" determined by weather and, additionally for PV, the time of day (see Section 9.2).

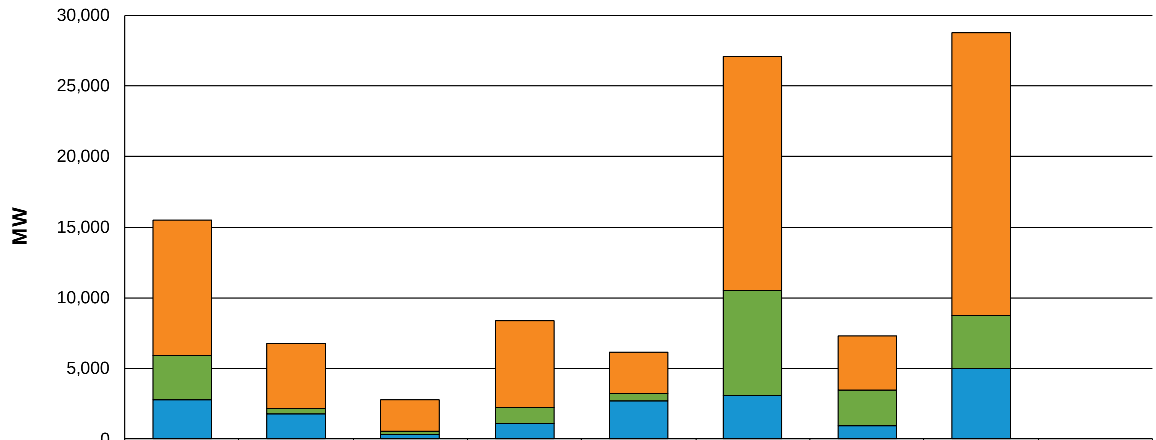
(f) Totals may not equal the sum due to rounding.

4.5.3 ISO Interconnection Request Queue and Clustering Interconnection

This section presents information on the resources in the ISO Interconnection Request Queue and describes the new interconnection process that clusters resources for considering multiple requests in the same study and allocating the costs of significant upgrades among the cluster participants.

4.5.3.1 Interconnection Requests and Generating Resources in the Interconnection Queue

The interconnection requests in the ISO's interconnection queue reflect the region's interest in building new generation capacity.[123] Figure 4-3 shows the capacity of the withdrawn, active, and commercial generation-interconnection requests in the queue by load zone as of April 1, 2019. As shown, over 19,000 MW of projects spread throughout New England have requested interconnection study. The top five load zones with the most project proposals are SEMA at approximately 7,400 MW, followed by CT (3,700 MW), ME (3,200 MW), RI (2,500 MW), and WCMA (1,100 MW).



	ME	NH	VT	WCMA	NEMA	SEMA	RI	CT	Total
Withdrawn	9,578	4,567	2,176	6,183	2,914	16,582	3,837	20,079	65,916
Active	3,200	391	230	1,144	470	7,422	2,491	3,699	19,047
Commercial	2,737	1,781	346	1,061	2,722	3,053	958	5,011	17,671

Figure 4-3: Capacity of generation-interconnection requests by load zone, November 1997 to April 2019 (MW).

Notes: All capacities are based on the projects in the ISO interconnection queue as of April 1, 2019, that would interconnect with the ISO system. Projects involving only transmission or that did not increase an existing generator's capacity were excluded. Projects with more than one listing in the queue, representing different interconnection configurations, were counted only once.

Since the first publication of the queue in November 1997, 142 generating projects (17,671 MW) out of 616 total generator applications (totaling 102,634 MW) have become commercial.[124] Since the queue's inception, 297 proposed projects totaling approximately 65,916 MW have been withdrawn, reflecting a megawatt attrition rate of 64%. The 177 active projects in the queue total 19,047 MW. Figure 4-4 shows the resources in the queue, by state and fuel type, as of April 1, 2019. Figure 4-5 shows the total megawatts of the same resources by fuel type in each load zone.

[123] The ISO provides monthly updates on the status of active generation interconnection requests, *NEPOOL Participant Committee COO Report for Monthly Updates* (Monthly COO Report). For example, see the April 2019 monthly COO Report at https://www.iso-ne.com/static-assets/documents/2019/04/april-2019-coo-report.pdf.

[124] Information on the queue is available at the ISO's "Interconnection Request Queue," webpage (2019), http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue. The projects proposed but withdrawn from the queue most often faced problems associated with financing, licensing, or insufficient market incentives.

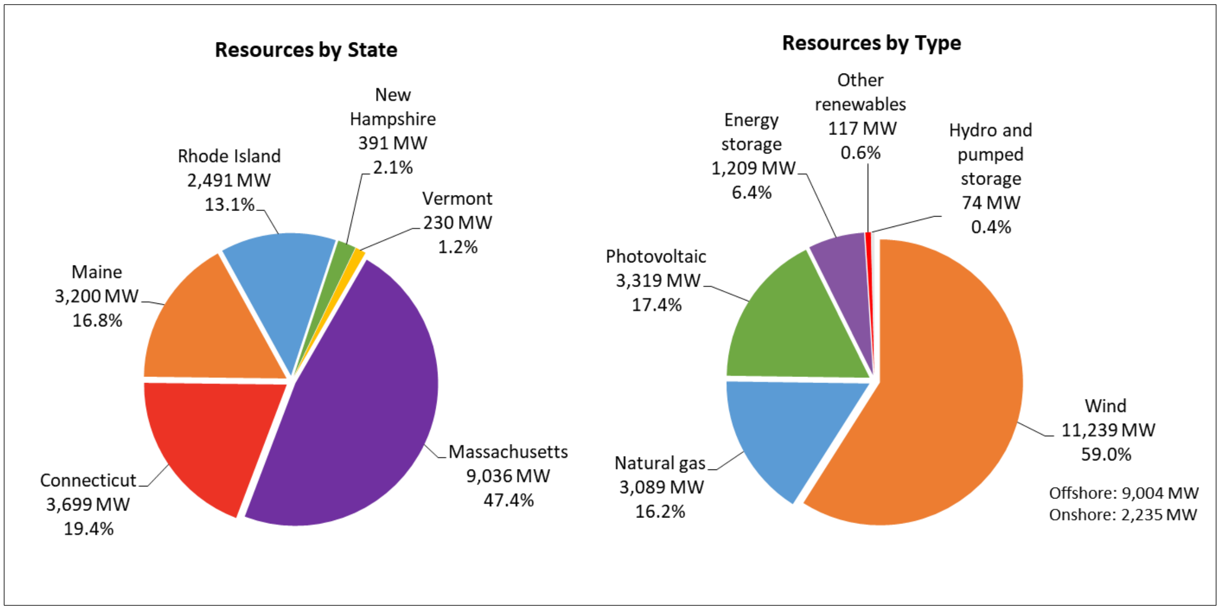


Figure 4-4: Resources active in the ISO interconnection queue, by state and fuel type, as of April 1, 2019 (MW and %).

Notes: The "Other Renewables" category includes 37 MW wood, 78 MW fuel cell, and 2 MW municipal solid waste. The totals for all categories reflect all queue projects that would interconnect with the system and not all projects in New England.

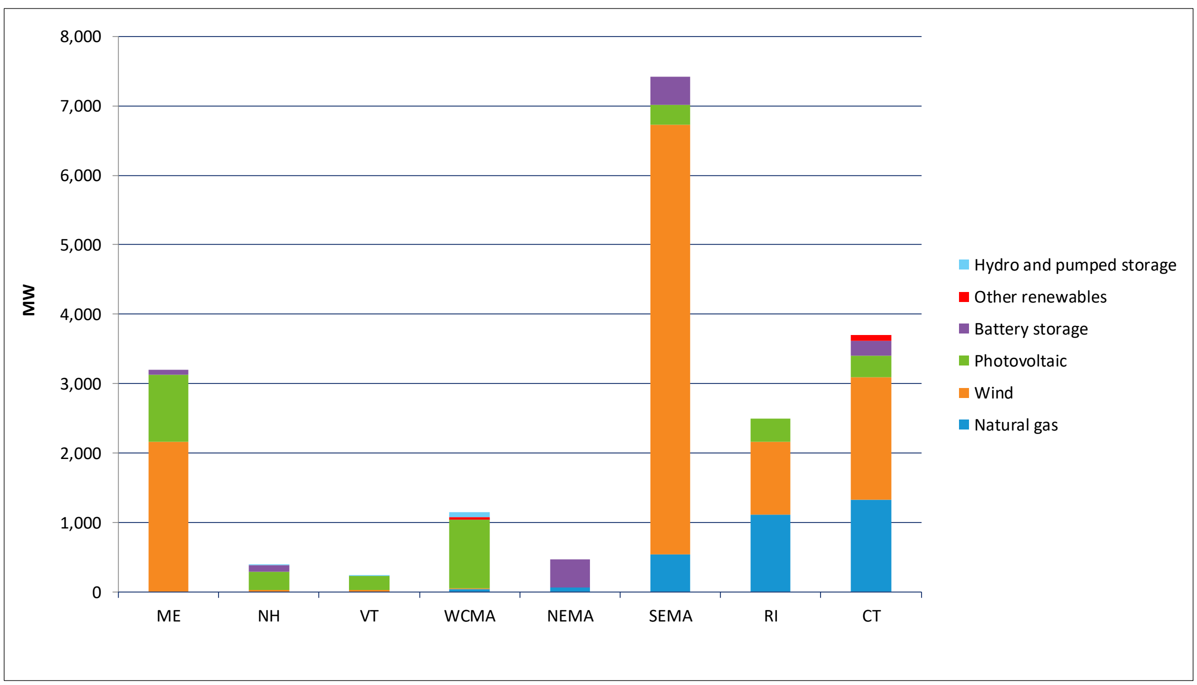


Figure 4-5: Resources active in the ISO interconnection queue, by fuel type in each load zone, as of April 1, 2019 (MW).

4.5.3.2 Clustering Interconnection Process

The New England states have increased targets for renewable energy (see Section 9.1), which has resulted in an influx of generator interconnection requests. The processing of the interconnection requests in New England has progressed in a timely manner and in accordance with the tariff deadlines. However, the interconnection of resources located in Maine have experienced a backlog (mostly wind interconnection requests).

To reduce the time to conduct system impact studies and address the interconnection queue backlog, particularly for generators in weak areas of the system, such as Maine, the ISO is working with stakeholders to improve the interconnection process. An example of a recent improvement is the development of a *cluster study approach*, which provides the means for considering multiple requests in the same study and allocating the costs of significant upgrades among the cluster participants.[125] The goal is to reduce the time taken to complete system impact studies for any combination of new resources and elective transmission upgrades. The initiative also seeks to address the curtailment and system operations performance issues for IBRs (see Section 9.2) and to meet the modeling and performance requirements that new NERC standards are introducing.

In March of 2018, the ISO published the first *Maine Resource Integration Study* (MRIS) to identify the transmission upgrades necessary to enable the interconnection of proposed new resources in northern and western Maine.[126] This MRIS was conducted pursuant to Attachment K of the ISO's *Open Access Transmission Tariff* (OATT), in consultation with the PAC.

This study was conducted in parallel with the development of an approach to clustering interconnection requests in the ISO-administered interconnection queue, which FERC approved on October 31, 2017.[127] The clustering approach reflected in the FERC-approved rules uses a two-phased study methodology in certain circumstances to expedite the consideration of two or more interconnection requests and allocate interconnection upgrade costs among interconnection customers (ICs) on a cluster basis.

The first phase of the clustering process involves conducting a transmission planning study, performed under the Regional System Planning Process pursuant to the OATT, Attachment K (Section 15.4), to identify the transmission infrastructure and associated system upgrades necessary to enable the interconnection of potentially all the proposed resources in the interconnection queue. This infrastructure is called a cluster-enabling transmission upgrade (CETU), and the study is referred to a Cluster-Enabling Transmission Upgrade Regional Planning Study (CRPS).

The second phase consists of conducting a Cluster-Interconnection System Impact Study (CSIS) pursuant to the interconnection procedures and a Cluster-Interconnection Facilities Study (CFAC). These studies must identify the specific facilities required to interconnect the resources that elect to move toward interconnection and meet the associated second-phase entry requirements. Consistent with Attachment K, Section 2.4 (d), the posting of the final CRPS report on the ISO website triggered the entry deadline for the CSIS (cluster entry deadline). Six projects met the cluster entry requirements and are proceeding through the system impact study phase.

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[125] ISO New England, "Interconnection Requests that Are Being Considered in the Maine Resource Integration Study," PAC memorandum (January 23, 2017), https://www.iso-ne.com/static-assets/documents/2017/01/2017_01_23_memo_pac_mri.pdf.

[126] ISO New England, *2016/2017 Maine Resource Integration Study* (March 12, 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/03/final_maine_resource_integration_study_report.pdf.

[127] FERC, *Order Accepting Tariff Revisions* (for Interconnection Queue Clustering), Docket No. ER17-2421-000 (October 31, 2017), https://www.iso-ne.com/static-assets/documents/2017/11/er17-2421-000_order_accept_interconnection_queue_clustering.pdf.

The MRIS constituted the first Cluster-Enabling Transmission Upgrade Regional Planning Study and forms the basis for the first Cluster-Interconnection System Impact Study to be conducted in accordance with the OATT, Schedule 22, Section 4.2.3; Schedule 23, Section 1.5.3.3; and Schedule 25, Section 4.2.3.[128] The MRIS identified the interconnection requests, by queue position, eligible to be included in the second-phase study, the transmission upgrades (i.e., CETUs and associated system upgrades) required to enable interconnection, and the cost allocation for eligible projects that elect to proceed to the second phase of the clustering process.

In June 2018, the ISO initiated a *Second Maine Resource Integration Study* to identify the transmission upgrades necessary to enable the interconnection of yet further proposed new resources in northern and western Maine. The second MRIS will evaluate the use of high-voltage direct-current (HVDC) connections to interconnect the additional resources.[129] The ISO anticipates completing this second cluster study by the fourth quarter of 2019.

4.5.3.3 Reform of Generator Interconnection Procedures and Agreements—FERC Order No. 845/845-A

On April 19, 2018, FERC issued Order No. 845, its final rule on Reform of Generator Interconnection Procedures and Agreements.[130] The rule concludes that interconnection reforms are necessary to facilitate entry of new generation into the market and to avoid harmful effects on competition and potentially unjust and unreasonable rates for customers. It also revises the pro forma Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA) (both contained in Schedule 22 of the OATT) to implement 10 specific reforms. The reforms are intended to improve certainty for interconnection customers, promote more informed interconnection decisions, and enhance the interconnection process.

On February 21, 2019, FERC issued Order No. 845-A, to provide additional clarity to its order.[131] Noteworthy changes that affect interconnections to the New England transmission system are as follows:

- Removes the limitation that interconnection customers may only exercise the option to build a transmission provider's interconnection facilities and stand-alone network upgrades in

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[128] OATT, Schedule 22, *Large Generator Interconnection Procedures* (January 29, 2019), https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch22/sch_22_lgip.pdf ; Schedule 23, *Small Generator Interconnection Procedures* (January 29, 2019), https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch22/sch_22_lgip.pdf; and Schedule 25, *Elective Transmission Upgrade Interconnection Procedures* (January 29, 2019), https://www.iso-ne.com/static-assets/documents/2015/02/sch_25.pdf.

[129] HVDC devices use a combination of solid-state switches and computerized automation that enables nearly instantaneous customized control of real or reactive power flows—far faster than traditional electromechanical switches. ISO New England, *Second Maine Resource Integration Study: Scope*, PAC presentation (September 27, 2018), https://www.iso-ne.com/static-assets/documents/2018/09/a12_second_maine_resource_integration_study_scope_rev1.pdf.

[130] FERC, *Reform of Generator Interconnection Procedures and Agreements*, final rule, Docket No. RM17-8-000; Order No. 845 (April 19, 2018), https://www.iso-ne.com/static-assets/documents/2018/04/a03_tc_2018_04_24_order_845.pdf or https://www.ferc.gov/whats-new/comm-meet/2018/041918/E-2.pdf.

[131] FERC, *Reform of Generator Interconnection Procedures and Agreements*, order on rehearing and clarification, Docket No. RM17-8-001, Order No. 845-A (February 21, 2019), https://www.ferc.gov/whats-new/comm-meet/2019/022119/E-1.pdf.

instances when the transmission provider cannot meet the dates proposed by the interconnection customer

- Allows interconnection customers to request a level of interconnection service lower than their generating facility capability
- Requires transmission providers to allow for provisional interconnection agreements that provide for the limited operation of a generating facility before completion of the full interconnection process
- Revises the definition of "generating facility" to explicitly include electric-storage resources
- Requires transmission providers to create a process for interconnection customers to use surplus interconnection service at existing points of interconnection

In response to these orders, the ISO submitted its compliance filing by the deadline of May 22, 2019.[132]

4.6 Summary

Sufficient resources are projected for New England through 2028 to meet the resource adequacy planning criterion, assuming no additional retirements and the successful completion of all new resources that have cleared the FCM. The planning analysis accounts for new resource additions that have responded to market improvements, state policies, and resource retirements. The ISO is committed to procuring adequate demand and supply resources through the FCM and expects the region to install adequate resources to meet the physical capacity needs that the ICRs will define for future years.

To date, resource-adequacy studies show that the most reliable and economic place for developing new resources is in NEMA/Boston and SEMA/RI. This is due to recent and anticipated retirements of aging fossil generation and the projected load growth in these areas. Transmission improvements are underway, and new capacity additions are projected that will help meet the regional and local capacity needs.

By design, the level of the ICR specified for New England could necessitate the use of specific OP 4 actions because the ICR calculation relies on the load relief these actions provide to meet the system's resource adequacy planning criterion. Several factors would affect the frequency and extent of OP 4 actions, including the amount of resources procured to meet capacity needs, their availability, and actual system loads. During extremely hot and humid 90/10 summer peak-load conditions, reliance on load and capacity relief to meet system needs could range from 1,150 MW to 2,500 MW during the study period. Although New England has adequate installed capacity to meet the winter peak demands, which is 6,000 MW to 7,000 MW lower than the summer peak demands, OP 4 actions may still be necessary during extreme cold weather. This is because the region relies on natural gas to fuel much of its baseload generation, and the availability of natural gas may be limited when the weather is cold. Section 7 discusses the region's immediate concerns about fuel-security issues, the availability of natural-gas-fired generators to produce energy, and the ISO's efforts to address these challenges over the long term.

The region is expected to meet future representative operating-reserve requirements for the system as currently planned. Fast-start generating resources with a short lead times for project construction can satisfy near-term operating-reserve requirements while providing operational flexibility to major load

[132] ISO New England, *Revisions to the Large Generator Interconnection Procedures and Agreement in Schedule 22 of Section II to the ISO New England Inc. Transmission, Markets and Services Tariff in Compliance with FERC Order Nos. 845 and 845-A*; *Docket No. ER19-___-000*, FERC filing (May 22, 2019), https://www.iso-ne.com/static-assets/documents/2019/05/order_845_compliance_filing.pdf.

pockets and the system overall. Continuing to properly locate and size resources electrically connected to major load pockets to replace the resource retirements would address the amount of reserves required within the load pocket and reduce the reliance on transmission facilities. Transmission improvements have and can continue to help reduce or eliminate operating-reserve needs in the major import areas.

Some of the 19,047 MW of resources in the interconnection queue will likely be developed to meet future resource needs. Renewable resources are predominately being built in states with aggressive Renewable Portfolio Standard (RPS) targets, specifically Massachusetts, Connecticut, and Rhode Island, and supported by state requests for proposal, which should help serve load in southern New England (refer to Section 8.3). Proposed onshore wind resources are predominantly in northern New England, and offshore wind resources are being proposed off the southeastern New England coast. New fast-start generation under construction in the SEMA/RI and NEMA/Boston areas will improve system reliability. However, delays in the construction of these new generators or additional retirements would decrease the amount of regional resources and could adversely affect the ability of the system to meet regional electricity needs. Overall, the ISO expects more generating resource additions than retirements in the region and resources to be sufficient to meet the net ICR for the next 10 years.

The ISO has improved the interconnection process and now uses a cluster study approach, which provides the means for considering multiple requests in the same study and allocating the costs of significant upgrades among the cluster participants in the interconnection queue. To date, the ISO has completed one cluster study and plans to complete a second by the end of 2019 for proposed resources in northern and western Maine.

Section 5
Transmission System Performance Needs Assessments and Upgrade Approvals

Since 2002, the ISO and regional stakeholders have made significant progress developing transmission solutions in New England that address existing and projected transmission system needs. Major transmission projects and other projects help maintain system reliability and enhance the region's ability to support a robust, competitive wholesale power market by reliably moving power from various internal and external sources to the region's load centers.

This section discusses the need for transmission reliability and provides an overview of the New England transmission system, updates on the performance of the system, and the status of several transmission planning studies. The progress of major transmission projects and various types of transmission upgrades in the region as of June 2019 are also provided.[133] The transmission planning studies account for known plans for resource additions and attritions (see Section 4) and the material effects of the EE forecast and the PV forecast (see Section 3). Previous RSPs, various PAC presentations, and other ISO reports contain information regarding the detailed analyses associated with many of these efforts.[134]

The *Transmission Planning Process Guide* details the existing regional system planning process and how transmission planning studies are performed, and the *Transmission Planning Technical Guide* references the current standards and details the current criteria and assumptions used in transmission planning studies.[135]

5.1 The Need for Transmission Reliability

A reliable, well-designed transmission system that provides regional transmission service is essential for complying with mandatory reliability standards (see Section 2.1.7) and supporting the secure dispatch and operation of generation that delivers numerous products and services. Adhering to evolving physical and cybersecurity standards due to the increased reliance on distributed resources and variable energy resources is a priority (see Sections 9.1.2 and 9.4.2). A reliable transmission system plays an important role in the following functions:

- Allowing access to capacity resources
- Providing immediate contingency response to sudden resource or transmission outages
- Regulating voltage and minimizing voltage fluctuations
- Stabilizing the grid after transient events
- Facilitating the efficient use of regional supply and demand resources
- Reducing the amount of reserves necessary for the secure operation of the system

[133] For further details about individual transmission projects, refer to the latest *RSP Project List* or *Asset Condition List* available at https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

[134] Past RSPs and other PAC materials and reports are available at https://www.iso-ne.com/system-planning/system-plans-studies/rsp and https://www.iso-ne.com/committees/planning/planning-advisory/.

[135] The latest versions of the ISO New England, *Transmission Planning Process Guide* and *Transmission Planning Technical Guide* are available at https://www.iso-ne.com/system-planning/transmission-planning/transmission-planning-guides.

- Facilitating the scheduling of equipment maintenance
- Receiving assistance from and providing it to neighboring balancing authority areas, especially during major contingencies affecting reliability, ensuring the reliability of the interconnected system
- Expediting system restoration after major events

5.2 Overview of New England's Transmission System

In New England, the power system provides electricity to diverse areas, ranging from rural agricultural to densely populated cities, and integrates widely dispersed and varied types of power supply resources. Geographically, approximately 20% of New England's peak loads are in the northern states of Maine, New Hampshire, and Vermont, and 80% are in the southern states of Massachusetts, Connecticut, and Rhode Island. Although the land area in the northern states is larger than the land area in the southern states, the greater urban development in southern New England creates the relatively larger demand and corresponding transmission density. This means that while the demands on the New England transmission system can vary widely, the system must reliably operate under the wide-ranging conditions present in the region at all times—in compliance with mandatory reliability standards—to move power from various internal and external sources to the region's load centers.

The New England transmission system consists of mostly 115 kV, 230 kV, and 345 kV transmission lines, which are generally longer and fewer in number in northern New England than in the southern states. The region has 13 interconnections with neighboring power systems in the United States and Eastern Canada. Nine interconnections are with New York (NYISO) (two 345 kV ties; one 230 kV tie; one 138 kV tie; three 115 kV ties; one 69 kV tie; and one 330 MW, ±150 kV HVDC tie—the Cross-Sound Cable interconnection). New England and the Maritimes (New Brunswick Power Corporation) are connected through two 345 kV alternating current (AC) ties.[136] New England also has two HVDC interconnections with Québec (Hydro-Québec; HQ). One is a 120 kV AC interconnection (Highgate in northern Vermont) with a 225 MW back-to-back converter station, which converts alternating current to direct current (DC) and then back to AC. The second is a ±450 kV HVDC line with terminal configurations allowing up to 2,000 MW to be delivered at Sandy Pond in Massachusetts (i.e., Phase II).

5.3 FERC Order No. 1000 Discussion

In May 2015, ISO New England implemented changes to the regional and interregional transmission planning process to comply with the directives in FERC Order 1000. The order established new electric transmission planning and cost allocation requirements for public utility transmission providers across the country. (Refer to Section 6.6 for a discussion of interregional aspects of Order 1000.) In addition, the order's objectives include the following:

- Introduce competition into the development of regulated transmission solutions by removing arrangements that protect the right of first refusal for incumbent transmission providers

[136] One exception is that Aroostook and Washington Counties in Maine receive electricity service from New Brunswick.

- Create a mechanism for transmission development to address public policies that drive transmission[137]

The FERC Order 1000 revised planning process includes the requirement to solicit proposals for competitive solutions to reliability projects that have a planning need that can be met beyond three years from the completion of the needs assessment and to implement a process for identifying and evaluating federal, state, and local public policies that create the need for additional transmission.[138] ISO New England began its first public policy process in January 2017 and will begin administering its second public process in January 2020. These processes are described in the *Transmission Planning Process Guide.*

On April 18, 2018, FERC completed an audit of ISO New England's compliance with Order 1000 as it relates to transmission planning and expansion and interregional coordination for the period of July 10, 2013, through June 30, 2017.[139] The ISO successfully passed this audit, with a result of no findings of noncompliance within the scope of the audit.

5.4 Completed Major Projects

Since the publication of the *2017 Regional System Plan*, the following major projects have been completed or are near completion:

- The Maine Power Reliability Program (MPRP) included the addition of significant new 345 kV and 115 kV transmission lines and new 345 kV autotransformers at key locations in Maine. All upgrades were placed in service by December 2018.
- The New Hampshire/Vermont 2020 Upgrades, located in Vermont, included the addition of a new 345/115 kV autotransformer, a new 230/115 kV autotransformer, several new 115 kV transmission lines, upgrades and rebuilds of several existing 115 kV lines, and several reactive device additions and substation upgrades. Most of these upgrades are in service with the exception of a new 115 kV line between Madbury and Portsmouth, NH, which is anticipated to be in service in May 2020.
- The Connecticut River Valley Upgrades included the addition of a 115 kV dynamic reactive device (+50 MVAR/−25 MVAR static VAR compensator [SVC]), the rebuild of a 115 kV

[137] Information on public policy transmission upgrades is available at https://www.iso-ne.com/system-planning/system-plans-studies/public-policy-transmission-upgrades.

[138] For a study at peak load levels, a *time-sensitive need* is a reliability-criteria violation that needs to be solved in three years or less of the completion of the relevant needs assessment (i.e., the posting of the final needs assessment report). Any needs identified for a study at off-peak load levels also are considered time sensitive because the static load level studied can occur under current-day system conditions. More information concerning the time-sensitive needs determination is available from the January 18, 2018, PAC presentation https://www.iso-ne.com/static-assets/documents/2018/01/a4_critical_load_level_and_need_by_date_determination_for_steady_state_peak_load_needs.zip. Developing solutions for time-sensitive needs follows the solutions study process, as detailed in the OATT, Attachment K, Section 4.2. A *non-time-sensitive need* is a criteria violation that can be solved beyond three years from the completion of the relevant needs assessment. These solutions follow the competitive solution process, as detailed in Attachment K, Section 4.3. Because load growth has flattened, as discussed in Section 3, with system load in year one of the planning horizon now being very close to the load in year 10, the passage of time, which historically corresponded to load growth, has become less of a driver for new reliability issues on the transmission system.

[139] FERC, *Audit of ISO New England, Inc.'s Compliance with its Transmission, Markets, and Services Tariff; and Commission Accounting, Reporting, and Record Retention Requirements,* final audit report (April 18, 2018), https://www.iso-ne.com/static-assets/documents/2018/04/pa16-6-000_4-18-18_final_audit_report.pdf.

transmission line, and the rebuild of a 115 kV station.[140] All upgrades were placed in service by November 2018.

- The Greater Hartford Central Connecticut (GHCC) 2022 Upgrades included the addition of two new autotransformers and 115 kV upgrades, including reconductoring lines, installing new lines, separating double-circuit towers (DCTs), rebuilding two stations, and adding reactive support to maintain voltage. Several of the projects within the GHCC suite of projects are already in service, and all the components of the preferred solutions are expected to be in service by December 2019.
- The Southwest Connecticut (SWCT) 2022 Upgrades included all 115 kV upgrades, such as rebuilding and reconductoring lines, installing new lines, rebuilding two stations, and adding reactive support to maintain voltage. Several of the projects within the SWCT suite of projects are already in service, and all the components of the preferred solutions are expected to be in service by June 2020. The SWCT 2025 update results showed that three transmission solutions identified in the 2022 upgrades were no longer required and were subsequently canceled.[141]
- The Pittsfield and Greenfield 2022 Upgrades included adding a new 345/115 kV autotransformer, adding reactive support to control voltage on the 345 kV system, adding a new 115 kV station, rebuilding a 115 kV station, rebuilding and reconductoring 115 kV lines, installing a new 115 kV line, separating 115 kV double-circuit towers, and adding reactive support to maintain voltage on the 115 kV system. All the projects within the Pittsfield and Greenfield suite of projects are already in service with the exception of a 115 kV station at Pochassic (in Westfield, MA), and a new 115 kV line between Pochassic and Buck Pond, also in Westfield, which will be placed in service by June 2020 (see Section 5.5.3).

Study efforts continue throughout New England to address remaining issues discussed in the next section.

5.5 Key Study Area Updates

Historically, the two most significant issues facing the northern New England area have been to maintain the general performance of the long 345 kV corridors, particularly through Maine, and to ensure sufficient system reliability to meet demand. The region faces thermal and voltage performance issues and stability concerns. The system of long 115 kV lines, with weak sources and high real- and reactive-power losses, is exceeding its ability to integrate generation and efficiently and effectively serve load.

The most significant concerns in the southern New England area involve maintaining the reliability of supply to serve load and developing the transmission infrastructure due to the retirement of generation throughout this area. In some areas, an aging low-capacity 115 kV system has been overburdened and is no longer able to serve load and support generation reliably. Ongoing planning and power system upgrades will ensure the system can meet its current level of demand and prepare for future power system conditions.

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140 SVCs are flexible alternating-current transmission system (FACTS) devices that provide dynamic voltage support, which can help regulate voltages and improve the stability performance of the system.

141 The Bunker Hill substation rebuild (*RSP Project List* #1571) and looping the 1990 (Frost Bridge–Baldwin–Stevenson) line into Bunker Hill (*RSP Project List* #1569) are no longer necessary due to the Towantic interconnection substation being functionally similar. The separation of the 3827 (Beseck–East Devon)/1610 (Southington–Mix Ave.–June St.) double-circuit tower (*RSP Project List* #1579), previously recommended to alleviate overloads on the 88003A/89003B lines, are no longer necessary with the additional generation in the SWCT area.

To address the issues in New England, study efforts have been progressing on a wide range of system concerns and have been grouped into several key study areas shown in Figure 5-1 and detailed below. However, over the past three years, material changes in study assumptions, inputs, and processes have prompted either pausing ongoing study efforts to incorporate the new changes or suspending the ongoing study efforts and restarting the studies. The first material changes came in early 2017 and included the following:

- Changes to Planning Procedure No. 3 (PP 3), *Reliability Standards for the New England Area Pool Transmission Facilities*[142]
- Incorporation of probabilistic planning methods to establish the dispatches used in needs assessment studies[143]
- Addition of resources as a result of FCA 11
- Retirement delist bids for FCA 12
- Updated load, energy-efficiency and photovoltaic forecasts
- Results of changes to NPCC classification of the bulk power system (BPS)[144]

In April 2018, the load, energy-efficiency, and behind-the-meter photovoltaic forecasts were made public, and the forecasts resulted in a significant reduction in the net load to be served.[145] Ongoing studies were paused as plans were developed to incorporate the new load forecasts into the studies.[146] In March 2019, for the second year in a row, the load, EE, and PV forecasts showed another significant reduction in net load. The new forecasts and the results of FCA 13 led to pausing ongoing studies again for developing new plans to incorporate these changes (see Section 4.1.3 for FCA results).[147]

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[142] ISO New England Planning Procedure No. 3, *Reliability Standards for the New England Area Pool Transmission Facilities* (September 15, 2017), https://www.iso-ne.com/static-assets/documents/2017/10/pp3_r8.pdf.

[143] ISO New England, *Creation of Needs Assessment Dispatches Revision 1*, presentation (September 6, 2017), https://www.iso-ne.com/static-assets/documents/2017/09/a6_creation_of_needs_assessment_dispatches.pdf.

[144] ISO New England, "Updates to System Studies," memorandum (February 24, 2017), https://www.iso-ne.com/static-assets/documents/2017/02/updates_to_system_study_memo.pdf, and *Updates to System Studies—Incorporating Changes in Criteria and Assumptions into Ongoing Assessments,* presentation (March 22, 2017), https://www.iso-ne.com/static-assets/documents/2017/03/a4_updates_to_system_studies.pdf.

[145] Transmission planning studies also reflect PV forecasts for energy-only resources and FCM resources under 5 MW. Studies also model larger PV plants.

[146] ISO New England, *Updating Needs Assessments to Reflect Latest Forecasts*, presentation (April 26, 2018), https://www.iso-ne.com/static-assets/documents/2018/04/a5_updating_needs_assessment_to_reflect_latest_forecasts.pdf.

[147] ISO New England, *Updating Needs Assessments to Reflect Latest Assumptions*, presentation (March 21, 2019), https://www.iso-ne.com/static-assets/documents/2019/03/a6_updating_needs_assessment_to_reflect_latest_assumptions.pdf (*Updating Needs Assessments* presentation).

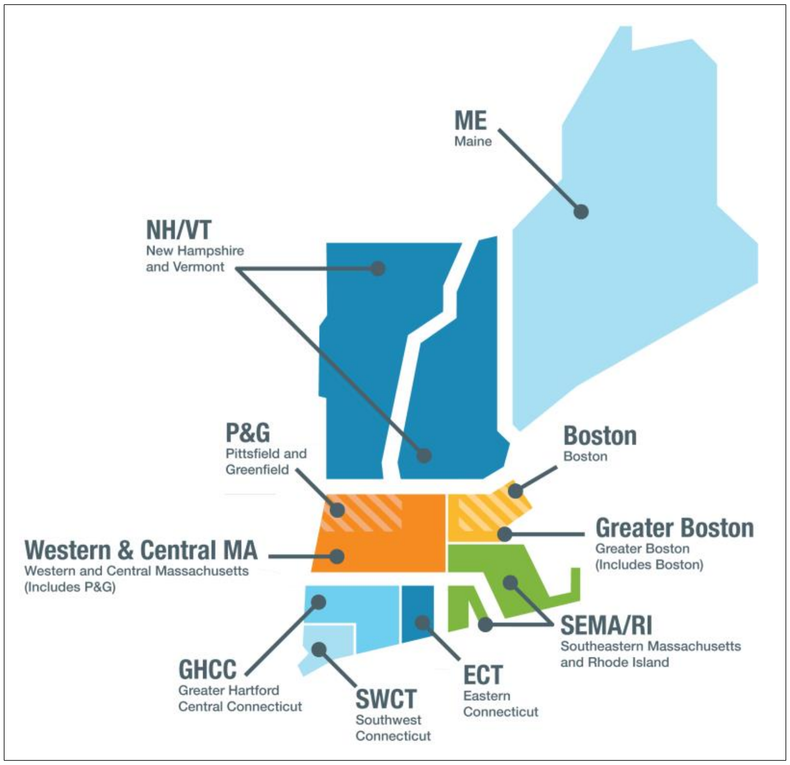

Figure 5-1: Key study areas in New England.

5.5.1 Southwest Connecticut Key Study Area

The Southwest Connecticut (SWCT) key study area is located inside the Southwest Connecticut import interface. It borders the New England to New York interface along the Connecticut state border.[148]

The SWCT study area has gone through four study efforts over the past 11 years. These study efforts are identified by the study horizon years of 2018, 2022, 2025, and 2027. All the upgrades identified in the 2018, 2022, and 2025 study efforts will be placed in service by September 2020. The major components of the preferred solutions for addressing the needs are listed in the latest version of the *RSP Project List* (see Section 5.9).

The 2022 needs assessment (published in June 2014) and the solutions study (published in February 2015) identified a number of criteria violations in the SWCT area and a set of transmission solutions to mitigate them. Before receiving approval of their proposed plan applications (PPAs), several new generators cleared in the FCM, resulting in the reassessment of transmission needs for the study area.[149] The 2025 needs assessment was initiated as a follow up to the 2022 needs assessment.

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[148] ISO New England, "Southwest Connecticut Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/swct.

[149] New resources include Towantic (725 MW) and Wallingford (90 MW), which received CSOs in FCA 9, and Bridgeport Harbor (484 MW), which received a CSO in FCA 10.

Since the completion of the SWCT 2025 update, the owner of the Bridgeport Harbor 3 unit submitted a retirement delist bid for FCA 12.[150] The main reason for the SWCT 2027 needs assessment was to examine if new needs appear in the study area due to the retirement of the Bridgeport Harbor 3 unit.[151] In addition, the study assessed minimum-load conditions for the entire State of Connecticut.

The results of the SWCT 2027 needs assessment for peak load indicated that no thermal or voltage violations were identified as pool transmission facility (PTF) needs for conditions with no contingencies or with first or second contingencies (N-0, N-1, or N-1-1 conditions). The steady-state testing performed at the minimum load level of 8,000 MW indicated four N-1-1 high-voltage violations that have been identified as PTF needs and no N-0 or N-1 thermal or voltage violations. The results of the short-circuit assessment indicated that no PTF breakers are overdutied in the study area. Because the needs identified in the SWCT 2027 needs assessment were the result of the minimum-load assessment, they could occur under current system conditions and thus were determined to be time sensitive.[152]

Eversource is currently evaluating solutions to the asset-condition concerns associated with the two Glenbrook static synchronous compensators (STATCOMs).[153] Proposed rehabilitation and improvements made to the STATCOMS could also solve the needs identified in the minimum-load assessment. The solution to the asset-condition issues of the Glenbrook STATCOM is expected to be identified in 2019.

5.5.2 Greater Hartford Central Connecticut Key Study Area

The Greater Hartford Central Connecticut (GHCC) key study area is located between the Connecticut import interface and the SWCT import interface, while only parts of the study area are within the Western Connecticut import area.[154] The GHCC study area represents about 35% of the Connecticut load.

All the Greater Hartford Central Connecticut 2022 upgrades are expected to be in service by December 2019.[155] The major components of the preferred solutions for addressing the needs are included in the latest version of the *RSP Project List* (see Section 5.9).

Currently, no peak-load studies on the GHCC study area are underway. A minimum-load assessment of the GHCC study area was conducted in the SWCT 2027 needs assessment, and no needs were identified in the GHCC study area (see Section 5.5.1).

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[150] ISO New England, *Southwest Connecticut 2025 Update* (March 2017), https://smd.iso-ne.com/operations-services/ceii/pac/2017/03/swct_2025_update_final.pdf.

[151] ISO New England, "Notice of Initiation of 2027 Southwest Connecticut Needs Assessment," (June 30, 2017), https://www.iso-ne.com/static-assets/documents/2017/06/2027_swct_needs_assessment_study_initiation_pac_notice.pdf.

[152] ISO New England, *Southwest Connecticut (SWCT) 2027 Needs Assessment* (July 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/07/final_ceii_swct_2027_na.pdf.

[153] A STATCOM is another type of flexible alternating-current transmission system device.

[154] ISO New England, "Greater Hartford Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/greater-hartford.

[155] The new Southwest Hartford–Newington 115 kV line project was changed from a four-mile underground line to a hybrid, 1.3-mile underground line and 2.4-mile overhead line, which resulted in a cost savings of $29.8 million. See the ISO's *GHCC Southwest Hartford to Newington 115 kV Line Project Update*, presentation (June 13, 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/06/a3_ghcc_sw_hartford_to_newington_115kv_line_upgrade_1.pdf.

5.5.3 Western and Central Massachusetts Key Study Area

The Western and Central Massachusetts (WCMA) key study area is bordered by the Connecticut border to the south, the New York border to the west, the Vermont and New Hampshire borders to the north, and the Boston import interface to the east.[156] The Pittsfield and Greenfield study area is within the WCMA study area and extends from the city of Pittsfield north to the Vermont border, east to Greenfield, and south to Amherst (MA).

All the Pittsfield and Greenfield 2022 upgrades are already in service (see Section 5.4) with the exception of a 115 kV station at Pochassic, and a new 115 kV line between Pochassic and Buck Pond, which will be placed in service by June 2020. The major components of the preferred solutions for addressing the needs are included in the latest version of the *RSP Project List* (see Section 5.9).

The needs assessment for the WCMA study area began in June 2017.[157] A draft WCMA 2027 scope of work was presented to the PAC in January 2018, but the effort was paused to take into account the 2018 updated load, EE, and PV forecasts.[158] A new WCMA 2028 scope of work was presented to the PAC in September 2018.[159] To account for the draft 2019 forecasts, the ISO posted a new WCMA 2029 scope of work and intermediate study files in August 2019.[160] The WCMA 2029 scope of work included the forecast data from the 2019 CELT Report.

5.5.4 Greater Boston Key Study Area

The Greater Boston key study area includes the communities north and east of Interstate 495 north to the New Hampshire border, the city of Boston, and the suburbs south of Boston.[161]

The Greater Boston study area has gone through two study efforts over the past 10 years. The first needs assessment, with study horizons of 2013 and 2018, was published in 2010.[162] Because the study area changed significantly, a second needs assessment, with study horizons of 2018 and 2023, was published in 2015.[163] The changes that prompted the updates can be categorized into four topics: load forecast and

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[156] ISO New England, "Western and Central Massachusetts Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas//western-and-central-massachusetts.

[157] ISO New England, "Notice of Initiation of WCMA Needs Assessment," (June 29, 2017), https://www.iso-ne.com/static-assets/documents/2017/06/2027_wcma_needs_assessment_study_initiation_pac_notice.pdf.

[158] *Updating Needs Assessments* presentation; see footnote 147.

[159] ISO New England, *WCMA 2028 Scope of Work*, presentation (September 27, 2018), https://www.iso-ne.com/static-assets/documents/2018/09/a11_wcma_2028_needs_assessment_scope_of_work_rev1.pdf.

[160] ISO New England, *Western and Central Massachusetts Area 2029 Needs Assessment—Scope of Work* (August 2019), https://smd.iso-ne.com/operations-services/ceii/pac/2019/08/draft_ceii_wcma_2029_na_sow.pdf.

[161] ISO New England, "Greater Boston Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/greater-boston.

[162] ISO New England, *Greater Boston Area Transmission Needs Assessment* (July 2010), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2012/boston_needs_report.ZIP.

[163] The *Greater Boston Area Transmission Needs Assessment* for the 2018 and 2023 study horizons was originally published January 20, 2015. A summary of minor updates is available at https://www.iso-ne.com/static-assets/documents/2016/07/summary_of_corrections_made_to_greater_boston_needs_assessment_report_final.pdf. The *Greater Boston Area Updated Transmission Needs Assessment* for the 2018 and 2023 study horizons (July 26, 2016) is available at https://smd.iso-ne.com/planning/ceii/reports/2010s/greater_boston_updated_needs_assessment_report_final.pdf.

demand resources, resource additions and retirements, transmission system topology, and system modeling.

