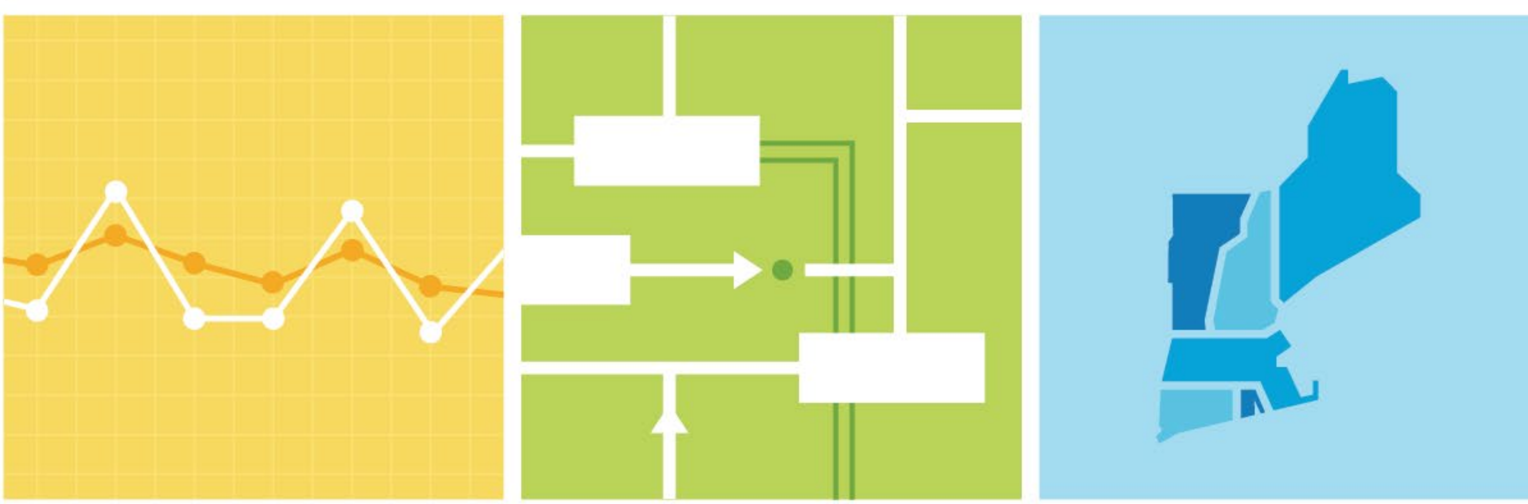
2023 Regional System Plan

NOVEMBER 1, 2023



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Preface/Disclaimer

ISO New England Inc. (the ISO or ISO-NE) 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 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* ("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

Regional System Plans 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, New England Power Pool (NEPOOL) members, market participants, and other stakeholders to meet or modify the needs of the system. Regional System Plans are not comprehensive plans of the region's power system but are intended as technical resources for policymakers, industry participants and other interested stakeholders. Additional information about the New England power system is available on the ISO website.

The regional system planning process in New England is open, transparent, and reflects advisory input from regional stakeholders, particularly attendees 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 *2023 Regional System Plan* (RSP23) and the regional system planning process identify the region's electricity needs and plans for meeting these needs for 2023 through 2032. RSP23 updates the RSP21 report by discussing study proposals, scopes of work, assumptions, draft and final study results, and other materials. The RSP23 also identifies key electric power system issues the region faces and how they can be addressed.

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 *2023 Regional System Plan.*

From System Planning

I am pleased to offer 2023's Regional System Plan (RSP23) to the public and stakeholders as an overview of ISO New England System Planning's work over the past several years. As the ISO prepares to enter its 27th year, our role in overseeing the regional power grid has never been more important.

Driven by a combination of policy goals and economics, New England is only just beginning to see and feel the effects of the clean energy transition. As you will see in this report, this transition promises far-reaching changes to the New England power grid. As part of the ISO's FERC-mandated responsibility as independent system operator, the RSP provides the public and stakeholders with a front-row seat to the evolution of the grid.

Dr. Robert Ethier
Vice President, System Planning

Since RSP21, the scale and rate of the grid's transformation have grown significantly. From load forecast increases and expected peak season shifts to Interconnection Request Queue growth and economic study advancements, many aspects of power grid administration are experiencing unprecedented change. The ISO and the processes we administer are evolving to accommodate and facilitate the clean energy transition, and this evolution will continue as the path of the transition becomes more clear.