The needs assessments showed thermal and voltage needs under peak load conditions in the Greater Boston study area, high-voltage needs in the Greater Boston study area under minimum-load conditions, and, as part of the short-circuit analysis, overdutied breakers in the downtown Boston subarea. The Greater Boston solutions study solved the needs from the latest needs assessment, the preferred solution components were presented to the PAC in February 2015, and the solutions study report was completed in August 2015.[164] The major components of the preferred solutions for addressing the needs includes multiple new 345 kV facilities, new 115 kV facilities, and upgrades to existing equipment within the study area. The Greater Boston suite of projects also included the addition of a +/- 200 MVAR STATCOM in Maine as a result of the stability testing performed for the preferred solution. Several of the projects within the Greater Boston suite of projects are already in service, and all the components of the preferred solutions are expected to be in service by May 2021. The details for the different solution components are included in the latest version of the *RSP Project List* (see Section 5.9).

The Boston study area is a subset of the Greater Boston key study area and is approximately bounded by the Boston import interface. Due to the submittal of retirement delist bids for Mystic units 7, 8, 9, and Jet for FCA 13, a Boston 2028 needs assessment was initiated on September 14, 2018.[165] Also, due to the new 2019 load, EE, and PV forecasts, this needs assessment was updated to include the load forecast data from the draft 2019 CELT Report.[166] The Boston 2028 needs assessment scope of work and intermediate study files were posted in March 2019, and the final needs assessment and study files were posted on June 10, 2019.[167] The results of the Boston 2028 needs assessment show a number of voltage violations at minimum load and thermal violations at peak load. In addition, an operational study will be performed to evaluate the impact of the retirement of Mystic 8 and 9 on system restoration plans, and any resulting needs will be communicated in the Boston 2028 needs assessment addendum.[168]

The needs found at minimum load are deemed time-sensitive because the load level is possible under current-day system conditions. The solutions study process, detailed in the OATT, Attachment K, Section 4.2, was used to solve the time-sensitive voltage violations identified at minimum load. As a result of the solutions study completed in October 2019, additional transmission facilities will be installed in the area to mitigate high-voltage needs found at minimum load.

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[164] ISO New England, *Greater Boston Preferred Solution,* presentation (February 18, 2015), https://www.iso-ne.com/static-assets/documents/2015/02/a2_isone_greater_boston_preferred_solution_non_ceii.pdf, and *Greater Boston Area Transmission Solutions Study* (August 12, 2015), https://smd.iso-ne.com/operations-services/ceii/pac/2015/08/final_greater_boston_transmission_solution_study_reports.zip.

[165] ISO New England, "Notice of Initiation of 2028 Boston Area Needs Assessment," (September 14, 2018), https://www.iso-ne.com/static-assets/documents/2018/09/notice_of_initiation_of_boston_2028_needs_assessment_study.pdf.

[166] *Updating Needs Assessments* presentation; see footnote 147.

[167] ISO New England, *Final Boston 2028 Needs Assessment* (June 10, 2019), https://smd.iso-ne.com/operations-services/ceii/pac/2019/06/ceii_boston_2028_na.pdf. The report and its appendices are posted under the Greater Boston Key Study Area, webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/greater-boston/.

[168] The retirement of the Mystic 8 and 9 resources would delay or inhibit the Boston 345 kV cable and load restoration without replacement of their dynamic reactive capability. Due to the confidentiality of the system restoration plan under the ISO's Information Policy, the ISO can only report the size and location of the needed reactive device.

The peak load needs were found to be non-time-sensitive because the needs were present in the study horizon cases of 2028 but were not observed in the time-sensitive cases of 2022. In addition, the system-restoration need for reactive support is considered a non-time-sensitive need because the retirement date of Mystic 8 and 9 is beyond the three-year time-sensitive period. The competitive solution process, detailed in Attachment K, Section 4.3, will be used to solve the non-time-sensitive, thermal violations identified at peak load. Once the preferred solution to solve the time-sensitive, minimum-load, voltage violations have been selected, the ISO anticipates issuing in early 2020 its first request for proposals (RFP) to solicit competitive bids from qualified transmission project sponsors (QTPSs) to solve the peak load needs.

5.5.5 Southeastern Massachusetts and Rhode Island Key Study Area

The Southeastern Massachusetts and Rhode Island (SEMA/RI) key study area focuses on the SEMA and the RI load zones, which encompass the areas within Massachusetts located south of Boston and the entire state of Rhode Island.[169]

The major goals of the SEMA/RI study were to determine any long-term system needs required to integrally serve the broad SEMA and Rhode Island areas. Several PAC presentations detailed needs in the study area, but a needs assessment was never completed due to the retirement announcements of Brayton Point in late 2013 and Pilgrim Nuclear Power Station in late 2015.[170] After the Pilgrim retirement announcement, the SEMA/RI study was restarted in late 2015 with a study horizon of 2026. The 2026 needs assessment was presented to the PAC in March 2016, and the report was published in May 2016.[171]

The needs assessment results continued to show various time-sensitive needs on the 115 kV system in all the SEMA/RI subareas. A 2026 solutions study solved the time-sensitive needs from the 2026 needs assessment; the preferred solution components were presented to the PAC in December 2016, and the solutions study report was completed in March 2017.[172] Most of the preferred solution components were identified on the 115 kV system and included adding a new switching station, reconductoring lines, installing new lines, separating double-circuit towers, and adding reactive support to maintain voltage.

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[169] ISO New England, "Southeastern Massachusetts and Rhode Island Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/sema-ri.

[170] ISO New England, *Southeastern Massachusetts and Rhode Island Area Needs Assessment (N-1)*, presentation (October 17, 2012), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2012/oct172012/sema_ri.pdf; *Southeastern Massachusetts and Rhode Island (SEMA/RI) Area Needs Assessment (N-1)*, presentation (February 19, 2014), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2014/feb192014/a8_sema_ri_needs_assessment.pdf; and *Southeastern Massachusetts and Rhode Island Area Needs Assessment (N-1-1)*, presentation (July 15, 2014), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2014/jul152014/a5_sema_ri_area_needs_2_n_1_1_rev1.pdf.

[171] ISO New England, *Southeastern Massachusetts and Rhode Island 2026 Needs Assessment, Revision 2*, presentation (March 22, 2016), https://smd.iso-ne.com/operations-services/ceii/pac/2016/05/final_sema_ri_2026_needs_assessment_presentation_rev2.pdf, and *Southeastern Massachusetts and Rhode Island Area 2026 Needs Assessment* (May 2016), https://smd.iso-ne.com/operations-services/ceii/pac/2016/05/final_sema_ri_needs_assessment_report.pdf.

[172] ISO New England, *Southeastern Massachusetts and Rhode Island 2026 Preliminary Preferred Solution*, presentation (December 2016), https://smd.iso-ne.com/operations-services/ceii/pac/2016/12/a3_sema_ri_2026_preliminary_preferred_solutions.pdf, and *Southeastern Massachusetts and Rhode Island Area 2026 Solutions Study, Revision 1* (March 2017), https://smd.iso-ne.com/operations-services/ceii/pac/2017/02/final_sema_ri_2026_solutions_study_report_rev1.pdf.

One 345 kV project required the separation of a DCT. The upgrades are expected to be placed in service by the end of 2021. The major components of the preferred solutions for addressing the needs are included in the latest version of the *RSP Project List* (see Section 5.9).

The Aquidneck Island area, which is part of the SEMA/RI Somerset–Newport subarea, underwent an advanced needs assessment and solutions study in early 2015.[173] The needs assessment results showed thermal overloads on the 115/69 kV autotransformer and 69 kV lines serving the area. The preferred solution components included the rebuild of a station and 69 kV lines and the conversion of 69 kV equipment to 115 kV. All the projects are expected to be in service by September 2020. The major components of the preferred solutions for addressing the needs are included in the latest version of the *RSP Project List* (see Section 5.9).

The needs assessment for the SEMA/RI study area began in June 2017 to identify remaining needs, if any.[174] This needs assessment includes the preferred solutions, which were developed to solve time-sensitive needs found in the SEMA/RI 2026 needs assessment. A draft SEMA/RI 2027 scope of work was presented to the PAC in December 2017, but the effort was paused to take into account the 2018 load, EE, and PV forecasts.[175] A new draft SEMA/RI 2028 scope of work was presented to the PAC in November 2018.[176] Due to the new forecasts and the uncertainty of the interconnections of several resources in the SEMA/RI area, the finalization of the SEMA/RI 2028 scope of work and intermediate study files was suspended.

In late 2016, a SEMA/RI minimum-load needs assessment began to evaluate the reliability performance and identify reliability-based transmission needs in the SEMA/RI study area under minimum-load conditions. The SEMA/RI minimum-load needs assessment was posted in August 2017.[177] High-voltage needs were identified under N-1 and N-1-1 contingencies in the Cape Cod area. The needs were determined to be time sensitive because the only needs identified were the result of the minimum-load assessment and can occur under current system conditions.

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[173] National Grid, *Newport RI (Aquidneck Island) Transmission Area Improvements—Needs and Preferred Solution*, PAC presentation (April 2015), https://smd.iso-ne.com/planning/ceii/reports/2010s/archive/a7_newport_aquidneck_island_transmission_area_improvements_presentation.pdf.

[174] ISO New England, "Notice of Initiation of Southeastern Massachusetts and Rhode Island (SEMA-RI) Needs Assessment," (June 29, 2017), https://www.iso-ne.com/static-assets/documents/2017/06/2027_sema_ri_needs_assessment_study_initiation_pac_notice.pdf.

[175] ISO New England, *Southeastern Massachusetts and Rhode Island (SEMA/RI) 2027 Needs Assessment Scope of Work,* presentation (December 20, 2017), https://www.iso-ne.com/static-assets/documents/2017/12/a_11_sema_ri_2027_needs_assessment_scope_of_work.pdf. Also, the *Updating Needs Assessments* presentation; see footnote 147.

[176] ISO New England, *Southeastern Massachusetts and Rhode Island 2028 Needs Assessment Scope of Work*, (November 15, 2018), https://www.iso-ne.com/static-assets/documents/2018/11/a3_sema_ri_2028_needs_assessment_scope_of_work.pdf.

[177] ISO New England, *Southeastern Massachusetts and Rhode Island Area 2026 Minimum Load Needs Assessment* (August 2, 2017), https://smd.iso-ne.com/operations-services/ceii/pac/2017/08/ceii_final_sema_ri_min_load_needs_assessment_report.pdf.

The SEMA/RI 2026 minimum-load solutions study began in September 2017.[178] Since that time, the minimum-load level evaluated in New England was decreased from 8,500 MW to 8,000 MW. In addition, determining a solution must be delayed until the interconnection designs in the study area have been finalized. Therefore, evaluation of the minimum-load needs in SEMA/RI will be revisited as part of the needs assessment described above.

5.5.6 Maine Key Study Area

The Maine key study area examines the entire state of Maine. In 2013, as a follow up to the Maine Power Reliability Program, a 2023 needs assessment studied the Maine transmission system. The 2023 needs assessment was presented to the PAC in September 2014, and the report was published in December 2016.[179] The results of the 2023 needs assessment show various time-sensitive needs on the 115 kV system.

Due to a large mill retirement, significant transmission system upgrades added to the study area since the 2023 needs assessment was completed, and after further review and analysis of the needs results, an addendum analysis report to the 2023 Maine needs assessment was completed.[180] The results of the addendum continued to show various time-sensitive needs on the 115 kV system and high-voltage needs on the 345 kV system at minimum-load levels. A 2023 solutions study developed alternatives to address the identified time-sensitive needs from the 2023 needs assessment, which the ISO presented to the PAC.[181] In early 2017, the 2023 solutions study was suspended, however, due to numerous changes in the study assumptions, inputs, and processes in 2017, as discussed above. Taking into account all these changes, a new needs assessment began on June 29, 2017, with the posting of the notice of initiation for the Maine needs assessment.[182] The Maine 2027 scope of work and intermediate study files were posted on March 3, 2018.[183]

The Maine 2027 needs assessment effort was suspended in February 2019 due to the change in the load, energy efficiency, and photovoltaic forecast information.[184] The 2019 draft forecasts and the results of the FCA 13 were used to update the models, and a new needs assessment focused on the Upper Maine

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[178] ISO New England, "Notice of Initiation of the 2026 Southeastern Massachusetts and Rhode Island (SEMA/RI) Minimum Load Solutions Study," (September 13, 2017), https://www.iso-ne.com/static-assets/documents/2017/09/2026_sema_ri_minimum_load_solutions_study_initiation_pac_notice.docx.

[179] ISO New England, "Maine Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/maine. Also, *Maine Transmission System 2023 Needs Assessment Steady State Results*, presentation (September 17, 2014), https://smd.iso-ne.com/operations-services/ceii/pac/2014/a3_maine_2023_needs_assessment_results.pdf, and, with TRC Engineers, LLC, et al., *Maine Transmission System 2023 Needs Assessment and TPL-001-4 Compliance Study Report* (December 2014), https://smd.iso-ne.com/operations-services/ceii/pac/2014/final_maine_2023_needs_assessment_tpl_001_4_compliance_report.pdf.

[180] ISO New England, *Final Addendum Analysis Report to the 2023 Maine Transmission System Needs Assessment* (April 28, 2016), https://smd.iso-ne.com/operations-services/ceii/pac/2016/04/2023-final-me-addendum-report_20160428.pdf.

[181] ISO New England, *Maine 2023 Solutions Study Update*, presentation (January 18, 2017), https://smd.iso-ne.com/operations-services/ceii/pac/2017/01/a4_maine_2023_solution_study_update.pdf.

[182] ISO New England, "Notice of Initiation of Maine (ME) Needs Assessment," (June 29, 2017), https://www.iso-ne.com/static-assets/documents/2017/06/2027_me_needs_assessment_study_initiation_pac_notice.pdf.

[183] ISO New England, *Maine 2027 Needs Assessment—Scope of Work* (March 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/03/final_ceii_2027_maine_na_sow.pdf.

[184] *Updating Needs Assessments* presentation; see footnote 147.

region began in June 2019 with the posting of the notice of initiation for the Upper Maine 2029 needs assessment.[185] The Lower Maine region will be evaluated when more information about the New England Clean Energy Connect (NECEC) HVDC project is known (refer to Sections 8.4 and 10.2) . The changes to the March 2018 needs assessment scope of work, reflecting 2029 system conditions for the Upper Maine 2029 needs assessment, was presented to the PAC in June 2019.[186]

5.5.7 New Hampshire and Vermont Key Study Area

The New Hampshire and Vermont (NH/VT) key study area is for the states of New Hampshire and Vermont.[187] As a follow up to the New Hampshire/Vermont 2020 Upgrades, the latest NH/VT needs assessment was completed using a study horizon of 2023. The 2023 needs assessment included updated load and resource assumptions and the retirement of the Vermont Yankee Nuclear Power Station. The 2023 needs assessment was presented to the PAC in March 2014, and the report was published in August 2014.[188]

The results of the 2023 needs assessment show various time-sensitive thermal and voltage needs on the 115 kV system in New Hampshire and Vermont and high-voltage needs on the 345 kV system at minimum-load levels in New Hampshire. The preferred solution components were for the 115 kV system and included rebuilding a new switching station, rebuilding a line, and adding reactive support to maintain voltage.

In early 2017, the 2023 solutions study was suspended, due to numerous study assumptions, inputs and processes changes that occurred in 2017, as discussed above. Taking into account all these changes, a new needs assessment for the New Hampshire area was initiated on June 29, 2017.[189] The New Hampshire 2027 needs assessment scope of work and intermediate study files were posted in March 2018, and revised versions of the scope and study files were posted in May 2018 to reflect the latest available load, EE, and PV forecasts at that time.[190] The New Hampshire 2027 needs assessment and

[185] ISO New England, *Notice of Initiation of Upper Maine (ME) 2029 Needs Assessment* (June 12, 2019), https://www.iso-ne.com/static-assets/documents/2019/06/2029_upperme_needs_assessment_study_initiation_pac_notice.pdf.

[186] ISO New England, *Upper Maine (ME) 2029 Needs Assessment Details* (June 19, 2019), https://www.iso-ne.com/static-assets/documents/2019/06/a5_upper_maine_2029_needs_assessment_details.pdf.

[187] ISO New England, "New Hampshire and Vermont Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/vt-nh.

[188] ISO New England, *New Hampshire/Vermont 2023 Needs Assessment Update*, presentation (March 17, 2014), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2014/mar172014/a7_nh_vt_2023_needs_assessment.pdf, and *New Hampshire/Vermont Transmission System 2023 Needs Assessment Report* (August 2104), https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/reports/2014/final_2023_nhvt_transmission_system_needs_assessment.pdf.

[189] ISO New England, "Notice of Initiation of New Hampshire (NH) Needs Assessment," (June 29, 2017), https://www.iso-ne.com/static-assets/documents/2017/06/2027_nh_needs_assessment_study_initiation_pac_notice.pdf.

[190] ISO New England, *New Hampshire (NH) 2027 Needs Assessment—Scope of Work, Revision 1* (May 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/05/final_ceii_2027_nh_na_sow_rev1_clean.pdf and ISO New England, *New Hampshire (NH) 2027 Needs Assessment—Scope of Work* (March 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/03/final_ceii_2027_nh_na_sow.pdf.

study files were posted in November 2018.[191] The results showed time-sensitive voltage needs on the 345 kV and 115 kV systems at peak load and high-voltage needs on the 345 kV system at minimum-load levels in New Hampshire.

The New Hampshire 2027 solutions study began in November 2018 to address the time-sensitive needs identified in the NH 2027 Needs Assessment.[192] This effort was suspended in February 2019 due to the change in the load, EE, and PV forecast information.[193] The 2019 forecasts and the results of the FCA 13 were used to update the models, and a new need assessment began in May 2019 with the posting of the notice of initiation.[194] The changes to the April 2018 scope of work reflecting 2029 system conditions for the NH 2029 needs assessment was presented to the PAC in May 2019.[195]

5.5.8 Eastern Connecticut Key Study Area

The Eastern Connecticut (ECT) key study area is the area in the eastern part of Connecticut not covered by the SWCT or GHCC studies.[196] The ECT study area is located outside the western Connecticut import interface and inside the Connecticut import/export interface. The study area also borders part of the New England east–west and west–east interfaces mainly along the Rhode Island border.

The ECT study area is a large load pocket served from the Killingly, Card, and Montville stations and a 115 kV line from Rhode Island. A needs assessment with a study horizon of 2022 was presented to the PAC in May and June 2013, and the report was published in June 2015.[197] The results of the 2022 needs assessment showed various time-sensitive needs on the 115 kV and 69 kV portions of the system.

A 2022 ECT solutions study began to address the time-sensitive needs found in the 2022 needs assessment, and solution alternatives were presented to the PAC in September 2016.[198] In early 2017, the 2022 solutions study was suspended because numerous study assumptions, inputs, and processes changed in 2017, as described above. Taking into account all these changes, a new needs assessment began on June 29, 2017, with the posting of the notice of initiation.[199] The ECT 2027 scope of work and intermediate study files were posted on March 3, 2018, and the ECT 2027 needs assessment and study

[191] ISO New England, *Final New Hampshire 2027 Needs Assessment* (November 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/11/final_ceii_new_hampshire_2027_needs_assessment.pdf.

[192] ISO New England, "Notice of Initiation of 2027 NH Solutions Study," (November 16, 2018), https://www.iso-ne.com/static-assets/documents/2018/11/pac_notice_nh_2027_ss.pdf.

[193] Refer to the *Updating Needs Assessments* presentation; see footnote 147.

[194] ISO New England, "Notice of Initiation of 2029 New Hampshire Needs," (May 3, 2019), https://www.iso-ne.com/static-assets/documents/2019/05/2029_nh_needs_assessment_study_initiation_pac_notice.pdf.

[195] ISO New England, *New Hampshire (NH) 2029 Needs Assessment Details—Revision 1* (May 21, 2019), https://www.iso-ne.com/static-assets/documents/2019/08/new_hampshire_2029_needs_assessment_details_revision_rev1_clean.pdf.

[196] ISO New England, "Eastern Connecticut Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/eastern-connecticut.

[197] ISO New England, *Eastern Connecticut Area Transmission 2022 Needs Assessment* (June 2015), https://smd.iso-ne.com/planning/ceii/reports/2010s/final_eastern_ct_2022_needs_assessment_report.pdf.

[198] ISO New England, *Eastern Connecticut 2022 Solutions Study Update*, presentation (September 21, 2016), https://smd.iso-ne.com/operations-services/ceii/pac/2016/09/a3_eastern_connecticut_2022_solution_study_update.pdf.

[199] ISO New England, "Notice of Initiation of Eastern Connecticut (ECT) Needs Assessment," (June 29, 2017), https://www.iso-ne.com/static-assets/documents/2017/06/2027_ect_needs_assessment_study_initiation_pac_notice.pdf.

files were posted on May 29, 2018.[200] Like the 2022 needs assessment, the ECT 2027 needs assessment showed various time-sensitive needs on the 115 kV and 69 kV portions of the system.

The ECT 2027 solutions study began in June 2018.[201] The 2027 ECT solutions study was near completion when the effort was suspended in February 2019 due to the changes in the load, EE, and PV forecasts. The draft 2019 forecasts were used to update the models and study files to form an updated ECT 2029 needs assessment. The changes made between the new ECT 2029 needs assessment and the past ECT 2027 needs assessment were presented to the PAC in April 2019.[202]

A minimum-load assessment for the ECT study area was conducted as part of the SWCT 2027 needs assessment, and no needs were identified in the ECT study area (see Section 5.5.1).

5.6 General Need for Future Transmission

Since 2002, 801 project components have been placed in service across the region to fortify the transmission system. In addition, 67 project components have a status of planned, proposed, or under construction. Overall, the estimated investment in New England to maintain reliability has been $10.9 billion from 2002 to June 2019, and another $1.3 billion is planned over the planning horizon.[203] With these system upgrades in place, combined with the changes in assumptions to needs assessments described previously, the need for additional reliability-based transmission upgrades to resolve peak load concerns is expected to decline over the planning horizon. (See Section 3.4, which shows a decline of net peak-load projections over the 10-year planning horizon.) Conversely, generation retirements and studies reviewing system performance, accounting for the integration of inverter-based resources (IBRs) and improved load modeling, may drive the need for additional reliability-based transmission upgrades (see Section 9).[204]

5.7 New England Asset Management

Because of the general age of the transmission system in New England, many assets across the system are reaching their end of life and are requiring significant refurbishment. Spending to address these concerns has increased significantly over the past few years. In addition, enhancements to existing substations are

[200] ISO New England, *Eastern Connecticut 2027 Needs Assessment Scope of Work* (March 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/03/final_ceii_2027_ect_needs_assessment_sow_clean.pdf, and *Eastern Connecticut 2027 Needs Assessment* (May 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/05/final_ceii_ect_2027_na.pdf.

[201] ISO New England, "Initiation of ECT 2027 Solutions Study," (June 1, 2018), https://www.iso-ne.com/static-assets/documents/2018/06/pac_notice_ect_2027_ss.pdf.

[202] ISO New England, "Eastern Connecticut (ECT) 2029 Needs Assessment Details—Revision 1", (April 2019), https://www.iso-ne.com/static-assets/documents/2019/05/eastern_connecticut_2029_needs_assessment_details_rev1_clean.pdf.

[203] The data are based on the June 2019 *Regional System Plan Project List*.

[204] Unlike traditional generators that run at the same frequency as the power system (i.e., synchronously), inverter-based technologies, such as wind, photovoltaics, and HVDC facilities, use power electronics to control the generator, converting between AC frequencies and between AC and DC frequencies (i.e., asynchronously with the AC power system).

needed to meet NERC's physical security standards.[205] The New England Asset Management Key Study Area is a repository to store all asset-condition-related PAC presentations.[206]

In 2016, the ISO created a New England Asset-Condition Update List to capture all asset-condition PAC presentations that occurred after May 18, 2015. The ISO updates the New England Asset-Condition Update List three times per year along with the *RSP Project List*. Since the New England Asset-Condition Update List has been created, 163 projects have been added to the list for a total of $2.65 billion as of the June 2019 update. Of the 163 projects, 63 are in service for a total of $849.2 million. The rest of the projects are in the proposed, planned or under construction status.[207]

5.8 Local System Plan

The Local System Plan (LSP) process is described in the OATT, Attachment K, Appendix 1. In general, LSP projects are needed to maintain the reliability of the nonpool transmission facility (non-PTF) system. While LSP projects are designed to serve the needs of the non-PTFs, they typically involve PTF components, which are not eligible for cost regionalization. Information regarding LSP projects is provided to stakeholders through the Transmission Owner Planning Advisory Committee (TOPAC) meetings.[208]

5.9 RSP Project List and Projected Transmission Project Costs

The *RSP Project List* is a summary of needed transmission projects for the region and includes information on project type, the primary owner, the transmission upgrades and their status, and the estimated cost of the PTF portion of the project.[209] The *RSP Project List* includes the status of reliability transmission upgrades, market-efficiency transmission upgrades, elective transmission upgrades, and generator-interconnection transmission upgrades (described in Section 2.1.1). The list also would include public policy transmission upgrades, although none have been identified to date. The ISO updates this list at least three times per year. Additional information on the project classifications included in the *RSP Project List* is available in the *Transmission Planning Process Guide*.

The ISO regularly updates the PAC on reliability transmission upgrade (RTU) and market-efficiency transmission upgrade (METU) (and, as appropriate, public policy transmission upgrade; PPTU) study schedules, scopes of work, assumptions, draft and final results, and project costs.[210] Projects are

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[205] NERC, *Reliability Standards for the Bulk Electric Systems of North America*, Standard CIP-014-2, *Physical Security*, (updated March 8. 2019), https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf.

[206] A PAC presentation is required for all asset-condition-related work where the cost estimate is greater than or equal to $5 million. ISO New England, "New England Asset Management Key Study Area," webpage (2019), https://www.iso-ne.com/system-planning/key-study-areas/new-england-asset-management/?load.more=1.

[207] Projects under the status of "concept" are not included.

[208] Links to the most recent LSPs are included on the ISO's *RSP Project List* at https://www.iso-ne.com/system-planning/system-plans-studies/rsp. Also refer to the ISO's "Transmission Owner Planning Advisory Committee." webpage (2019) at https://www.iso-ne.com/committees/planning/topac.

[209] The *RSP Project List* (XLS file) is available at https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

[210] PAC materials and meeting minutes are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html.

considered part of the Regional System Plan consistent with their status and are subject to transmission cost allocation (TCA) for the region. RSP19 incorporates information from the June 2019 *RSP Project List.*

This section discusses RTUs underway and their costs and the status of the ETUs in the region. It also explains why no market-efficiency-related transmission upgrades have been needed and provides information on several transmission upgrades developed and paid for by generator developers.

5.9.1 Reliability Transmission Upgrades

As of June 2019, the total estimated cost of transmission upgrades—proposed, planned, and under construction—was approximately $1.3 billion, as shown in Table 5-1. The ISO maintains a spreadsheet that lists all projects where a TCA application has been submitted and identifies those costs the ISO deemed as localized in accordance with Schedule 12C of the OATT.[211]

[211] ISO New England, "Summary of ISO-NE Reviewed TCA Applications under Schedule 12C of the Tariff," spreadsheet (December 31, 2018), https://www.iso-ne.com/static-assets/documents/2018/02/tca_application_status.pdf.

Table 5-1
Estimated Cost of Reliability Projects as of June 2019 Plan Update (Million $)

Projects	Project Costs (millions of $)[(a)]
Major projects	
Maine Power Reliability Program	1,466
Greater Hartford and Central Connecticut	307
New England East–West Solution (NEEWS)	1,581
NEEWS (Greater Springfield Reliability Project)—$676.0 million	
NEEWS (Rhode Island Reliability Project)—$362.3 million	
NEEWS (Interstate Reliability Project)—$482.3 million	
NEEWS (other)—$59.6 million	
Southeast Massachusetts/Rhode Island Reliability Project	327
Pittsfield-Greenfield Project	179
Greater Boston—North, South, Central, Western Suburbs	832
New Hampshire Solution—Southern, Central, Seacoast, Northern	328
Vermont Solution—Southeastern, Connecticut River	82
Southwest Connecticut	399
Subtotal[(b)]	**5,501**
Other projects[(c)]	**6,792**
New projects[(d)]	**0**
Total[(b)]	**12,294**
Minus "concept" projects	**0**
Minus "in-service" projects	**−10,9,47**
Aggregate estimate of active projects in the plan[(b)]	**1,347**

(a) Transmission owners provided all estimated costs, which may not meet the guidelines described in Planning Procedure No. 4, *Procedure for Pool-Supported PTF Cost Review*, Attachment D, "Project Cost Estimating Guidelines" (May 6, 2016), https://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp04_0/pp4_0.pdf.

(b) Totals may not sum due to rounding.

(c) The "Other Projects" category is the sum of all other project costs in the *RSP Project List* not explicitly listed above. The cost estimates for projects in the "Major Projects" category move to the "Other Projects" category once they are completed.

(d) The cost for the "New Projects" category reflects updated costs from the June 2017 project list update compared with the March 2017 update.

The PTO Administrative Committee provides annual informational filings to FERC on the current regional transmission service rates and annual updates to the ISO and NEPOOL on projected regional transmission rates, as shown in Table 5-2.[212]

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212 Regional transmission service is comprised of *regional network service* (RNS) and *through-or-out (TOUT) service.* RNS is the transmission service the ISO provides over the PTFs, described in the OATT, Part II.B, that network

Table 5-2
Actual and Forecast Regional Transmission Service Rates, 2018 to 2023[(a)]

	2018	2019	2020	2021	2022	2023
	Actual[(b)]		Forecast[(c)]			
Estimated additions in service and CWIP ($ millions)[(d)]	N/A	N/A	1,076	930	1,036	704
Forecasted revenue requirement ($ millions)	N/A	N/A	148	125	145	94
Total revenue requirement ($ millions)	2,146	2,188	2,336	2,461	2,606	2,700
Year-prior 12 CP (kW)[(e)]	19,436,373	19,542,342	19,542,342	19,542,342	19,542,342	19,542,342
RNS rate increase from prior year ($/kW-year)	−1.53	1.51	8	6	7	5
RNS rate ($/kW-year)	110.43	111.94	120	126	133	138
RNS rate assuming a 54.1% load factor) ($/kWh)	0.018	0.019	0.019	0.020	0.021	0.022
TOUT service rate ($/kWh)	0.01261	0.01278	0.014	0.014	0.015	0.016

(a) The figures may not agree because of rounding.

(b) August 3, 2018 PTO Administrative Committee (PTO-AC) Informational Filing, June 14, 2019 PTO-AC informational filing.

(c) Source: *RNS Rates: 2019–2023 PTF Forecast,* PTO-AC Rates Working Group presentation at the NEPOOL RC /TC Summer Meeting (July 16–17, 2019), https://www.iso-ne.com/static-assets/documents/2019/07/a03_rc_tc_2019_07_16_17_five_year_forecast.pptx. The 2020–2023 rate forecast reflects PTO Administrative Committee estimated data and assumptions and is preliminary and for illustrative purposes only. Therefore, such estimates, assumptions, and rates are expected to change as current data become available.

(d) "CWIP" refers to construction work in progress.

(e) "12 CP" refers to the average of all the monthly regional network loads (per the OATT, Section 21.2) for the 12 months of the calendar year on which the rate is based.

5.9.2 Lack of Need for Market-Efficiency-Related Transmission Upgrades

To date, the ISO has not identified the need for METUs, primarily designed to reduce the total net production cost to supply the system load, because of the following:

- Reliability transmission upgrades have resulted in significant market-efficiency benefits, particularly when out-of-merit operating costs were reduced.
- The development of economic resources and fast-start resources in response to the ISO's wholesale electricity markets has also helped eliminate congestion and Net Commitment-Period Compensation (NCPC).[213]

This section summarizes the historical systemwide congestion and NCPC. Economic studies are analyzing future system performance that may identify future need for METUs (see Section 2.1.1.2).

customers use to serve load within the New England Control Area. The ISO's TOUT service over the PTFs allows a real-time market transaction to be exported out of or "wheeled through" the New England area, including services used for network resources or regional network load not physically interconnected with a PTF.

[213] NCPC is a payment to a supply resource that responded to the ISO's dispatch instructions but did not fully recover its start-up and operating costs in either the Day-Ahead Energy Market or Real-Time Energy Market.

5.9.2.1 Transmission Congestion

As shown in Table 5-3, recent experience has demonstrated that the regional transmission system has low congestion among the New England load zones relative to the Hub. At approximately negative $65 million in 2018, the total day-ahead and real-time congestion costs remain small, and mitigation by additional transmission upgrades does not appear warranted. The congestion occurred primarily in the day-ahead market and was driven by cleared energy supplies in northern Maine imports from New Brunswick, and imports on the New York North interface.[214] An economic study for the BHE area is underway and, if warranted, the ISO would follow up with a METU analysis (see Section 9.3.5). Planned reliability transmission upgrades could reduce congestion costs further, as well as reduce transmission system losses.

Table 5-3
ISO New England Transmission System Day-Ahead, Real-Time, and Total Congestion Costs and Credits, 2003 to 2018 ($)

Year	Day-Ahead Congestion[a, b]	Real-Time Congestion[a, c]	Total Congestion[a, d]
2003	−$85,964,588	−$1,385,442	−$87,350,030
2004	−$82,384,177	$2,833,577	−$79,550,600
2005	−$273,449,871	$6,814,010	−$266,635,861
2006	−$192,419,271	$12,683,233	−$179,736,038
2007	−$130,145,862	$17,721,136	−$112,424,726
2008	−$125,358,187	$4,295,716	−$121,062,471
2009	−$26,681,125	$1,593,273	−$25,087,852
2010	−$37,321,849	−$622,287	−$37,944,136
2011	−$17,957,036	−$246,892	−$18,203,928
2012	−$29,326,997	−$174,471	−$29,501,468
2013	−$46,186,914	−$175,059	−$46,361,973
2014	−$34,218,158	$2,153,173	−$32,064,985
2015	−$30,168,691	−$1,038,608	−$31,207,299
2016	−$34,272,410	−$4,599,343	−$38,871,754
2017	−$39,213,542	−$2,171,319	−$41,384,861
2018	−$67,792,715	$3,260,036	−$64,532,680

(a) Negative numbers indicate charges to load; positive numbers indicate credits to load.

(b) Day-ahead congestion charges = the amount billed to load minus payments to the generators.

(c) Real-time congestion refers to deviations from day-ahead charges. Additional outages, problems, and non-day-ahead load issues that cause additional generator dispatch within the congested zone results in a credit to load. Less generation within the zone results in a real-time charge to load.

(d) Total congestion refers to money the ISO uses to pay FTR holders.

[214] The New York North interface consists of seven AC ties to upstate NY; it excludes the two ties from New England to Long Island.

The transmission system has remained operable. Major operating interfaces have remained within acceptable transfer limits at all times.[215] Table 5-3 shows the real-time congestion on the system is approximately $3 million.

The highest mean annual positive difference in the congestion component of the LMPs was $0.15/MWh at the BOSTON RSP subarea relative to the Hub.[216] The BHE RSP subarea had the highest mean negative congestion difference at $7.83/MWh. Portions of the system remote from load centers, especially northern Maine, have high negative loss components.

5.9.2.2 Transmission Improvements to Load Pockets Addressing Reliability Issues

The performance of the transmission system depends on embedded generators operating to maintain reliability in several smaller areas of the system. Consistent with ISO operating requirements, the generators may be required to provide second-contingency protection or voltage support to avoid overloads of transmission system elements. Reliability may be threatened when only a few generating units are available to provide system support, especially when considering normal levels of unplanned or scheduled outages of generators or transmission facilities. This transmission system dependence on local-area generating units typically can result in reliability payments associated with out-of-merit unit commitments. The total cost for these reliability payments are a small portion of the overall wholesale electricity market costs in New England of $9.8 billion in 2018.

Some areas currently depend on out-of-merit generating units to some degree to maintain reliability. The NCPC in the Boston area totaled approximately $14.5 million for 2018, approximately 82% of the New England total. After the upgrades being pursued as part of the Greater Boston projects are placed in service, the need to run units out of merit (and subsequent NCPC) is expected to decline (see Section 5.5.4).

Generating units in load pockets may receive second-contingency or voltage-control payments for must-run situations. Table 5-4 shows the NCPC by type and year. The 2009, 2010, 2011, and 2012 figures showed a significant decrease from the preceding years, averaging less than $17 million per year. The 2013, 2014, 2015, and 2016 figures show a modest increase, averaging approximately $43 million per year. Payments were lower again during 2017 and 2018 at under $18 million. Reliability transmission upgrades typically improve the economic performance of the system, however, upgrading transmission solely to reduce NCPC is has not been justified.

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[215] See the ISO's "Energy, Load, and Demand Report," webpage, 2018 Flows and Limits on 36 Thermal and Stability Interfaces (2019), https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/historical-hourly-flows-and-limits.

[216] ISO New England, "Real-Time and Historical Data for Informed Market Decisions," webpage, Grid Reports section (2019), https://www.iso-ne.com/markets-operations/iso-express.

Table 5-4
Net Commitment-Period Compensation by Type and Year (Million $)

Year	Second Contingency[a]	Voltage	Total[b]
2003[c]	36.0	14.4	50.4
2004	43.9	68.0	111.9
2005	133.7	75.1	208.8
2006	179.9	19.0	199.0
2007	169.5	46.0	215.5
2008	182.9	29.4	212.3
2009	17.5	5.0	22.5
2010	3.9	5.1	9.0
2011	6.0	5.8	11.9
2012	8.8	14.9	23.6
2013	38.0	16.6	54.6
2014	32.4	6.2	38.5
2015	42.7	5.4	48.1
2016	31.1	1.45	32.6
2017	12.5	3.4	15.9
2018	15.0	2.7	17.7

(a) NCPC for first-contingency commitment and distribution support is not included.

(b) Numbers may not add precisely due to rounding.

(c) NCPC under Standard Market Design began in March 2003.

Transmission solutions continue to be put in place where proposed generating or demand resources have not relieved transmission system performance concerns. The ISO is studying many of these areas, and while transmission projects are still being planned for some areas, other areas already have projects under construction and in service to mitigate dependence on generating units. Reliability transmission upgrades were used to address these system performance concerns, which contributed to a substantial reduction in out-of-merit operating costs.

5.9.3 Required Generator-Interconnection-Related Upgrades

No significant transmission system upgrades resulted from the interconnection of generators. Most of the generator-interconnection-related upgrades are fairly local to the point of interconnection of the generator. The *RSP Project List* identifies the PTF upgrades for interconnections.

Several wind generating plants participate in clustering studies that expedite the consideration of two or more interconnection requests and allocate interconnection upgrade costs among the interconnection customers (ICs). To date, the ISO has conducted the *2016/2017 Maine Resource Integration Study* (MRIS) to identify the transmission upgrades necessary to enable the interconnection of proposed new resources in northern and western Maine (see Section 4.5.3.2).[217] A second study is underway, *Second Maine*

[217] ISO New England, *2016/2017 Maine Resource Integration Study* (March 12, 2018), https://smd.iso-ne.com/operations-services/ceii/pac/2018/03/final_maine_resource_integration_study_report.pdf. Also see Section 4.5.3.2.

Resource Integration Study, to identify the transmission upgrades necessary to enable the interconnection of yet further proposed new resources in northern and western Maine.[218]

5.9.4 Elective Transmission Upgrades

A number of new elective transmission upgrades have been added to the ISO Interconnection Request Queue. Many of these are focused on delivering zero- or low-carbon resources to or within New England. As of June 1, 2019, the following projects, by queue positions (QPs), have active interconnection requests as elective transmission upgrades:

- QP-499: 1,090 MW, 300 kV HVDC/AC tie; HQ Des Cantons substation to Public Service of New Hampshire (PSNH) Deerfield substation
- QP-501: 1,000 MW HVDC tie—import only, HQ 735 kV substation to the Vermont Electric Power Company (VELCO) 345 kV Coolidge substation
- QP-506: 1,000 MW internal HVDC—north to south flow, Northern Maine Independent System Administrator (NMISA) to NSTAR 345 kV K Street substation
- QP-571: 850 MW internal 345 kV AC transmission line between the Wyman area and the Iberdrola 345 kV Larrabee Road substation
- QP-627: 1,200 MW HVDC tie north-south flow from Québec to Northern New Hampshire at the National Grid 230 kV Comerford substation
- QP-639: 1,200 MW HVDC tie north-south flow from Québec to Maine at the Avangrid 345 kV Larrabee Road substation
- QP-640: 1,000 MW HVDC tie north-south flow from New Brunswick to Massachusetts at the 345 kV lines leaving Pilgrim substation
- QP-651: 600 MW AC tie from New York to western Massachusetts—bidirectional; NY Alps substation to Western Massachusetts Electric Company (WMECO) 345 kV Berkshire substation
- QP-657: ETU to increase Downeast Loop transfer in Maine
- QP-668: NE Clean Power Link—controllable HVDC tie; capacity network import (CNI) only
- QP-738: Internal AC noncontrollable ETU—interface upgrade in Maine
- QP-740: Internal AC noncontrollable ETU to Avangrid Larrabee Road 345 kV substation in Maine
- QP-741: Internal AC non-controllable ETU to Avangrid Larrabee Road 345 kV substation in Maine
- QP-742: Internal AC non-controllable ETU to Avangrid Larrabee Road 345 kV substation in Maine
- QP-828: ETU for simultaneous delivery of specific queued projects in Southeast Massachusetts
- QP-837: 1,200 MW HVDC line (controllable) into National Grid 345 kV Brayton Point substation
- QP-873: 1,200 MW HVDC line (controllable) into Eversource 345 kV Mystic substation
- QP-889: ETU for the deliverability of specific projects

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[218] ISO New England, *Second Maine Resource Integration Study: Scope* (September 27, 2018), https://www.iso-ne.com/static-assets/documents/2018/09/a12_second_maine_resource_integration_study_scope_rev1.pdf.

- QP-890: Increase transfer capability for north to south flows (Norwalk Harbor substation to Northport substation)
- QP-891: 1,400 MW HVDC line into Millstone

5.10 Summary

Transmission projects have been placed in service across New England since 2002. These projects help maintain system reliability, enhance the region's ability to support a robust, competitive wholesale power market by reliably moving power from various internal and external sources to the region's load centers, and ensure the system can meet its current level of demand and prepare for future load growth.

Between summer 2017 and summer 2019, the Maine Power Reliability Program, the New Hampshire/Vermont 2020 Upgrades, Connecticut River Valley Upgrades, GHCC 2022 Upgrades, SWCT 2022 Upgrades, and the Pittsfield and Greenfield 2022 Upgrades were either placed in service or nearing completion. Study work remains to be done in the ECT, Maine, WCMA, New Hampshire, Boston, and SEMA/RI areas.

In May 2015, ISO New England implemented the changes to the regional and interregional transmission planning process to comply with the directives in FERC Order 1000. As of summer 2019, the ISO expects to issue a request for proposals soliciting competitive bids to solve the non-time-sensitive needs in Boston in early 2020. The second cycle of the public policy process is scheduled to begin in January 2020.

Many new elective transmission upgrades have been proposed, which focus on delivering zero or low-carbon resources to New England. As of June 1, 2019, 14 projects are under study as elective transmission upgrades, and three have received approval of their proposed plan applications.

All transmission projects are developed to meet the reliability requirements of the entire region and are fully coordinated regionally and interregionally. Most projects on the *RSP Project List* are subject to regional cost allocation. Transmission projects identified through the regional transmission planning process help the ISO meets all required transmission planning requirements, and little congestion is currently evident on the system.