The RSP is intended as an informational snapshot of the many functions of the power grid's operation and future at one moment in time. In addition to this RSP, the ISO's Annual Work Plan is an important resource that lists all near-term ISO projects, and showcases the kinds of forward-thinking endeavors needed to meet the challenges of decarbonization. The Planning Advisory Committee and other stakeholder venues also provide further detail and up-to-date information about important changes in system planning.

The ISO's role in ensuring that the New England power grid stays reliable as it undergoes this transformation is vital, but states, consumers, and the industry also play crucial roles. Collaboration between all key players is essential, and the ISO will continue in this spirit of collaboration as the clean energy transition unfolds.

Contents

Figures

Tables

Section 1: Executive Summary

New England is in the midst of an unprecedented shift in both the production and consumption of electricity. Driven in large part by public policies, renewable production sources like wind, solar and battery storage have begun to replace conventional thermal generation (i.e., coal, gas, and oil) and are expected to substantially displace these resources in the decades to come. Given their dependence on weather patterns, clean energy resources produce energy with more variability than conventional resources. Additionally, since many solar and wind resources are smaller in scale and located farther from more populated areas, they are more geographically scattered than traditional natural gas and coal plants. Thus, the shift in resource types is also accompanied by a shift from mostly centrally dispatched generation toward more distributed generation.

Given their geographic diversity, these distributed energy resources are often located in regions that may lack adequate transmission infrastructure, which poses challenges to the grid. Other fundamental aspects of the power grid are also changing rapidly. The spinning turbines of thermal power plants that run on fossil fuels or nuclear reactors help support the stability of the power system by providing inherent benefits that mitigate sudden changes in demand. The power-electronic-based resources and distributed resources that will comprise the future grid lack these inherent benefits—so the shift toward these resources requires the region to develop new ways to ensure the balance and stability thermal resources have historically provided.

This significant shift in the ways New England sources energy is accompanied by changes in the way New England consumes energy. As electricity becomes more prevalent in heating buildings and powering vehicles, demand patterns will evolve. In New England, demand for electricity typically peaks in the summer, with a smaller peak occurring in the winter. However, electrification of the heating and

The ISO's roles and responsibilities

ISO New England is authorized by the Federal Energy Regulatory Commission (FERC) to perform three critical roles for the region spanning Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, and most of Maine. Through collaboration and innovation, the ISO fulfills these three roles: **grid operation**, **market administration,** and **power system planning.**

The ISO's system planning work ensures that the regional transmission system can reliably deliver power to consumers under a wide range of future system conditions. The Regional System Plan (RSP) is a comprehensive planning report on the resources and transmission facilities needed to maintain the reliability of New England's power system over a 10-year horizon, while also accounting for market efficiencies and economic and environmental considerations. Stakeholders responsible for developing needed resources can use the RSP to assess their options for satisfying these needs and commit to developing market resource projects. Developing an RSP at least once every three years is one of the ISO's FERC-mandated responsibilities.[1]

[1] Per Attachment K: Regional System Planning Process of the Open Access Transmission Tariff (Section II of the ISO Tariff).

transportation sectors will result in a significant increase in both total demand and peak demand, and push peak demand into the winter months. As a result of the accelerated growth in solar resources, daily patterns in demand during peak seasons will also change. In short, the power grid of the future looks radically different from the power grid of the past, and immense resource and transmission build-outs, along with flexible loads and modifications to our grid planning processes, are required to meet the changed needs.

Since the 2021 Regional System Plan (RSP21), the ISO has continued to progress toward meeting the challenges of the future grid, including key system planning enhancements, economic study process modifications, proposed Tariff changes, shifts in resource adequacy analyses, and more. However, uncertainty remains. In 2022, the ISO published a detailed study of the future operational characteristics of the power system, the Future Grid Reliability Study. This study reveals that in addition to the massive quantities of solar and wind resources needed to produce clean electricity, significant quantities of balancing resources will be required to maintain system reliability, and that today's short-duration battery storage technologies are not able to ensure energy adequacy. Federal and state policies continue to accelerate decarbonization and the associated evolution of the grid. The ISO is working to help stakeholders in the region attain decarbonization goals; however, continued retirements of legacy generators will remove much-needed dispatchable resources from an evolving power system. This 2023 Regional System Plan (RSP23) represents a comprehensive look at how the ISO is facilitating the clean energy transition over a 10-year horizon, and identifies areas in need of further focus if the region is to continue to provide reliable and competitively priced electricity.