A total of 801 project components have been placed in service across the region since 2002. Another 67 project components have a status of planned, proposed, or under construction. Overall, the estimated investment in New England to maintain reliability has been $10.9 billion from 2002 to June 2019, and another $1.3 billion is planned over the planning horizon. With these system upgrades in place, combined with the changes in assumptions to needs assessments, the need for additional reliability-based transmission upgrades may decline over the planning horizon, however additional needs may be driven by generation retirement and the impact of increased energy efficiency and photovoltaic programs.

Section 6
Interregional Coordination

Interconnections with neighboring systems allow for the exchange of capacity and energy. Tie lines facilitate access to a diversity of resources; compliance with environmental obligations; and the more economic, interregional operation of the system. New England is well situated, given the seasonal diversity of demand in neighboring regions, especially the winter-peaking Canadian provinces.[219] Quantifying these benefits, identifying potential needs for additional interconnections, and coordinating the planning of the interconnected system are becoming increasingly important.

As summarized in this section, the ISO coordinates its planning activities with neighboring systems and across the Eastern Interconnection (EI). Consistent with the mandatory reliability requirements of the North American Electric Reliability Corporation, the ISO identifies and resolves interregional planning issues, as shown by needs assessments and solutions studies. The ISO coordinates with neighboring regional planning entities to analyze the interconnection-wide system, identify interregional transfer and seams issues, and determine whether interregional transmission solutions are more efficient or cost effective than solely regional solutions. With other entities within and outside the region, including neighboring areas, the ISO conducts studies that aim to, for example, improve production cost models, share simulation results, investigate the challenges to and possibilities for integrating renewable resources, improve competitive electricity markets in North America, and address other common issues affecting the planning of the overall system.

The ISO also participates in numerous interregional planning activities with the US Department of Energy (DOE), the Northeast Power Coordinating Council, and NERC-designated areas in the United States and Canada. The overriding purpose of these efforts is to enhance the overall reliability of the interregional electric power system.

6.1 US Department of Energy Studies

The US Department of Energy establishes national energy policy, conducts a range of studies, and leads research and development projects. ISO New England participates in many of these activities, including the following:

- Policy conferences that explore key issues, at which ISO staff present information or attend as participants[220]
- Congestion studies, where the ISO annually provides input and data on system planning practices and issues[221]

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[219] Interconnecting different time zones provide additional diversity. The Atlantic time zone used by the Maritime provinces is an hour later than the Eastern Time Zone use by New England.

[220] See current issues, such as system security practices, at DOE's Office of Electricity website, https://www.energy.gov/oe/office-electricity.

[221] US DOE, "National Electric Transmission Congestion Study," webpage (2019), https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/national-2.

- DOE research and development projects, where the ISO serves as technical reviewers and users of information (see Section 9.4)

6.2 Eastern Interconnection Planning Collaborative Studies

Most of the electric power planning coordinators of the Eastern Interconnection, including ISO New England, formed the Eastern Interconnection Planning Collaborative (EIPC) in 2009 to address their portion of North American planning issues, combine the existing regional transmission expansion plans, and analyze the interconnection-wide system. Since that time the EIPC has conducted several studies. The *State of the Eastern Interconnection* describes EIPC's planning activities and summarizes results from studies and analyses on the collective transmission plans in the Eastern Interconnection.[222]

EIPC produces "Roll-Up Reports" that combine the individual plans of each of the major planning coordinators in the Eastern Interconnection.[223] These reports verify that the individual plans function well together to maintain bulk power system reliability throughout the interconnection and identify potential constraints resulting from interconnection-wide power-flow interactions, which provide feedback to inform and enhance regional plans. EIPC has used several power-flow models to analyze various future scenarios of interest to the states and other stakeholders. It also has extensively investigated the gas-electric power system interface and continues sharing important lessons.[224]

EIPC provides information, data, and support regarding planning issues relevant to the Eastern Interconnection to various state and federal agencies (e.g. National Council on Electricity Policy [NCEP], DOE, and FERC).[225] EIPC issued comments to DOE on its *Annual Transmission Data Report* and supported DOE's National Renewable Energy Laboratory (NREL) on the *Eastern Renewable Generation Integration Study*.[226] EIPC has advised NCEP on several issues affecting the electric power industry, such as the means of overcoming challenges posed by the large-scale development of distributed energy resources (DERs).

EIPC entities responsible for system planning developed a production-cost model of the Eastern Interconnection. With stakeholder input, EIPC plans on conducting production-costing analyses in the future.

With the addition of inverter-based, nonsynchronous generation and planned synchronous resource retirements, the ability of the EI to maintain frequency has come into question. In support of NERC, EIPC conducted an analysis that improved the models of system response to frequency events and assessed

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[222] EIPC, *State of the Eastern Interconnection* (October 3, 2018), https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5bb502d41905f4207c241e4d/1538589397643/EIPC-State+of+the+Eastern+Interconnection+10-3-18.pdf. Also see "Eastern Interconnection Planning Collaborative Completes Report on the State of the Eastern Interconnection, press release (October 4, 2018), https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5bb503b38165f55177b274f3/1538589619569/Press+Release+EIPC+Completes+State+of+Grid+Report+FINAL+10-4-18.pdf.

[223] EIPC Roll-Up Reports are available at https://www.eipconline.com/eipcstudydocuments.

[224] The final reports from EIPC's work undertaken with the support of DOE is available at https://www.eipconline.com/.

[225] The National Council on Electricity Policy has subsumed the activities of the Eastern Interconnection States Planning Council (EISPC); see http://electricitypolicy.org/eispc/.

[226] DOE, *Annual US Transmission Data Review* (March 2018), https://www.energy.gov/sites/prod/files/2018/03/f49/2018%20Transmission%20Data%20Review%20FINAL.pdf. NREL, "Eastern Renewable Generation Integration Study," webpage (n.d.), https://www.nrel.gov/grid/ergis.html.

the 2022 system.[227] The results showed acceptable system performance after fully considering the anticipated retirements of older high-inertia synchronous generators and additions of planned nonsynchronous resources within the EI.

EIPC and NERC have discussed the collaborative's assuming power-flow and stability modeling responsibilities for creating NERC base-case libraries beginning in 2020. In the role of designated entity, as described in NERC Standard MOD-032, EIPC may then fully manage the NERC model-development effort currently overseen by the Eastern Interconnection Reliability Assessment Group (ERAG).[228] Regardless of the outcome of the negotiations, EIPC will direct its planning coordinators and their representatives in the Multiregional Modeling Working Group (MMWG) on assembling network models of the EI.

6.3 Electric Reliability Organization Overview

ISO New England is responsible for complying with applicable NERC standards addressing bulk system operations and planning.[229] In addition, the ISO participates in regional and interregional studies required for compliance.

Through its committee structure, NERC, which is the FERC-designated Electric Reliability Organization (ERO), regularly publishes reports that assess the reliability of the North American electric power system.[230] Annual long-term reliability assessments evaluate the future adequacy of the power system in the United States and Canada for a 10-year period. The reports project electricity supply and demand, evaluate resource and transmission system adequacy, and discuss key issues and trends that could affect reliability. Summer and winter assessments evaluate the adequacy of electricity supplies in the United States and Canada for the upcoming peak demand periods in these seasons. Special regional, interregional, or interconnection-wide assessments are conducted as needed.

In December 2018, NERC issued its annual *Long-Term Reliability Assessment* (LTRA), analyzing reliability conditions across the North American continent.[231] This report discusses transmission additions, generation projections, and reserve capability by reliability council area. The 2018 NERC LTRA offers several key findings:

- The Electric Reliability Council of Texas (ERCOT) is projected to have reserve margins below its reference value identified as necessary for meeting resource-adequacy requirements starting in 2019, while the Midwest Reliability Organization-Midcontinent ISO (MRO-MISO), and NPCC-Ontario are projected to have reserve margins below their reference margin level by 2023. However, these areas have other resources that may be advanced to satisfy their systems' needs.

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[227] EIPC, *Frequency Response Task Force 2018 Final Report* (February 27, 2019), https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5ca541769b747a55f8444c03/1554334072121/EIPC_FRTF_2018_Final_Report_Public_Version_EC_Approved_2019-02-27.pdf.

[228] NERC, *MOD-032-1—Data for Power System Modeling and Analysis* (May 1, 2014), https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-032-1.pdf.

[229] ISO New England serves as a NERC reliability coordinator, planning coordinator, transmission operator, and transmission planner for the New England system; refer to NERC's *Glossary of Terms Used in NERC Reliability Standards* (March 8, 2019), https://www.nerc.com/files/glossary_of_terms.pdf.

[230] See NERC's "Reliability Assessment and Performance Analysis," webpage (2019), https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

[231] NERC, *2018 Long-Term Reliability Assessment* (December 2018), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf.

The report indicates that probabilistic assessments of future conditions can highlight additional reliability challenges. It also notes that resource-adequacy shortfalls can occur during off-peak periods in the Western Interconnection, especially in areas with large penetrations of variable energy resources.[232] All other areas, including New England, were projected as having sufficient resources through 2023.

- Reliance on natural gas generation increases in some areas with continuing resource-mix changes, and fuel-assurance mechanisms are being developed. The LTRA acknowledges the important roles that market rules and mechanisms can play to address energy-security issues.
- As a result of the analysis conducted by EIPC, NERC expects frequency response to remain adequate through 2022 (see Section 6.2).
- The increasing amounts of solar and wind resources require more flexible capacity to support ramping requirements. Improved forecasting also helps manage changes in ramping requirements.
- Over 30 GW of new distributed solar photovoltaics expected by the end of 2023 will affect system planning, forecasting, and modeling needs, which must be addressed.[233]

Based on the assessment's key findings, NERC developed several recommendations:

- Enhance NERC's reliability-assessment process to account for energy-adequacy issues.
- Develop guidelines to assess fuel limitations and disruption scenarios and leverage industry experience when developing reliability guidelines. The report acknowledges most of New England's large natural-gas-fired generating units lack firm fuel contracts, but ISO New England improves situational awareness through fuel surveys and coordination with pipeline operators. Wholesale market enhancements also promote the reliable operation of the system.
- Improve interconnection-wide frequency-response modeling, which has degraded with time resulting from reduced inertia and reduced frequency response from generators and loads. The report discusses the need for studying how the proper application of new technologies can improve the speed and extent of required responses.
- Ensure that system studies incorporate DERs. However, several challenges must be overcome to collect data and address issues of observability and controllability.
- Flexible ramping resources will be needed to offset variable energy production.

NERC identified the following emerging issues that could impact reliability on the overall electric power system over the 10-year horizon:

- Development of bulk power storage of all types can provide needed flexibility of system response.

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[232] The *Western Interconnection* (WI) extends from western Canada south to Baja, California in Mexico, reaching eastward over the Rocky Mountains to the Great Plains. All the electric utilities in the WI are electrically tied together during normal system conditions and operate at a synchronized frequency of an average 60 Hz. See the DOE webpage, "Learn More about Interconnections" (n.d.), https://www.energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/recovery-act-0.

[233] The 30 GW includes both utility-scale DERs, which connect directly to the distribution bus or to the distribution bus through a dedicated, non-load-serving feeder, and retail-scale DERs, which offset residential, commercial, and industrial loads.

- Clear and precise operating responsibilities must be defined and understood, and coordination must be achieved among the entities responsible for maintaining reliability in the Western Interconnection, whose numerous operating entities have experienced many reliability coordinator changes. Leveraging experience and training will facilitate a smooth transition of the reorganization of the western grid's reliability coordinator providers and responsibilities.
- Potential risk must be assessed for significant electricity demand growth resulting from increased electrification of transportation, heat pumps, and industrial loads. Scenario analyses can assist with understanding these risks.
- Reactive power requirements for transmission-connected devices becomes more complex with significant additions of inverter-based providers of dynamic voltage control. Additional data, performance monitoring, and studies can assess future risks.
- System restoration models must better account for DERs and coordinate with needed underfrequency load-shedding (UFLS) and undervoltage load-shedding (UVLS) schemes. Adaptive protection can prevent system collapse, as was evident in Europe when the disconnection of DERs played a role.[234]

The shift toward using inverter-based resources can reduce system strength and contribute to subsynchronous resonance and control-interaction issues that must be addressed. System assessments should include short-circuit ratio calculations to identify potential issues.[235] Solutions include control settings that avoid adverse interactions, improved transmission system strength, and the deployment of synchronous condensers. In addition, a number of NERC groups have been formed to address several reliability issues:

- The Inverter-Based Resource Performance Task Force (IRPTF) shares lessons learned through worldwide experience about the growing amount of resources asynchronously connected.[236] The task force also examines methodologies to determine sufficient levels of ancillary services to address the challenges and potential risks from increasing amounts of DERs.
- The System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) addresses the effects of the growing penetrations of DERs on bulk power system planning,

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[234] NERC LTRA 2018, p. 47, footnote 51: (1) On September 28, 2003, a blackout affected more than 56 million people across Italy and areas of Switzerland. The disruption lasted for more than 48 hours as crews struggled to reconnect areas across the Italian peninsula. The reason for the blackout was that during this phase, the UVLS could not compensate for the additional loss of generation when approximately 7.5 GW of distributed power plants tripped during underfrequency operation. (2) On November 4, 2006, at around 10:10 p.m., the interconnected grid of the Union for the Coordination of Transmission of Electricity (UCTE, a part of the European Network of Transmission System Operators for Electricity) was affected by a serious incident originating from the north German transmission grid, which led to power supply disruptions for more than 15 million European households and a splitting of the UCTE's synchronously interconnected network into three areas. The imbalance between supply and demand as a result of the splitting was further increased in the first moment due to a significant amount of tripped generation connected to the distribution grid. In the overfrequency area (i.e., the northeast portion of UCTE), the lack of sufficient control over generation units contributed to the deterioration of system conditions in this area (long-lasting overfrequency with severe overloading on high-voltage transmission lines). Generally, the uncontrolled operation of dispersed generation (mainly wind and combined heat and power) during the disturbance complicated the process of reestablishing normal system conditions).

[235] The *short-circuit ratio* is a measure of the strength of the system in areas where inverter-based resources connect the system. It is calculated as the short-circuit availability divided by the nameplate million volt-amperes (MVA) rating of the IBRs connected to a given bus. Ratios under 3.0 (as is the case in much of Maine; see Section 9.6.2), pose particular technical challenges for establishing acceptable control system performance of the interconnecting IBR.

[236] Refer to NERC's "Inverter-Based Resource Performance Task Force," webpage (2019), https://www.nerc.com/comm/PC/Pages/Inverter-Based-Resource-Performance-Task-Force.aspx.

modeling, and reliability.[237] SPIDER consists of four subgroups focusing on DER: models used in studies, verification of these models, studies of increasing penetration, and coordination with other industry activities to share information.

- The Electric-Gas Working Group (EGWG) will assess the wide range of BES and natural gas interdependency concerns raised in the NERC report, *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*.[238] The EGWG will also identify the need for new simulation methods and current best practices as a means to better educate and inform the electric power industry. (Section 7 discusses New England's energy-security risks in more detail.)
- Other groups are addressing a variety of reliability issues in a number of ways:[239]
    - Assessing resource performance and methods for evaluating resource adequacy to properly account for variable energy resources and DERs
    - Improving system models and analysis to assess the reliability effects of geomagnetic disturbances
    - Providing guidance on system event analysis and application of phasor measurement units (PMUs)[240]
    - Collecting data necessary for modeling and assessing the system
    - Addressing system protection and control issues arising from variable short-circuit availability and high penetrations of inverter-based resources

6.4 IRC Activities

Created in April 2003, the ISO/RTO Council (IRC) is an industry group consisting of the nine functioning ISOs and RTOs in North America.[241] These ISOs and RTOs serve two-thirds of the electricity customers in the United States and more than 50% of Canada's population. The IRC works collaboratively to develop effective processes, tools, and standard methods for improving competitive electricity markets across much of North America. Each ISO/RTO manages efficient, robust markets that provide competitive and reliable electricity service, consistent with its individual market and reliability criteria.

While the IRC members have different authorities, they have many planning responsibilities in common because of their similar missions. As part of the ISO/RTO authorization to operate, each ISO/RTO independently and fairly administers an open, transparent planning process among its participants. These activities include exchanging information, treating participants comparably, resolving disputes,

[237] This effort succeeds NERC's Distributed Energy Resources Task Force (DERTF) and Essential Reliability Services Task Force/Working Group (ERSTF/ERSWG).

[238] NERC, *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System* (November 2017), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf.

[239] Additional information about these activities is available at https://www.nerc.com/comm/PC/Pages/default.aspx.

[240] A *phasor measurement unit* is a device that measures the electrical waves on the power grid at a remote site using synchronized real-time measurements (i.e., synchrophasors) and global positioning satellite (GPS) technology, which accurately monitor the performance of the grid and provide specific data for operating the system and enhancing its design.

[241] More information on the ISO/RTO Council is available at https://isorto.org/.

coordinating infrastructure improvements regionally and interregionally, conducting economic planning studies, and allocating costs. This ensures a level playing field for developing infrastructure driven efficiently by competition and meeting all reliability requirements.

IRC members have coordinated on a number of reports, filings, and presentations with national government agencies.[242] The IRC has issued coordinated positions on NERC reports and proposed standards and has submitted FERC filings on issues of common concern for its members, including the following:

- Extension of the time period to comply with FERC Order 845, which reformed the interconnection procedures and agreements for large generators (i.e., those with a generating capacity of more than 20 MW; see Section 4.5.3.3)[243]
- Comments on the notice of proposed rulemaking (NOPR) to approve supply-chain risk-management reliability standards, which requested FERC to (1) reconsider the requirement for NERC to include in the proposed standards Electronic Access Control or Monitoring Systems (EACMS) associated with medium and high impacts to BES cybersystems and (2) approve the 18-month implementation plan proposed by NERC[244]
- Comments on the NOPR concerning reporting of cybersecurity incidents, which requested greater clarity in the reporting obligation so that only more meaningful information must be reported, which would reduce unnecessary burden to the ISO/RTOs[245]

The ISO/RTOs also are coordinating discussions with FERC on the commission's staff efforts to revise the metrics that measure ISO/RTO operations, markets, and administration.[246] IRC members also have coordinated on a number of technical issues, including the use of software and the sharing of planning techniques, such as the modeling of distributed energy resources.

6.5 Northeast Power Coordinating Council Studies and Activities

The Northeast Power Coordinating Council is one of six regional entities located throughout the United States, Canada, and portions of Mexico responsible for enhancing and promoting the reliable and efficient operation of the interconnected bulk power system.[247] NERC has authorized NPCC to create regional standards to maintain and enhance the reliability of the international, interconnected BES in

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[242] Refer to the IRC website (2019) at https://isorto.org/#committee-section.

[243] ISO/RTO Council, "Motion of the ISO/RTO Council to Extend the Time Period to Comply with Order No. 845," FERC Filing (May 17, 2018), https://www.iso-ne.com/static-assets/documents/2018/05/irc_motion_to_extend_time_to_comply_rm17-8.pdf.

[244] ISO/RTO Council, "Comments of the ISO/RTO Council," FERC filing (March 26, 2018), https://www.iso-ne.com/static-assets/documents/2018/03/irc_comments_supply_chain_risk_nop_3_26_18r.pdf. Also see: FERC, "Supply Change Risk Management Reliability Standards," NOPR, 83 Federal Register (FR) 3433 (January 25, 2018), 162 FERC ¶ 61,044 (2018).

[245] ISO/RTO Council, "Comments of the ISO/RTO Council," FERC filing (February 26, 2018), https://www.iso-ne.com/static-assets/documents/2018/02/rm18-2-000_irc_comments_on_nopr.pdf.

[246] FERC, "Commission Information Collection Activities (FERC-922); Comment Request," notice of information collection and request for comments 84 FR 32908 (July 10, 2019), https://www.federalregister.gov/documents/2019/07/10/2019-14669/commission-information-collection-activities-ferc-922-comment-request.

[247] The Florida Reliability Coordinating Council (FRCC) merged with the Southeastern Reliability Corporation (SERC) and ceased operation on August 31, 2019, leaving the NPCC, SERC, ReliabilityFirst (RF), Midwest Reliability Organization (MRO), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).

northeastern North America. As a member of NPCC, the ISO fully participates in NPCC-coordinated interregional studies with its neighboring areas.

NPCC assesses seasonal reliability and, periodically, the reliability of the planned BPS. It also evaluates annual long-range resource adequacy. All studies are well coordinated across neighboring area boundaries and include the development of common databases that can serve as the basis for internal studies by the ISO. ISO New England assessments demonstrate full compliance with NERC and NPCC requirements for meeting resource adequacy and transmission planning criteria and standards.[248]

NPCC activities also include issuing several special reports and updating guidelines and criteria. One ongoing project will provide guidelines for analyzing DERs in planning studies to capture interactions with the bulk power system. Another establishes methods for identifying busses that must be considered in planning assessments and requiring redundant protection schemes.

6.6 Northeastern ISO/RTO Planning Coordination Protocol

Each ISO/RTO develops individual system reliability plans, production cost studies, and interconnection studies, mindful of potential significant interregional impacts. To facilitate interregional coordination and communication among all interested parties, the Joint ISO/RTO Planning Committee (JIPC) and the Interregional Planning Stakeholder Advisory Committee (IPSAC) were established.[249] The JIPC has successfully implemented the Northeastern ISO/RTO Planning Coordination Protocol and the subsequent Amended and Restated Northeastern ISO/RTO Planning Protocol, which has further improved interregional planning among neighboring areas as part of regional compliance with FERC Order 1000. The IPSAC provided stakeholder input to the JIPC.

Regarding interregional planning, Order 1000 required all transmission providers to develop further procedures with neighboring regions to provide for the following:

- Sharing information regarding the respective needs of each region and potential solutions to these needs
- Identifying and jointly evaluating interregional transmission facilities that may be more efficient or cost-effective solutions to these regional needs

In addition to the Amended Planning Protocol, ISO New England, NYISO, and PJM, with input from their regional stakeholders and IPSAC, jointly developed other documents that FERC has determined comply with the interregional planning principles required by Order 1000. The three regions developed the *Northeast Coordinated System Plan 2017* (NCSP17) and other IPSAC meeting materials, and they participate in a number of activities in accordance with these requirements, which demonstrate continued, collaborative interregional planning.[250]

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[248] In 2018, ISO New England participated in the NPCC Internal Control Evaluation investigation. Based on demonstrated ISO-NE internal controls, NERC removed the planning standards from the scope of its June 2018 on-site audit of ISO-NE.

[249] ISO New England, "Interregional Planning Stakeholder Advisory Committee," webpage (2019), https://www.iso-ne.com/committees/planning/ipsac.

[250] ISO New England, NYISO, and PJM, *2017 Northeast Coordinated System Plan* (April 30, 2018), https://www.iso-ne.com/static-assets/documents/2018/05/2017_ncsp_final_043018.pdf. NCSP19 is scheduled for completion during the second quarter of 2020.

NCSP17 summarizes the 2016 and 2017 interregional planning activities under the responsibilities of the JIPC and references other interregional activities, such as work associated with the NERC, ReliabilityFirst, and NPCC. NCSP17 and IPSAC materials show that the regions have enhanced the timely exchange of needed databases and models required to perform planning studies and have coordinated interregional studies for resource adequacy, transmission planning, economic performance, and other issues.

Recent planning activities among ISO New England, NYISO, and PJM, discussed with IPSAC, include the interregional planning process, regional needs, and projects meeting the regional needs. The information helps stakeholders identify potential interregional solutions that may be more efficient or cost effective than improvements discussed in the ISO/RTOs' respective regional plans. Additional IPSAC discussions addressed interconnection queue studies with potential interregional impacts and how the JIPC has coordinated these studies. These include the coordination of elective transmission upgrades, which involve ties with neighboring systems (see Section 5.9.4). To date, the ISO/RTOs have not identified new interregional transmission projects that would be more efficient or cost effective in meeting the needs of multiple regions than proposed regional system improvements.

The ISO/RTOs have also enhanced the timelines and procedures for interregional planning. These entities will continue to share system information for conducting joint and individual planning studies. Input from the IPSAC and JIPC will provide additional perspectives in addressing current and future challenges, and stakeholder input will continue to provide valuable contributions in future planning cycles.

6.7 Interregional Transfers

Interconnections with neighboring regions provide opportunities for exchanging capacity, energy, reserves, and mutual assistance during capacity-shortage conditions. Capacity imports help New England meet its Installed Capacity Requirements and promote competition in the FCM. The tie-reliability benefits from the interconnections also can lower the ICR. Additionally, imports provide resource diversity and can lower regional generation emissions, especially imports of hydro.

6.7.1 Import Capabilities

The ISO's planning studies use the energy and capacity import capabilities shown in Table 6-1 of the 13 interconnections New England has with neighboring power systems in the United States and Eastern Canada.

Table 6-1
Assumed External Interface Import Capability, Summer 2019 to Summer 2028 (MW)[a]

Interconnection	Import Type	Assumed Import Capability
New York–New England AC	Energy[b]	1,400
	Capacity	1,400
Cross-Sound Cable	Energy[c]	330
	Capacity	0
Maritimes–New England	Energy[d]	1,000
	Capacity	700
Québec–New England (Highgate)[e]	Energy	217
	Capacity	200
Québec–New England (Phase II)	Energy[f]	2,000
	Capacity	1,400

(a) Limits are for the summer period. These limits may not include possible simultaneous impacts and should not be considered as "firm."

(b) The AC import capabilities do not include the Cross-Sound Cable (CSC) and the Northport–Norwalk Cable. Simultaneously importing into New England and Connecticut can lower the New York to New England AC capability.

(c) Import capability on the CSC is dependent on the level of local generation in Connecticut.

(d) The electrical limit of the Maritimes (New Brunswick)–New England tie is 1,000 MW. When adjusted for the ability to deliver capacity to the greater New England control area, the New Brunswick–New England transfer capability becomes 700 MW.

(e) The capability listing for the Highgate facility is for the New England AC side of the Highgate terminal.

(f) Because of the need to protect for the loss of the Phase II DC tie (rated at 2,000 MW) at the full import level in the PJM and NY systems, ISO New England has assumed its transfer capability to be 1,400 MW for calculating capacity and reliability. This assumption is based on the results of loss-of-source analyses conducted by PJM and NY. The procedure and daily limits are shown at the ISO's "Operations Report: Single-Source Contingency," webpage (2019), http://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/single-src-cont.

Historically, New England experienced net capacity and energy imports. The ISO expects this trend to continue, given the amount of import capacity supply obligations resulting from the Forward Capacity Auctions (see Section 4.1.3) and the number of tie-line projects in the ISO's interconnection queue (Section 4.5.3), which could provide additional opportunities for importing energy from neighboring power systems.

The summer import CSOs for FCA 10 (for the 2019/2020 capacity commitment period) through FCA 13 (for the 2022/2023 period) range from 1,450 MW (in FCA 10) to 1,188 MW (in FCA 13). The tie-reliability benefits used in calculating the ICR ranges from 1,990 MW to 2,020 MW during that same period, with over half provided from Québec (i.e., Hydro-Québec). Summer import CSOs that cleared in FCA 13 are greatest from HQ at 44%, as illustrated in Figure 6-1. The figure also shows cleared summer import CSOs for FCA 13 by generation type. Most of the import capacity is backed by the HQ control area, which is predominately hydroelectric facilities but also includes coal, oil, petroleum, natural gas, nuclear, wood, and wind generation.

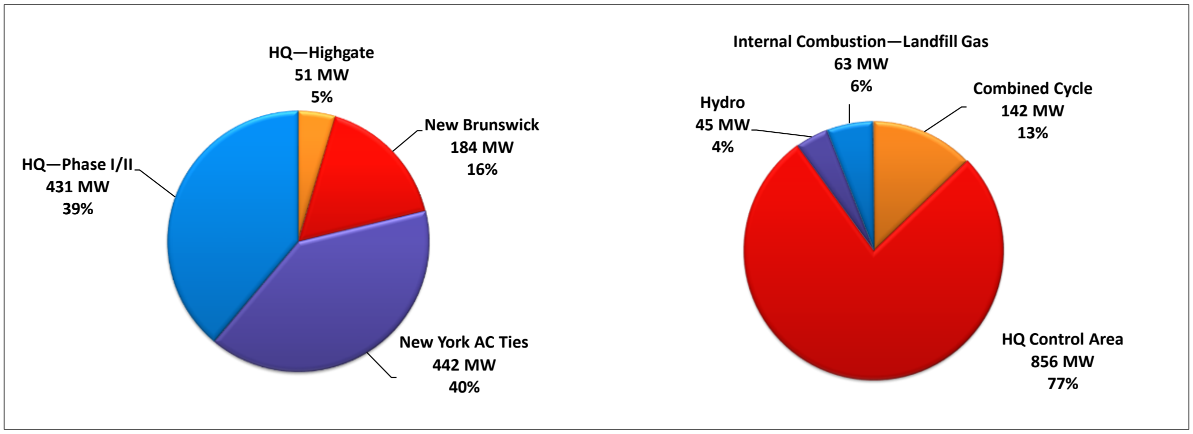

Figure 6-1: FCA 13 Import capacity supply obligation by interface (left) and generation type (right) (MW).

Note: The ISO has no detail regarding the resource mix of the HQ control-area-backed imports. It does have a list of resource types without specific resource names or megawatt allocations.

The annual net energy imports have increased from 9,363 GWh in 2009 to over 20,000 GWh for 2014 through 2018. Imports have supplied approximately 16% to 17% of the total New England net energy for load since 2014.[251]

6.7.2 Avoided New England Emissions due to Imports

New England imported 23,549 GWh of energy (i.e., gross imports without accounting for exports) during 2018. Over half the energy imports were from HQ, which is predominantly a hydro system.[252] Avoided New England emissions associated with energy imports were estimated using the 2017 New England system average emission rates (see Section 8.5).[253] The estimated avoided emissions were 2.07 ktons of nitrogen oxides (NO_X), 0.54 ktons of sulfur dioxide (SO_2), and 4,746 ktons of carbon dioxide (CO_2). Table **6-2** shows the estimated avoided emissions due to imports from Québec, as well as from New Brunswick and New York.

[251] ISO New England, *Locational Marginal Prices and Interface Flows* are posted on the ISO webpage, "Energy, Load, and Demand Reports, Zonal Information, Price-Responsive Demand Aggregation Zone LMP statistics (Congestion Component) (begins June 1, 2018, with price-responsive demand [PRD] inception), https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info, and Historical Hourly Flows and Limits, 2018 Flows and Limits on 36 Thermal and Stability Interfaces, https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/historical-hourly-flows-and-limits.

[252] Energy imports were 1,848 GWh over Highgate and 10,373 GWh over Phase II.

[253] *2017 ISO New England Electric Generator Air Emissions Report*, https://www.iso-ne.com/static-assets/documents/2019/04/2017_emissions_report.pdf.

Table 6-2
Estimated Avoided Emissions in New England Due to Imports[a]

Point of Interconnection	Imports (GWh)	NO_X (ktons)	SO_2 (ktons)	CO_2 (ktons)
Québec	13,919	2.09	0.56	4,746
New Brunswick	4,058	0.61	0.16	1,384
New York	5,572	0.84	0.22	1,900
Total	**23,549**	**3.53**	**0.94**	**8,030**

(a) Emissions are based on 2017 system emission rates as reported in the *2017 ISO New England Electric Generator Air Emissions Report* (April 2019), https://www.iso-ne.com/static-assets/documents/2019/04/2017_emissions_report.pdf. These rates are 0.30 lb/MWh for NO_X, 0.08 lb/MWh for SO_2, and 682 lb/MWh for CO_2. The data do not account for emissions in other systems. The 2017 emissions report includes additional information regarding average incremental emissions, which can be supplemented with a January 2019 Environmental Advisory Group (EAG) presentation that included the load-weighted percentage marginal fuel type by month. See *Environmental Regulatory Update* (January 29, 2019), slide 25, https://www.iso-ne.com/static-assets/documents/2019/01/envtlupdate_20190129.pdf.

6.8 Summary

The ISO coordinates planning activities with the Northeast Power Coordinating Council and throughout North America through NERC studies, as well as joint system assessments and studies of planned projects and planning activities with neighboring systems. The JIPC, IRC, and EIPC also have all coordinated interregional activities and discussion, such as of the effects of environmental regulations and the development of renewable resources.

The ISO has achieved full compliance with all required planning standards and has successfully implemented the Northeastern ISO/RTO Planning Protocol, which has further improved interregional planning among neighboring areas. It will continue this effort as part of ongoing regional compliance with FERC Order 1000. Stakeholder input has been provided through the IPSAC.

Interconnections with neighboring systems provide access to capacity and energy and reduce emissions within the New England area. The interconnections have improved regional reliability and the economic operation of the system. The ISO fully reflects the energy and capacity import capabilities of the interconnections in its planning studies.

Section 7
Energy Security

As the operator of the region's six-state power system, ISO New England must plan and operate the grid to ensure a reliable power system, which requires a reliable supply of fuels used to generate electricity. Energy security—the assurance that resources will have or be able to get the natural gas, wind, sun, or other fuel they need to generate sufficient electricity to meet system demand, when they need it—is critical to ensure the region's power system reliability. Although New England has adequate capacity resources to meet projected electricity demand, as more limited-energy resources are developed and traditional generating resources retire, in some situations, the grid may not be able to supply enough energy to meet demand.

This section summarizes capacity and energy production in New England and the region's natural gas infrastructure. It also discusses energy-security risks and natural gas and oil price volatility, and ongoing risk analyses and efforts to mitigate these risks to ensure that the region has enough energy to reliability serve firm load.

7.1 Overview of Energy-Security Risks in New England

New England's energy-related risks to current and future power system reliability are as follows:

- The region relies heavily on natural-gas-fired generators, and their need for fuel has raised reliability issues because of seasonal constraints on the natural gas delivery system and the increasing reliance on imported liquefied natural gas (LNG), which can be an important complement to pipeline gas.
- Gas pipelines serving the region operate at or near capacity; they will not be expanded until customers make new firm commitments. Also, the lack of firm fuel contracts by gas-fired generators has limited funding for natural gas infrastructure expansion, which results in limited availability of gas pipeline transportation at times of peak demand. Instead, generators are relying on fuel delivered just in time.
- Most natural-gas-fired generators with dual-fuel capability (i.e., oil back up) have limited on-site fuel-storage capacity for the oil, and some resources need an extended time to switch fuels and replenish liquid fuels.
- Older oil and coal resources face energy-production constraints, with coal- and oil-fired generators potentially experiencing issues with fuel availability, delivery, and environmental restrictions on some operations and total operating hours (see Section 8), along with other challenges caused by their infrequent operation.
- The availability of natural gas and New England's reliance on this fuel also has an immediate effect on wholesale energy market prices; spot-market gas prices typically either set or closely follow the price for wholesale electricity.
- New England also faces the retirement of older, uneconomic non-gas-fired generation that can store fuel (e.g. nuclear, coal, and oil), which will indirectly increase the region's reliance on the remaining gas-fired generators.

Longer term, New England's energy-security risks may not be limited to the winter period. Energy from solar and wind generators is weather dependent and not always available. Constraints or uncertainties to the fuel supply are a concern even when supplemental fuel-supply arrangements would be cost effective as a means to reduce reliability risks.

7.2 Capacity and Electric Energy Production in the Region by Fuel Type

New England's capacity and electric energy production in 2018 indicates that the region is highly dependent on natural-gas-fired generation. As shown in Figure 7-1, approximately 49% of the region's winter generation in 2018 was fueled by natural gas. Nuclear generation supplied 30% of the electric energy, but each of the other types of generating resources produced less than 8%.

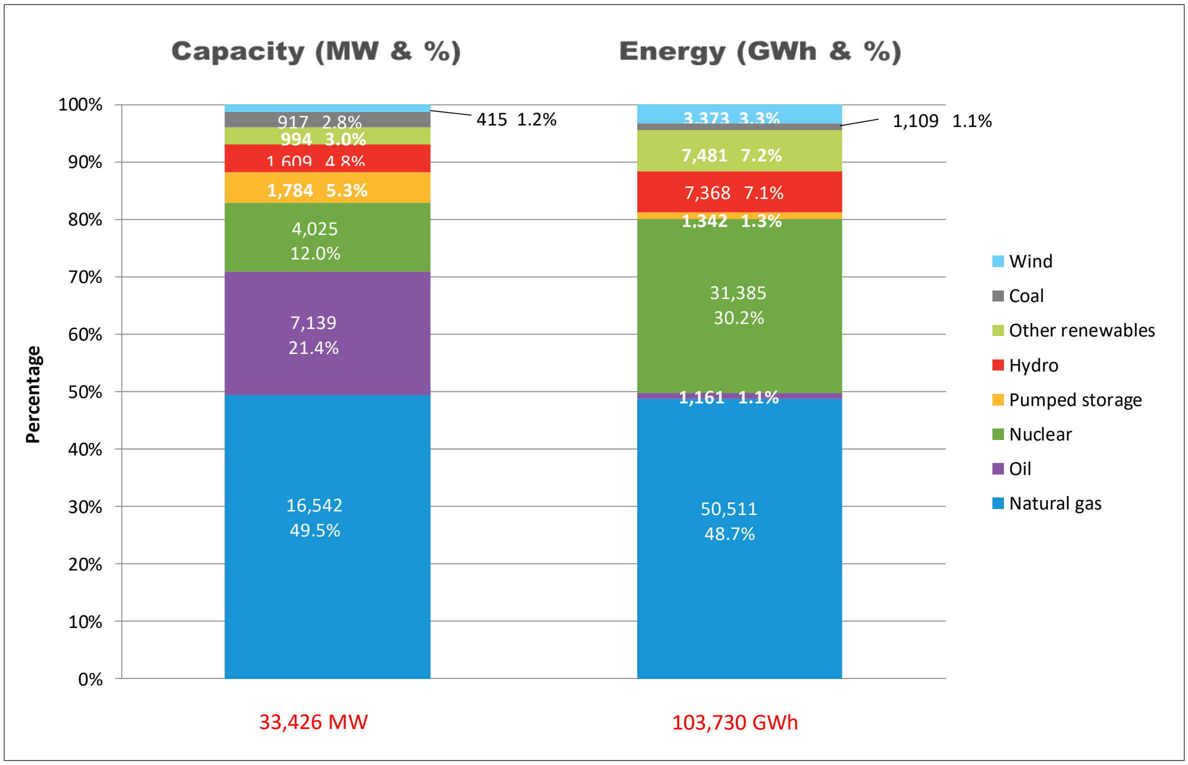

Figure 7-1: New England's generator winter seasonal claimed capability (MW, %) and annual electric energy production (GWh, %) by fuel type for 2018.

Note: The capacity and energy statistics exclude the capacity and energy associated with imports and behind-the-meter generation not registered in the region's wholesale energy markets. In 2018, the NEL, accounting for both EE and BTM PV, was 123,430 GWh, pumped storage consumed an additional of 1,804 GWh, and the net imports into the region were 21,505 GWh, which represents 17% of the 2018 system net energy for load. (Numbers may not add in the figure due to rounding.)

Sources: The capacity data are the same as 2019 CELT Report data (https://www.iso-ne.com/static-assets/documents/2019/04/2019_celt_report.xls). The annual energy data are based on the March 1, 2019, 90-day resettlement of total electric energy production for 2018.

The region expects to rely on natural gas-fired generators to balance the system, especially with the large-scale addition of variable renewable resources. In 2000, natural gas fueled just 15% of the region's electricity, while today it is closer to 50%. It has become the dominant fuel used to produce electricity in New England, displacing higher-emitting and less economic power plants.[254] However, most newly built natural-gas-fired generators do not have dual-fuel capability due to the difficulty to obtain operating

[254] The use of cleaner-burning natural gas generators, along with emission controls on fossil-fuel-burning generators and other factors, has contributed to a significant decline in regional air emissions (see Section 8.5). Natural gas prices are typically lower than other fossil fuels for most of the year (see Section 7.4).

permits. Additionally, for facilities that have obtained permits, the maximum allowable hours to run on the back-up fuel is often so few that pursuing operating on oil is not economical. Existing dual-fuel generators often need extended time to either or both switch fuels or replenish liquid fuels, making it uneconomic to continue operating as a dual-fuel generator or to maintain the secondary fuel on site.

Recent Forward Capacity Market auction results (see Section 4.1.3) show the retirement of regional coal- and oil-fired generators as well as the loss of two nuclear plants.[255] As additional generators retire, units in the ISO interconnection queue, which primarily are natural-gas-fired generation and photovoltaic and wind resources (see Section 4.5.3), will likely replace them. The growth of offshore and onshore wind and photovoltaics resulting from state renewable targets and legislative funding ensure their development (see Section 8.4). Figure 7-2 shows the expected regional resource winter capacity mix for 2019, 2022, and 2028. As indicated, offshore wind generation in the capacity mix is expected to grow from approximately 0.1% in winter 2019 to 10.1% in 2028.

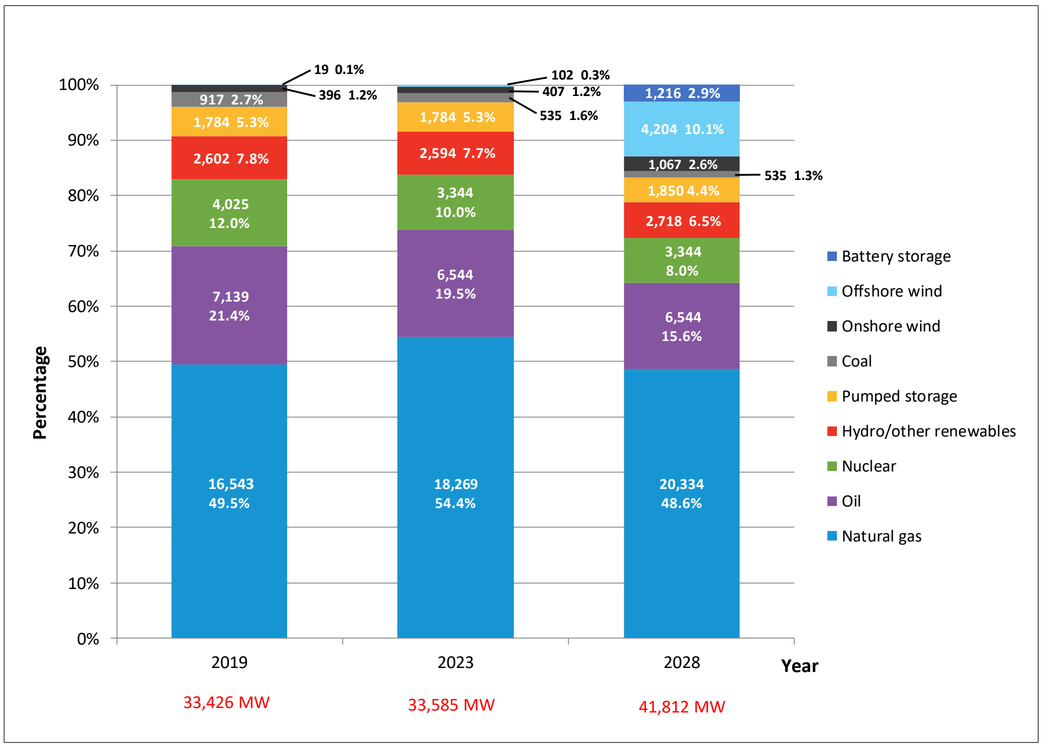

Figure 7-2: New England generator winter capability by fuel type based on the 2019 CELT Report, the interconnection queue, and FCM-cleared capacity for 2019, 2023 and 2028 (MW, %).

Note: The figure does not include interchange with neighboring regions (see Section 6.7). It also does not include active demand resources, EE, and BTM PV (see Section 3). A total of 1,869 MW of PV resources forecasted to be added by summer 2028 are not reflected in the winter capabilities. Onshore wind is derated to 30% of nameplate capacity based on an average ratio of winter SCC to nameplate for existing wind units, and offshore wind is derated to 50% of nameplate capacity based on the anticipated ratio of winter SCC to nameplate for existing as well as proposed wind facilities. For 2019, 2023, and 2028, respectively, the figure shows offshore wind at 19 MW (0.1%), 102 MW (0.3%), and 4,204 MW (10.1%); onshore wind at 396 MW (1.2%), 407 MW (1.2%), and 1,067 MW (2.6%); battery storage at 0 MW (0%), 0 MW (0%), and 1,216 MW (2.9%); and coal at 917 MW (2.7%), 535 MW (1.6%), and 535 MW (1.3%).

[255] By 2019, more than 5,150 MW of generation will be retired, including Salem Harbor Station (749 MW); Vermont Yankee (604 MW); Norwalk Harbor Station (342 MW); Brayton Point Station (1,535 MW); Mount Tom Station (143 MW); Pilgrim Nuclear Power Station (677 MW); Bridgeport Harbor 3 (383 MW); Mystic 7 (575 MW); Mystic Jet (9 MW); Pawtucket Power (54 MW), and over 1,200 MW of demand-response resources.

The unavailability of fuel, coupled with the unpredictability of renewable resources, could result in operational issues. Winter operable-capacity analyses indicate under certain extreme conditions that the region may face shortfalls and may need to rely on additional imports or load and capacity-relief actions from OP 4, *Actions during a Capacity Deficiency,* to meet peak demand (see Section 4.3).

7.3 Natural Gas Infrastructure

The natural gas pipeline system within New England is relatively small, and its access to the rest of the North American pipeline network is limited. This section summarizes the natural gas delivery system in New England, including LNG terminals, and pending improvements to the pipeline system.

7.3.1 Natural Gas Pipelines and LNG Terminals

Natural gas-fired generators receive fuel from five interstate pipelines serving New England:

- Three originate from the south and west:
  - Algonquin Gas Transmission (AGT) Pipeline
  - Tennessee Gas Pipeline (TGP)
  - Iroquois Gas Transmission System (IGTS)
- The Portland Natural Gas Transmission System (PNGTS) originates in the northwest portion of New Hampshire.
- The Maritimes and Northeast (M&N) Pipeline originates in the Canadian Maritime province.

Three LNG import terminals also serve New England, two onshore and one offshore:

- The Everett LNG Facility (a.k.a Distrigas) in Everett, Massachusetts and New Brunswick's Canaport LNG terminal
- Northeast Gateway's Deepwater Port (offshore LNG terminal)

The Everett LNG Facility is connected to the AGT and TGP pipelines and the local gas distribution company (National Grid)—the gas utility serving Boston's residential, commercial, and industrial customers. The Canaport LNG terminal sends gas through the Brunswick pipeline, which directly connects to the M&N Pipeline. The M&N Pipeline can deliver gas to the Canadian Maritimes provinces. Figure 7-3 shows the major natural gas infrastructure serving New England.

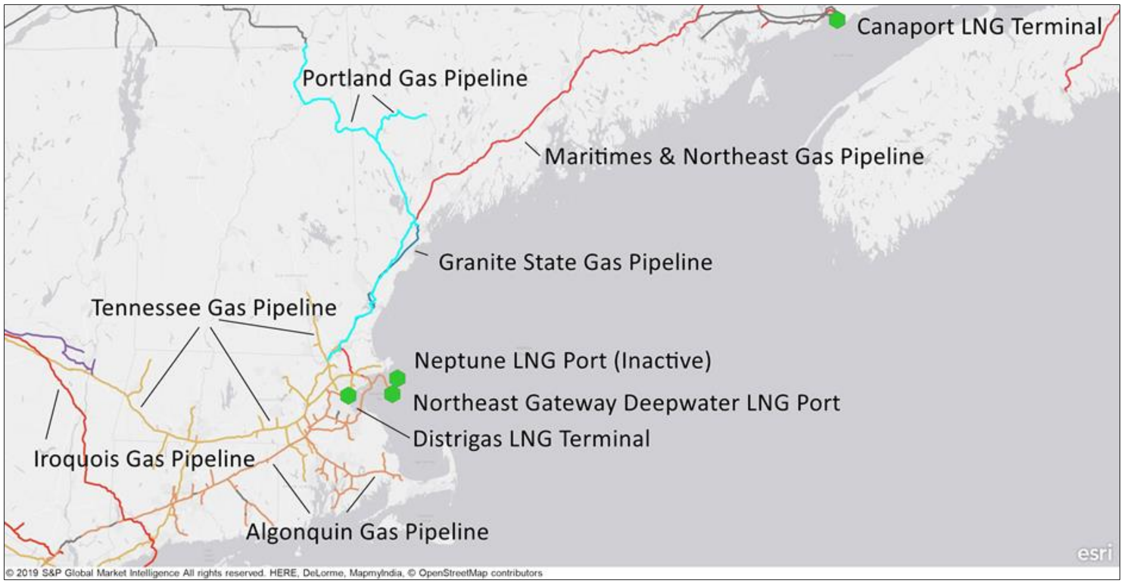

Figure 7-3: Map of natural gas infrastructure serving New England (operating pipelines, LNG import terminals, and gas hub pricing points in New England).

Source: © 2019 S&P Global Market Intelligence All rights reserved. DeLorme, Maymylndia, © OpenStreetMap contributors.

Figure 7-4 shows the natural gas supply sources, including the Utica and Marcellus shales, and Figure 7-5 shows the interstate gas pipeline network in the lower 48 states. Figure 7-5 shows that New England has only two pipelines that can directly access Marcellus and Utica shale gas.

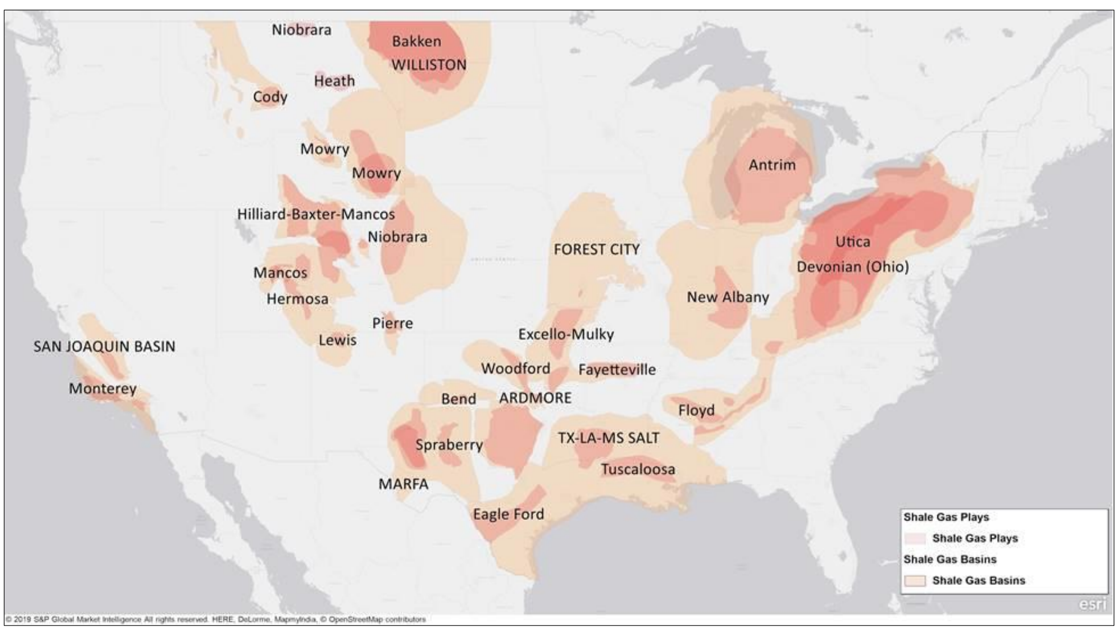

Figure 7-4: Natural gas supply basins in the continental United States, May 2019.

Source: © 2019 S&P Global Market Intelligence All rights reserved. DeLorme, Maymylndia, © OpenStreetMap contributors.

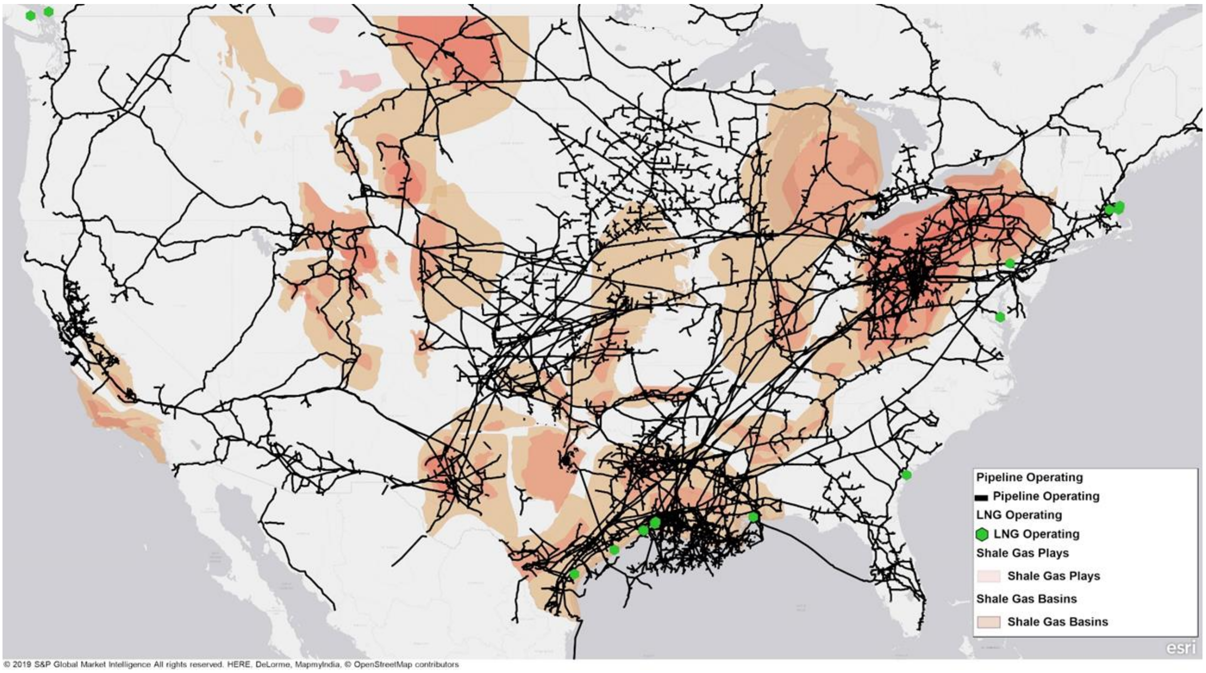

Figure 7-5: Natural gas interstate pipeline network in the continental United States, May 2019.

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7.3.2 Pipeline Improvements

Unlike the electric power industry, which builds infrastructure in anticipation of demand, interstate natural gas pipeline companies require shippers and customers to enter into long-term firm commitments before infrastructure can be developed. Although the gas pipelines serving the region operate at or near capacity, they will not be expanded until customers make new firm commitments. FERC, which must approve interstate pipeline projects, bases its decision that a pipeline project is in the public convenience and a necessity in large part on the existence of firm contractual commitments.

At present, eight proposed pipeline-expansion projects are under development across the Northeast, as shown in Table 7-1, which would specifically bring either new or incremental pipeline capacity directly or indirectly to New England. Several minor expansion projects were or are planned to be commercialized in the near term, bringing the total net contracted transportation capacity into New England to 3.59 billion cubic feet/day (Bcf/d) before December 2023.[256] The realization of other pipelines in various stages of planning and siting seems unlikely, although their development would improve the availability of natural gas to generating units.

[256] ISO New England, *Forward Capacity Auction 14 (FCA 14): Fuel Security Review Inputs Development* (March 29, 2019), https://www.iso-ne.com/static-assets/documents/2019/03/a03_rc_2019_03_29_iso_fca14_fuel_security_inputs_development.pptx.

Table 7-1
Summary of Pipeline Modifications Benefiting New England[a, b]

Project/Company	Description	Estimated In-Service Date	Status
Portland Xpress **PNGTS**	PNGTS has executed Precedent Agreements with several local gas distribution companies in New England and Atlantic Canada to recontract certain system capacity set to expire in 2019, as well as expand the PNGTS system to bring its certificated capacity up to 0.3 Bcf/d. The approximately $80 million Portland XPress Project (PXP) will proceed concurrently with upstream capacity expansions. The in-service dates of PXP are being phased-in over a three-year period that began Nov. 1, 2018.	2019–2020	Announced Mar. 2017. Filed application with FERC for Phase I, Apr. 2018. Phase I went in service on Nov. 1, 2018, with volumes of 40,000 dekatherms/day (Dth/d). Phase II, approved by FERC, is scheduled for Nov. 2019 in service. Phase III was approved by FERC, Feb. 2019 and is scheduled to be in service, Nov. 2020.
Westbrook Xpress **PNGTS**	Phase I will increase the certificated capacity on the northern portion of its system from Pittsburg, NH, to Westbrook, ME, by 42.4 Dth/d, effective Nov. 1, 2019. Phase II would add 63 Dth/d in 2021; Phase III would add 18 Dth/d by 2022.	Nov. 1, 2019; Phase 11, 2021; Phase III, 2022	Filed with FERC, Dec. 2018
Atlantic Bridge **Enbridge**	Incremental expansion on Algonquin and M&N to serve New England and Canadian Maritimes. Proposed capacity of approximately 133,000 Dth/d. Partial service began in Nov. 2017 at 40,000 Dth/d.	Nov. 2017 (partial)/ 2019–2020	Announced, Feb. 2014. Filed with FERC, Oct. 2015. Received environmental assessment from FERC, May 2016. FERC issued certificate, Jan. 2017. FERC allowed construction work to begin on certain facilities in CT, Mar. 2017. Partial service began, Nov. 2017. Full project path expected in service in second half of 2019/first half 2020. FERC granted 2-year permitting extension, Dec. 2018. MA Dept. of Environmental Protection (MA DEP) issued air quality permit, Jan. 2019.
Northeast Supply Enhancement **Williams/Transco**	The project would add natural gas pipeline infrastructure in PA, NJ, and NY. It is designed to provide customers access to an additional 400 million cubic feet/day (MMcf/d) of natural gas (enough to serve the daily needs of about 2.3 million homes). The project will provide service to National Grid.	2020	FERC prefiling, May 2016. Filed with FERC, Mar. 2017. FERC issued draft Environmental Impact Statement (EIS), Mar. 2018. New York State Dept. of Environmental Conservation (NYS DEC) denied water quality certificate, stating application was incomplete, Apr. 2018. FERC issued final EIS, Feb. 2019.
Station 261 **Tennessee Gas Pipeline/Kinder Morgan**	The 261 upgrade projects will create 101,400 Dth/d of additional transportation capacity of natural gas on the existing Tennessee Gas Pipeline system. Projects are located in Agawam, MA, and include the Looping Project and the Horsepower (HP) Replacement Project. The Looping Project involves the installation of 2.1 miles of a 12-inch diameter pipeline loop that will run parallel and adjacent to an existing TGP pipeline. The company will also remove an inactive 6-inch diameter pipeline and replace it with the new 12-inch diameter pipeline loop upgrade in certain locations. The HP Replacement Project involves the replacement of two existing turbine compressor units with one new, cleaner-burning turbine compressor unit, as well as the installation of auxiliary facilities at TGP's existing Compressor Station 261. Customers are Columbia Gas of MA and Holyoke Gas and Electric.	Nov. 2020	Announced late 2017. Filed with FERC, 2018

Project/Company	Description	Estimated In-Service Date	Status
Constitution Pipeline **Cabot/Williams**	The approximately 124-mile Constitution Pipeline is designed to extend from Susquehanna County, PA, to the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, NY. The proposed capacity is 650 MMcf/d. Cabot and Southwestern are shippers.	2020	Announced spring 2012. Filed with FERC, Jun. 2013. FERC issued final EIS, Oct. 2014. Authorized by FERC, Dec. 2014. NY DEC denies water quality permit, Apr. 22, 2016; company affirms plans to continue with project, Apr. 25, 2016. FERC grants 2-year extension, July 2016. US Court of Appeals for Second District upholds NY DEC denial of certificate, Aug. 2017. FERC finds that NYS DEC did not waive its authority in decision, and Constitution announced it will seek rehearing at FERC and petitioned US Supreme Court, all in Jan. 2018. Supreme Court declines to hear Court of Appeals case, Apr. 2018. FERC denies request for rehearing, and pipeline developers announce they will appeal to federal district court, both in July 2018. FERC grants 2-year extension, Nov. 2018.
Wright Interconnect Project (WIP) **Iroquois Gas Transmission**	This project will enable delivery of up to 650,000 Dth/d of natural gas from the terminus of the proposed Constitution Pipeline in Schoharie County, NY, into both Iroquois and the Tennessee Gas Pipeline under a 15-year capacity lease agreement with Constitution.	2020	Announced Jan. 2013. Filed with FERC, Jun. 2013. FERC issued final EIS, Oct. 2014. Authorized by FERC, Dec. 2014. FERC grants 2-year extension, Aug. 2016. FERC grants 2-year extension, Nov. 2018.
Northern Access **National Fuel Gas Supply and Empire Pipeline**	Capacity of 350,000 Dth/d on Empire, and 140,000 Dth/d to be delivered to the Tennessee 200 line; project involves approximately 99 miles of 24-inch pipeline and a compressor station upgrade and one new compressor station.	2022	Filed with FERC, Mar. 2015; amendment filed in Nov. 2015. FERC issued environmental assessment, Jul. 2016. Approved by FERC, Feb. 2017. NYS DEC denies water-quality certificates, Apr. 2017. FERC denies rehearing of its permit, stating NYS DEC had waived its authority on water-quality certificate by its delay in rendering decision, Aug. 2018. Federal appeals court rules that NY DEC did not provide sufficient information to support its denial of project's water quality certificate, Feb. 2019.

(a) The Northeast Gas Association (NGA) prepared this summary based on publicly-available information. NGA notes that this information may change pending project developments, and the list may not include all projects.

(b) National Grid has proposed a 1 Bcf LNG facility in Providence, RI, for local gas distribution company peak shaving, which is not anticipated to directly benefit New England generators because it is meant to serve LDC customers.

The ISO continues to monitor if and when any power generators within New England sign a firm contract for any portion of these regional upgrades and also any upgrades to natural gas infrastructure to maintain operational awareness of the changing capacity of the regional natural gas system.

7.4 Natural Gas and Oil Price Volatility

Because natural gas plants make up such a large part of the New England generating fleet, the availability of this fuel has an immediate effect on power grid reliability and market prices. For example, the planned or unplanned outage of a major gas pipeline at any time of year may affect many thousands of megawatts of generation. Additionally, when gas-fired generators are unavailable to run or are derated, the ISO must commit equal amounts of non-gas-fired (replacement) generation to satisfy peak load and operating reserve requirements. Because oil- and coal-fired generation may need to limit their run times to comply with recent environmental restrictions (see Section 8), the ISO's replacement generation plan may quickly erode. These energy-production limitations create challenges to operating the system reliably and economically.

As shown in Figure 7-6, New England's heavy reliance on natural gas-fired generation has resulted in spot-market gas prices either setting or closely following the price for wholesale electricity. The daily volatility in natural gas fuel prices (dollars/million British thermal units; $/MMBtu) was at its greatest during the winters of 2013/2014 and 2014/2015. Gas prices were more stable during the winters of 2015/2016, 2016/2017, and 2018/2019, likely attributable to more mild winters, the ISO's Winter Reliability Program and LNG deliveries.[257]

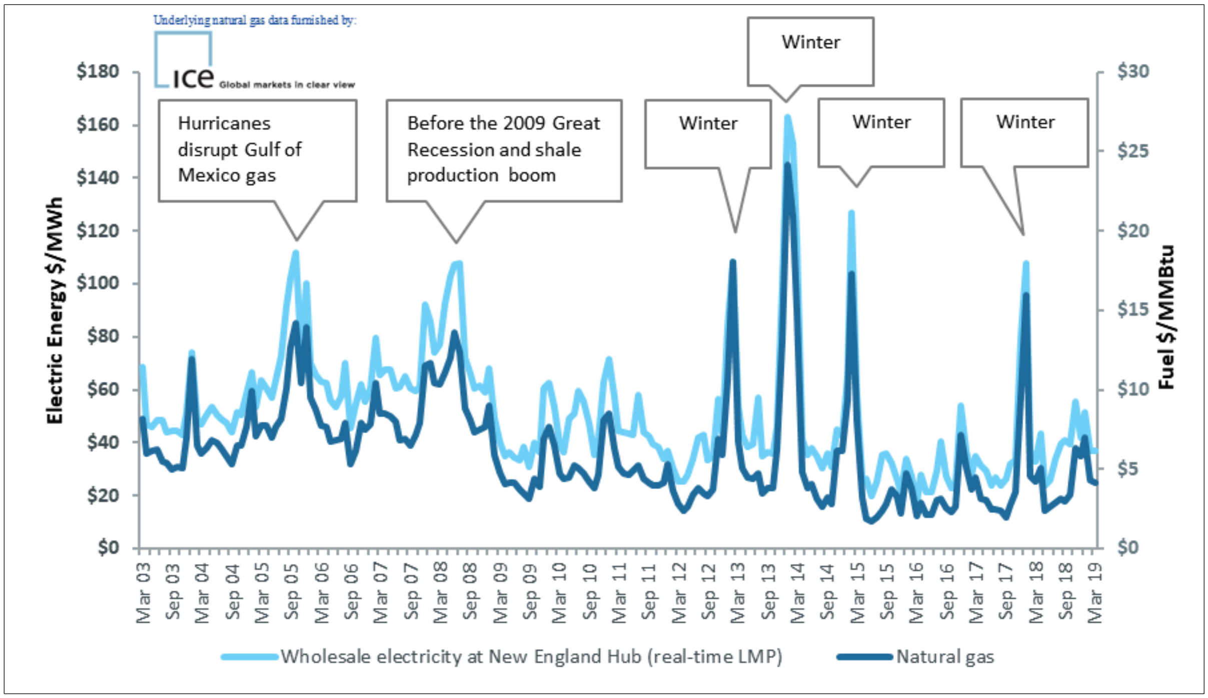

Figure 7-6: Monthly average natural gas prices and real-time Hub LMPs compared with regional natural gas prices, March 2003 to March 2019 ($/MWh; $/MMbtu).

Note: Underlying natural gas data furnished by the Intercontinental Exchange (ICE). The regional natural gas price is the average Massachusetts price, which is the volume-weighted average of pricing points for Algonquin, Tennessee, and Dracut.

Figure 7-7 shows wholesale electricity and natural gas market data for New England trading hubs and the Marcellus price. Although the Marcellus shale dominates continental gas production, pipeline limitations in New York and into New England typically cause price separation between New England and Marcellus supplies. Imported LNG can supply New England and may mitigate higher New England prices by providing firm supply during peak demand periods. The higher commodity cost of imported LNG can result in higher electric energy prices in New England.[258]

[257] The Winter Reliability Program addressed the reliability challenges created by New England's increased reliance on natural-gas-fueled generation and was intended to be a stop-gap measure until revised, market-based incentives were in effect. Under the program, selected resources were compensated through a monthly payment derived from the resources' bids under an "as-bid" pricing mechanism, rather than a uniform clearing price, in addition to any compensation they received for capacity (in the Forward Capacity Market), energy, ancillary services, or other services. See FERC, *Order on Proposed Tariff Revisions*, Docket No. ER15-2208 on the Winter Reliability Program (September 11, 2015), https://www.iso-ne.com/static-assets/documents/2015/09/er15-2208-000.pdf.

[258] Regional LNG storage facilities can vaporize gas for injection into the pipelines and thus help the region meet peak gas demand. These facilities may require advance contracting to assure adequate on-site inventories.

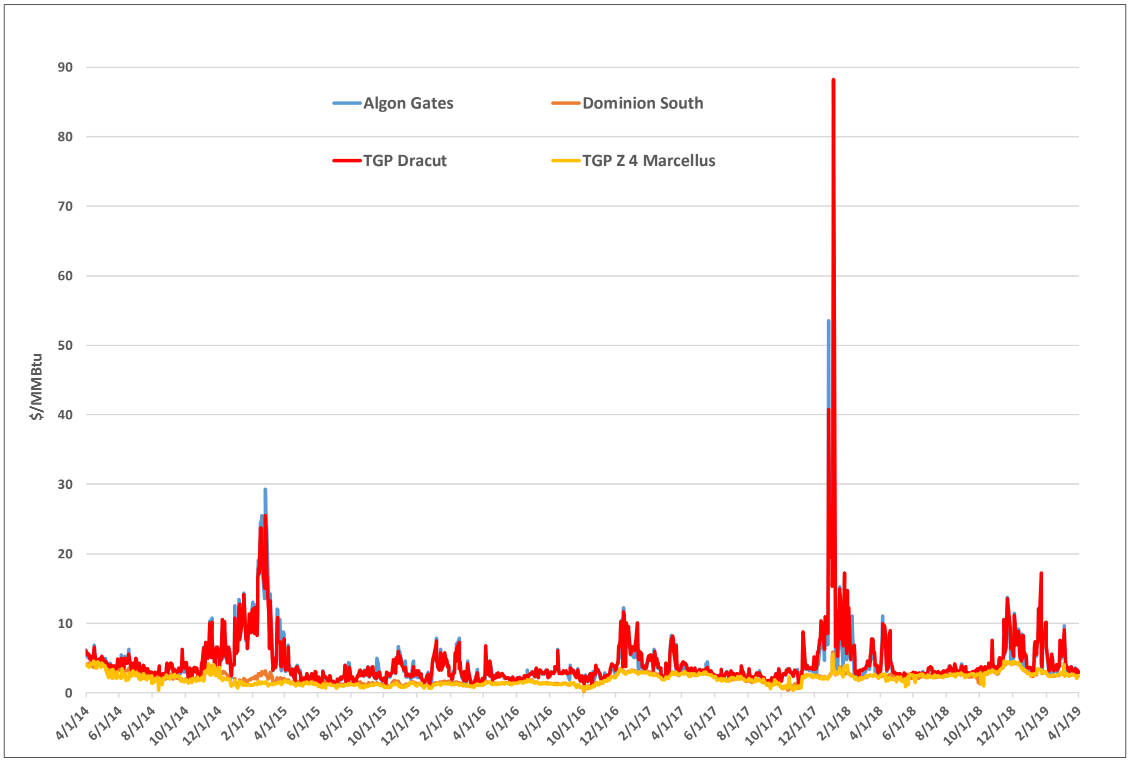

Figure 7-7: Natural gas market data, April 2014 to April 2019 ($/MMBtu).

Source: S&P Global Market Intelligence, Daily Spot Natural Gas Prices using NYMEX and CME Clearport market data provided by DTN ($/MMBtu) (accessed May 7, 2019).

Table 7-2 shows natural gas futures prices for January and February 2014 to 2019.

Table 7-2
Comparison of 2014 to 2019 Winter Futures Prices ($/MMBtu, $/MWh)[(a)]

	Location	2014 Futures[(b)]	2015 Futures[(c)]	2016 Futures[(d)]	2017 Futures[(e)]	2018 Futures[(f)]	2019 Futures[(g)]
Natural gas ($/MMBtu)[(h)]	Algonquin (New England)	11.76	21.45	9.69	7.71	8.42	9.20
	Transco Zone 6 non-NY (Mid-Atlantic)	4.78	9.09	6.21	6.26	6.12	6.79
	Dominion South (Marcellus)	3.66	2.85	1.97	2.14	2.88	2.76
	Southern California border	3.95	4.30	2.85	3.79	3.22	3.86
	Henry Hub	3.87	4.08	2.77	3.55	3.30	3.20
Power ($/MWh)[(i)]	Massachusetts hub	99.88	183.88	89.28	78.93	79.00	97.54
	PJM western hub	44.90	72.60	50.56	55.80	48.04	54.42
	Northwest (Mid-Columbia trading point)[(j)]	37.73	35.75	24.88	32.05	27.29	30.70
	Southern California (SP-15)[(k)]	42.25[(j)]	46.13	33.76	41.18	35.22	49.00

(a) **Sources:** S&P Global Market Intelligence, Natural gas futures ($/MMBtu) using NYMEX and CME Clearport market data provided by DTN. Power futures ($/MWh) using OTC Global Holdings power forwards on peak (accessed May 7, 2019).

(b) January and February 2014 futures pricing is as of October 1, 2013.

(c) January and February 2015 futures pricing is as of October 1, 2014.

(d) January and February 2016 futures pricing is as of October 1, 2015.

(e) January and February 2017 futures pricing is as of October 1, 2016.

(f) January and February 2018 futures pricing is as of October 1, 2017.

(g) January and February 2019 futures pricing is as of October 1, 2018.

(h) Gas prices ($/MMBtu) shown are regional futures prices (the sum of the Henry Hub future contract price plus the regional basis futures).

(i) Power prices ($/MWh) shown are peak financial swap prices.

(j) The Mid-Columbia electric trading point is a center point along the Columbia River on the border between Washington and Oregon states.

(k) SP-15 refers to California Independent System Operator's (CAISO's) zone covering southern California. The futures pricing for SP-15 2014 is as of October 31, 2013.

In general, mild weather conditions reduce gas demand, which lead to the greater availability of pipeline gas. LNG vaporization from Canaport, Distrigas, and Excelerate LNG (offshore buoy), continue to provide incremental gas supplies directly to the northeastern part of the regional gas system, which improves gas grid reliability.

Figure 7-8 shows the LNG supplies delivered to the region for the past three winters, accounting for December through March. Winter 2016/2017 LNG deliveries into New England declined to approximately 41 Bcf compared with approximately 48 Bcf in winter 2015/2016 and 64 Bcf during winter 2014/2015. The ISO has observed on the regional pipeline electronic bulletin boards an increased LNG sendout, which is a result of the recently improved availability of spot-market LNG within the Atlantic basin and contracts made in advance of the winter. LNG deliveries help address the regional energy-security issue.

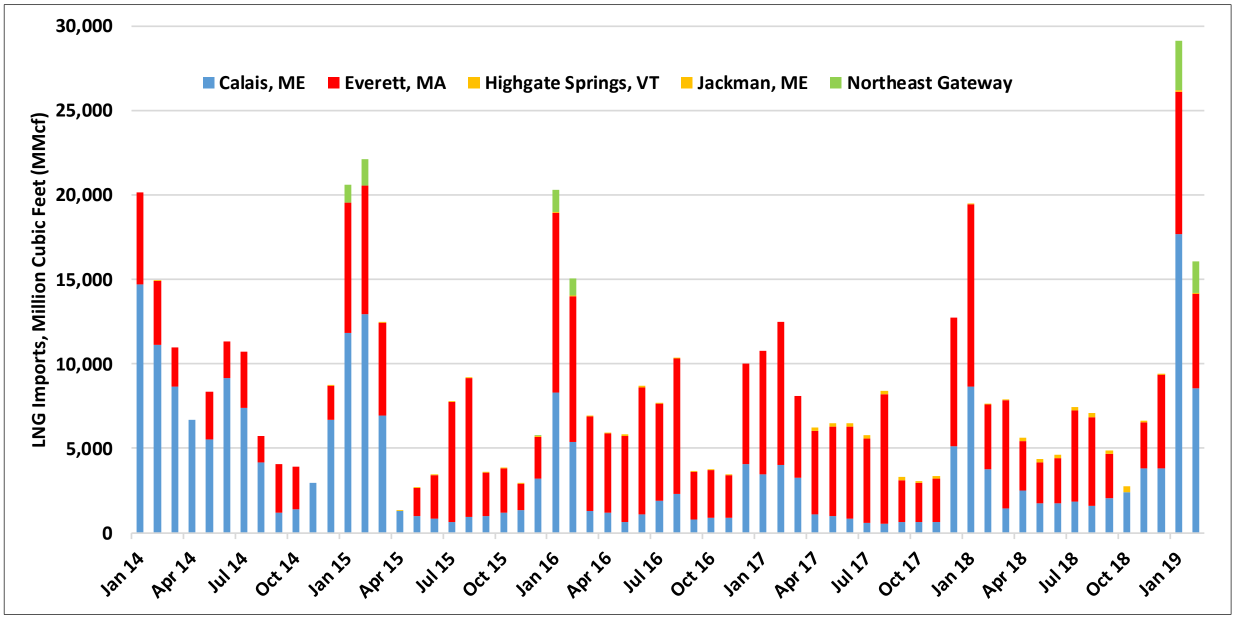

Figure 7-8: Comparison of LNG deliveries for winter 2014/2015 through winter 2018/2019 (MMcf).

Source: EIA, *US Liquefied Natural Gas Imports by Point of Entry, US Natural Gas Pipeline Imports by Point of Entry*, data table; see Canaport deliveries via Calais point-of-entry) (accessed May 7, 2019), https://www.eia.gov/dnav/ng/ng_move_poe1_a_epg0_iml_mmcf_m.htm, http://www.eia.gov/dnav/ng/ng_move_poe1_a_epg0_irp_mmcf_m.htm.

7.5 Fuel Constraints in New England

Natural gas pipeline constraints, the logistics of marine shipping of LNG and fuel oil, the impact of New England's weather on the availability and timing of fuel deliveries, and the amount and timing of electricity generated by renewable resources all contribute to an increased level of uncertainty for ISO system operations.[259] Additionally, many states' increasingly stringent air-emission limitations may prevent gas-only generators from installing oil-fired backup systems. The region's heavy reliance on natural-gas-fired generators and imported LNG and the seasonal constraints on the regional natural gas delivery system have highlighted the need for generators to procure firm fuel.

Fuels for generating units may be more limited in New England than in most other regions because, as shown in Section 7.3, New England is "at the end of the pipeline" when it comes to the fuels used most often to generate the region's power. New England has no indigenous fossil fuels, and therefore fuels must be delivered by ship, truck, pipeline, or barge from distant places (see Section 7.3.1).

Energy from wind generators isn't always available, although offshore wind tends to blow more steadily than onshore wind. Energy storage can help balance output from variable energy resources, but utility-scale energy storage would need to be procured in substantial quantities, and a transmission system build-out may also be required (see Section 9). The retirement of older nongas facilities that store fuels (oil and nuclear) exacerbates the full-supply issue.

[259] LNG is imported to New England from overseas by oceangoing tankers, typically from Trinidad and Tobago. Most cargoes of LNG must be contracted and scheduled months before winter begins; once contracted, the LNG won't arrive for at least five days. LNG availability can also be affected by global weather or political events.

7.5.1 Fuel Constraints during Winter

On multiple occasions in recent winters, the ISO has had to manage the system with uncertainty about whether power plants could arrange for the fuel—primarily natural gas and oil—needed to run. Constraints, or limitations, on the fuel-supply chain are not unusual, particularly during bad weather. Winter storms can impede deliveries from LNG tankers, oil barges, and oil tanker trucks. Low temperatures can increase heating demand for natural gas, oil, and LNG, leaving less fuel available for power plants. The timing of fuel consumption and of fuel replenishment can be significant as well. In December, the weather is typically milder. As winter progresses in time and intensity, generators' oil and LNG inventories are depleted and tanks must be refilled rapidly. On many days, pipeline capacity is sufficient for both the local gas utilities and the natural-gas-fired power plants, but during the coldest weeks of the year, this natural gas delivery infrastructure cannot meet all the demand for natural gas for both home heating and power generation. As a result, natural-gas-fired power plants—which typically buy pipeline capacity released by local gas utilities on the secondary market—may not be able to access natural gas.

Another factor is the time of day of winter peak demand, which occurs after the sun has set. On sunny days, solar arrays can help reduce consumption of fossil fuels used for power generation, hence preserving oil and gas to help meet future peak demands. However, as discussed in Section 3.3, solar PV itself does not assist in meeting the daily winter peak demand.

As a result of all these factors, the region's winter reliability concerns are likely to continue until generators decide to sign firm contracts for LNG or incremental gas pipeline capacity.

7.5.2 Winter Cold Snaps and Spells

The region's energy-security risk has been evident to the ISO since a 2004 cold snap when more than 6,000 MW of natural-gas-fired generators were unavailable due to non-firm-fuel contracting, pipeline constraints, economic outages, and other operational issues. Similar challenges have emerged during cold spells in recent winters, including in late December 2017 into early January 2018 and in January 2019.

7.5.2.1 Winter 2017/2018 Cold Spell

From December 26, 2017, to January 8, 2018, New England experienced an extremely cold stretch of weather, with all major cities in New England averaging temperatures below normal for at least 13 consecutive days, of which 10 days averaged more than 10°F below normal.[260] Boston, for example, experienced its most extreme cold weather in 100 years. This cold spell resulted in a temporary, but dramatic, spike in the price of natural gas in New England, which in turn triggered the heavy use of oil for electricity production, high wholesale electricity prices and greater NO_X, SO_2, and greenhouse gas emissions. Nonfirm contracting and other natural gas pipeline operational issues associated with fuel procurement and pipeline constraints resulted in gas pipeline companies invoking operation flow orders, thereby reducing supply to gas-fired generation.[261] Figure 7-9 illustrates the change in generation mix before, during, and after this cold spell.

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[260] ISO New England, "Winter 2017/2018 Recap: Historic Cold Snap Reinforces Findings in Operational Fuel-Security Analysis," *ISO Newswire* article (April 25, 2018), http://isonewswire.com/updates/2018/4/25/winter-20172018-recap-historic-cold-snap-reinforces-findings.html.

[261] An *operational flow order* is a mechanism invoked by gas pipeline companies to protect the operational integrity of the pipeline.

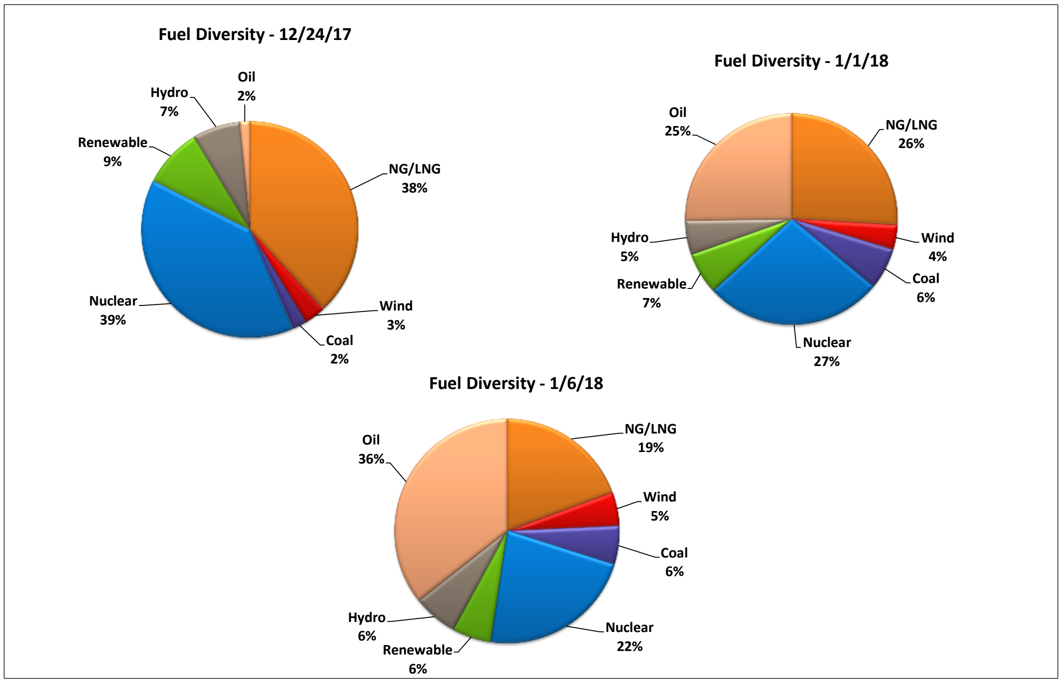

Figure 7-9: Shifting generation mix before and during the cold spell of winter 2017/2018 (%).

Source: ISO New England, I*ntroduction: Winter Generator Readiness Seminar*, presentation (October 30, 2018), https://www.iso-ne.com/static-assets/documents/2018/10/2018-2019-winter-generator-readiness-seminar-combined.pdf.

7.5.2.2 Winter 2019 Cold Snaps

In late January and early February 2019, New England faced two 3-day cold snaps where the eight-city New England mean temperature was below normal.[262] On January 21, the low temperature of 4.4°F was 21.2°F below the normal of 25.6°F, making this New England's winter peak load day, with an actual peak load of 20,722 MW (23,925 MW after reconstitution). The trigger was a severe winter storm that produced heavy inland snow, sleet, and ice, while coastal areas received heavy rain and flooding and high winds. Within a week, another three-day cold snap occurred where, again, low temperatures contributed to increased electrical and gas demands. The eight-city, New England mean temperature on January 31, 2019, was 6.5°F, 19.0°F below the normal of 25.5°F. Well-timed deliveries of imported LNG helped keep regional natural gas prices from rising during these two periods of high demand.

7.6 Assessing the Energy-Security Risk

The ISO has conducted several studies to help fulfill its responsibility of ensuring a reliable supply of electricity for the region. In one study, the ISO evaluated the level of operational risk posed to the power system by a wide range of potential fuel-mix scenarios.[263] The study quantified the risk by calculating whether enough fuel would be available for the system to satisfy consumer electricity demand and to maintain power system reliability throughout an entire winter.

The study results indicate the risk of future energy shortfalls is greater by winter 2024/2025 than today. All but one of the 23 scenarios studied showed that the regional power system could experience system

[262] The periods were from January 20–22, 2019, and January 31–February 2, 2019.

[263] ISO New England, *Operational Fuel-Security Analysis* (January 2018), https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

stress, requiring system operators to invoke emergency procedures. All but four scenarios show that some level of load shedding would be needed to maintain integrity of the New England power system. Therefore, the region is currently maintaining a delicate balance to ensure system reliability. Should any of the five key variables—retirements of coal- and oil-fired generators, LNG injection levels, the availability of oil as well as the permitted ability to burn oil, electricity imports, and the development of renewables—degrade from current expectations, the New England system is in jeopardy of not being able to serve load.

The ISO also conducted an analysis based on assumptions provided by the Massachusetts Clean Energy Center, the *High-Level Assessment of Potential Impacts of Offshore Wind Additions to the New England Power System During the 2017/2018 Cold Spell*.[264] This study focused on the impact on production costs, environmental emissions, fossil fuel savings, and locational marginal prices for several offshore wind scenarios of 400 MW, 800 MW, and 1,600 MW. In general, the results show that offshore wind connections to the load centers in southern New England are well situated. Offshore wind production during the 2017/2018 cold spell would likely have reduced production costs, environmental emissions, fossil fuel consumption by generating units, and LMPs. However, for relatively short periods during the cold spell, the wind profile reduced to close to 0 MW. Section 9.1 includes additional discussion of the effects of variable energy resources. Sections 9.3.2 and 9.3.3 discuss economic analysis of other scenarios.

In 2018, NPCC conducted a fuel-assurance analysis for New England. The study assessed the loss of generators resulting from forced outages of pipelines serving the region. The results showed that system resiliency was good during the 2018 August peak and that ISO New England operators would have sufficient time to prevent cascading electrical outages in neighboring systems. However, the study also concluded the following:

- Natural gas deliverability constraints occurring during the peak heating season would be further exacerbated by contingencies on the natural gas system.
- While the adverse effects of pipeline constraints can be diminished through greater supplies from LNG facilities, this may require fuel contracts.
- Oil-fired generation may also require contract arrangements for fuel.

Also, as mentioned in Section 6.3, see NERC 's 2017 report, *Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System*.