1.1 Four Pillars of the Clean Energy Transition

The ISO is helping to reliably plan and operate the grid as the region transitions to clean energy. The ISO's *2022 Regional Electricity Outlook* describes four pillars critical to a reliable clean energy transition:

1. Providing **significant amounts of clean energy** in order to achieve decarbonization goals. Eventually, clean energy will meet most consumer demand, with legacy resources like natural gas used to fill gaps.
2. Maintaining a robust fleet of **balancing resources** that do not require certain weather conditions to keep electricity supply and demand in equilibrium. These balancing resources will keep energy flowing when renewables are not able to run.
3. Ensuring **energy adequacy** through a robust energy supply chain for those balancing resources, or with sufficient reserves to withstand extended periods of severe weather events or supply constraints.
4. Developing **robust transmission,** such as installing new dynamic reactive support facilities, to integrate renewable resources, meet increased loads, and transmit and distribute clean energy throughout New England.

1.1.1 Relation of Key Results of RSP23 to the Four Pillars of the Clean Energy Transition

Various key results of RSP23 present areas of progress and concern related to the four pillars of the clean energy transition. This executive summary provides an overview of these key results, with the following sections exploring these results in further detail.

- Recent federal and regional policy changes (Sections 1.3and 1.4, Section 2, Section 3) have driven an influx of proposed resources requesting interconnection and **robust transmission** (Sections 1.6 and 1.7).
- Load forecast findings (Section 1.5, Section 4) reveal a shift from a summer-peaking system to a winter-peaking system, and predict a winter morning peak that could soon exceed the winter evening peak. This pattern (two daily peaks) would be a first for the New England power grid and will present challenges to **energy adequacy**.
- Low minimum loads (Sections 1.5 and, Section 1.6, Section 4) will result in resources being dispatched off more frequently, and thus fewer **balancing resources** will be online at any one time. Without the traditional quantity of balancing resources, grid operators must find other ways to balance electricity supply and demand in order to maintain a stable power grid.
- Investments in **robust transmission** (Sections 1.6 and 1.7, Section 5) and interconnection have been made, but much more transmission infrastructure is necessary to support the exponential growth in **clean energy** resources like wind, solar, and storage. This increased transmission infrastructure will be required across New England.
- Interconnection requests (Section 1.7.1, Section 6) point to the growing role of **clean energy**. Nearly half of current proposals are for wind power projects, with battery storage making up 38% of the queue and solar representing 16%.
- Recent ISO economic studies (Section 1.9, Section 8) find that during the coldest days of the year, New England's future grid may lack sufficient pipeline infrastructure to meet the region's fuel demand for both home heating and power generation, creating a dependence on liquefied natural gas imports that may result in **energy adequacy** concerns. Other non-carbon-emitting energy storage technologies can help fill this void, but studies suggest the quantity of energy storage needed is infeasible from an economic and physical perspective, and the required storage resources would not have adequate opportunity to charge.

These and other takeaways are discussed in the following section. An overview of System Planning and RSP23 can be found in Section 1.10 of this executive summary, and is described in further detail in individual sections.

1.2 Highlights and Key Results of RSP23

The following sections summarize the key results of studies and analyses from each group responsible for providing relevant information for RSP23. More detailed information can be found in the relevant sections of this report.

1.3 State and Federal Initiatives

The ISO engages with public officials, policymakers and others regarding policies and programs at the state and multistate levels that can have a significant impact on the wholesale electricity markets and transmission. Many of the six New England states have created initiatives designed to encourage electrification of heating and transportation. Federal efforts by FERC, the US Department of Energy (DOE), Congress, and the White House also have implications for the sector. These initiatives and efforts are summarized here and described in more detail in Section 2.

1.3.1 Congressional Activities at the Federal Level

The *Infrastructure Investment and Jobs Act* (IIJA) is $1.2 trillion investment signed in late 2021 that contains a number of electricity and transmission provisions. The *Inflation Reduction Act*, signed in late 2022, similarly contains fiscal incentives for a host of clean energy technologies. The ISO expects these congressional actions to increase interconnection requests and have a direct impact on transmission needs and growth of electrification over the next decade and beyond.