7.7 Potential Solutions

Addressing the energy-security issue is the region's highest-priority challenge. Because the ISO has no jurisdiction over other industries' fuel-supply chains or the authority to require generators to make long-term investments in fuel-supply contracts, it has employed emergency operating procedures and implemented market design changes to incentivize generators to arrange for routine and reliable fuel deliveries. The ISO also has improved communication and coordination with natural gas pipeline operators. Discussions about possible solutions to the region's energy-security risk commenced in 2018.

[264] ISO New England System Planning Department, "High-Level Assessment of Potential Impacts of Offshore Wind Additions to the New England Power System During the 2017/2018 Cold Spell," memorandum (December 17, 2018), https://www.iso-ne.com/static-assets/documents/2018/12/2018_iso-ne_offshore_wind_assessment_mass_cec_production_estimates_12_17_2018_public.pdf.

7.7.1 Operational Enhancements

The ISO has been able to maintain power system reliability during severe winter conditions by using emergency operating procedures. Revisions to OP 21, *Energy Inventory Accounting and Actions During An Energy Emergency*, include the integration of a 21-day energy assessment and reporting mechanism based partly on generator fuel and emissions availability information reported to the ISO by lead market participants.[265] Results of the 21-day energy assessment, which are publicly available, may trigger the declaration of an Energy Alert or an Energy Emergency and will serve to raise the region's awareness of near-term energy availability, or lack thereof.[266] These declarations allow sufficient time for stakeholders, including lead market participants, regulators, and ISO system operations to take necessary actions to lessen the likelihood or minimize the impact of an actual or forecasted energy deficiency.[267]

7.7.2 Market and Other Solutions

Although the region is projected to have sufficient resources to meet capacity requirements and enough transmission facilities to meet reliability criteria, it must address energy-security issues to meet its energy-supply needs. The limited availability of the natural gas generating units or renewables can present energy-security risks to the region at any time of the year but especially during winter periods.

7.7.2.1 Near-Term Solutions

To address near-term operational energy-security risks in winter, sparked by limited availability of fuel for gas-fired generators and presented by retirement bids, the ISO incorporated a fuel-security reliability review and cost-allocation methodology into the Forward Capacity Market for retaining and compensating generators needed for fuel security (see Section 4.1.3.4).[268] This is not a market-based solution but rather a reliability review to establish a need for a particular resource. This interim step will address regional winter energy security for capacity commitment periods 2022/2023, 2023/2024, and possibly 2024/2025 while the ISO and its stakeholders develop a longer-term, market-based approach.

7.7.2.2 Long-Term Solutions

Measures to address longer-term energy-security risks are under development. The current suite of market products does not provide sufficient financial incentives for market participants to undertake them because making up-front investments in fuel-supply certainty would likely reduce the energy market payments the generator receives, resulting in misaligned incentives. The ISO's efforts are directed at three measures:

- Strengthening generation owners' financial incentives to undertake more robust fuel-supply arrangements, when cost effective, while not prescribing what form these fuel-supply arrangements may take

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[265] ISO New England Operating Procedure No. 21, *Energy Inventory Accounting and Actions During An Energy Emergency* (October 19, 2018), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf.

[266] ISO New England, "21-Day Energy Emergency Forecast and Report," webpage (2019), https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/21-Day-Energy-Assessment-Forecast-and-Report-Results.

[267] Pursuant to OP 21, at a minimum, the ISO will collect fuel-availability data on a weekly basis during the winter (December through March) and a biweekly during nonwinter months (April through November).

[268] See the ISO's "Energy-Security Improvements Key Project," webpage (2019), https://www.iso-ne.com/committees/key-projects/energy-security-improvements.

- Rewarding resource flexibility that helps manage, and prepare for, energy-supply uncertainties during the operating day, given the increasingly just-in-time nature of the power system
- Efficiently allocating electricity production across multiple days from resources that have limited stored (non-just-in-time) energy sources.

The proposed long-term energy-security solution builds on the region's competitive wholesale electricity structure.[269] The ISO is considering the following market initiatives to help achieve the aforementioned objectives:

- Multi-day-ahead market: Expand the current one-day-ahead market into a multi-day-ahead market, optimizing energy (including stored fuel energy) over a multiday timeframe and producing multiday clearing prices for market participants' energy obligations.
- New ancillary services in the day-ahead market: Create several new, voluntary ancillary services in the day-ahead market that provide, and compensate for, the flexibility of energy "on demand" to manage uncertainties each operating day.
- Seasonal forward market: Conduct a voluntary, competitive forward auction that provides asset owners with the incentive—and necessary compensation—to invest in supplemental supply arrangements for the coming winter.

These new markets could help signal, through transparent market prices, the costs of operating a reliable power system as the profile of resources comprising the New England fleet continues to evolve. The ISO expects to submit a FERC filing by October 15, 2019, outlining the long-term market enhancements.

7.8 Summary

Risks to current and future power system reliability hinges on the availability of fuel to New England generators so that they can provide the electric energy needed for meeting system demand. The operational challenges experienced during recent cold spells highlight the need for the ISO to manage energy-production limitations. During extremely cold weather, regional gas-fired power plants' lack of firm fuel contracts limits the operational availability of these generators. Inclement weather can also hamper oil and LNG deliveries to the region. The inability of natural gas pipelines to serve coincidental gas and electric sector demands results in the need for replacement resources.

Expanding the region's fuel infrastructure would benefit New England, but major improvements are not currently planned. Siting new gas pipelines in New England can be a long and difficult process and will not address short-term needs. Siting and permitting flexible dual-fuel generators also remains challenging.

Variable generation from renewable resources complicates both fuel-availability and energy-security concerns. Renewable generators generally can help supply the demand for energy and displace the traditional fuels that have been generating it, but the output of wind and solar facilities depends on the weather and time of day. For example, solar panels can reduce the consumption of natural gas and oil during sunny winter days, so more oil and gas are available later to generate electricity to meet the daily winter peak demand. Solar energy cannot help directly with the winter peak, however. Similarly, wind

[269] ISO New England, *Energy Security Improvement*, discussion paper (April 2019), https://www.iso-ne.com/static-assets/documents/2019/04/a00_iso_discussion_paper_energy_security_improvements.pdf.

generation can reduce consumption of fossil fuels but can reduce to 0 MW outputs during extraordinarily low or high wind conditions.

The ISO has implemented near-term market and operational changes to address energy-security risks, and it continues discussions with stakeholders on long-term market solutions. Some of these improvements are as follows:

- Enhancing Operating Procedure No. 21, which developed new situational awareness and forecasting tools for system operators to confirm fuel availability for natural-gas-fired generators
- Increasing awareness through improved communication and coordination with interstate pipeline operators
- Introducing an energy-security reliability review methodology into the Forward Capacity Market to address short-term needs

Energy security could be further improved in a number of ways:

- Firm contracts between power generators and natural gas pipelines would support the building of new natural gas pipeline capacity.
- Firm contracts with natural gas suppliers, including LNG operators, would improve the availability of natural gas for electric power generation.
- The use of existing and new dual-fuel capability at generators would provide alternative supplies of fuel when natural gas supplies are limited.
- Adequate on-site storage and replenishment of liquid fuels would increase generation reliability at dual-fuel power plants.

The ISO will continue to work with stakeholders, regulators, and policymakers to determine whether further operational or market design measures will be needed to address the existing and future energy-security risks.

Section 8
Environmental Regulations and Goals Affecting the Power System

Various elements of the power system are subject to federal and state environmental laws and regulations and multistate initiatives for controlling pollution, emissions, or discharges and protecting human health and the environment. The New England states also have targets for the development of low- or zero-emitting resources.

Siting and environmental permitting requirements for new and existing generation are often complex and may involve multiple federal and state regulatory entities, all of which could result in proposed project modifications to meet compliance; delays in the planning, development or implementation of a project; or project cancelation. Compliance with environmental requirements may involve major capital investments for new projects, remediation measures, or operation changes at existing facilities. Generator owners and load-serving entities (LSEs) must weigh potential capital and operating costs, including those for environmental compliance, against potential revenues. The results of these analyses influence their business plans, which can include the retirement of generating units.

System reliability could suffer if the aggregate effect and timing of all such compliance efforts limit generator energy production, reduce capacity output, or contribute to unit retirements. However, to date, most national and state regulators have provided compliance options in several recent rulemakings and permitting decisions, recognizing the reliability value that low-capacity fossil steam generators (primarily oil-fired units) provide in maintaining energy security (see Section 7.2).

This section summarizes environmental regulations affecting generators, governmental efforts to promote the development of renewable resources, and the relicensing timelines for hydroelectric generators and nuclear units. The section also discusses regional air emissions and water-usage trends resulting from recent environmental requirements. Note that issues associated with interconnecting inverter-based technologies are discussed in Section 9.

8.1 Federal Environmental Regulations Affecting Generators

Compliance obligations for generators from existing and pending federal environmental requirements differ by resource age, economics, location, fuel type, and available pollution control technologies. In the region, existing and new fossil-fired generators (coal, oil, and natural gas) generally operate advanced pollution control technologies that reduce air emissions and wastewater discharges. Changes in applicable air, water, wildlife protection, and greenhouse gas emission standards, including those for carbon dioxide (CO_2), however, could affect the economic performance of nuclear and fossil-fired generators by imposing seasonal or year-round operational constraints or result in additional capital costs for installing environmental remediation measures. Renewable generators (hydro, wind, solar) may experience operational constraints due to changing wildlife and water quality protection requirements.

Certain federal environmental requirements and compliance options are highly uncertain at present. Significant programmatic and budgetary changes at various federal departments and agencies with environmental oversight responsibilities affecting the power sector are under consideration or implementation at present.[270] Several changes impose stronger environmental compliance requirements, while others allow for fewer restrictions or greater flexibility in meeting requirements. Pursuant to various executive orders and legislation, EPA is reconsidering several major air and water quality rules in the following areas that affect various classes of existing and new generators:[271]

- Surface water withdrawals (for cooling water use and consumption)
- Wastewater discharges into surface water
- Mercury, acid gas, and other toxic air emissions
- Ozone (O_3) transport and fine particulate matter ($PM_{2.5}$) and sulfur dioxide (SO_2) emissions
- Greenhouse gases (GHGs), especially CO_2 emissions

Several of these federal environmental regulations and policies affecting power generators have stalled or experienced setbacks due to litigation or procedural challenges. Until these matters are resolved, uncertainty and risks of delay for permitting and operations may impact new and existing generators and transmission facilities.

8.1.1 Impact of US Clean Water Act Regulations on the Region's Generators

Several US *Resource Conservation and Recovery Act* (RCRA) and *Clean Water Act* (CWA) regulations affect electric power generators (see Table 8-1).[272] Some of the CWA regulations are as follows:

- Under Sections 316 and 402, EPA and state authorities (with delegated federal authority) regulate cooling water systems and thermal discharges.
- Section 316(a) deals with thermal variances in National Pollution Discharge Elimination System (NPDES) permits.
- Section 316(b) regulates the design and operation of cooling water intake structures (CWIS).[273]

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[270] These agencies include the Council on Environmental Quality (CEQ), Department of Agriculture (Forest Service, Natural Resources Conservation Service, Office of Environmental Markets), Department of Commerce (National Oceanic and Atmospheric Administration, National Marine Fisheries Service), Department of Energy, Department of Interior (Bureau of Ocean Energy Management, Bureau of Land Management, Bureau of Reclamation, National Park Service, US Fish and Wildlife Service), and the Environmental Protection Agency (EPA).

[271] EPA, *Evaluation of Existing Regulations*, 82 FR 17793, request for comment (April 13, 2017), https://www.federalregister.gov/d/2017-07500, implementing Executive Order 13777 of February 24, 2017, *Enforcing the Regulatory Reform Agenda* (March 1, 2017), https://www.federalregister.gov/d/2017-04107.

[272] EPA, *Resource Conservation and Recovery Act,* 42 USC §6912 et seq. (1998), https://www.epa.gov/rcra/resource-conservation-and-recovery-act-rcra-overview, and *Clean Water Act*, 33 USC §1251 et seq. (1972), https://www.epa.gov/laws-regulations/summary-clean-water-act.

[273] Cooling water intake structures can cause adverse environmental impact; organisms may be killed or injured due to the high velocity of the water withdrawal, heat, chemicals used to clean the cooling system, or other physical stresses. Fish and other larger wildlife may be killed or injured due to *impingement* (i.e., when they are trapped against screens at the front of an intake structure), while smaller organisms, such as fish eggs and larvae, can be harmed by *entrainment* (i.e., when drawn through a facility's intake screens with the cooling water). Regulated CWA Section 316(b) facilities have NPDES permits and are designed to withdraw at least 2 million gallons/day from waters of the United States. Permitted electric power generators equipped with once-through CWISs must use the best technology available to reduce fish impingement and entrainment. A range of technologies can satisfy this requirement depending on site-specific circumstances.

- Section 304 mandates effluent limitations guidelines (ELGs) for wastewater discharges from electric power generators.[274]
- Section 402 requires NPDES permits to control thermal pollutants, among others, on the basis of technology and water quality standards.[275]

The CWIS Rule and the ELG requirements were challenged but upheld in court; permit revisions may result in changing compliance obligations for generators, potentially limiting the operational flexibility of some units.[276]

[274] ELGs were updated in 2015 to address the increasing toxicity of wastewater discharges as the addition of scrubbers and other pollution control devices—installed to reduce air pollutant emissions under *Clean Air Act* programs—transferred pollutants to the wastewater streams in the process of reducing air pollution. EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, final rule, 80 FR 67837 (November 3, 2015), https://www.federalregister.gov/d/2015-25663.

[275] EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, final rule, 79 FR 48299 (August 15, 2014); applies to existing and new cooling water intake structures at power plants and manufacturers. EPA, *Effluent Limitation Guidelines and Standards for the Stream Electric Power Generating Point Source Category*, final rule, 80 FR 67837 (November 3, 2015). The main pollutants of concern for these discharges include metals (mercury, arsenic, and selenium), nitrogen, and total dissolved solids generated by the operation of air pollution control devices (i.e., scrubbers). National Renewable Energy Laboratory (NREL) *Water-Related Power Plant Curtailments: An Overview of Incidents and Contributing Factors*, NREL/TP-6A20-67084 (December 2016). https://www.nrel.gov/docs/fy17osti/67084.pdf.

[276] *Cooling Water Intake Structure Coalition v. EPA*, 898 F.3d 173 (July 23, 2018).

Table 8-1
Major US *Clean Water Act* and *Resource Conservation and Recovery Act* Rules Affecting Coal, Natural Gas, and Nuclear Generation

Title	Year Finalized	Years Implemented	Major Provisions	Generation Sources Affected
Cooling Water Intake Rule	2001 (Phase 1) 2003 (revised Phase 1) 2014 (Phase 2)	Phase 2: 2014–2018 2018 litigation upholds 316(b) rule	Promulgated under 316(b) of the *Clean Water Act*. New sources regulated under Phase I and existing sources regulated under Phase II. States consider requirements for power plants on a case-by-case basis. Requires controls to reduce mortality to fish and other aquatic organisms.	Coal Natural gas Nuclear
Steam Electric Effluent Limitation Guidelines	1974; policy updates in 1977, 1978, 1980, 1982, and 2015	1982, 2015–2017 EPA suspends 2015 rule for review; litigation suspended	Established limitations on the discharge of toxic and other chemical pollutants and thermal discharges from existing and new steam electric power plants, as well as pretreatment standards. The 2015 update sets the first federal limits on levels of toxic metals that can be discharged.	Coal Natural gas
Coal Combustion Residuals Rule (under RCRA)	2015	2015–2018 2018 rule revised; court overrules changes	Addresses groundwater contamination risks from coal combustion residuals (i.e., "coal ash") disposal in unlined landfills and surface impoundments by establishing national standards for disposal	Coal

Source: US DOE, *Staff Report to the Secretary on Electricity Markets and Reliability* (August 2017), https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf. Updated by ISO New England.

In New England, 5.85 GW of existing fossil thermal electric capacity rely on larger once-through cooling systems subject to the CWIS Rule and could incur additional compliance costs (operational changes or retrofits) during periodic water permit reviews.[277] Another 4.13 GW of existing capacity have partially compliant cooling systems, and 2.12 GW of existing capacity (mainly newer facilities with combined-cycle units) have already-compliant recirculating cooling systems. The cooling water and wastewater discharge rules may also require new thermal electric energy capacity to install dry, hybrid, or closed-cycle cooling systems and control or eliminate certain wastewater discharges under new discharge requirements.

Annual water use and intensity for power generation has declined in New England between 2016 (1,643 billion gallons) and 2018 (1,511 billion gallons) as fossil and nuclear thermal electric capacity has either retired or been displaced by less-water-intensive sources of power generation (e.g., solar and wind).[278] See Figure 8-1.

[277] Energy Information Administration, "Thermoelectric cooling water data," webpage (DOE, November 5, 2018, release date; accessed February 2019), https://www.eia.gov/electricity/data/water/, and Form EIA-923, *Power Plant Operations Report* (data for 2018), https://www.eia.gov/electricity/data/eia923/.

[278] The water intensity of power generation is the average amount of water withdrawn per unit of total net electricity generated.

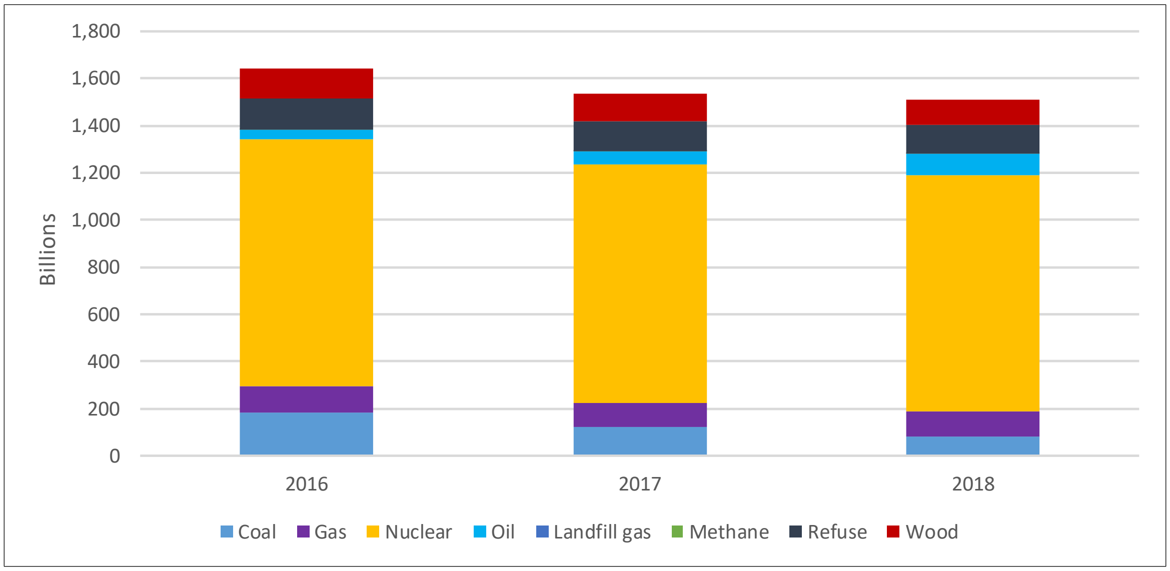

Figure 8-1: Estimated systemwide annual water withdrawals by fuel type in New England, 2016 to 2018 (billions of gallons).

Note: Water intensity data (gallons/MWh) from regional generators reporting to DOE's Energy Information Administration (EIA) are used to develop water-withdrawal factors (gallons/MWh) for each fuel type, multiplied by daily reported generation (MWh). Hydroelectric, solar, wind, and storage facilities were assumed to have zero water-intensity factors for this calculation.

Sources: EIA, "Thermoelectric cooling water data," webpage (November 5, 2018, release date; accessed February 2019), https://www.eia.gov/electricity/data/water/; Form EIA-923, *Power Plant Operations Report* (data for 2018), https://www.eia.gov/electricity/data/eia923/; and ISO New England, "Daily Generation by Fuel Type," webpage (data for 2016–2018), https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type.

While annual water withdrawals have declined, oil-fired capacity equipped with once-through cooling withdrew more water per unit of electricity than any other fuel type, as reflected in a spike in water withdrawals from regional electric power generators during the 2017/2018 cold spell (see Figure 8-2 and Section 7.5.2.1).[279]

[279] From the end of December 2017 to the beginning of January 2018, New England experienced an extremely cold stretch of weather, where average temperatures in all major New England cities were below normal for at least 13 days, with 10 days averaging more than 10°F below normal. A blizzard brought snow and ice into the region on January 4 and 5, causing severe coastal flooding.

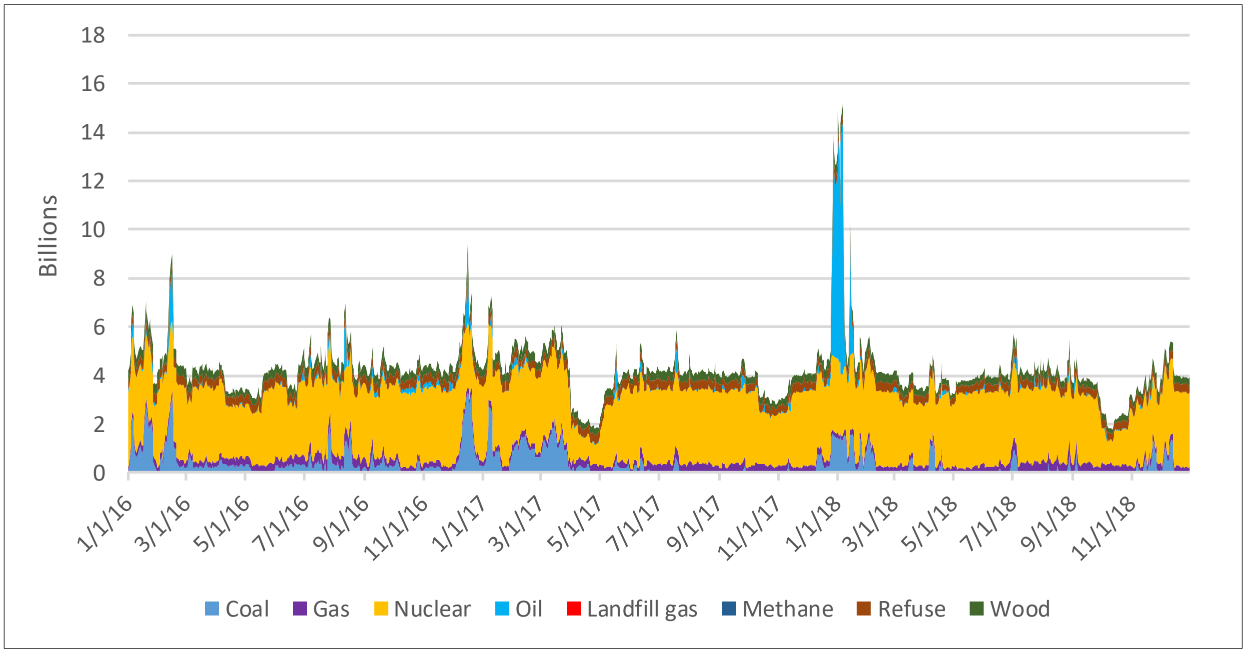

Figure 8-2: Estimated systemwide daily water withdrawals by fuel type in New England, 2016 to 2018 (billions of gallons).

Note: Water intensity data (gallons/MWh) from regional generators reporting to EIA are used to develop water withdrawal factors (gallons/MWh) for each fuel type, multiplied by daily reported generation (MWh). Hydroelectric, solar, wind, and storage facilities were assumed to have zero water-intensity factors for this calculation.

Sources: EIA, "2018 Thermoelectric Cooling Water Data," webpage (accessed February 2019), https://www.eia.gov/electricity/data/water/; Form EIA-923, *Power Plant Operations Report* (data for 2018), https://www.eia.gov/electricity/data/eia923/; and ISO New England, "Daily Generation by Fuel Type," webpage (data for 2016–2018), https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type.

EPA and the New England states are implementing the final CWA Section 316(b) CWIS Rule requirements to mitigate the adverse impacts to aquatic life of once-through cooling systems with a design intake flow of at least 2 million gallons/day (MGD). As shown in Figure 8-3, 12.1 GW of existing steam electric generators (nuclear, coal, oil, natural gas, and bio/refuse) in New England withdraw cooling water using once-through systems engineered with a design intake flow of 2 MGD or greater.[280] While EPA anticipated most retrofits occurring between 2018 and 2022, regional delays with several existing water permit reviews could push this schedule beyond 2022.

[280] Cheryl A. Dieter and Molly A. Maupin, et al., *Estimated Use of Water in the United States, 2015*, Circular 1441 (US Geological Survey, 2018), https://doi.org/10.3133/cir1441.

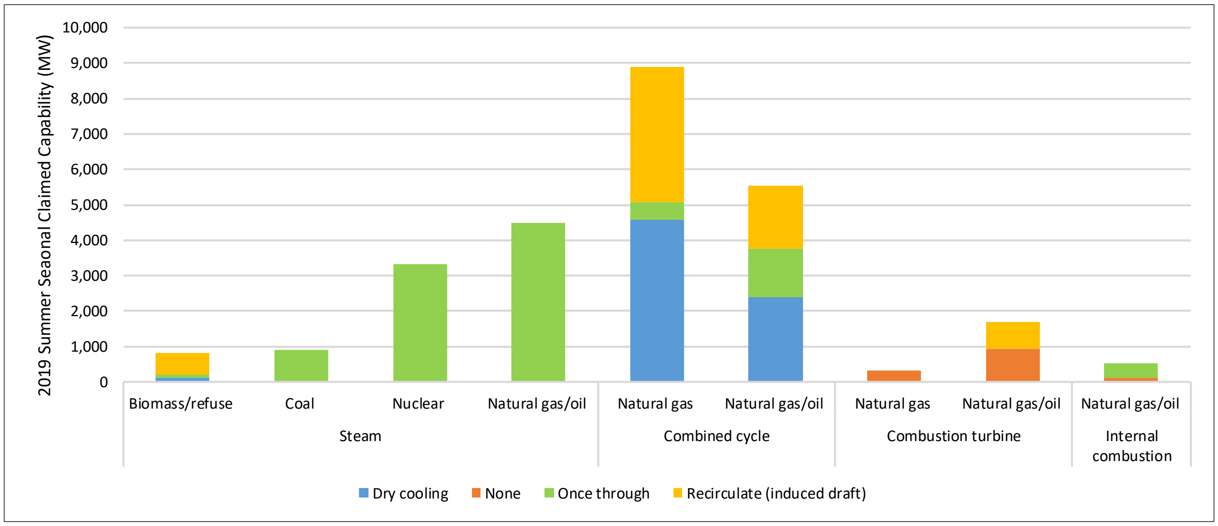

Figure 8-3: Summer claimed capability and cooling technology type in New England, 2018 (MW).

Note: Thermal cooling system data are available for 25.5 GW of existing system capacity in New England (excluding hydro, wind, and photovoltaic); 11.0 GW use open once-through thermal cooling systems, 6.2 GW use recirculating (induced draft) cooling systems, 7.0 GW use dry/hybrid cooling systems, and 1.36 GW report no cooling water systems. Cooling system data were unavailable for 1.0 GW. Resources <15 MW and resources retired before 2018 are excluded.

Sources: EIA, "Thermoelectric Cooling Water Data," webpage (November 5, 2018, release date; accessed February 2019), https://www.eia.gov/electricity/data/water/; Form EIA-923, *Power Plant Operations Report* (data for 2018), https://www.eia.gov/electricity/data/eia923/; and ISO New England, 2019 CELT Report (April 30, 2019), http://www.iso-ne.com/system-planning/system-plans-studies/celt#.

8.1.2 US *Clean Air Act* Requirements and Federal Greenhouse Gas Regulations

Air pollution regulations currently require local emission sources and those located upwind to limit ozone, particulate matter, and sulfur dioxide and their precursors (NO_X and SO_X), which assists New England states in meeting various environmental standards for the upwind pollutants found in the region.[281] The upwind air pollution can contribute to degraded air quality near an existing or new fossil generator in New England, possibly requiring New England state regulators to impose local operational constraints on in-region generators.[282] Additionally, other pollution sources nearby (transportation or industrial) or further upwind could limit the operational flexibility, fuel switching, or retrofits (uprates) at regional generators. Worsening air quality (such as ozone trends in southern New England) could necessitate installing or retrofitting more stringent air pollution controls on new and existing fossil generators.

To the extent federal environmental protections are weakened, upwind air pollution sources could switch to less effective pollution controls or operate pollution controls less frequently or at lower

[281] EPA, *National Ambient Air Quality Standards for Sulfur Dioxide*, final rule, 84 FR 9866 (March 18, 2019) (after review, 2010 primary SO_2 standard retained without changes); *National Ambient Air Quality Standards for Particulate Matter*, final rule, 78 FR 3086 (January 15, 2013); Secondary *National Ambient Air Quality Standards for Oxides of Nitrogen and Sulfur,* final rule, 77 FR 20218 (April 3, 2012) (existing secondary SO_2 standard retained without changes); *National Ambient Air Quality Standards for Sulfur Dioxide*, final rule, 75 FR 35520 (June 22, 2010).

[282] EPA has proposed downgrading Connecticut from moderate to serious nonattainment with the 2008 ozone standard, which, if finalized, may trigger additional control requirements for in-state fossil power generators. EPA, *Determinations of Attainment by the Attainment Date, Extensions of the Attainment Date, and Reclassification of Several Areas Classified as Moderate for the 2008 Ozone National Ambient Air Quality Standards*, proposed rule, 83 FR 56781 (November 11, 2018), https://www.federalregister.gov/d/2018-24816.

removal efficiencies. Recent regulatory activities and potential new regulations in adjacent control areas also could affect New England's native generation, resulting emissions, and compliance obligations.[283] If not adequately addressed, the upwind air pollution also could complicate siting decisions, forcing developers to accept stricter operating constraints to ensure compliance with more stringent local air-quality protections and creating more uncertainty about whether adequate generating capacity will be available where needed across the region.

As shown in, Table 8-2 many *Clean Air Act* (CAA) actions affect New England's fossil-fuel power generators and the region's air emissions. Regional and federal GHG regulations also present a range of environmental and economic implications.

Table 8-2
Major *Clean Air Act* Rules Impacting Coal, Natural Gas, and Oil-Fired Generation

Rule	Updates	Regulatory Activity	Major Provisions	Generation Sources Affected
New Source Review	1980; policy updates in 1996 and 2002	1980; 2002 updates 2018 EPA revises applicability	Affects stationary sources of air pollutants. Requires that a new or modified power plant obtain a preconstruction permit to ensure, among other things, that modern pollution control equipment is installed. Requirements differ depending on whether or not the plant is located in an area that meets the requirements under the National Ambient Air Quality Standards.	Coal, natural gas
Mercury and Air Toxics Standards	2012, 2015, 2018	2015–2016 took effect 2018 EPA proposes rollback	Limited mercury, arsenic, acid gases, and other toxic pollutants emissions from coal- and oil-fired generators Initial compliance due by April 2015; certain generators received multiyear compliance extensions through 2017.	Coal, oil
Regional Haze Rule	1999; policy revisions in 2017	Implemented; Revised state plans due in 2021; some plans under review	Requires states to develop long-term strategies, including enforceable measures to improve visibility in 156 national parks and wilderness areas. Aims at returning visibility to natural conditions by 2064.	Coal, oil, natural gas
Cross-State Air Pollution Rule (CSAPR)	2011	Phase 1: 2015 Phase 2: 2017	Replaced the Clean Air Interstate Rule starting January 1, 2015; requires states to reduce power plant emissions of SO_2 and NO_X that contribute to ozone emissions and fine-particle pollution in other states. Although none of the New England states are required to reduce their emissions pursuant to phase 2 of CSAPR, the region will benefit from emissions reductions required of upwind states.	Coal, natural gas

Source: US DOE, *Staff Report to the Secretary on Electricity Markets and Reliability* (August 2017), https://www.energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf (updated by ISO New England, May 2019).

[283] The State of New York is proposing more stringent summer ozone precursor (NO_X) emission limits for peaking generating units, which will take effect between 2023 and 2025. Affected generators may meet the proposed limits, retire, or not run noncompliant units during the ozone season. They also could comply by meeting an average output-based emission limit, which includes renewables and storage, as a daily average emission rate. New York Department of Environmental Conservation, *Proposed Part 227-3, Ozone Season Oxides of Nitrogen (NO_X) Emission Limits for Simple Cycle and Regenerative Combustion Turbines* (February 2019), https://www.dec.ny.gov/regulations/116131.html.

In 2018, EPA finalized regulations implementing requirements for the 2015 ozone standard, which may require operational changes and potential pollution control retrofits for fossil capacity across southern New England.[284] The 2015 ozone standard imposes more stringent technology-based performance standards for new or modified fossil fuel generators.

8.1.2.1 Implementation of Mercury and Air Toxics Standards

Of the 5.61 GW of remaining coal- and oil-fired steam thermal electric generators subject to the Mercury and Air Toxics Standards (MATS), 84% are residual oil-fired and qualify as limited-use units, with limited compliance obligations. Litigation involving the 2016 MATS supplemental finding was suspended indefinitely in April 2017, but affected generators must continue complying with MATS.[285] In December 2018, EPA proposed reconsideration of the 2016 supplemental finding, limiting consideration of health benefits in the cost-benefit analysis justifying MATS.[286] However, in New England state air toxics requirements remain as backstops for affected generators.

Most of the region's coal- and residual oil-fired steam generators larger than 25 MW are already complying with the standard's emissions limits for acid gases, toxic metals, and mercury based on maximum achievable control technologies (MACTs). Or, they are subject to the less-stringent requirements for limited-use units based on low individual-unit capacity factors.[287] Residual oil-fired capacity is the largest segment of the regional generation mix affected by MATS. The MATS capacity factor exceptions threshold for limited-use units (8%) will likely become more important to system reliability in future years because the affected generators may be required to curtail their output during critical periods.

8.1.2.2 CAA Ozone and Fine Particulate Matter Emission Limits

While New England native electric generator emissions have declined over the past decade (see below), persistent ozone and fine particulate levels remain at unacceptable levels in some portions of the region. Also, the ozone and fine particulate matter generated far upwind of New England has hampered considerable regulatory efforts to improve local air quality.

Under the *Clean Air Act*, state and federal air regulators are required to address deteriorating air-quality trends across southern New England (particularly due to ozone and fine particulate matter), resulting in more stringent emissions limits for native fossil generators.[288] To minimize air-quality impacts, permits

[284] EPA, *Implementation of the 2015 National Ambient Air Quality Standards for Ozone: Nonattainment Area State Implementation Plan Requirements*, final rule, 83 Fed. Reg. 62998 (December 6, 2018) https://www.federalregister.gov/d/2018-25424; *National Ambient Air Quality Standards for Ozone*, final rule, 80 Fed. Reg. 65292 (October 26, 2015), https://www.federalregister.gov/articles/2015/10/26/2015-26594/national-ambient-air-quality-standards-for-ozone.

[285] The D.C. Circuit removed the case from its calendar, suspending it indefinitely, and directed EPA to file 90-day status reports. Anthracite Region Independent Power Producers Association (ARIPPA) v. EPA, No. 15-1180 order (April 27, 2017) (D.C. Circuit).

[286] EPA, *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units-Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, proposed rule, 84 Fed. Reg. 2670 (February 7, 2019), https://www.federalregister.gov/d/2019-00936.

[287] EPA developed standards under Section 112(d) to reduce hazardous air pollutant emissions from this source category. EPA, *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units*, final rule, 77 FR 9304 (February 16, 2012).

[288] For example, beginning in 2018, Connecticut's *NOx Emissions from Fuel-Burning Emission Units* regulations, section RCSA 22a-174-22e, requires more stringent NO_X emission limits for boilers, turbines, and engines located at major sources specific to each type of equipment and fuel type, and RCSA 22a-174-22f requires smaller sources of

for new advanced, highly efficient generators (<4,000 MMBtu/hour gross heat input) are subject to narrower operating ranges than older less efficient (>8,000 MMBtu/hour gross heat input).[289]

8.1.2.3 US Clean Power Plan

Federal greenhouse gas policy and regulation are in a state of flux, and at the time of publication, the outcomes for generators of pending regulatory actions and litigation remain unclear.

In August 2015, EPA finalized the Clean Power Plan (CPP), for existing fossil-fuel-fired power plants under Section 111(d) of the *Clean Air Act*. The CPP would have required affected fossil power plants to reduce CO_2 emissions 32% nationwide by 2030 from a 2005 baseline, with the initial reductions due by an interim 2022 deadline and additional milestones before the final 2030 deadline.[290] In August 2018, EPA proposed a replacement rule, the Affordable Clean Energy (ACE) Rule, limiting applicability to modifications on site at coal-fired generating units.[291] EPA issued the ACE Rule in June 2019, which simultaneously repealed the CPP.[292] The ACE is expected to have a negligible impact on the New England power system.

8.2 Regional and State Greenhouse Gas Regulations and Goals

Regardless of any subsequent EPA actions on greenhouse gas emissions, the New England states are assessing, developing, and implementing other requirements, initiatives, and incentives to reduce GHGs, directly or indirectly affecting native fossil generators and the regional bulk power system. Thus, the states' various GHG-reduction initiatives to reduce CO_2 and other emissions are expected to continue. These include the enactment of state-specific generator emissions caps though the Regional Greenhouse Gas Initiative (RGGI) and Renewable Portfolio Standards (RPSs).

At the regional and state levels, air, water, and CO_2 standards could emerge as more stringent for native fossil generator compliance. In 2018, all New England states, New York, and several other states

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NO_X to maintain equipment in good operating condition, monitor daily emissions during the summer months, and to avoid exceeding daily emission limits. See Connecticut Department of Energy and Environmental Protection (CT DEEP), "Control of nitrogen oxides emissions from fuel-burning equipment at major stationary sources of nitrogen oxides," RCSA 22a-174-22e, and "High daily NOx emitting units at non-major sources of NOx," RCSA Section 22a-174-22f (December 22, 2016), Connecticut eRegulations portal, https://eregulations.ct.gov/eRegsPortal/Search/RMRView/PR2015-193.

[289] For example, a new dual-fuel combined-cycle generator with a seasonal claimed capability greater than 450 MW is limited to a total of 500 hours of cold, warm, and hot startups and shutdowns per calendar year; any fuel switching must be completed within 1 hour; all emissions during startup, shutdown, steady-state, transient, and minimum operating load conditions count toward annual emission limits; and generators must shut down when they exceed any emissions limit that cannot be corrected within 3 hours.

[290] EPA, *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, final rule, 80 FR 64509 (October 23, 2015), https://www.federalregister.gov/d/2015-22837. On February 9, 2016, the US Supreme Court stayed the implementation of the CPP, pending completion of litigation, which was held in abeyance in April 2017 by the D.C. Circuit Court of Appeals. In March 2017, an executive order directed EPA to review the CPP and 111(b) Standards of Performance for Greenhouse Gas Emissions for Power Plants and suspend, revise, or rescind the final rules and associated guidance and memoranda, subject to all applicable legal requirements.

[291] EPA, *Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, proposed rule (October 16, 2017), 82 Fed. Reg. 48035, https://www.federalregister.gov/d/2017-22349.

[292] The ACE establishes heat-rate improvement, or efficiency improvement, as the best system for reducing CO_2 emissions from coal-fired generators. EPA. "Affordable Clean Energy Rule," webpage (2019), https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule.

introduced carbon tax bills, which would establish economywide charges on the distribution or sale of greenhouse-gas-emitting items, including electricity,[293] For example, Massachusetts adopted a declining CO_2 cap beginning in 2018 affecting existing and new fossil generators larger than 25 MW.[294] New initiatives to electrify the transportation and building sectors are emerging as well, as discussed below.

Figure 8-4 shows the New England states' goals for reducing GHG emissions.

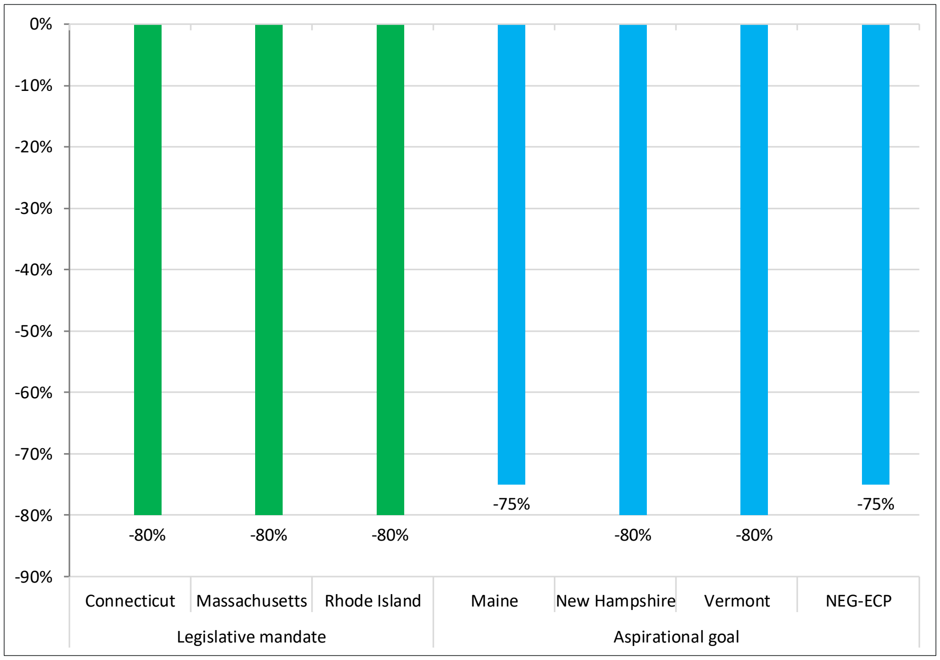

Figure 8-4: New England state goals for reducing in greenhouse gas emissions (percentage reduction in GHGs economywide by 2050).

[293] See, for example: State of Massachusetts, *Reducing CO_2 Emissions from Electricity Generating Units*, 310 CMR 7.74, (as amended August 2018), https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774, and *An Act to Advance Clean Energy. Chapter 227 of the Acts of 2018* (August 9, 2018), https://www.mass.gov/service-details/clean-peak-energy-standard. Also see: Brook Detterman, "Will Massachusetts and Other Northeastern States Move to Aggressively Price Carbon Emissions?," web article (Beveridge and Diamond, February 27, 2019), https://www.bdlaw.com/air-climate-change/publications/will-massachusetts-and-other-northeastern-states-move-to-aggressively-price-carbon-emissions/.

[294] State of Massachusetts, *Reducing CO_2 Emissions from Electricity Generating Units*, 310 CMR 7.74, (as amended, August 2018), https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774; and *An Act to Advance Clean Energy. Chapter 227 of the Acts of 2018* (August 9, 2018), https://www.mass.gov/service-details/clean-peak-energy-standard.

8.2.1 Regional Greenhouse Gas Initiative

Since 2009, the region's fossil-fuel generators larger than 25 MW have been subject to a CO_2 emissions budget cap to comply with the Regional Greenhouse Gas Initiative.[295] RGGI is a mandatory, market-based cap-and-trade program to reduce CO_2 emissions across nine New England and Mid-Atlantic states. The New England region also has an economywide climate action goal to reduce GHGs within a range of 35–45% by 2030 and 75–85% by 2050 from a baseline of 1990 emission levels.[296] This equates to annual emissions of 105 to 124 metric tons of carbon dioxide equivalent (CO_2e) by 2030 and 29 to 47 metric tons of CO_2e equivalent by 2050, compared with approximately183 million metric tons of CO_2e emissions from across all economic sectors in New England in 2018. Similar to the regulatory activities in neighboring areas for controlling other air pollutants (see Section 8.1.2), the GHG control activities may indirectly affect native generation, either increasing or decreasing compliance obligations.[297]

8.2.1.1 CO_2 Allowances from RGGI-Affected Generators

Based on the RGGI Model Rule, each participating state's individual CO_2 Budget Trading Program operates in aggregate to limit CO_2 emissions from affected generators. RGGI-affected generators within each state must acquire and surrender RGGI CO_2 allowances equal to their CO_2 emissions over a three-year control period (the fourth control period runs from January 1, 2018, to December 31, 2020). Any private entity can retain (i.e., bank) a RGGI CO_2 allowance indefinitely until it is surrendered to satisfy a compliance obligation in a future year. RGGI states adjust this annual cap to account for banked CO_2 allowances.

In 2019, the RGGI cap is 58.2 million short tons of CO_2 per year, declining 2.5% through 2020. According to the RGGI market monitor, 99 million RGGI CO_2 allowances were considered surplus at the end of 2018 and estimates that due to current and planned (after 2020) adjustments to the RGGI cap to reduce this surplus, vintage allowances from 2009–2018 are expected to be exhausted by the end of 2025.[298]

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[295] The RGGI CO_2 budget (cap) is equal to the total number of CO_2 allowances issued by RGGI states in a given year. A CO_2 allowance represents a limited authorization for an affected RGGI electric power generating unit to emit one short ton of CO_2, as issued by a participating state. RGGI Market Monitor, *Report on the Secondary Market for RGGI CO_2 Allowances: Fourth Quarter 2018* (February 2019), https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2018_Q4.pdf. Also see: RGGI, Inc., "Program Overview," webpage (2019), https://www.rggi.org/design/overview.

[296] Northeast States for Coordinated Air Use Management (NESCAUM), *Greenhouse Gas Mitigation Analysis for New England*, white paper (September 2018), p. 4, https://www.nescaum.org/documents/nescaum-ghg-mitigation-analysis-new-england-201808-rev.pdf/.

[297] Beginning in 2021, existing electric generating units in New York will need to meet CO_2 emissions standards of either 1,800 lbs/MWh gross electrical output or 180 lbs/MMBtu or retire. According to the New York Department of Conservation (NY DEC), Part 251 will prevent the operation of high-carbon sources of energy, such as coal-fired generating units that do not use carbon capture and sequestration or some other advanced CO_2 emission-reduction technology. NY DEC, *Part 251, CO_2 Performance Standards for Major Electric Generating Facilities* (May 9, 2019), https://www.dec.ny.gov/regulations/113544.html.

[298] RGGI, Inc., *Annual Report on the Market for RGGI CO_2 Allowances: 2018* (April 2019), p. 7, https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Annual-Reports/MM_2018_Annual_Report.pdf.

8.2.1.2 RGGI Program Review

The RGGI states completed a periodic comprehensive program review in December 2017, adopting a new 30% regional emissions cap reduction between 2020 and 2030 and design changes, as follows, for the upcoming fifth control period (2021 to 2023) and beyond:[299]

- Timing of policy implementation—The post-2020 annual reduction targets extend to 2030.
- Adjustment of banked allowances—The program review accounts for banked RGGI CO_2 allowances accrued from 2014 to 2020.
- Reserve price—The post-2020 floor auction price was modified.
- Emissions-containment reserve (ECR)—Beginning in 2021, participating states will permanently withhold 10% of RGGI CO_2 allowances from their base budgets any year a quarterly auction clearing price falls below a trigger price. The ECR trigger price is set at $6.00 per allowance in 2021 and increases 7% per year.[300]
- Cost-containment reserve (CCR)—A reserved quantity of allowances, currently 10 million allowances, will be offered during quarterly auctions if any auction clears higher than $10.50 per RGGI CO_2 allowance during 2019. Beginning in 2021, the CCR trigger-price threshold increases to $13.00 per RGGI CO_2 allowance. Also in 2021, the CCR will switch from a fixed quantity of 10 million RGGI CO_2 allowances to a fixed percentage (10%) of the total annual RGGI cap. For 2021, the CCR will decline to 7.51 million allowances (10% of the 75.14 million allowance cap in 2021).[301]
- Offsets—The electric power sector's reduction in sulfur hexafluoride (SF_6) emissions and end-use energy efficiency in the building sector have been eliminated as eligible offset projects that can generate RGGI allowances. Other verification requirements for remaining offset categories were also updated.

Each RGGI state or any jurisdiction joining the program must include the principal design elements of the 2017 RGGI Model Rule before the next control period begins on January 1, 2021.

8.2.2 Electrification

A further means of reducing greenhouse gas emissions calls for electrifying transportation vehicles and increasing the use of electricity to provide heat, particularly through applications of efficient heat pumps.

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[299] RGGI, Inc., "2017 Program Review," webpage (2019), https://www.rggi.org/program-overview-and-design/program-review and "Principles to Accompany Model Rule Amendments" (December 19, 2017), https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Principles_Accompanying_Model_Rule.pdf.

[300] An *emissions-containment reserve* is a quantity of allowances that will be permanently withheld from circulation to secure additional emission reductions if auction prices fall below a preset trigger price. Allowances withheld in this way will not be reoffered for sale in a future auction. Maine and New Hampshire do not intend to implement an ECR.

[301] The $13.00 CCR trigger price for 2021 will increase 7% annually. RGGI, Inc., "RGGI 2016 Program Review; Principles to Accompany Model Rule Amendments," (December 19, 2017; accessed April 11, 2019), https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Principles_Accompanying_Model_Rule.pdf; and "Program Overview and design/Elements of RGGI," webpage (2019), https://www.rggi.org/program-overview-and-design/elements.

Once supplied by renewable generation, the conversion of these loads would further reduce overall carbon emissions.

Several New England states are actively exploring the expansion of carbon-reduction initiatives through the multistate Transportation and Climate Initiative (TCI).[302] The TCI states are exploring the design of a regional low-carbon transportation policy proposal that would cap and reduce carbon emissions from the combustion of transportation fuels through a cap-and-invest program or other pricing mechanism, after which each jurisdiction will decide whether to adopt and implement the policy. Massachusetts has a goal to have 300,000 electric vehicles registered by 2025, and Maine has a goal to have 100,000 heat pumps in the state by 2025.

The nature of this type of demand will likely become increasingly managed by "prosumers," who may choose to not participate in the wholesale energy markets but—if given the opportunity—will respond to price signals at the retail level and other triggers that vary consumption, which will depend on state policy preferences and decisions.

The ISO continues to monitor electrification and anticipates additional growth of demand by midcentury (see Section 3.5) and potential issues with the increased use of inverted-based technologies and distributed energy resources to fuel this new demand (see Section 9.2).

8.3 Renewable Portfolio Standards

The New England states continue to pursue a range of policies to increase the deployment of renewable energy and distributed resources. *Renewable Portfolio Standards* are state policy targets for LSEs in that state to meet the future demand for electric energy using renewable energy resources. All six New England states have Renewable Portfolio Standard targets for the proportion of electric energy that load-serving entities must provide using renewable resources. LSEs can satisfy or exceed their RPS obligations in a number of ways:

- Developing the renewable resources in the ISO's Interconnection Request Queue
- Importing qualifying renewable resource energy from adjacent balancing authority areas
- Building new renewable resources in New England not yet in the queue
- Developing behind-the-meter projects
- Acquiring Renewable Energy Certificates (RECs) from eligible renewable resources qualified by each state
- Using renewable fuels in existing generators, as specified in each state's standards
- Making state-established *alternative compliance payments* (ACPs) if their qualified renewable resources fall short of providing sufficient renewable energy credits to meet the RPSs

State RPS policies typically include resource classes for new and existing resources. The targets for existing resources increase the overall requirements over the resource classes or requirements for new resources only.

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[302] The states participating in the TCI are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. More information about the TCI is available at the "Transportation and Climate Initiative," webpage (2019), https://www.transportationandclimate.org/.

Figure 8-5 shows the Renewable Portfolio Standards for each New England state for new renewable energy. Individual state RPS targets for 2020 range from requiring 10% to 59% of the energy LSEs procure to be from renewable resources, which has driven new proposals for renewable energy. This trend is expected to continue as state targets increase incrementally to the middle of the century; all states have, or are considering, RPS targets that extend to 2025 and beyond. Some states are considering either or both raising their requirements or accelerating them further, with Massachusetts implementing a Clean Peak Energy Standard that requires local LSEs to obtain electric energy during seasonal peak periods from qualified new renewable, energy-storage, or demand-response resources, and Maine enacting a new RPS goal to increase Class 1 to 50% by 2030.[303] The wide range of RPS percentage targets results from the varying definitions of renewable resources by each New England state.

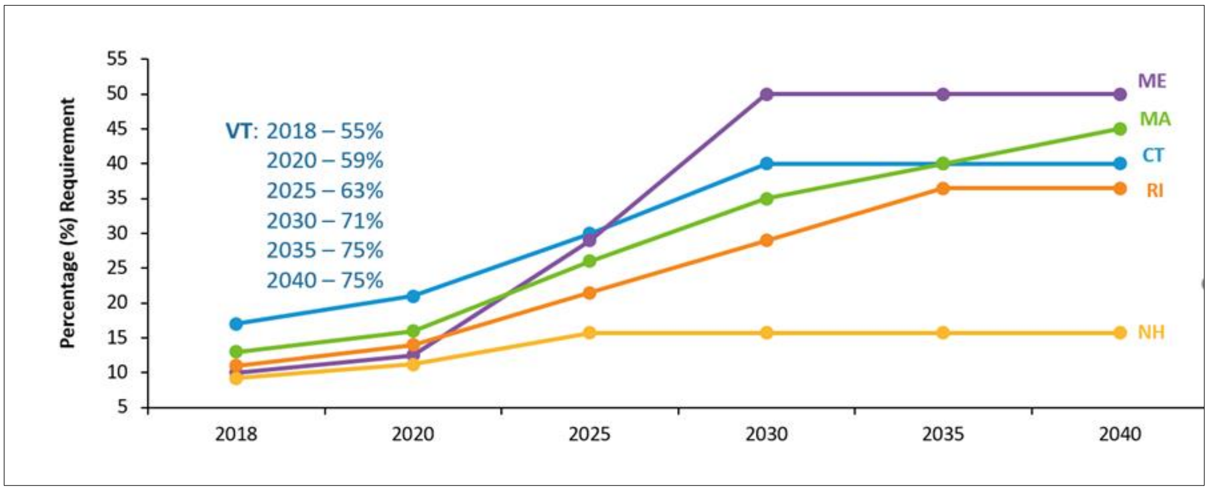

Figure 8-5: Percentage of Class I (new renewable energy resources) required for the New England states' Renewable Portfolio Standards, 2018 to 2040.

Notes: Connecticut's Class I RPS requirement plateaus at 40% in 2030. Maine's Class I RPS requirement increases to 50% in 2030 and remains at that level each year thereafter. Massachusetts' Class I RPS requirement increases by 2% each year between 2020 and 2030, reverting back to 1% each year thereafter, with no stated expiration date. New Hampshire's percentages include the requirements for both Class I and Class II resources (Class II resources are new solar technologies beginning operation after January 1, 2006). New Hampshire's Class I and Class II RPS requirements plateau at 15.7% in 2025. Rhode Island's requirement for "new" renewable energy plateaus at 36.5% in 2035. Vermont's "total renewable energy" requirement plateaus at 75% in 2032; it recognizes all forms of new and existing renewable energy and is unique in classifying large-scale hydropower as renewable.

8.4 State Requests for Proposals to Procure Renewables

Beginning in 2015, the southern New England states began issuing requests for proposals (RFPs) to procure renewable and other clean energy resources to achieve their public policy goals. In one instance, the states issued an RFP jointly to improve the economies of scale. Through these procurement efforts, which range from 20 MW to 2,000 MW, the states seek long-term contracts for the development (or

[303] State of Massachusetts, *Reducing CO_2 Emissions from Electricity Generating Units*, 310 CMR 7.74, (as amended, August 2018), https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774; and *An Act to Advance Clean Energy.* Chapter 227 of the Acts of 2018 (August 9, 2018), https://www.mass.gov/service-details/clean-peak-energy-standard. 129th Maine Legislature, First Legislative Session—2019, *An Act to Reform Maine's Renewable Portfolio Standard*, L.D. 1494 (April 4, 2019), *An Act To* http://legislature.maine.gov/bills/display_ps.asp?PID=1456&snum=129&paper=SP0457.

retention) of more than 5,000 MW of clean energy resources.[304] The states are targeting most of the resources to be on line in the 2020 to 2024 timeframe. Some of the states' activities are as follows (also see Section 10.2 for more details):

- In 2015, Connecticut, Massachusetts, and Rhode Island jointly issued a request for proposals for clean energy and transmission, which resulted in a selection of approximately 390 MW of solar and wind resources.[305]
- In May 2018, Rhode Island selected 400 MW from Deepwater Wind's Revolution Wind project through a competitive procurement process in collaboration with Massachusetts.[306] A separate procurement in 2019 may procure an additional 400 MW of newly developed renewable energy resources.
- Connecticut
    - In January 2018, the Connecticut Department of Energy and Environmental Protection (CT DEEP) issued a generation-based RFP for renewable energy, including offshore wind.[307]
    - In June 2018, the state selected 200 MW from Deepwater Wind's Revolution Wind project as a winner, as well as 52 MW from four fuel cell projects.[308] The Public Utilities Regulatory Authority (PURA) is still reviewing contracts from the zero-carbon RFP, which are equivalent to 45% of the state's load and include a 10-year contract with Millstone Nuclear Facility for 50% of its output; an 8-year contract with Seabrook Station for 1.9 million MWh; an additional 100 MW of offshore wind; and 165 MW of solar from nine projects (one paired with storage).
    - Legislation passed in 2019 authorizes another procurement of 2,000 MW of offshore wind by 2030, with the first phase of procurements occurring through 2019 (see Section 10.2.1).
- Massachusetts
    - In a 2017 solicitation, Massachusetts selected a transmission project for an HVDC tie with Québec—Central Maine Power's New England Clean Energy Connect Project—which received contract approval from the Massachusetts DPU in 2019 and is still under siting review in Maine.

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[304] The 5,000 MW does not include the imminent 2,000 MW of additional offshore wind that Connecticut will be procuring but for which it has not yet issued an RFP.

[305] States of Connecticut, Rhode Island, and the Commonwealth of Massachusetts, "Notice of Request for Proposals from Private Developers for Clean Energy and Transmission," (November 12, 2015), https://cleanenergyrfpdotcom.files.wordpress.com/2015/11/clean-energy-rfp-final-111215.pdf.

[306] MA DOER, "Request for Proposals for Long-Term Contracts for Offshore Wind Energy Projects," (June 29, 2017), https://macleanenergy.files.wordpress.com/2017/02/section-83c-request-for-proposals-for-long-term-contracts-for-offshore-wind-energy-projects-june-29-2017.pdf.

[307] CT DEEP, "Notice of Request for Proposals from Private Developers for Clean Energy," (January 31, 2018), http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/0fa7e92df14f12248525822600682775/%24FILE/2018.01.31_FINAL%20RFP.pdf.

[308] State of Connecticut, "Notice of Request for Proposals from Private Developers for Zero-Carbon Energy," (July 31, 2018), http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/f18419651b249e2e852582db006cbca3/%24FILE/2018.08.1_FINAL%20RFP%20-%20updated.pdf.

- Massachusetts passed new legislation in July 2018 that directs the Massachusetts Department of Energy Resources (DOER) to study the procurement of an additional 1,600 MW of offshore wind, above and beyond the 1,600 MW authorized by legislation passed in 2016. In 2019, DOER determined the additional 1,600 MW procurement should proceed. See Section 10.2.3.

While Massachusetts, Connecticut and Rhode Island are leading the region in terms of procuring long-term renewable energy contracts, other key developments highlight the strong upward trend toward renewable energy deployment in the region:

- The New Hampshire legislature passed legislation that would set up a commission to study whether to pursue long-term energy contracting for clean energy resources.
- In 2018, Maine issued an RFP for capacity resources that resulted in a contract for 100 MW of solar.[309] The legislature is also reviewing multiple bills to increase the state's Renewable Portfolio Standard and establish new statewide goals for reducing greenhouse gas emissions.

Other statewide policy mechanisms, such as financial incentives and net-metering, are significant drivers of renewable energy deployment across the region, as summarized in Section 10.2).

8.5 Regional Emissions Trends and Compliance Costs

New England emissions of carbon dioxide, nitrogen oxides, and sulfur dioxide from the region's generators and the cost of compliance with environmental regulations are presented below.

8.5.1 CO_2 Emissions from New England States' Electricity Generating Sector

The New England states' electricity generating sector CO_2 emissions in 2018 (24.5 million short tons) are already below all the aggregate regional 2022–2030 US Clean Power Plan caps of 32.3 to 28.6 million short tons. CO_2 emissions from RGGI-affected generators in the entire nine-state RGGI program declined between 2009 (123.8 million short tons) and 2017 (66.2 million short tons). In 2018, emissions from RGGI generators increased (73.3 million short tons) by 11% above 2017 emissions (66.2 million short tons), although the New England RGGI states' emissions declined to 24.5 million short tons in 2018, a slight decline from 24.7 million short tons in 2017.[310] Figure 8-6 shows the total RGGI emissions for each compliance year compared with the RGGI cap.

[309] State of Maine, "2018 Long-Term Contract RFP, Docket No. 2018-00137," (July 24, 2018), https://www.maine.gov/mpuc/electricity/rfps/longterm2018/index.shtml.

[310] RGGI emissions compliance data is available at the RGGI CO_2 Allowance Tracking System, https://www.rggi.org/allowance-tracking/rggi-coats, and at the EPA, Air Markets Program data website (RGGI emissions data), https://ampd.epa.gov/ampd/. RGGI, Inc., "Program Overview," webpage (n.d.), https://www.rggi.org/design/overview.

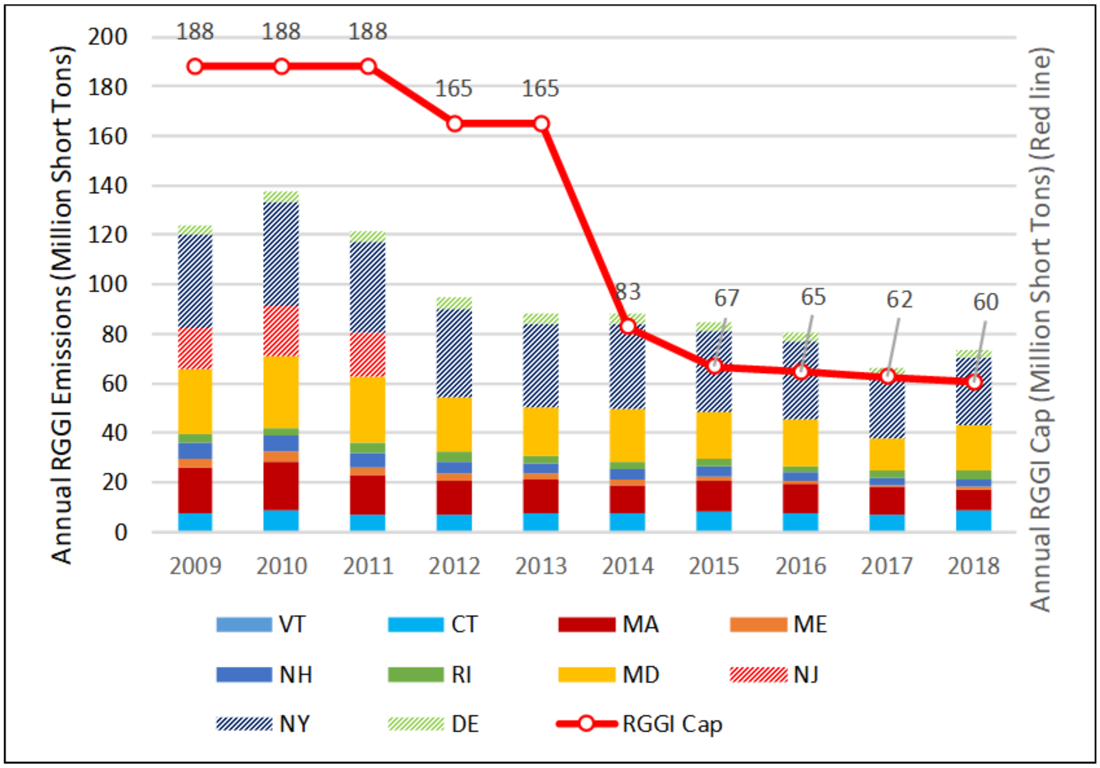

Figure 8-6: RGGI annual emissions by state compared with the annual CO_2 emissions cap, 2009 to 2018 (million short tons).

Note: New England states are shown in solid bars; other RGGI states are shown in shaded bars.

Sources: RGGI, Program Overview and Design (annual caps) (2019), https://www.rggi.org/program-overview-and-design/elements; RGGI CO_2 Allowance Tracking System (annual state RGGI emissions), https://rggi-coats.org/eats/rggi/ and at the EPA, Air Markets Program data website (RGGI emissions data), https://ampd.epa.gov/ampd/.

The greater use of lower-emitting fuels, energy efficiency, wind and photovoltaic resources, and imports from neighboring systems and added environmental controls could decrease regional power sector emissions further.

8.5.2 ISO Tracking of Emissions Trends

The ISO tracks the system emissions, rates, and trends for NO_X, SO_X, and CO_2 to help gauge the potential effects of future environmental regulations on the system and in response to requests from the states for emissions data. The ISO's most recent air emissions report, the *2017 ISO New England Electric Generator Air Emissions Report*, provides detailed historical trends and emissions rate data using methodologies developed with input from stakeholders.[311]

Air emissions from power generators are sensitive to changes in weather, economic activity, energy prices, and the fuel mix. Over the past decade, a shift in generation production, lower demand, the implementation of increasingly stringent air-quality rules within and upwind of New England, and new incentives for lower-emitting resources have all contributed to declines in New England power sector emissions. From 2007 through 2017, total system emissions decreased: NO_X by 56%, SO_2 by 96%, and CO_2 by 41%. The current emissions trends result from the regional shift away from older oil- and coal-

[311] *2017 ISO New England Electric Generator Air Emissions Report* (April 2019), https://www.iso-ne.com/static-assets/documents/2019/04/2017_emissions_report.pdf.

fired generation toward more efficient natural-gas-fired, nonemitting native renewable generation, and increasing the reliance on imports from adjacent control areas (see Section 6.7.2). Other factors that lowered emissions include the following:

- High capacity factors achieved by nuclear generators
- Growth of energy efficiency and renewable resources (i.e., wind and solar; see Sections 3.2, 3.3, and 4.5.3.1) with low or zero emissions
- More stringent environmental control requirements on new or modified fossil generators, all of which reduce the production of pollutants (Sections 8.1 and 8.2)
- Transmission improvements, which decrease the dispatch and commitment of high-polluting generators (Sections 5.4 and 5.5)

Figure 8-7 shows the regional annual emissions for New England from 2007 to 2017.

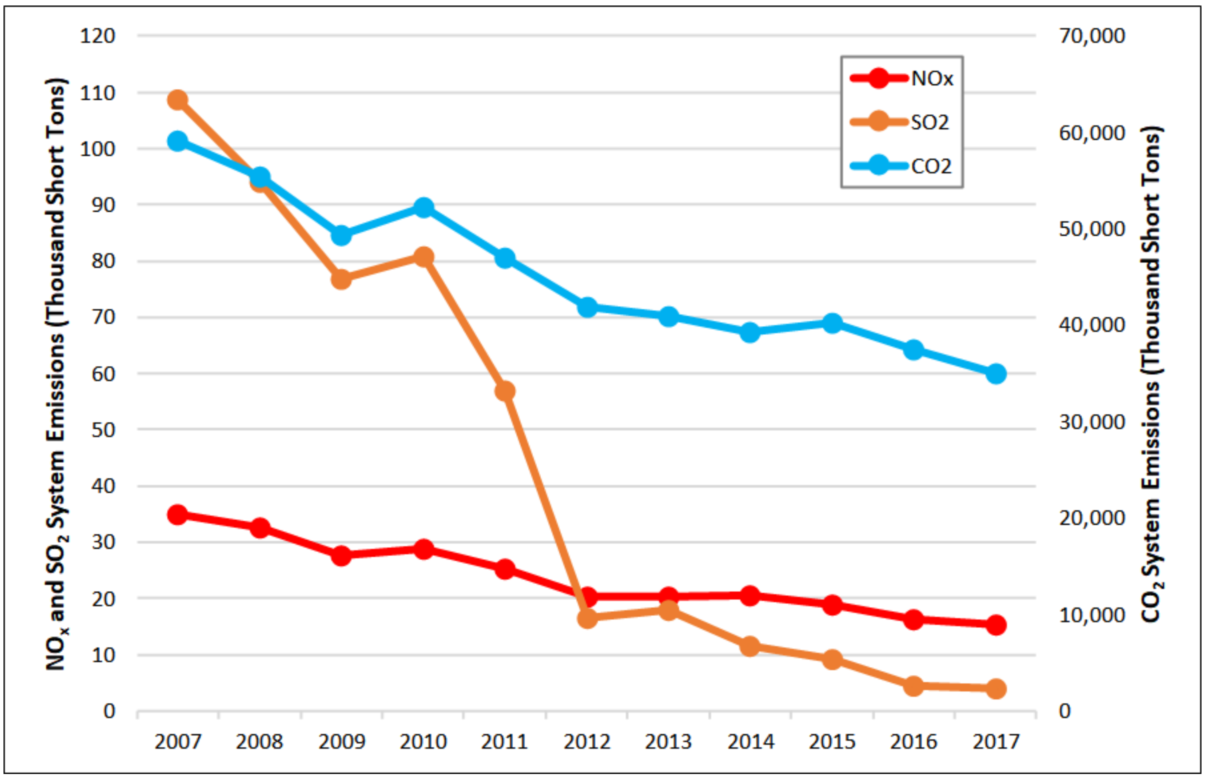

Figure 8-7: New England system annual emissions of NO_X, SO_2, and CO_2, 2007 to 2017 (thousand short tons).

Source: *2017 ISO New England Electric Generator Air Emissions Report* (April 2019), https://www.iso-ne.com/static-assets/documents/2019/04/2017_emissions_report.pdf.

From 2016 to 2017, total NO_X system emissions decreased by 6%, SO_2 system emissions decreased 11%, and CO_2 system emissions decreased 7%, while the proportion of annual energy production by fuel type remained similar. In 2017, natural-gas-fired generation's share of the annual real-time energy production declined slightly to 48% from 49% in 2016, while nuclear generation remained unchanged at 31%. Native hydro generation increased slightly to 8% compared with 7% in 2016, while the share of annual energy production for other fuel types (landfill gas, methane, refuse, solar, steam, and wood) remained at 7%. Wind's share of generation increased to 3% in 2017, compared with 2% in 2016, which marked the first time wind generation produced more energy than oil- and coal-fired generation combined in the region.

8.5.3 Cost of Compliance with Environmental Regulations

Compliance costs for generating units vary by age, economics, location, and readiness of commercially available control technologies. As the median age of the fossil generation fleet declines, existing generating units, particularly those employing advanced combustion turbines—both oil- or natural-gas-fired—reflect higher efficiencies and operate best-available pollution control technologies for air emissions and water discharges.[312] The costs across New England for CO_2 emission allowances under RGGI and the Massachusetts' *Global Warming Solutions Act* (GWSA) also promote lower systemwide CO_2 emissions by increasing operating costs for higher-emitting generators.[313] Between 2017 and 2018, emission allowance costs represented between 3% to 7% of variable fuel costs according to the ISO's internal market monitor. In 2017, RGGI CO_2 prices averaged \$3.71/metric ton, increasing to \$4.86/metric ton in 2018, while GWSA CO_2 allowance prices averaged \$8.77/metric ton in 2018.[314] Figure 8-8 highlights that CO_2 allowance costs have a relatively small impact on generation production costs and consequently do not have a noticeable impact on the economic merit order of generation.

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312 Energy Information Administration, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019* (February 26, 2019), https://www.eia.gov/outlooks/aeo/electricity_generation.php.

313 State of Massachusetts, *An Act Establishing the Global Warming Solutions Act*, 2008 acts, Chapter 298 (August 7, 2008), https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter298.

314 RGGI, *Quarterly Secondary Market Reports (2017–2018)*, https://www.rggi.org/auctions/market-monitor-reports; State of Massachusetts, "Electricity Generator Emissions Limits (310 CMR 7.74), webpage (2019), see *Massachusetts Carbon Allowance Market Monitor Reports*, https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774#massachusetts-carbon-allowance-registry-auctions.

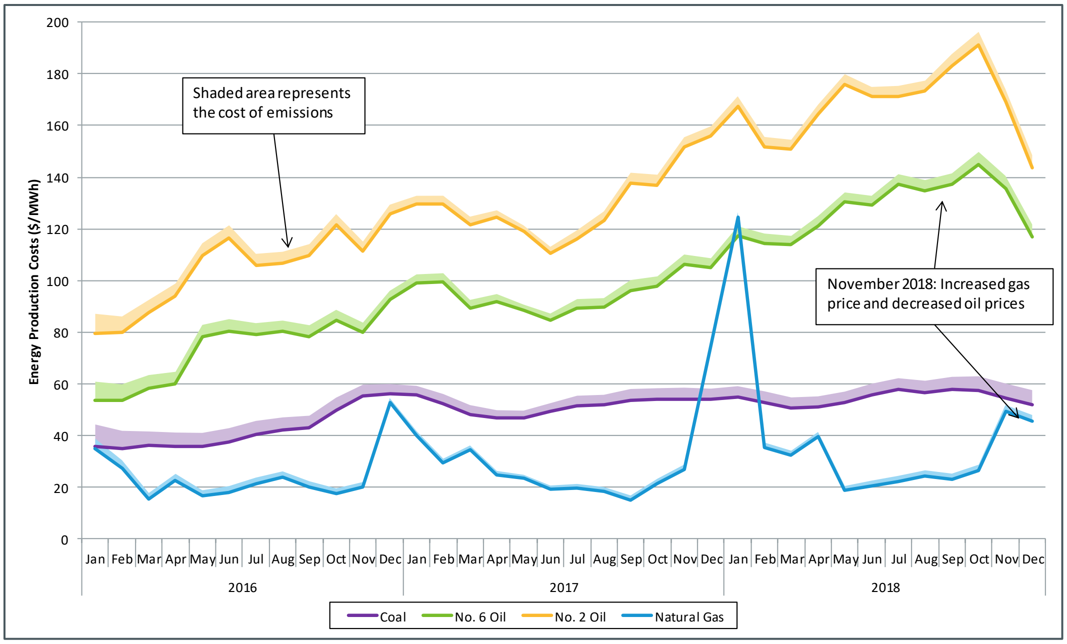

Figure 8-8: Contribution of CO_2 allowance costs to energy production costs, 2016 to 2018 ($/MWh).

Notes: The line series for each fuel category illustrates the quarterly estimated production cost using the average heat rate for generators of a representative technology type. The height of the shaded band above each line series represents the average additional energy production costs attributable to CO_2 emissions allowance costs in each category. The standard efficiency heat rates (MMBtu/MWh) used in the graph are as follows: natural gas, 7.8; no. 6 oil, 10.2; no. 2 oil, 11.7.

Source: ISO New England*, Greenhouse Gas Regulatory Update*, Environmental Advisory Group presentation (January 29, 2019), slide 14, https://www.iso-ne.com/static-assets/documents/2019/01/ghgupdate_20190129.pdf.

8.6 Update of Regional Nuclear Generation Licensing Renewals

Nuclear generation includes 3,335 MW, or 11%, of the regional summer claimed capability and produced 31,384 GWh, or 30%, of all native generation in 2018.[315] All remaining nuclear generators require an operating license, which is subject to renewals or extensions, as summarized in Table 8-3.

Table 8-3
New England Operating Nuclear Power Plants

Unit Name	Operating (OP)/ Renewed License Dates	License Expiration Date	Reactor Type	Summer Peak (MW)[(a)]	Reactor Vendor/Type
Millstone 2	September 26, 1975/ November 28, 2005	July 31, 2035	Pressurized water	859	Combustion Engineering (vendor)
Millstone 3	January 31, 1986/ November 28, 2005	November 25, 2045	Pressurized water	1,225	Westinghouse/ four-loop
Seabrook	OP: March 15, 1990	March 15, 2030	Pressurized water	1,251	Westinghouse/ four-loop

(a) Operating license information from the Nuclear Regulatory Commission's (NRC) website, http://www.nrc.gov/info-finder/reactor/. Summer peak (seasonal claimed capability) megawatts from ISO New England, 2019 CELT Report, Tab 2.1, "Generator List with Existing and Expected SCC" (showing the seasonal rating of generating units).

[315] Avoided CO_2 emissions from native nuclear generation in 2018 are estimated to be approximately 9.7 million metric tons based on average system CO_2 emission rate of approximately 309 kilograms/MWh.

The Nuclear Regulatory Commission's Continued Storage Rule revised the general environmental impacts of spent nuclear fuel storage operations at closed reactor sites nationwide, including 11 sites in New England.[316]

8.7 Update on Hydroelectric Generation Relicensing

Conventional hydroelectric generators are among the oldest generators on the system, which include 1,434 MW, or 4.6%, of the regional summer claimed capability and represent 8,710 GWh, or 8.4%, of all native generation in 2018.[317] In addition to providing capacity and electric energy, hydroelectric units traditionally have been well suited to provide regulation and reserves. However, whether, and to what extent, their relicensing requirements have an impact on changes to their operating flexibility is unclear.

The licenses for approximately 2,361 MW of existing hydroelectric generators, including 1,172 MW of pumped-storage capacity, will expire between 2019 and 2025.[318] FERC is pursuing an integrated relicensing review for several hydroelectric projects located on the Connecticut River, which is ongoing.[319] Relicensing must take into consideration the requirements for adequately and equitably protecting and mitigating damage to fish and wildlife (and their habitats) and historic resources based on the recommendations and input of relevant state and federal fish and wildlife and historic-preservation entities. The ISO is monitoring such proceedings to assess the impacts of operational restrictions, including the maintenance of minimum flows without bypass turbines or spillage (i.e., water allowed to pass through the dam without generating electricity), on the ability of hydroelectric generators to offer regulation and reserve services.

8.8 Conclusions

Existing and pending federal and state environmental regulations and multistate initiatives may require generators to consider adding air pollution control devices; modifying or reducing water use and wastewater discharges; and, in some cases, limiting operations. The actual compliance timelines and costs will depend on the timing and substance of the final regulations and site-specific circumstances of the electric generating facilities. Based on these and other economic factors, some generator owners may determine certain resources are uneconomical and retire their facilities instead of making major investments in environmental compliance measures.

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[316] The rule assessed the environmental effects of storing spent nuclear fuel at a reactor site for various periods following the reactor's licensed life for operation, allowing dry cask storage of spent nuclear fuel at reactor sites. NRC, *Continued Storage of Spent Nuclear Fuel*, final rule, 79 Fed. Reg. 56238 (September 19, 2014).

[317] ISO New England, 2019 CELT Report, Tab 2.1, "Generator List with Existing and Expected SCC" (showing the seasonal rating of generating units), https://www.iso-ne.com/static-assets/documents/2019/04/2019_celt_report.xls. Also see: "2019 Daily Generation by Fuel Type," webpage (2019), https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type.

[318] FERC issues initial and renewal hydroelectric project licenses for 30 to 50 years typically, although it may issue temporary annual licenses to continue an expired license during a relicensing review. Refer to: FERC, "Pending Licenses, Relicenses and Exemptions," spreadsheet (August 22, 2019), https://www.ferc.gov/industries/hydropower/gen-info/licensing/pending-lre.xls; and "Active Licenses," spreadsheet (August 13, 2019), https://www.ferc.gov/industries/hydropower/gen-info/licensing/pending-lre.xls.

[319] FERC issued revised schedules for remaining field work, consultation, and analyses studies required for amended license applications through most of 2019. FERC, *Revised Process Plan and Schedule—Wilder, Bellows Falls, and Vernon Hydroelectric Projects* (February 15, 2018), https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14822954; *Modification to Integrated Licensing Process Schedule, TransCanada Hydro Northeast, Inc., and Firstlight Hydro Generating Company* (December 21, 2012), https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13140524; Connecticut River Joint Commission, *Relicensing of Connecticut River Dams* (accessed March 8, 2019).

All the New England states have Renewable Portfolio Standard targets for the amount of electric energy load-serving entities provide by renewable resources; individual state targets for 2020 range from requiring LSEs to provide 10% to 59% of the energy they procure from renewable resources, which has driven new proposals for renewable energy. Some of the states also have issued requests for proposals for renewables development. The increased use of various types and amounts of renewable resources may require operational modifications or retrofits, resulting in additional environmental compliance costs. Additionally, the units are likely to experience higher operations and maintenance costs.

The New England states also take part in the Regional Greenhouse Gas Initiative for limiting carbon dioxide emissions by power plants and other emission-reduction efforts. Regional generator air emissions remain relatively low compared with historical levels, due to the generation fuel mix, including—in order of percentage share of 2017 annual energy production—native natural gas, nuclear, hydro, wind, other fuel type (landfill gas, methane, refuse, solar, steam and wood), oil, and coal. Higher emissions, however, occur during the winter months because of the burning of oil by generators when natural gas is more expensive or in limited supply. The retirement of nuclear units would tend to increase regional emissions, but the addition of low- or zero-emitting resources would tend to reduce longer-term emissions. A combination of thermal generator retirements and the decreased use of remaining fossil thermal capacity has decreased water use and consumption for power generation compared with historical levels.

Section 9
Grid Transformation

Environmental laws, regulations and policies; economics; and a desire for grid resiliency continue transforming the electric power grid into one where renewable resources provide increasing amounts of electric energy (see Sections 3.3 and 4.5.3.1). A longer-term method for decreasing overall carbon dioxide emissions couples the growth of renewable electric energy supplies with the electrification of the transportation and heating sectors. With the continued decline in the capital costs for renewable resources, technological innovations have been facilitating the integration of large amounts of variable energy resources (VERs) (wind and photovoltaics) and energy storage. Additionally, high-voltage direct-current (HVDC) and flexible alternating-current transmission system (FACTS) devices are helping increase transmission system transfer limits and enabling renewable resource development.[320] This large-scale development of inverter-based technologies, however, is adding complexity to planning and operating the power system.

To address these challenges, the ISO has been conducting a number of studies, gathering operational data and observations, and participating in projects assessing the development and integration of variable energy resources and other aspects of transformation to an AC/DC network.

9.1 A Changing Grid

To meet the region's environmental goals, the New England states have individually and collectively established targets for renewable energy and energy efficiency. As a result, the use of inverter-based technologies and energy efficiency has grown rapidly and is transforming the New England power grid.

9.1.1 Government Policies Changing the Grid

As discussed in Section 8.3, the New England states' Renewable Portfolio Standard targets and related policies are driving new proposals for renewable energy, a trend expected to continue to the middle of the century. In addition to RPSs, the states' goals for reducing greenhouse gas emissions are encouraging the development of EE and PV and are regulating emissions from larger-scale electric power plants. The states also have individually and collectively issued a number of RFPs for more than 5,000 MW of clean energy resources and an HVDC interconnection to deliver Canadian hydro power (see Section 10.2). Additionally, the states work cooperatively on regional electricity matters when they have common objectives (Section 10.1).

9.1.2 The Growth of Inverter-Based Technologies and Distributed Resources

The ISO anticipates the widespread growth of inverter-based technologies, as noted throughout RSP19, including, wind generation, photovoltaics, HVDC, and battery energy-storage systems, which have the physical capability to act as generators, demand, or both. In addition, inverter-based applications of FACTS devices are expected to grow in New England as a means of providing dynamic voltage support. As shown in Section 4.5.3, Figure 4-4), the ISO interconnection queue includes 15,767 MW of total wind, solar, and battery resources, proposed as follows:

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[320] According to the Institute of Electrical and Electronics Engineers (IEEE), *flexible alternating-current transmission systems* incorporate power-electronics-based controllers and other static controllers to enhance controllability and power-transfer capability in power systems. See the IEEE's Power and Energy Society's webpage: http://www.ieee-pes.org/nari-hingorani-facts-award.

- **Wind—**11,316 MW (nameplate), comprising 59.4% of resources in the ISO's queue
- **Solar—**An additional 3,070 MW (nameplate) of large-scale PV generation (16.1% of the queue), with the PV forecast showing a total of 6,744 MW (nameplate under 5 MW) developing by 2028 (see Section 3.3.1)
- **Battery energy-storage systems—**1,381 MW (nameplate) slated for regional development

As of June 1, 2019, 17 HVDC projects are under study as ETUs, and three have received approval for their proposed plan applications. Since RSP17, one static synchronous compensator (STATCOM) rated −/+ 200 MVAR and one +50 MVAR/−25 MVAR static VAR compensator (SVC) have been installed to provide dynamic support to the transmission system (see Sections 5.4 and 5.5).

The increased development of VERs and distributed resources (which includes reductions in demand resulting from energy efficiency), and more imports from neighboring systems (both AC and DC) would decrease the extent that large fossil-fired generation served demand at any given time. In addition to reducing the region's dependence on fossil fuels, the growth of inverter-based technologies and distributed resources lowers emissions, encourages broader markets by providing more elastic price signals, and improves system resiliency.

9.2 Issues with Transformation of the Grid

The transition to the grid of the future, however, represents a major change in the electric power industry that affects its overarching structure, physical operation, and planning. Variable energy resources' dependence on weather to produce energy, coupled with the ISO's inability to directly observe or control most distributed-resource outputs, adds complexity for planning and operating the system holistically. But system models and analyses must accurately address these uncertainties, and the ISO must understand demand projections and variable- and distributed-resource outputs, as well as the state of the power system overall, for meeting planning and operating objectives, managing risks, and administrating the wholesale power markets. System security would need to be improved as well by better coordinating the planning and operations of transmission and distribution (T&D) systems where flows are likely to become more variable.

The ISO has already experienced the "duck curve" as a result of the growth of PV, meaning that system demand net of EE and all PV is lower during daylight, sunny hours resulting from PV production.[321] The midday drop in this "demand curve net of VERs" resembles the "belly" of a duck, the decrease in the curve after dawn represents the tail, and the demand increase at dusk shows the head. As shown in the Figure **9-1** duck curve, minimum daily demand net of VERS were experienced in the afternoon of April 21, 2018. The figure also shows the effect that increased PV development could have on the load shapes for typical summer and winter peak days based on the demand shapes of July 19, 2013, and January 7, 2014, respectively. PV reduces the summer peak net of VERs and reduces energy consumption net of VERs in both summer and winter, which could reduce the need for natural gas consumption by generating units. Summer peaks net of VERs would occur later in the day and exhibit a long increase in demand up to the peak. Winter operating periods display increased variability resulting from peak demand occurring after the sun has set, during snow cover, and when weather patterns change rapidly. For example, changes in snow cover could result in significant changes in the shapes of day-to-day demand net of VERs.

[321] "All PV" accounts for behind-the-meter PV, FCM PV, and non-FCM PV.

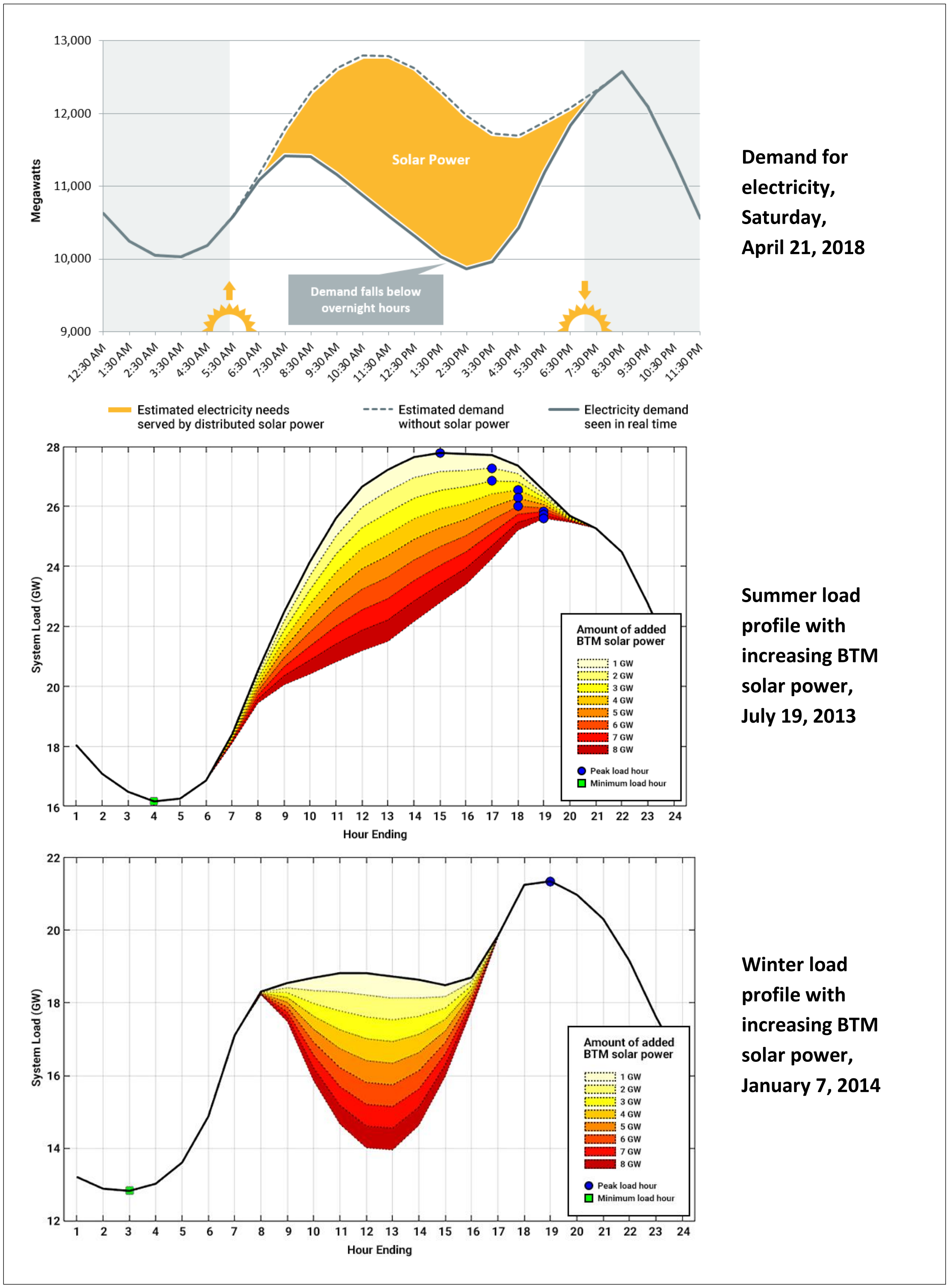

Figure 9-1: Shapes of net demand on spring, summer, and winter peak days for varying levels of all PV.

Note: *Hour ending* (HE) denotes the preceding hourly time period. For example, 12:01 a.m. to 1:00 a.m. is hour ending 1. Hour ending 6:00 p.m. is the time period from 5:01 p.m. to 6:00 p.m.

While less subject to change than PV, wind resource outputs also vary with the weather. Extraordinarily high or low wind speeds can result in reducing wind turbine outputs to 0 MW. The net variability in gross demand, demand response, PV output, and wind resource output could create issues for meeting system requirements for ancillary services of ramping, regulation, reserves, and voltage control. Gas-fired generating units may be limited in providing these services because scheduling natural gas fuel supplies can lack flexibility. The overall decreased operation of fossil fuel generators calls for new ways to provide vital ancillary services. The variations in system strength (short-circuit levels), especially in areas and during periods with fewer synchronous machines operating on the system, highlight the need for system-protection upgrades (called adaptive protection) and other capital improvements. These improvements include those that allow for two-way power flows on the distribution system, an operating mode for which it was not originally designed.

The anticipated increase in demand due to the electrification of the transportation and other sectors (see Section 8.2.2) and the state policy preferences for increasing renewable resources, including DERs, to meet the growing demand exacerbates the issues of observability, controllability, and cybersecurity. As these electrification initiatives take hold, more and more consumers (i.e., prosumers) are anticipated to respond to price signals and other incentives or disincentives, especially at the retail level, with ever-varying levels of consumption.

9.3 ISO Analyses of the Economic Performance of the System and Other Studies

Economic studies provide metrics depicting various system-expansion scenarios and the advantages and challenges associated with selected possible future scenarios based on stakeholder assumptions. These scenarios generally assess system performance at a higher, less-detailed level, such as possible additional imports from Canada, resource retirements, and resource additions, but they do not assess the performance of individual asset owners or provide detailed transmission system plans. The key metrics developed include estimates of production costs, transmission congestion, electric energy costs for New England consumers, and a number of others. These metrics suggest the most economical locations for resource development and the least economical locations for resource retirements. The economic studies also framed many of the key issues that New England would need to address for the large-scale development of variable energy resources.

9.3.1 2016 Economic Study—Phase I

Phase I of the 2016 ISO New England Economic Study was conducted at the request of the New England Power Pool. The study, *2016 NEPOOL Scenario Analysis—Implications of Public Policy on ISO New England Market Design, System Reliability and Operability, Resource Costs and Revenues, and Emissions*, examined six resource-expansion scenarios of the regional power system and provides information about the potential effects of these different future changes on resource adequacy, operating and capital costs, and options for meeting environmental policy goals.[322] The results of the study were presented such that stakeholders can make their own assumptions on capital costs for new resources and transmission development costs, which were considerably higher for developing resources further from the Hub. Some of the major results and conclusions related to grid transformation are as follows:

- Transitioning New England to a system with decreasing amounts of traditional resources (e.g., coal, oil, nuclear) and increasing amounts of renewable resources will prove physically and

[322] ISO New England, *2016 Economic Study: NEPOOL Scenario Analysis Report: Implications of Public Policies on ISO New England Market Design, System Reliability and Operability, Resource Costs and Revenues, and Emissions* (November 20, 2017), https://www.iso-ne.com/static-assets/documents/2017/11/final_2016_phase1_nepool_scenario_analysis_economic_study.docx.

economically challenging.[323] The large-scale development of renewable resources reduces energy prices, which affects the economic viability of resources. Observability, controllability, and interconnection performance are key technical issues that must be addressed for distributed resources and the large-scale development of wind generation resources.

- Efficient storage technologies, such as pumped storage and distributed storage, and changes in tie schedules can provide systemwide flexibility and facilitate the integration of variable resources. Well-sized and placed resources of various types show the potential for relieving congestion and meeting requirements for regulation, ramping, and reserves. Increasing the development of energy-storage technologies used for energy-price arbitrage makes them less economic because storage equalizes LMPs across all hours.
- The large-scale development of inverter-based technologies will require the addition of special controls on power system resources and new transmission equipment, especially to compensate for the loss of traditional resources that provide inertia and short-circuit availability. The needs are exacerbated by the changing nature of demand, especially the large-scale use of energy-efficiency measures, which further increases the complexity of operating and planning the system by increasing exposure to light load conditions.[324]
- Advanced software will facilitate future analysis of the system, especially to conduct probabilistic simulations that consider variable energy resource production.

9.3.2 2016 Economic Study—Phase II

Supplemental studies of the Phase I NEPOOL Scenario Analysis assessed several market and operational issues. For each of the Phase I scenarios, the Phase II Scenario Analysis examined the following:

- Representative Forward Capacity Auction clearing prices
- The ability of the natural gas system to supply fuel to generators
- Changes in the amounts of regulation, ramping, and reserves

The FCA analysis considered energy market revenues from the Phase I simulations and then determined FCA clearing prices and revenues consistent with market rules. Because resources could retire and develop in the intervening years, the FCA pricing results do not capture the effect of transitions in the resource mix. All resources in the scenarios were considered "existing resources," and the results provide relative FCA clearing prices across scenarios rather than absolute FCA prices.[325]

All scenarios showed the need for additional revenue streams outside the wholesale electricity markets for capacity and energy. Scenarios that added renewables resulted in the greatest revenue shortfalls for

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[323] As part of the 2016 Economic Study, the ISO met with the PAC to discuss many of the challenges of integrating renewable resources. EPRI, *Grid Impacts and Challenges Arising from the Integration of Inverter-Based Variable Resources,* PAC presentation (October 19, 2016), https://www.iso-ne.com/static-assets/documents/2016/10/a3_integration_and_planning_of_large_amounts_of_inverter_based_resources.pptx.

[324] Light load conditions can present high-voltage issues and trigger overgeneration situations.

[325] Analysis Group, *Capacity Market Impacts and Implications of Alternative Resource Expansion Scenarios: An Element of the ISO New England 2016 Economic Analysis* (July 3, 2017), https://www.iso-ne.com/static-assets/documents/2017/07/final_analysis_group_2016_economic_analysis_capacity_market_impacts.pdf.

all resource types given the higher cost of new entry for renewables and depressed energy market revenues.

The second Phase II study examined natural gas system deliverability issues by considering six scenarios for natural gas supply to the region compared with the seasonal fuel requirements of natural-gas-fired generation, recognizing that the local gas distribution company loads must be served first.[326] The study concluded the region will need to rely on the large-scale addition of energy efficiency and resources that use fuels other than natural gas, such as renewable resources, to supplement the natural gas supply to meet electric power system energy needs during the winter operating season.

The third Phase II study examined intrahour ramping, regulation, and reserve requirements of the system for the six scenarios. The requirements were quantified through simulation results of each of the scenarios with higher levels of variable energy resources.[327] The results show the following:

- Beyond the load-following and ramping reserves provided by dispatchable resources, curtailment of semidispatchable resources becomes an integral part of balancing performance for the study scenarios.[328]
- Scenarios with greater penetrations of solar and wind generation exhibit systematically higher forecast errors (of demand net of VERs). In the absence of immediate improvements in forecasting technology, these imbalances are mitigated by greater quantities of operating reserves.
- The commitment of dispatchable resources and their associated quantities of committed load-following and ramping reserves has a complex, difficult-to-predict, and nonlinear dependence on the amount of variable resources and the load profile statistics.
- Higher quantities of load-following and ramping reserves dispatched in real time improves balancing performance. Curtailment also directly supports the balancing role of load-following and ramping reserves.
- The combination of curtailment of semidispatchable resources and the commitment of dispatchable resources within each RSP zone serves to respect interface constraints.

9.3.3 2017 Economic Study

The *Exploration of Least-Cost Emissions-Compliant Scenarios of the 2017 ISO New England Economic Study* examined several low-carbon-emitting resource-expansion scenarios of the regional power system and the potential effects of these different future changes on resource adequacy, operating and capital costs, and options for meeting environmental policy goals. The study examined three combinations of large-scale renewable wind, PV, and EE resources, as well as plug-in electric vehicles and distributed storage

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[326] ISO New England, *2016 Economic Study Results: Peak-Gas-Day/Hour Capacity and Energy Analysis*, PAC presentation (May 25, 2017), https://www.iso-ne.com/static-assets/documents/2017/08/a3_2016_economic_study_natural_gas_capacity_and_energy_analysis_rev1.pdf.

[327] ISO New England, *2016 Economic Phase II Study—Regulation, Ramping, and Reserve*, PAC presentation (December 20, 2017), https://www.iso-ne.com/static-assets/documents/2017/12/a2_2016_economic_study_phase_2_regulation_ramping_reserves_introduction.pdf; and Amro Farid, *2016 Economic Study Phase II: Regulation, Ramping, and Reserves—Scenario Results* (Thayer School of Engineering, Dartmouth College, December 20, 2017), https://www.iso-ne.com/static-assets/documents/2017/12/a2_2016_economic_study_phase_2_ramping_regulation_reservers_scenario_results.pdf.

[328] Semidispatchable resources reduce output to respect system constraints by *spilling* wind or sun but cannot increase output because they normally use all available wind and sun for energy production. Spilled renewables can include imports from Canada, hydro, wind, and photovoltaics.

that built on the 2016 Economic Study. The results generally supported the results of Phase I of the 2016 Economic Study and also showed that regional carbon-reduction obligations may require flexible compliance options (such as proposed by the Regional Greenhouse Gas Initiative; see Section 8.2.1), additional imports from neighboring systems, and the large-scale development of energy efficiency and renewable resources.

9.3.4 2018 Economic Study Request

Although the ISO did not receive a 2018 Economic Study request, it did analyze the potential impacts of offshore wind additions in New England during the 2017/2018 cold spell using assumptions provided by the Massachusetts Clean Energy Center, as described in Section 7.6. The results showed that offshore wind connections to the load centers in southern New England are well situated and that offshore wind production during the 2017/2018 cold spell would have reduced production costs, environmental emissions, fossil fuel consumption by generating units, and LMPs.

9.3.5 2019 Economic Study Requests

The ISO received three requests in 2019 for economic studies:[329]

- NESCOE requested analysis of offshore wind scenarios of 1,000 MW, 2,000 MW, 4,000 MW, 5,000 MW, and 7,000 MW. In addition to asking the ISO to provide metrics similar to Phase I of the 2016 Economic Study, NESCOE requested results showing more detailed information on favorable interconnection points and costs, capacity benefits, and ancillary service requirements.
- Anbaric Development Partners requested an update of the 2015 Economic Study and offshore wind scenarios of 8,000 MW, 10,000 MW, and 12,000 MW. Requested metrics include energy market prices, environmental emissions, and impacts on fuel security for a winter 2014/2015 load shape.
- RENEW Northeast requested analysis of the Orrington-South interface in Maine, where the transfer limit varies with the status of generation and transmission facilities being in or out of service.

9.4 Industry Solutions for Facilitating the Approaches to Grid Transformation

The response to system events by inverter-based technologies must be understood and reflected in planning and operating studies, including voltage and frequency ride-through characteristics, control system responses and interactions with other devices, and variations resulting from changes in system strength (short-circuit levels, especially during times and in areas with fewer synchronous machines operating on the system).

Lead researchers and analysts in the electric power industry have issued white papers, performed considerable analysis, and conducted studies that quantify the extent of grid-transformation issues and

[329] Anbaric, "2019 ISO New England Economic Study Request for Offshore Wind Impacts," (April 1, 2019), https://www.iso-ne.com/static-assets/documents/2019/04/anbaric_2019_economic_study_request.pdf; NESCOE, "Request for 2019 Economic Study to Analyze Offshore Wind Integration," (April 1, 2019), https://www.iso-ne.com/static-assets/documents/2019/04/nescoe_2019_economic_study_request.pdf; and RENEW, "2019 Economic Study Request: Economic Impact of Targeted Upgrades to the Orrington-South Interface Limit,"(April 1, 2019), https://www.iso-ne.com/static-assets/documents/2019/04/renew_2019_economic_study_request.pdf. Also see: ISO New England, *2019 Economic Studies—Draft Scope of Work and High-Level Assumptions*, PAC presentation (May 21, 2019), https://www.iso-ne.com/static-assets/documents/2019/05/a2_2019_economic_study_draft_scope_of_work_and_high_level_assumptions.pptx.

have postulated best practices that facilitate the successful integration of inverter-based technologies and demand resources. While not comprehensive, this section summarizes several of the best practices identified by DOE national laboratories, EIPC, the Electric Power Research Institute (EPRI), the Institute of Electrical and Electronics Engineers (IEEE), the International Council on Large Electric Systems (CIGRE), and the Power System Engineering Research Center (PSERC).[330]

9.4.1 Improved Forecasting

Modern forecasting methods improve the accuracy of projecting energy production by wind and PV resources and demand consumption, including by plug-in electric vehicles. However, large penetrations of distributed energy resources and demand response requires more sophisticated measures for ascertaining situational awareness needed for operating and planning the system. Direct measurements, such as smart meters and microphasor measurement units on the distribution system, and indirect measurements, such as artificial intelligence and statistics to establish the most likely state of the system, can be used alone or in combination to address observability. State-estimation techniques use a limited number of system measurements to determine key system quantities.

9.4.2 Integration of Variable Energy Resources

The US Department of Energy's National Renewable Energy Laboratory (NREL) develops data and tools for analyzing wind and PV resources, and the national labs perform studies that can be used to identify key integration issues. For example, NREL's publicly available information can be used to determine the locations for developing variable energy resources that would be expected to have high energy outputs based on historical levels of wind and irradiance. The values can also be used to align variable energy resource outputs with historical load shapes that would be suitable for conducting studies.

NREL also conducted a number of scenario analyses to identify the effects that high amounts of wind and PV resources would have on the power system.[331] The studies showed that VER development would reduce system energy costs and emissions. However, the large-scale addition of wind and solar resources would require fossil-fueled generators to ramp up and ramp down more frequently, which could increase unit emissions and degrade their reliability. Studies also showed that considerable transmission development would be required for integrating remote wind resources. These types of studies frame issues that must be addressed when other entities conduct studies of their own systems.

A number of industry studies by NERC and EIPC have quantified the amounts of ancillary services that would be needed for different scenarios of grid development and how these services could be provided. (see Sections 6.2 and 6.3). With ongoing research and studies by DOE, results suggest that implementing specific types of controls for VERs and demand and the continued reliance on fossil-fueled resources can all help meet system needs. For example, wind resources can decrease the magnitude of the drop in system frequency and the duration of the low-frequency system response resulting from the sudden loss of large generating units. Both wind and PV resources can provide "down" operating reserves in response to overgeneration situations. They also can provide "up" reserves if they initially operate at lower outputs than physically possible based on the availability of wind or sun, but this could require market reforms

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[330] For additional information on these entities refer to the following: DOE NREL, https://www.nrel.gov/; EIPC, https://eipconline.com/; EPRI, http://www.epri.com/; IEEE, http://www.ieee.org/index.html; CIGRE, https://www.cigre.org/; and PSERC, http://www.pserc.wisc.edu/home/index.aspx.

[331] NREL, *2018 Standard Scenarios Report: A U.S. Electricity Sector Outlook* (November 2018), https://www.nrel.gov/docs/fy19osti/71913.pdf; "Standard Scenarios," webpage (n.d.), https://www.nrel.gov/analysis/standard-scenarios.html; and *The Western Wind and Solar Integration Study Phase 2* (September 2013), https://www.nrel.gov/docs/fy13osti/55588.pdf.

that would pay more for these ancillary services than for providing energy. Fossil-fueled generators provide ancillary services and system inertia, which improves system stability performance. Demand response delivers needed flexibility to the system, and it can assist in meeting ramping and reserve requirements. Several power systems worldwide have adopted many of these practices to achieve higher penetrations of variable energy resources.

Several technical papers show that demand resources can provide frequency response. For example, heating and ventilation systems using variable-frequency drive systems can be modified at little cost to improve the overall frequency response of the system. The technical literature also discusses how the broad and rapid adoption of internet-connected devices holds promise for using demand to improve the overall security and economic performance of the system, such as by providing price response or allowing direct control by a system operator.[332] The industry recognizes and is addressing the cybersecurity issues surrounding the increased reliance on distributed resources.

"Smart-inverter" applications to DERs provide dynamic voltage support and may offer other ancillary control options. DOE and EPRI studies show that smart inverters increase hosting capacity of DERs, improve power quality, provide voltage regulation, and exhibit synergies with bulk power system operations that increase transmission system transfer limits, which allows for greater production by wind generators. Advanced smart inverters that can facilitate network operations under conditions of low inertia and provide blackstart capability are in the early stages of development and application. Work is ongoing by grid operators, equipment owners, manufacturers, and policymakers. Although smart inverters have been implemented worldwide, they may present several barriers that must be overcome, including liability issues, longer interconnection study times, the need for system protection improvements, and the promulgation of policies and procedures that improve safety and system performance.

9.4.3 Microgrids

Microgrids meet resiliency and reliability needs by effectively providing an uninterruptable power supply to critical loads.[333] They may also improve environmental performance by facilitating renewable resource integration, such as photovoltaics and combined heat and power plants. Microgrids afford opportunities for economically delivering energy, capacity, and ancillary services to their demand, but in most installations they feature the ability to interchange power with the local grid. A number of microgrids have been installed, such as the one at the Philadelphia Navy Yard, and technical work continues to facilitate their development.[334]

9.4.4 Energy Storage

Energy storage can mitigate overall system variability and improve the use and economics of the T&D systems by shaving peaks and increasing valleys of net demand. However, the more storage added to

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[332] The architecture of the grid remains an open issue for assigning control responsibility to the distribution system operator, transmission system operator, or both.

[333] A *critical load* must have reliable service and is usually restored as early as possible during system restoration. Examples include police and fire stations, emergency shelters, healthcare facilities, pharmacies, grocery stores, gas stations, and the like.

[334] David J. Smith, "Philadelphia Navy Yard Advanced Microgrid," IDEA 2015 infographic presentation, Boston, MA (The Burns Group, June 29, 2015), http://www.burns-group.com/wp-content/uploads/2016/10/The_Navy_Yard_Advanced_Microgrid_IDEA_2015.pdf.

system, the less economical it may become for providing energy arbitrage in the energy markets as a result of reduced differences between peak and off-peak prices of electricity.

Energy can be stored in a variety of ways, such as by using water and temperature variations, compressed air, flywheels, and batteries. Water storage has long been used at pumped-storage plants and at hydroelectric plants that have peaking and ponding capabilities.[335] Smart thermostats can vary temperatures used to heat and cool environments and processes. Creating hydrogen as a fuel using renewable energy is another technology for storing energy. In addition, varying the time of operation of water pumps and agitators in water treatment plants provides an opportunity to shift load and provide demand response.

Battery and other types of energy-storage systems can provide rapid electrical responses and improve distribution system performance and hosting capacity of DERs, provide resource capacity, deliver ancillary services (e.g., regulation, ramping, reserves, and voltage control), increase transmission system capacity and flexibility of response, enhance power plant efficiencies, and provide blackstart.[336] Storage can be a critical component of microgrids. Collocating these systems with PV or wind resources can decrease the net variability of output, reduce the amount of spilled resources (i.e., the output that must be curtailed to respect system constraints), and improve the overall reliable and economic performance of the VER. Storage, however, consumes more energy than it can provide, and limitations of the extent of energy that can be stored may limit applications.

9.4.5 Other Effects

The overall structure of the electric power system will need to change, especially to improve coordination between the T&D systems. Pacific Northwest National Laboratory has performed considerable work on developing grid architectures that consider regulatory structures, markets, control performance, stakeholder inputs, and a variety of other issues. One structure, sometimes referred to as the *hybrid grid*, has large generators and other power resources connected to the regional transmission system in combination with thousands of small resources connected behind-the-meter directly to retail customer sites or local distribution utilities. The transmission system operator optimizes the use of the overall power system, including the dispatch of all wholesale DER services, but has no visibility into the distribution system. The structure includes a distribution system operator (DSO) who optimizes the dispatch of the distribution system and provides system information needed by the transmission system operator. This is because distribution utilities and local customers must address issues posed by VER integration on the distribution system, such as voltage regulation and power quality, and may need to apply local storage and grid-transformation technologies to improve electrical performance. The hybrid grid model also includes customer aggregators who coordinate with both the transmission system operator and the DSO.

The variability of the system state, including power flows and voltages, requires new methods of analyzing the system and assessing system security. Physical system improvements would also be required, including those that provide situational awareness, allow for flexible system responses, and

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[335] With regard to hydroelectric plants, "peaking" usually applies to daily storage and "ponding' applies to storage for longer periods, such as on weekends, for seasons, and even for multiyear periods, as is the case with many facilities in Hydro-Québec.

[336] *Blackstart* generating units can start up without an outside electricity supply, generally by using batteries or compressed air.

accommodate distribution power flows that could feed or draw from the transmission system.[337] The variability in power flows and short-circuit availability requires the use of adaptive protection and control systems. Transmission additions that connect VERs over wide areas can also mitigate the need for systemwide flexibility and ancillary services because different weather conditions decrease the variability of the total production of wind and PV.[338]

9.4.6 Research Participation and Technical Support

The ISO strives to keep up to date with new technologies that can have an impact on the region's electric power grid. As policymakers set targets and allocate public funds for developing smart grid initiatives and renewable resource generation, the ISO analyzes the effects of these technologies on system operations and reliability.[339]

The ISO currently participates in several research projects sponsored by DOE, PSERC, and EPRI that support the successful integration of advanced technologies. Additionally, the ISO is providing technical and other support for the development of demand-response-related and other market-related standards by the North American Energy Standards Board (NAESB).[340] The ISO staff and stakeholders remain professionally active in IEEE, a society that, among other functions, develops standards for the interconnection and operation of smart grid technologies.[341]

9.5 IEEE 1547 Standard for Interconnecting Distributed Energy Resources

IEEE Standard 1547, *Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces,* establishes criteria and requirements for the interconnection of distributed resources with electric power systems.[342] This document provides a uniform standard for the performance, operation, testing, safety considerations, and maintenance of the interconnection. Its requirements apply to interconnections of DERs, including synchronous machines, induction machines, and power inverters/converters. The criteria and requirements are applicable to all DER technologies interconnected to electric power systems at typical primary and secondary distribution voltages.

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[337] Power traditionally flowed from the transmission system to distribution system.

[338] Dale Osborn, *ARPA-E Transmission Planning,* presentation (MISO, September 29, 2016), https://arpa-e.energy.gov/sites/default/files/ARPA-E%20Dale%20Osborn.pdf, and *HVDC for DOE*, presentation (September 28, 2016), https://www.energy.gov/sites/prod/files/2016/10/f33/2_HVDC%20Panel%20-%20Dale%20Osborn%2C%20MISO.pdf.

[339] Grid transformation encompasses smart grid technologies. IEEE describes the *smart grid* as a "next-generation" electrical power system that typically employs the increased use of communications and information technologies for generating, delivering, and consuming electrical energy. See the IEEE's "Smart Grid Community" webpage (2019) for a full discussion of smart grid technology: https://www.ieee.org/membership-catalog/productdetail/showProductDetailPage.html?product=CMYSG735.

[340] ISO/RTO Council, "North American Wholesale Electricity Demand-Response Program Comparison, 2018 Edition," webpage and Excel spreadsheet (November 2018), https://isorto.org/reports-and-filings/ and https://isorto.org/wp-content/uploads/2018/12/2018-Demand-Response-Program-Comparison.xlsx.

[341] Also refer to IEEE's Power and Energy Society at http://www.ieee-pes.org/, which publishes *Power and Energy Magazine*, written for technical and nontechnical readers alike.

[342] *Interoperability* refers to the ability of computer systems or software to exchange and make use of information, including between devices made by different manufacturers. IEEE, "IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems," webpage (2016), http://grouper.ieee.org/groups/scc21/1547/1547_index.html.

IEEE Standard 1547was originally designed for relatively small penetrations of DERs and did not require resources, such as distributed PV, to be able to "ride through" a fault on the transmission system.[343] This is because the original standard was written to meet distribution system requirements, and the lack of ride-through capabilities did not have a material effect on transmission system performance for small penetrations of DERs.

A revision effective in April 2018 (i.e., IEEE 1547-2018) reflects performance requirements appropriate for large penetrations of distributed generation and represents an important step for the industry defining performance requirements and expectations for DERs. The revised standard identifies required performance capabilities for voltage and frequency response and voltage and frequency ride-through. Power quality, islanding performance, and interoperability on distribution networks are also covered. In addition, the standard recognizes applications of smart inverters, as described in Section 9.4.2. Adoption of the new features in IEEE Standard 1547 will improve transmission and distribution reliability and facilitate the successful integration and operation of additional DERs that could not otherwise be allowed to reliably and safely interconnect to the system.

Additional standards for testing inverters to fully implement all features of IEEE 1547 (IEEE 1547.1 and UL 1741) are underway. Approval of the new standards is expected no earlier than 2020. Fortunately, all the New England states adopted the voltage and frequency ride-through provisions of IEEE 1547-2018 by November 2018. This action greatly improves system reliability by preventing the likelihood of widespread trips of DER interconnections, which could result in unacceptable system performance for the New England transmission system.[344]

9.6 Regional Integration of Variable Energy Resources, Demand Response, and Storage

The response to system events by inverter-based technologies must be understood and reflected in planning and operating studies. These responses include voltage and frequency ride-through characteristics, control system responses and interactions with other devices, and variations resulting from changes in system strength, especially when and where fewer synchronous generators are operating on the system. New England remains a technical leader in successfully integrating wind, PV, storage, demand response, and HVDC and FACTS devices. Several improvements to planning and operating improvements are in place, and the ISO has implemented several updates to the wholesale electricity markets. Several of the technology developments and challenges affecting the planning of the New England region involve integrating grid-transformation equipment, improving operator awareness and system modeling, and using phasor measurement units (PMUs).

9.6.1 Improved Forecasts for Wind, PV, and Demand

ISO New England has implemented improvements to forecasting techniques that account for wind, PV, and demand. The ISO incorporates VER forecasting into ISO processes, scheduling, and dispatch services. Wind generators participating in the wholesale markets can download individual unit forecasts of their expected output, which can help market participants build a strategy for bidding in the Day-Ahead

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[343] *Ride-through capabilities* reduce unwanted tripping of DERs resulting from contingency events on the transmission and distribution systems.

[344] System contingencies in California and Australia tripped a large number of DERs and resulted in a large-scale blackout. See Charlie Vartanian, et al., *Power and Energy Magazine*, Vol. 16, No. 6 (November/December 2018), pp 55–56, on California events, and Aaron Bloom, et al, *Power and Energy Magazine,* Vol. 15, No. 6 (November/December 2017), pp 24–25, on Australia events. Issues of *Power and Energy Magazine* are available at: http://magazine.ieee-pes.org/, Also refer to the Section 6.3 discussion on NERC's emerging issues (i.e., in Europe) and the need for improved system restoration models and adaptive protection.

Energy Market. The operational forecasts provide better situational awareness and result in more reliable and economical operation of the system. As the amount of wind and PV grows, operational forecasts of variable energy resources take on increasing importance. The ISO is also working to improve its longer-term forecasts of PV and demand used for planning.

9.6.2 Regional Integration of Wind Resources

The ISO's interconnection process requires accurate models of wind generator units for steady-state, stability, and transient analyses, which become particularly important in areas of the system with low short-circuit ratios.[345]

Limited transmission infrastructure in northern and western Maine poses the primary obstacle to interconnecting new onshore wind resources. A number of generators currently connected leave this part of the transmission system at its performance limit with little to no remaining margin. Each interconnection request for new resources involves lengthy and complex study work to identify the significant transmission infrastructure, and individual projects are not able or willing on an individual basis to make the scale of system upgrade investments warranted.

As discussed in Section 4.5.3.2, the ISO's developed a set of clustering revisions to the interconnection procedures for reducing the time for performing system impact studies in Maine and elsewhere on the New England transmission system, should similar conditions arise. It also conducted a strategic infrastructure study—the *Maine Resource Integration Study* to identify the transmission upgrades necessary for interconnecting proposed resources in Maine.

9.6.3 Regional Integration of Photovoltaic Resources and Other Distributed Generation Resources

New England has witnessed significant growth in the development of solar photovoltaic resources over the past few years, and continued growth of PV is anticipated (see Section 3.3). Existing amounts of PV have caused noticeable effects on system operation and, as they grow, are anticipated to have a greater effect on the system's need for regulation, ramping, reserves, and voltage support. Interestingly, new flow patterns from distribution substations into (instead of out of) the transmission system when PV production is high have resulted in new uses of the transmission system and have increased the need for dynamic voltage support. The ISO has engaged in a number of actions to examine and prepare for the effects of large-scale PV development in the region.

At present, the ISO's demand-forecast method considers demand history as an input, which captures the growth and production non-PV DERs. To date, the region has not experienced the large-scale growth of other types of DERs, which would present challenges similar to PV. The ISO continues to monitor this situation and actively examines its processes for improving its demand forecasts (see Section 3.3). This includes applications of modern analysis techniques, such as the latest methods of big data analysis and artificial intelligence.

With more behind-the-meter technologies and time-varying retail rates, demand could become more price responsive and less predictable to operators of the bulk power system. The ISO's work with regional stakeholders will help position the region to best integrate rapidly growing DER resources in a way that maintains reliability and allows the states to realize the public policy benefits they have

[345] Ratios under 3.0, as is the case in much of Maine, pose particular technical challenges for establishing acceptable control system performance of the interconnecting IBR.

identified as the basis for their DER programs. The ISO continuously works to improve its demand forecast methods to account for additional variations in the net demand.

Distribution owners are reviewing and improving processes and methodologies for integrating DERs. These activities address using cluster analyses for non-FERC-jurisdictional resources, providing information on the hosting capacity of distribution circuits, and making better use of smart inverters. Distribution owners are also modernizing distribution system equipment to better accommodate the large-scale development of DERs.

9.6.4 Energy-Storage Resources

Since 2015, the ISO has been preparing for the arrival of grid-scale (in-front-of-the-meter) battery-storage resources. The ISO has successfully processed interconnection requests for electric-storage resources using the existing interconnection procedures and agreements (see Section 4.5). Most new proposals for electric-storage resources make use of inverter-based technologies, and for the ISO to efficiently process the interconnection requests for these technologies, the requests must include appropriately robust equipment design. The power system models must perform well in the network study analysis, and the equipment must meet established performance requirements, such as power-factor, ride-through, and frequency requirements.

9.6.5 Operational Efficiencies through Advanced Technology

To satisfy an increasing number of required transmission plan studies and enhance the ISO's ability, speed, and costs of using more detailed and sophisticated system models and scenarios, the ISO uses cloud computing. The initiative—the first of its kind for large-scale power system simulation studies in the industry—is already yielding successful early results.[346] In addition, various projects to create new systems and tools for greater operational and planning efficiencies and performance are also underway.

The ISO remains a leader in the application of phasor measurement units, which include projects related to voltage stability, control room visualization, and power system modeling. The ISO uses PMUs for detecting oscillation sources, which identifies potential control system issues in power system equipment and improves the overall modeling of the system.[347] The revised OP 22, *Disturbance Monitoring Requirements,* requires transmission owners to install new PMUs at points of interconnection for all new and existing generation units over 100 MW, all new 345 kV substations, new elements at existing 345 kV substations, and other locations designated by the ISO.[348] The ISO also uses PMUs as a backup for emergency monitoring and control for a complete loss of the System Control and Data Acquisition and Energy Management System (SCADA/EMS).

Where appropriate and cost effective, the application of power electronics to the power system through HVDC and FACTS devices and other advanced technologies can address performance concerns on the transmission system. The ISO is also a leader in simulating detailed models of demand characteristics, HVDC, FACTS, and wind and PV resources and accounting for potential adverse interactions resulting

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[346] The 2026 SEMA/RI Solution Study (see Section 5.5.5) used cloud-computing systems to evaluate various transmission solutions in a very short period.

[347] A severe oscillation on the Eastern Interconnection occurred on January 11, 2019. The source of the 0.25 Hz oscillation was identified as a failed control signal to a plant in Florida, which resulted in a local 200 MW power swing and 50 MW in New England.

[348] ISO New England, Operating Procedure No. 22, *Disturbance Monitoring Requirements* (February 8, 2018), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op22/op22_rto_final.pdf. The region is expected to get 10 more PMUs, increasing from 46 units as of May 1, 2019, to 56 units.

from the widespread use of inverter-based technologies. These types of simulations increase the complexity of system studies, which must accurately model control and protection systems and their interactions.

9.6.6 Market Updates to Achieve Grid Transformation

The ISO has employed a number of changes to the wholesale electricity markets that improve the overall economic efficiency and reliability of the system. Several of these changes also facilitate grid transformation.

The ISO implemented "do-not-exceed" (DNE) dispatch that subjects wind and hydro VERs to economic dispatch and participation in energy price formation in real time.[349] Thus, when transmission limits start to bind, the dispatch reflects the energy supply offers of wind and hydro resources, which can be dispatched down and set the price when marginal. Compared with the manual curtailment of resources, which does not reflect the congestion price, DNE dispatch reflects the lower value of energy in an export-constrained area. The DNE dispatch changes enhance reliable system operation by eliminating much of the need for the manual curtailment of these resources. These improved price signals better inform future decisions about resource siting.

Additional revisions to the market rules, referred to as the "resource-dispatchability changes," broaden the range of resources subject to economic dispatch.[350] The resource-dispatchability changes further improve price formation and provides more accurate locational signals to developers when considering where to locate new resources. Other changes to the wholesale electricity markets affecting grid transformation are as follows:

- Fast-start pricing, which helps incentivize power resources that can quickly ramp up their output to bridge the steep increase in grid demand that occurs after the sun has set.
- Negative pricing bids in the energy market, which creates a disincentive for grid resources to operate when the system has surplus power. Negative pricing also provides a market-based way to manage resources such as wind that may choose to continue producing electricity at prices below zero because they receive other sources of income, for example, the federal production tax credit.[351]
- Beginning with FCA 13, Competitive Auctions with Sponsored Policy Resources accommodate the entry of New England state-sponsored new resources. This market mechanism uses a substitution auction to enable new resources unable to acquire a CSO in a primary auction (due

[349] Dispatchable generators were required to offer into the Day-Ahead Energy Market beginning May 31, 2019, and for the June 1, 2019, operating day to address curtailment issues. See the ISO's "Do Not Exceed Dispatch Project" webpage (June 14, 2019), https://www.iso-ne.com/participate/support/customer-readiness-outlook/do-not-exceed-dispatch#project-overview.

[350] The rules apply to all resource types with a few exceptions: solar, settlement-only resources, external transactions, nuclear, and demand response not part of PRD. See FERC, *Order Accepting Proposed Tariff Revisions*, Docket Nos. ER17-68-000 and ER17-68-001, 157 FERC ¶ 61,189 (December 9, 2016), https://www.iso-ne.com/static-assets/documents/2016/12/er17-68-000_12-9-16_order_accept_resource_dispatchability_revisions.pdf, and ISO New England, *Resource-Dispatchability Requirements*, presentation (June 14, 2016), slide 6, https://www.iso-ne.com/static-assets/documents/2016/06/a4_presentation_resource_dispatchability_requirements.pptx.

[351] For more information on this tax credit, see the DSIRE webpage, "Renewable Electricity Production Tax Credit" (updated February 28, 2018), https://programs.dsireusa.org/system/program/detail/734.

to its Minimum-Offer Price Rule) the potential to obtain a CSO from an existing resource seeking to retire (see Section 4.1.3.3.).

- Demand-response resources have been fully integrated into the wholesale energy, reserves, and capacity markets since June 1, 2018. FERC Order No. 745, *Demand-Response Compensation in Organized Wholesale Energy Markets*, requires organized wholesale energy markets to pay demand-response providers the market price for electric energy for reducing consumption below expected levels, when doing so lowers costs to consumers and helps balance real-time supply and demand.[352] To comply with the order, the ISO modified its existing demand-response programs and is implementing various market-rule changes for fully integrating demand response and further improving overall market efficiency. The *price-responsive demand* (PRD) design enabled active demand response to participate in the energy market as a dispatchable, price-responsive product accessed based only on price in the same manner as generation.[353] The ISO also has proposed modifications to the market rules to allow demand-response resources that participate in the energy market to also provide reserves, similar to other supply resources.
- In response to FERC Order No. 841, two sets of tariff changes took effect in April 2019 to better enable batteries and other new storage technologies to participate in New England markets.[354] As part of the compliance filing, the ISO modified its market rules to recognize the physical and operational characteristics of electric-storage resources to further facilitate their participation in all markets. The "participation model" for energy storage is applicable to all types of electric-storage technologies 100 kW or greater where the energy-storage resource can participate in markets to provide all services within their capabilities and manage their own state of charge. In addition, as part of the Enhanced Storage Participation Rules, grid-scale batteries and other emerging storage technologies can be dispatched and priced in the Real-Time Energy Market in a manner that more fully recognizes their ability to transition continuously and rapidly between a charging state (as demand) and a discharging state (as generation).[355]
- The ISO now performs subhourly settlements over shorter periods, which rewards desired resource performance responding to rapid changes in the system.

ISO New England has long recognized the role of distributed energy resources in the wholesale electricity markets. The ISO has been adapting (and will continue to adapt) its market design to accommodate the transition to a growing level of DERs. A distribution system operator could determine the feasibility of operating DERs in the system's footprint and coordinate the economic dispatch of these resources with the ISO, which would develop a systemwide demand curve for power that reflects distributed energy

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[352] FERC, *Demand-Response Compensation in Organized Wholesale Energy Markets*, final rule, Docket No. RM10-17-000, Order No. 745 (March 15, 2011), https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf.

[353] ISO New England, "Price-Responsive Demand Key Project," webpage (2019), https://www.iso-ne.com/committees/key-projects/implemented/price-responsive-demand.

[354] FERC, *Electric-Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, final rule, 162 FERC ¶ 61,127 (February 15, 2018), https://www.iso-ne.com/static-assets/documents/2018/09/a06_tc_2018_09_18_order.pdf, and ISO and NEPOOL, *Revisions to ISO New England Inc. Transmission Markets and Services Tariff in Compliance with FERC Order 841: Docket ER19-470*, compliance filing (December 3, 2018), p. 4, https://www.iso-ne.com/static-assets/documents/2018/12/rev_in_compliance_with_order_841.pdf.

[355] ISO New England and NEPOOL, "ISO New England Inc. and New England Power Pool; Docket No. ER19-__-000; Enhanced Storage Participation Revisions," FERC filing (October 10, 2018), p. 1, https://www.iso-ne.com/static-assets/documents/2018/10/er19-84-000_enhanced_storage_revisions.pdf.

resource costs. Clearly identifying which entity will be responsible for functioning as the distribution system operator in a high-DER future will be essential early in this transition.

9.7 Summary

New England's electric power grid is rapidly changing, in large measure in response to public policies. The growth of inverter-based resources and demand resources provides many advantages of reduced energy costs, lower emissions, and less dependence on natural gas-fired generation. However, it also increases the complexity of real-time operations, regional planning, and the economic performance of the system.

The ISO and outside organizations have performed research and conducted analyses that have helped frame grid-transformation issues and work toward possible solutions. ISO economic studies show the effects of the large-scale development of inverter-based technologies and build on work provided by NREL and other organizations. For example, ISO economic studies rely on NREL data sets critical for modeling hypothetical wind and PV resources in its planning studies. The ISO will continue to track industry research and monitor the effects that increased amounts of VERs have on system performance.

The development of renewables is facilitated by advances in transmission technologies (e.g., FACTS, HVDC, and adaptive protection). Analysis tools for more accurate forecasting of the state of the system and accounting for its probabilistic nature in studies can improve the overall operations and planning of the system. The application of phasor measurement units and modern analysis techniques also provide improved measurements of key data, estimates of the state of the system, and security analysis. Special controls, especially on inverter-based technologies and demand, can help achieve more reliable and economic performance of the system.

The ISO is actively enabling the reliable integration of renewable and distributed resources through improvements in regional planning, operations, and markets processes. The implementation of a cluster study methodology as part of the ISO's interconnection process better facilitates the planning of new wind resources. The ISO also improved its forecasting of wind resource and PV production and the dispatch methods used for operating the system. The region currently applies the voltage and frequency ride-through characteristics required by recently approved standards for interconnecting distributed energy resources. A number of improvements to the wholesale markets promote resource responses, such as system flexibility, that facilitate grid transformation.

Demand resources and storage technologies hold the promise of providing needed system flexibility. Cyber- and physical security requirements must be met to ensure a secure operation independent of any potential changes in the industry structure.

Operational coordination between the wholesale market and retail-level distributed resources and microgrids is complex, and it will remain important for all resources that provide wholesale grid reliability services to have the same obligations and performance incentives. At present, the ISO relies on aggregators to integrate small-scale distributed resources into the wholesale market, much as the ISO does with demand-response providers. For example, the ISO's integration of demand response paved the way for the full integration of storage and microgrids. Non-FERC-jurisdictional cluster studies administered by distribution owners should facilitate the interconnection of new distributed energy resources.

Section 10
Multistate and State Initiatives

As described throughout RSP19, the ISO is involved in a number of initiatives aimed at developing and integrating new technologies, improving operating and planning procedures, and updating the wholesale markets to enhance system reliability. Federal initiatives, by FERC, DOE, and the White House, also address reliability as well as security issues. At the state and multistate levels, the focus of this section, a number of initiatives and policies have a significant impact on the wholesale electricity markets and transmission developed to meet system needs, specifically influencing the timing, type, and location of resources and transmission infrastructure. Initiatives and policies of each of the six New England states, and jointly, also address renewable energy and environmental concerns.

10.1 Multistate Initiatives

While each New England state has a unique set of energy policy objectives and goals, they have worked together continually to identify, discuss, and address energy issues of common interest. This section discusses activities at the multistate level that affect the regional power system.

10.1.1 Coordination among the New England States

Each of the New England states is actively involved in the ISO's regional planning process, individually and through the New England States Committee on Electricity (NESCOE).[356] NESCOE serves as one forum for representatives from the states to participate in the ISO's decision-making processes, including those dealing with resource adequacy and system planning and infrastructure expansion.

In addition to NESCOE, the ISO works collaboratively with the New England Conference of Public Utilities Commissioners (NECPUC), the New England governors' offices, and the states' consumer advocates. The ISO provides monthly updates to the states on regional stakeholder discussions regarding the regional planning process and the wholesale electricity markets.[357]

The New England states also participate in national organizations, such as the National Association of State Energy Offices (NASEO) and the National Council on Electricity Policy (NCEP), recently reinvigorated by the National Association of Regulatory Utility Commissioners (NARUC).[358] In 2018, NASEO and NARUC established a joint task force on comprehensive energy planning.[359] As requested, the ISO and committees it supports (e.g., the Eastern Interconnection Planning Collaborative) provide information and coordinate on key issues affecting large national areas.

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[356] More information about NESCOE is available at www.nescoe.com.

[357] ISO New England, "Presentations, Speeches, and Other Materials," webpage (2019), "External Affairs Monthly Issues Memo" filter by document type, http://www.iso-ne.com/about/government-industry-affairs/materials.

[358] More information on NASEO, the NCEP and NARUC is available at https://www.naseo.org/, http://electricitypolicy.org/about/, and https://www.naruc.org/, respectively.

[359] NARUC and NASEO, "Task Force on Comprehensive Electricity Planning," webpage (2019), http://bit.ly/NARUCNASEOFacts.

10.1.2 Consumer Liaison Group

The ISO and regional electricity market stakeholders created the Consumer Liaison Group (CLG) in 2009 as an additional means to facilitate the consideration of consumer interests in determining the needs and solutions for the region's power system.[360] With representatives from state offices of consumer advocates and attorneys general, large industrial and commercial consumers, chambers of commerce, and others, the CLG meets quarterly to address various electricity issues affecting consumers. With the input of CLG members, a Coordinating Committee guides CLG meeting agendas and ideas for special guest speakers and discussion topics.

In 2018, the CLG discussed the changing wholesale electricity markets, the evolution of energy efficiency, and the electrification of the heating sector. On March 12, 2019, the CLG Coordinating Committee (CLGCC) and the ISO issued the *2018 Report of the Consumer Liaison Group*, which summarizes the activities of the CLG in 2018.[361] It also provides an update on ISO activities and initiatives, as well as wholesale electricity costs and retail electricity rates.

10.1.3 New England State Governors' Actions

The six New England governors collaborate across borders to advance their common goals. As a recent example of these efforts, on March 15, 2019, the six New England governors issued a joint statement announcing a commitment to regional cooperation on energy issues and to work in coordination with ISO New England and through NESCOE.[362]

10.1.4 New England Governors and Eastern Canadian Premiers

At their August 2018 meeting, the New England Governors and Eastern Canadian Premiers (NEG ECP) reaffirmed their commitment toward clean energy sources and their focus on regional opportunities to reduce greenhouse gas emissions through the Regional Climate Change Action Plan.[363] Among other provisions, they acknowledged that the extreme temperatures in recent years have caused spikes in energy demand, resulting in high costs for consumers and an increased reliance on energy sources with high GHG emission rates. This reliance on high-emitting resources is attributable to a system with limited energy diversification and storage, particularly during winter. They also acknowledged that diversifying the resource mix and using clean energy sources during extreme-temperature events will decrease energy costs and increase environmental benefits. The group resolved the following:

- Encouraging policies that diversify resources and target affordable clean energy sources, including during peak periods, is important.

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[360] The end-user sector in the NEPOOL stakeholder process and the ISO stakeholder committees also convey consumer interests. Additional information on the CLG is available at http://www.iso-ne.com/committees/consumer-liaison.

[361] ISO New England and CLGCC, *2018 Report of the Consumer Liaison Group* (March 12, 2019), https://www.iso-ne.com/static-assets/documents/2019/03/2018_report_of_the_consumer_liaison_group_final.pdf.

[362] For the full text of the governors' statement, see: Ned Lamont, Janet Mills, et al., "New England Governors' Commitment to Regional Cooperation on Energy Issues," signed proclamation by the six New England governors (March 15, 2019), https://www.coneg.org/wp-content/uploads/2019/03/New-England-Governors-Statement-of-Cooperation-on-Regional-Energy-3-15-19.pdf.

[363] NEG ECP, "Resolution Concerning Energy Security and Affordability," Resolution 42-2 (August 13, 2018), https://www.coneg.org/wp-content/uploads/transferred/Data/Sites/1/media/documents/correspondence/42-2_en.pdf; and *2017 Update of the Regional Climate Change Action Plan* (August 28, 2017), https://www.coneg.org/wp-content/uploads/transferred/Data/Sites/1/media/documents/reports/2017-rccap-final.pdf.

- System planners and operators should strengthen and diversify the generation resource mix and storage capabilities to reduce energy costs and improve system resilience during periods of extreme temperatures.
- Clean energy resources needed to serve winter peaks and reduce GHG emissions should include onshore and offshore wind, large hydro, demand response, energy efficiency, and advanced battery and storage systems.
- The Northeast International Committee on Energy (NICE) should research policies to reduce barriers and improve operational standards for encouraging a greater reliance on energy storage, resource diversity, and the use of clean energy.

10.2 Individual State Initiatives, Activities, and Policies

The New England states have worked together continually to identify, discuss, and address energy issues of common interest. Even with this history of cooperation, each state has a unique set of energy policy objectives and goals. This section builds on the discussion of RPSs and procurement policies discussed in Section 8.4 and summarizes additional actions the individual New England states have taken pertaining to regional system planning, including several recently implemented laws, policies, and initiatives. The current trends show an increased focus on offshore wind, energy efficiency, and energy-storage deployment, as well as grid-modernization efforts.

10.2.1 Connecticut

Connecticut state law requires the Connecticut Department of Energy and Environmental Protection (DEEP) to periodically prepare a comprehensive energy and climate strategy. The most recent strategy, released in 2018, included recommendations for growing and sustaining renewable and zero-carbon generation in the state and region, improving grid reliability and resiliency, and grid modernization.[364]

The CT DEEP continues to pursue clean energy under its procurement authority. Under the state's Clean Energy Sources RFP, Connecticut selected its first-ever offshore wind bid, a 200 MW project from Revolution Wind.[365] Winners of the Zero-Carbon RFP included Millstone Nuclear, Seabrook Station, solar resources, and an additional 100 MW of offshore wind.[366] A 2019 bill authorizes DEEP to procure up to another 2,000 MW of offshore wind by 2030, with the first phase of procurements occurring through 2019.[367]

In 2019, the legislature also passed an energy omnibus bill that restored net-metering and directs the Public Utilities Regulatory Authority to study the value of distributed generation while determining the

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364 CT DEEP, *Comprehensive Energy Strategy* (February 8, 2018), http://www.ct.gov/deep/lib/deep/energy/ces/2018_comprehensive_energy_strategy.pdf.

365 CT DEEP, "Energy Filings," webpage; see Procurement of Clean Energy and Renewable Resources Pursuant to Public Acts 13-303, 15-107 and 17-144 (n.d.), http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=16.8&Seq=3.

366 CT DEEP, "Energy Filings," webpage, see Procurement for Zero-Carbon Resources Pursuant to CT General Statutes – 16a-3m (n.d.), http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=1&Count=30&Expand=15&Seq=4.

367 CT DEEP, "Energy Filings," webpage, see Public Act 19-71 – Section 1—Procurement of Offshore Wind Facilities (n.d.), http://www.dpuc.state.ct.us/DEEPEnergy.nsf/$EnergyView?OpenForm&Start=21&Count=30&Expand=44&Seq=6.

future net-metering replacement tariff program.[368] The bill also requires the Connecticut Department of Transportation and DEEP to inventory land and identify areas suitable for the installation of renewable resources, authorizes the state's utilities to own energy-storage systems, and raises the virtual net-metering cap to 20 MW.

10.2.2 Maine

In 2019, the state enacted a series of energy bills. One bill requires the governor's Energy Office to study transmission grid reliability, the retirement of biomass generation, and retail rate stability in northern Maine.[369] Under a separate bill, the Energy Office is directed to analyze by December 31, 2019, the state's becoming a net exporter of energy by 2030 through the development and expansion of energy generating capacity, energy conservation, and energy efficiency. The effort is part of the development of the state's periodic energy plan, which was last updated in 2015.[370]

Additionally, the legislature approved a new goal for 80% of retail sales of electricity to come from renewable resources by 2030 and 100% by 2050, while also increasing the state's RPS for Class I resources from 10% by 2020 to 50% by 2030.[371] Other bills enacted in the 2019 session require the following:

- Investigation and identification of nonwire alternatives to proposed transmission lines and projects[372]
- A new goal of installing 100,000 heat pumps by 2025[373]
- The restoration of net-metering[374]
- Directing the state's efficiency program to include beneficial electrification.[375]

Governor Janet Mills also repealed the state's previous moratorium on wind.

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[368] CT General Assembly, *An Act Concerning a Green Economy and Environmental Protection*, Public Act No. 19-35 (June 2019), https://cga.ct.gov/asp/cgabillstatus/cgabillstatus.asp?selBillType=Bill&bill_num=5002&which_year=2019.

[369] State of Maine, *Resolve, to Study Transmission Grid Reliability and Rate Stability in Northern Maine*, H.P 1271—L.D. 1796, Session Laws of Maine Chapter 71 Resolves (June 17, 2019), http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=HP1275&item=3&snum=129.

[370] State of Maine, *Resolve, To Increase Energy Independence for Maine*, H.P. 479—L.D.658 (May 17, 2019), http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=HP0479&item=3&snum=129.

[371] 129th Maine Legislature, First Legislative Session—2019, *An Act To Reform Maine's Renewable Portfolio Standard*, L.D. 1494 (April 4, 2019), http://legislature.maine.gov/bills/display_ps.asp?PID=1456&snum=129&paper=SP0457.

[372] 129th Maine Legislature, First Legislative Session—2019, *An Act to Reduce Electricity Costs through Nonwire Alternatives*, L.D. 1181 (March 12, 2019), http://legislature.maine.gov/bills/display_ps.asp?PID=1456&snum=129&paper=HP0855.

[373] 129th Maine Legislature, First Legislative Session—2019, *An Act to Transform Maine's Heat Pump Market to Advance Economic Security and Climate Objectives*, L.D. 1766 (May 21, 2019), http://www.mainelegislature.org/legis/bills/display_ps.asp?ld=1766&PID=1456&snum=129.

[374] 129th Maine Legislature, First Legislative Session—2019, *An Act to Eliminate Gross Metering*, L.D. 91 (January 15, 2019), http://www.mainelegislature.org/legis/bills/display_ps.asp?ld=91&PID=1456&snum=129.

[375] 129th Maine Legislature, First Legislative Session—2019, *An Act to Support Electrification of Certain Technologies for the Benefit of Maine Consumers and Utility Systems and the Environment*, L.D. 1463 (April 2, 2019), http://www.mainelegislature.org/legis/bills/display_ps.asp?PID=1456&snum=129&paper=&paperld=l&ld=1464.

In spring 2019, the Maine Public Utilities Commission (ME PUC) issued a certificate of public need for the New England Clean Energy Connect (NECEC) Project, a 145-mile HVDC transmission line Central Maine Power proposed and Massachusetts selected under its renewable energy solicitation. This project will bring up to 1,200 MW of large-scale hydropower from Hydro-Québec in eastern Canada to Maine.[376] Remaining permit reviews are ongoing, with decisions anticipated by the end of 2019.

10.2.3 Massachusetts

Massachusetts has reached significant milestones in the implementation of renewable energy legislation passed in 2016, called *An Act to Promote Energy Diversity*.[377] The state's electric distribution companies, in consultation with the Department of Energy Resources (DOER), have selected winning bidders and filed executed contracts with the Department of Public Utilities (MA DPU) for review and approval. The state selected an 800 MW offshore wind proposal from developer Vineyard Wind and 1,090 MW from the NECEC proposal (see above).[378] The DPU approved the contracts between Vineyard Wind and the state's electric distribution companies in April 2019.[379] The MA DPU approved the NECEC hydropower contracts in 2019. In May 2019, the state's electric distribution companies issued a second offshore wind solicitation to procure up to 800 MW of additional offshore wind generation.[380]

Legislation passed in 2018 called on the DOER to investigate the necessity, benefits, and costs of requiring the state's electric distribution companies to solicit an additional 1,600 MW of offshore wind, over and above the 1,600 MW authorized by the 2016 legislation.[381] The DOER released its study results in May 2019, concluding that the state's electric distribution companies should proceed with solicitations for an additional 1,600 MW of offshore wind and enter into long-term contracts if found to be cost effective.[382]

Also in 2018, the state established an energy-storage target of 1,000 MWh by December 31, 2025 (expanding on DOER's previous energy-storage target of 200 MWh by 2020).[383] Additionally, the DPU-approved *Three-Year Energy Efficiency Plan* includes incentives for customers who purchase energy-storage devices that can be dispatched during summer and winter peak demand periods.[384]

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[376] ME PUC, *Order Granting Certificate of Public Convenience and Necessity and Approving Stipulation* (May 3, 2019), https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/CaseMaster.aspx?CaseNumber=2017-00232.

[377] MA General Court, *An Act to Promote Energy Diversity*, Chapter 188 of the Acts of 2016 (August 8, 2016), https://malegislature.gov/Laws/SessionLaws/Acts/2016/Chapter188.

[378] Information relating to the solicitations is available at MACLEANENERGY.COM. "Massachusetts Clean Energy," webpage (2019), https://macleanenergy.com/.

[379] MA DPU, See Docket Nos. 18-76, 18-77, and 18-78, (April 12, 2019), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10617251.

[380] Information relating to the solicitation is available at MACLEANENERGY.COM. "Massachusetts Clean Energy," webpage, 83C II (2019) https://macleanenergy.com/83c-ii/.

[381] MA General Court, *An Act to Advance Clean Energy*, Chapter 227 of the Acts of 2018 (August 9, 2018), https://malegislature.gov/Laws/SessionLaws/Acts/2018/Chapter227.

[382] MA DOER, *Offshore Wind Study* (May 2019), https://www.mass.gov/files/documents/2019/05/31/OSW%20Study%20-%20Final.pdf.

[383] MA General Court, *An Act to Advance Clean Energy*, Chapter 227 of the Acts of 2018 (August 9, 2018), https://malegislature.gov/Laws/SessionLaws/Acts/2018/Chapter227.

[384] Mass Save, *Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan 2019–2021* (October 31, 2018), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9998895.

10.2.4 New Hampshire

Over the 2019–2020 legislative biennium, the New Hampshire legislature is pursuing many policy measures to increase and retain renewable energy resources across the state. In 2019, the governor began work with federal agencies and the Gulf of Maine region to pursue offshore wind development.[385]

The New Hampshire Public Utilities Commission (NH PUC) will review revisions to the state's current Energy Efficiency Resource Standard (EERS, which officially began in 2018), including the electricity and gas savings targets, in 2020. The NH PUC also continues to study options to promote grid modernization through a collaborative, nonadjudicated regulatory process. Having fully completed restructuring upon the final sale of its generation assets in 2018, Public Service of New Hampshire (doing business as Eversource) is now solely a distribution and transmission company. The Department of Environmental Services (NH DES) continues its program to improve energy efficiency at wastewater treatment plants, having achieved savings in several municipalities and identified savings in dozens more.[386]

10.2.5 Rhode Island

Rhode Island continues to make progress toward Governor Gina Raimondo's strategic goal to increase the state's clean energy projects to 1,000 MW by the end of 2020.[387] In furtherance of this goal, Rhode Island selected 400 MW from Deepwater Wind's Revolution Wind project through a competitive offshore wind solicitation conducted by Massachusetts in 2018.[388] The Rhode Island Public Utilities Commission (RI PUC) approved the contract between National Grid and the project developer in May 2019.[389] National Grid is in the midst of conducting a separate solicitation, which may result in the procurement of an additional 400 MW of newly developed renewable energy resources for the state.[390]

10.2.6 Vermont

Vermont policymakers continue to explore the appropriate role of battery storage in the state's energy mix. In 2019, lawmakers required that proposed energy-storage facilities greater than 500 kW receive a certificate of public good from the Public Utility Commission (VT PUC).[391] Most investments in energy infrastructure in Vermont require a certificate of public good.

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[385] NH Office of Strategic Initiatives, "Offshore Renewable Energy Task Force," webpage (2017), https://www.nh.gov/osi/special-projects/offshore-renewable.htm.

[386] NH DES, "Wastewater Treatment Plants Recognized for Improvements in Energy Efficiency: WWTPs Recognized Include Epping, North Conway, Pittsfield, Somersworth, Troy, Winnipesaukee River Basin Program," press release (May 2, 2019), https://www.des.nh.gov/media/pr/2019/20190502-wastewater-treatment.htm.

[387] RI Office of Energy Resources, "Governor's 1,000 by '20 Clean Energy Goal," webpage (2019), http://www.energy.ri.gov/renewable-energy/governor-clean-energy-goal.php.

[388] The Revolution Wind project is 700 MW in total capacity and holds queue position 781 in the ISO's Generator Interconnection Queue; see Section 4.5.3 and the ISO's "Generator Interconnection Queue," spreadsheet (2019), https://irtt.iso-ne.com/reports/external.

[389] RI and Providence Plantations PUC, "The Narragansett Electric Company d/b/a National Grid Review of Power Purchase Agreement Pursuant to RI Gen, Laws § 39-31-1 to 9," report and order, Docket No. 4929 (May 28, 2019), http://www.ripuc.org/eventsactions/docket/4929-NGrid-Ord23609_6-7-19.pdf.

[390] National Grid, "2018 Request for Proposals for Long-Term Contracts for Renewable Energy" (2019), https://ricleanenergyrfp.com/.

[391] VT General Assembly, *An Act Relating to Miscellaneous Energy Subjects,* H.133, enacted as Act 31 (May 23, 2019), https://legislature.vermont.gov/bill/status/2020/H.133.

Through its annual transportation bill, lawmakers specified that the Public Utility Commission does not have jurisdiction over individuals, otherwise not regulated by the PUC, who sell or supply electricity for charging electric vehicles.[392] In the same bill, the legislature requires that 50% of newly purchased or leased vehicles for the state fleet need to be either hybrids or electric vehicles, and this percentage increases to 75% by July 1, 2021.

10.3 Summary of Initiatives

The ISO's planning and market activities are closely coordinated among the six New England states, with neighboring systems, across the Eastern Interconnection, and nationally. Each New England state has a unique set of energy policy objectives and goals and continues to implement laws, policies, and initiatives that affect the regional system planning in New England. The ISO continues to work closely with the states and their policy prerogatives for increasing renewable energy in a manner that will ensure reliability.

[392] VT General Assembly, *An Act Relating to the Transportation Program and Miscellaneous Changes to Laws Related to Transportation*, H.529, enacted as Act 59 (2019), https://legislature.vermont.gov/Documents/2020/Docs/ACTS/ACT059/ACT059%20Act%20Summary.pdf.

Section 11
Key Findings and Conclusions

In accordance with all requirements in the *Open Access Transmission Tariff*, ISO New England's *2019 Regional System Plan* discusses the electric power system's needs and the amounts, locations, and types of resource development that can meet these needs from 2019 through 2028. RSP19 also discusses the status of transmission system assessments, transmission system planning studies, and projects needed for meeting reliability requirements and improving the economic performance of the system. Other discussions include interregional planning requirements and risks to the regional electric power system; the likelihood, timing, and potential consequences of these risks; and mitigating actions. Some of the other highlights of RSP19 include strategic planning challenges expected over the 10-year planning horizon and how the region is analyzing and addressing these challenges.

This section summarizes the key findings of RSP19 and conclusions about the outlook for New England's electric power system over the next 10 years:

- Forecasts of the regional net peak and annual use of electric energy show negative growth resulting from the additions of PV, EE, and other BTM resources, which are reflected in the planning processes. Net peak demand, thus, is not a key driver of new infrastructure needs over the 10-year planning horizon. Growth of demand over the longer term seems likely, however, with additional electrification of transportation and the use of efficient heat pumps replacing fossil systems for providing heating and cooling.
- The region has significant potential for developing renewable resources and is actively addressing several key technical challenges to successfully integrate these resources. The variability of net demand resulting from the addition of BTM PV creates the increased need for regulation, ramping, reserves, and voltage control, a need that increases further with the addition of larger-scale PV and wind development. This need can be met by flexible resources, storage, demand response, FACTS devices, which can provide dynamic voltage control, and other controls on variable energy resources. The ISO remains a leader in technological innovation, as shown by the widespread use of phasor measurement units, techniques for analyzing VERs, and the extensive application of FACTS devices. The ISO also implemented state-of-the art short-term forecasting techniques, including for wind and solar resources, that facilitate the reliable and economic operation of the system.
- Needed capacity and operating reserves are provided through the wholesale markets, but resource retirements and the need for successfully integrating VERs pose future challenges to the reliable and economic operation of the system. RSP19 shows that the use of OP 4 procedures would likely be required over the planning horizon, especially during winter peak demand periods. Studies of expected system conditions show that developing new resources near load centers, particularly in the NEMA/Boston and SEMA/RI areas, would provide the greatest reliability benefit to the system. Proposed development of offshore wind resources interconnecting with these areas appears to be electrically well situated. The large-scale development of wind resources in northern New England, however, would require significant additional transmission system improvements.
- As of June 1, 2019, the ISO Interconnection Request Queue includes 17 elective transmission upgrades under study and three that have received approval of their proposed plan applications. Many of these ETUs have been proposed to deliver zero- or low-carbon resources. The ISO implemented cluster studies that facilitate the development of renewable resources.

- Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion and Net Commitment-Period Compensation. The total 2018 congestion cost was $64.5 million for congestion resulting from transmission constraints, and the total 2018 NCPC cost was $17.7 million for voltage and second-contingency NCPC, of the $9.8 billion total wholesale electricity markets costs in 2018. Generator retirements, off-peak system needs, the growth of inverter based technologies, and changes to mandatory planning criteria promulgated by NERC and NPCC will drive the need for longer-term transmission projects.
- RSP19 complies with the intraregional and interregional planning processes required by the ISO's *Open Access Transmission Tariff*. The ISO planning processes reflect Order 1000 requirements, probabilistic study assumptions, and changes to national and regional criteria. The ISO anticipates issuing its first competitive solicitation for transmission improvements by early 2020. Coordinated planning activities with other systems will continue growing, particularly to provide access to a greater diversity of resources, including hydro imports and VERs, and to comply with environmental requirements.
- The regional reliance on natural-gas-fired generation, coupled with natural gas pipeline constraints and uncertain LNG deliveries can pose reliability issues and lead to price spikes in the wholesale electricity markets. The ISO and interregional organizations assessed these risks in a number of energy-security studies, and the ISO took a number of actions to improve the overall reliable and economical operation of the system. Further improvements in the wholesale electricity markets will be required, which will be discussed with stakeholders in 2019 and beyond. The greater development of renewable resources, energy efficiency, imports from neighboring regions, and continued investment in gas-efficiency measures are also part of the solution to the regional energy-security issue.
- Environmental regulations, other public policies, and economic considerations all will affect the future operation of existing resources and the mix of new regional resources, such as to influence the retirement of oil and coal generators and the addition of natural-gas-fired and renewable generation. The addition of renewables can suppress energy market prices and may further encourage the retirement of traditional generating units. Generator environmental compliance depends on final federal regulations and site-specific circumstances, which have been subject to uncertainty and delays that could affect generator permitting and operations. Carbon emissions targets will likely be the key regional environmental constraint on energy production by fossil-fired generating units.
- New England is transforming to a sustainable hybrid grid that supports the connection of more renewable energy and more effective use of distributed energy resources. Grid operators will need to be able to observe and control variable and distributed resources to realize the full benefits of energy storage, microgrids, and smart grid technologies. The New England states implemented voltage and frequency ride-through requirements of IEEE 1547, which will improve overall system reliability. The full implementation of recently approved interconnection standards and testing requirements for distributed resources will prove vital for ensuring overall system reliability and facilitating the economical development of renewable resources, such as PV.
- Federal and state policies and initiatives will continue to affect the planning process, such as the effect of policies promoting EE, PV, and wind resources.
- Because the New England electric power system is energy limited, ISO markets continue evolving to make reliable and economic use of storage resources, demand response, and flexible resources

that provide needed ancillary services. Changes in the ISO's administration of the wholesale electricity markets continue improving operational security and flexibility.

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 described in the *2019 Regional System Plan*, the region is working toward meeting all challenges for planning and operating the system in accordance with all requirements.

Acronyms and Abbreviations

Acronym/Abbreviation	Description
°F	degrees Fahrenheit
$/kW-mo; $/kW-m	dollar(s) per kilowatt-month
$/kW-yr	dollar(s) per kilowatt-year
$/MMBtu	dollar(s) per million British thermal units
$/MWh	dollar(s) per megawatt-hour
12 CP	average of all the monthly regional network loads (per the OATT, Section 21.2) for the 12 months of the calendar year on which the rate is based
50/50	refers to a 50/50 peak load—a peak load with a 50% chance of being exceeded because of weather conditions, expected to occur in the summer in New England at a weighted New England-wide temperature of 90.2°F, and in the winter, 7.0°F
90/10	refers to a 90/10 peak load—a peak load with a 10% chance of being exceeded because of weather conditions, expected to occur in the summer in New England at a weighted New England-wide temperature of 94.2°F, and in the winter 1.6°F
AC; ac	alternating current
ACE	*Affordable Clean Energy Act* (US EPA)
ACP	alternative compliance payment
AEO	Annual Energy Outlook (EIA)
AGT	Algonquin Gas Transmission
AMR*XY*	*20XY Annual Markets Report*
ARA	annual reconfiguration auction
ARIPPA	Anthracite Region Independent Power Producers Association
Bangor Hydro	1) Bangor Hydro Electric Company 2) active-demand-resource dispatch zone
Bcf; Bcf/d	billion cubic feet; billion cubic feet per day
BES	bulk electric system (NERC)
BHE	1) RSP subarea of northeastern Maine 2) Bangor Hydro Electric Company
Boston	active-demand-resource dispatch zone (sentence capitalization)
BOSTON, BOST	RSP subarea of Greater Boston, including the North Shore (all capitalized)
BPS	bulk power system (NPCC)
BTM	behind the meter
Btu	British thermal unit
CAA	*Clean Air Act* (US)
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CAMS	Customer Asset-Management System
CASPR	competitive auction with sponsored policy resources
CC	combined cycle
CCP	capacity commitment period
CCR	cost-containment reserve
CEII	critical energy infrastructure information
CELT	capacity, energy, loads, and transmission
2018 CELT Report	*2018–2027 Forecast Report of Capacity, Energy, Loads, and Transmission*

Acronym/Abbreviation	Description
2019 CELT Report	*2019–2028 Forecast Report of Capacity, Energy, Loads, and Transmission*
Central MA	Central Massachusetts active-demand-resource dispatch zone
CETU	cluster-enabling transmission upgrade
CEQ	Council on Environmental Quality (US)
CFAC	Cluster-Interconnection Facilities Study
CFR	Code of Federal Regulations
CHP	combined heat and power
CIGRE	International Council on Large Electric Systems
Cir.	Circuit (court)
CLG	Consumer Liaison Group
CMA/NEMA	RSP subarea comprising central Massachusetts and northeastern Massachusetts
CNG	compressed natural gas
CNI	capacity network import
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COO	chief operating officer
CPP	Clean Power Plan (US EPA)
CRA	contingency reserve adjustment (factor)
CRPS	Cluster-Enabling Transmission Upgrade Regional Planning Study
CSC	Cross-Sound Cable
CSIS	Cluster-Interconnection System Impact Study
CSO	capacity supply obligation
CT	1) State of Connecticut 2) RSP subarea that includes northern and eastern Connecticut 3) Connecticut load zone 4) capacity zone area within the Connecticut import interface, including the RSP bubbles for CT, SWCT, and NOR plus the Scitico substation served from western Massachusetts
CWA	*Clean Water Act* (US)
CWIS	cooling water intake structure
d/b/a	doing business as
DC	direct current
D.C.	District of Columbia
D.C. Cir.	District of Columbia Circuit (US Court of Appeals)
DCT	double-circuit tower
DEEP	Department of Energy and Environmental Protection (CT)
DER	distributed energy resource
DERTF	Distributed Energy Resources Task Force (NERC)
DG	distributed generation
DGFWG	Distributed Generation Forecast Working Group
DOC	Microsoft Word file
DOE	Department of Energy (US)
DOER	Department of Energy Resources (MA)
DNE	do not exceed
DPU	Department of Public Utilities (MA)
DRCR	demand response capacity resource

Acronym/Abbreviation	Description
DSO	distribution system operator
EACMS	Electronic Access Control or Monitoring System
DVAR	dynamic voltage ampere reactive
Eastern CT	Eastern Connecticut active-demand-resource dispatch zone
ECR	emissions-containment reserve
ECT	eastern Connecticut; key transmission study area
EE	energy efficiency
EEI	electronic export information
EEF	energy-efficiency forecast
EERS	Energy-Efficiency Resource Standard (NH PUC)
EFORd	equivalent demand forced-outage rate
EGWG	Electric-Gas Working Group (NERC)
EI	Eastern Interconnections
EIA	Energy Information Administration (US DOE)
EIPC	Eastern Interconnection Planning Collaborative
EISA	Energy Independence and Security Act of 2007 (US)
EMS	Energy Management System
EISPC	Eastern Interconnection States Planning Council
ELG	Effluent Limit Guidelines (for Electric Steam Generation) (US EPA)
EOR	energy-only resource
EPA	Environmental Protection Agency (US)
EPRI	Electric Power Research Institute
ERAG	Eastern Interconnection Reliability Assessment Group (NERC)
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ERSTF	Essential Reliability Services Task Force (NERC)
ERSWG	Essential Reliability Services Working Group (NERC)
ETU	elective transmission upgrade
F.3d	*Federal Reporter*, third series
FACTS	Flexible Alternating-Current Transmission System
FCA	Forward Capacity Auction
FCA #	# st/nd/rd/th Forward Capacity Auction
FCM	Forward Capacity Market
Fed. Reg.	*Federal Register*
FERC	Federal Energy Regulatory Commission
FR	*Federal Register*
FRCC	Florida Reliability Coordinating Council
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GHCC	Greater Hartford/Central Connecticut (part of NEEWS)
GHG	greenhouse gas
GPS	global positioning satellite
Greater Connecticut; Greater CT	1) RSP study area that includes the RSP subareas of NOR, SWCT, and CT 2) capacity zone 3) reserve zone

Acronym/Abbreviation	Description
Greater Southwest Connecticut; Greater Southwest CT; Greater SWCT	1) RSP study area that includes the southwestern and western portions of Connecticut and comprises the SWCT and NOR subareas 2) reserve zone
GSP	gross state product
GW	gigawatt
GWh	gigawatt-hour(s)
GWSA	*Global Warming Solutions Act* (MA)
HE	hour ending
HP	horsepower
HQ	Hydro-Québec Balancing Authority Area
HQICC	Hydro-Québec Installed Capability Credit
(the) Hub	ISO New England energy trading hub
HV	high voltage
HVDC	high voltage, direct current
hydro	hydroelectricity
IBR	inverter-based resource
IC	interconnection customer
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IEEE	Institute of Electrical and Electronics Engineers
IGTS	Iroquois Gas Transmission System
IPSAC	Inter-Area Planning Stakeholder Advisory Committee
IRC	ISO/RTO Council
IRPTF	Inverter-Based Resource Performance Task Force (NERC)
ISO	Independent System Operator
(the) ISO	Independent System Operator of New England; ISO New England
ISO/RTO	Independent System Operator/Regional Transmission Organization
ISO tariff	ISO New England's *Transmission, Markets, and Services Tariff*
JIPC	Joint ISO/RTO Planning Committee
ktons	kilotons
kV	kilovolt(s)
kW	kilowatt
kWh	kilowatt-hour
lb	pound
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedure
LLC	limited liability company
LMP	locational marginal price
LNG	liquefied natural gas
LOLE	loss-of-load expectation
Lower SEMA	Lower Southeast Massachusetts active-demand-resource dispatch zone
LSE	load-serving entity
LSP	Local System Plan
LSR	local sourcing requirement

Acronym/Abbreviation	Description
LTRA	*Long-Term Reliability Assessment* (NERC)
M&N	Maritimes and Northeast Pipeline
MA	Massachusetts
MACT	maximum achievable control technology
MA DEP	Massachusetts Department of Environmental Protection
MA DPU	Massachusetts Department of Public Utilities
Maine	active-demand-resource dispatch zone
MATS	Mercury and Air Toxics Standard (US EPA)
Mcf	1,000 cubic feet
MCL	maximum capacity limit
MDth/d	thousand dekatherms per day
ME	1) State of Maine 2) RSP subarea that includes western and central Maine and Saco Valley, New Hampshire 3) Maine load zone 4) Maine capacity zone, including the area north of the ME-NH interface and comprising the RSP bubbles for BHE, ME, and SME 5) Maine active-demand-resource dispatch zone
ME PUC	Maine Public Utilities Commission
METU	market efficiency transmission upgrade
MGD	millions gallons per day
MMBtu	million British thermal units
MMcf; MMcf/d	million cubic feet; million cubic feet per day
M-MVDR	*Manual for Measurement and Verification of On-Peak Demand Resources and Seasonal Peak Demand Resources* (ISO New England)
MMWG	Multiregional Modeling Working Group (NERC)
MPRP	Maine Power Reliability Program
MRI	marginal-reliability-impact
MRIS	*Maine Resource Integration Study*
MRO-MISO	Midwest Reliability Organization-Midcontinent ISO
MTF	merchant transmission facility
mtons	million tons
MVA	million volt-ampere
MVAR	megavolt-ampere reactive
MW	megawatt(s)
MW_{AC}	the megawatts converted from the direct-current electricity produced by the photovoltaic panels to alternating current, which typically is supplied to utility customers
MW_{DC}	the megawatts generated by photovoltaic panels, which produce direct-current electricity
MWe	electrical megawatts (of nuclear power plants)
MWh	megawatt-hour(s)
N-1	first-contingency loss
N-1-1	second-contingency loss
N/A	not applicable
NAESB	North American Energy Standards Board
NARUC	National Association of Regulatory Utility Commissioners
NASEO	National Association of State Energy Offices

Acronym/Abbreviation	Description
NB	1) Province of New Brunswick 2) New Brunswick (Maritimes) balancing authority area
NCEP	National Council for Electricity Policy
NCPC	Net Commitment-Period Compensation
NCSPXY	Northeast Coordinated System Plan 20XY
n.d.	no date
NECEC	New England Clean Energy Connect (Central Maine Power)
NECPUC	New England Conference of Public Utilities Commissioners
NEEWS	New England East–West Solution
NEG-ECP	New England Governors-Eastern Canadian Premiers
NEL	net energy for load
NEMA	1) RSP subarea for northeast Massachusetts 2) Northeast Massachusetts load zone
NEMA/Boston	1) combined load zone that includes northeast Massachusetts and the Boston area 2) capacity zone, including the area within the Boston import interface and comprising the RSP bubble for BOSTON 3) reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NESCAUM	Northeast States for Coordinated Air Use Management
NESCOE	New England States Committee on Electricity
New Hampshire	active-demand-resource dispatch zone
NH	1) State of New Hampshire 2) RSP subarea comprising northern, eastern, and central New Hampshire; eastern Vermont; and southwestern Maine 3) New Hampshire load zone 4) New Hampshire active-demand-resource dispatch zone
NH DES	New Hampshire Department of Environmental Services
NH PUC	New Hampshire Public Utilities Commission
NICE	Northeast International Committee on Energy
NICR	net Installed Capacity Requirement
NGA	Northeast Gas Association
NMISA	Northern Maine Independent System Administrator, Inc.
NNE	1) northern New England 2) export-constrained capacity zone, which includes the area north of the North–South interface and comprises the RSP bubbles for BHE, ME, SME, NH, and VT
No.	number
NOPR	notice of proposed rulemaking
NOR	RSP subarea that includes Norwalk and Stamford, Connecticut
Northern CT	Northern Connecticut active-demand-resource dispatch zone
Northshore	active-demand-resource dispatch zone
Northwest Vermont	active-demand-resource dispatch zone
Norwalk-Stamford	active-demand-resource dispatch zone
NO_X	nitrogen oxide(s)
NPCC	Northeast Power Coordinating Council, Inc.
NPDES	National Pollution Discharge Elimination System (US EPA)
NRC	Nuclear Regulatory Commission (US)

Acronym/Abbreviation	Description
NREL	National Renewable Energy Laboratory (US DOE)
NY	1) State of New York 2) New York Balancing Authority Area
NYISO	New York Independent System Operator
NYS-DEC	New York State Department of Environmental Conservation
NYMEX	New York Mercantile Exchange
O_3	ozone
OATT	*Open Access Transmission Tariff*
OP	Operating; operating date
OP 4	ISO Operating Procedure No. 4, *Action during a Capacity Deficiency*
OP 7	ISO Operating Procedure No. 7, *Action in an Emergency*
OP 8	ISO Operating Procedure No. 8, *Operating Reserve and Regulation*
OP 14	ISO Operating Procedure No. 14, *Technical Requirements for Generators, Demand Resources, Asset-Related Demands, and Alternative Technology Regulation Resources*
OP 19	ISO Operating Procedure No. 19, *Transmission Operations*
PAC	Planning Advisory Committee
PC	Participants Committee (NEPOOL)
PDR	passive demand resource
PG	Pittsfield–Greenfield
PJM	PJM Interconnection LLC; the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia
PM	particulate matter
$PM_{2.5}$	fine particulate matter
PMU	phasor measurement unit
PNGTS	Portland Natural Gas Transmission System
pnode	pricing node
Portland, ME	Portland, Maine, active-demand-resource dispatch zone
PP 3	ISO Planning Procedure No. 3, *Reliability Standards for the New England Area Pool Transmission Facilities*
PP 10	ISO Planning Procedure No. 10, *Planning Procedure to Support the Forward Capacity Market*
PPA	proposed plan application
PPTU	public policy transmission upgrade
PRD	price-responsive demand
PSERC	Power System Engineering Research Center (US DOE)
PSNH	Public Service of New Hampshire
PSPC	Power Supply Planning Committee (NEPOOL)
PTF	pool transmission facility
PTO	participating transmission owner
PTO-AC	Participating Transmission Owner-Administrative Committee
PUC	Public Utilities Commission (ME, NH, RI, VT)
PURA	Public Utilities Regulatory Authority (CT)
PV	photovoltaic
PXP	Portland Xpress Project
QP	queue project

Acronym/Abbreviation	Description
QTPS	qualified transmission project sponsor
queue (the)	ISO Interconnection Request Queue
RC	Reliability Committee
RCRA	*Resource Conservation and Recovery Act* (US EPA)
REC	Renewable Energy Certificate
REO	Regional Energy Outlook
RF	ReliabilityFirst
RFP	request for proposals
RGGI	Regional Greenhouse Gas Initiative
RI	1) State of Rhode Island 2) RSP subarea that includes the part of Rhode Island bordering Massachusetts 3) Rhode Island load zone 4) Rhode Island active-demand-resource dispatch zone
RNS	Regional Network Service
ROP	Rest-of-Pool capacity zone
ROS	Rest-of-System reserve zone, which excludes the other, local reserve zones
RPS	Renewable Portfolio Standard
RSP	Regional System Plan
RSP*XY*	*20XY Regional System Plan*
RTO	Regional Transmission Organization
RTR	renewable technology resource
RTU	reliability transmission upgrade
SA	substitution auction
SB	Senate Bill
SBC	systems benefits charge
SCADA	System Control and Data Acquisition
SCC	seasonal claimed capability
Seacoast	active-demand-resource dispatch zone
SEMA	1) RSP subarea comprising southeastern Massachusetts and Newport, Rhode Island 2) Southeastern Massachusetts load zone 3) active-demand-resource dispatch zone
SEMA/RI	Southeastern Massachusetts/Rhode Island capacity zone, the area within the SEMA/RI import interface, comprising the RSP "bubbles" for SEMA and RI
SENE	Southeastern New England import-constrained capacity zone, which includes the area within the Southeast New England interface, comprising the RSP 'bubbles" for SEMA, RI, and BOSTON
SERC	Southeastern Reliability Corporation
SF_6	sulfur hexafluoride
SMD	Standard Market Design
SME	RSP subarea for southeastern Maine
SO_2	sulfur dioxide
SOR	settlement-only resource
SP-15	CAISO zone covering southern California
SPIDERWG	System Planning Impacts from Distributed Energy Resources Working Group
SPR	sponsored policy resource
Springfield, MA	Springfield, Massachusetts, active-demand-resource dispatch zone

Acronym/Abbreviation	Description
STATCOM	static synchronous compensator
SVC	static voltage ampere reactive (VAR; V) compensator
SWCT	RSP subarea for southwestern Connecticut; key transmission study area
T&D	transmission and distribution
TBD	to be determined
TC	Transmission Committee
TCI	Transportation and Climate Initiative
TCA	transmission cost allocation
Technical Guide	ISO New England's *Transmission Planning Technical Guide*
TGP	Tennessee Gas Pipeline
TOPAC	Transmission Owner Planning Advisory Committee
TOUT	through-or-out service
TRE	Texas Reliability Entity
TSA	Transmission Security Analysis
UCTE	Union for the Coordination of Transmission of Electricity (Europe)
UFLS	underfrequency load shedding
US	United States
USA	United States of America
USC	United States Code
UVLS	undervoltage load shedding
VAR	voltage-ampere reactive
VELCO	Vermont Electric Power Company
VER	variable energy resource
Vermont	active-demand-resource dispatch zone
VT	1) State of Vermont 2) RSP subarea that includes Vermont and southwestern New Hampshire 3) Vermont load zone 4) Vermont active-demand-resource dispatch zone
VT PUC	Vermont Public Utility Commission
VTWAC	Vermont Weather Analytics Center
WCMA	Western/Central Massachusetts load zone
WECC	Western Electricity Coordinating Council
Western CT	Western Connecticut active-demand-resource dispatch zone
Western MA	Western Massachusetts active-demand-resource dispatch zone
WI	Western Interconnection
WIP	Wright Interconnect Project
WMA	RSP subarea for western Massachusetts
WMECO	Western Massachusetts Electric Company
WMPP	Wholesale Markets Project Plan
WWTP	wastewater treatment plant
XLS	Microsoft Excel file
yr	year