1.3.2 FERC Initiatives and Recent Notices of Proposed Rulemaking

A number of recent FERC efforts have targeted issues related to the integration of renewable energy generation and electric transmission planning and development. Since RSP21, FERC has also issued notices of proposed rulemaking (NOPRs) and final rules that will change various aspects of planning, interconnection requests, and transmission development. The various NOPRs and final rules are summarized as follows:

NOPR	Date of Issue/Final Rule Date
Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022)	April 2022/TBD
Improvements to Generator Interconnection Procedures and Agreements, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 (2022)	January 2022/July 2023

1.3.3 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). The ISO also works collaboratively with the New England Conference of Public Utilities Commissioners (NECPUC), the New England governors' offices, state energy offices, and the states' consumer advocates to provide information and assistance. The New England states have coordinated on applications to pursue funding through the *Infrastructure Investment and Jobs Act (IIJA)*'s Grid Innovation Program to support innovative approaches to transmission and distribution infrastructure. ISO staff provided technical assistance for these proposals. The ISO also coordinated with the states on proposals related to the Northern Maine Procurement, a transmission line from northern Maine to ISO territory, the New England Clean Energy Connect (NECEC) transmission line, and a Hydrogen Hub proposal submitted by Connecticut, Maine, Massachusetts, Rhode Island, Vermont, New York, and New Jersey.

1.3.4 Renewable Portfolio Standards

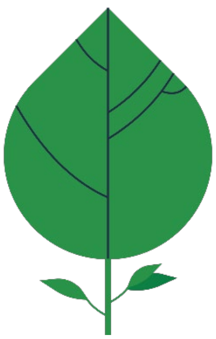
To support the development of renewable energy resources, state Renewable Portfolio Standards (RPS) require electricity providers to serve a minimum percentage of their retail load using renewable energy. A summary of current standards is illustrated in Section 2.4.1.

1.3.5 Individual State Policies

The ISO actively monitors New England state legislative actions related to the power grid. All the New England states have passed various legislation related to the clean energy transition in the legislative sessions since RSP21. These actions are detailed in Section 2.4. The ISO continues to provide technical support and long-term planning to the New England states and will need ongoing state input to support a reliable clean energy transition.

1.4 Environmental Regulations and Goals Affecting the Power System

In addition to federal and state initiatives, the ISO expects recent changes in federal and state environmental laws to have a significant impact on the future power system, driven by carbon emissions targets and efforts designed to control other pollutants like nitrogen oxides and sulfur dioxide. How resources and generators are permitted and sited will also be affected by federal and state policymaking. Various changes in federal and state policy since RSP21 are summarized here and detailed further in Section 3.



The nature of implementation of these policy changes is still uncertain. Inadequate transmission, the retirement of legacy fuel sources outpacing new builds of clean energy resources, and interconnection delays as a result of rapid renewable growth in both the distribution and transmission systems are of particular concern. While the general goal of federal and state policies is to increase renewable production and decrease legacy fuel source production, additional attention should be given to the supporting infrastructure needed to make these changes successful.

1.4.1 Federal Environmental Policy Changes Related to Executive Order of 2021

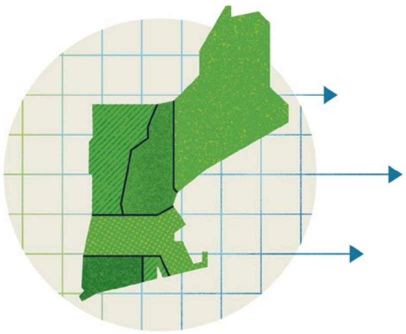
Several significant policy-related changes since RSP21 are connected to the ongoing and expected actions of the Environmental Protection Agency (EPA) as a result of President Joe Biden's *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*, signed in January 2021. The order directed the EPA to review rules that were published during President Donald Trump's administration between 2017 and 2021. This review is designed to ensure laws reflect the best available science, improve public health, and protect the environment. Various ongoing and expected changes that could affect the power industry were included in the EPA's Fall 2022 Unified Agenda of Regulatory and Deregulatory Actions. Specific actions related to hazardous air pollutants, the *Clean Air Act of 1970*, and wastewater discharges are detailed further in Section 3.

1.4.2 Revised Definition of Waters of the United States

The Clean Water Act of 1972 established federal jurisdiction over navigable bodies of water that are defined as Waters of the United States (WOTUS). The definition of WOTUS has been revised several times since the 1970s and has been the subject of continuous litigation since its inception. In response to the executive order, the definition was revised once again in the 2023 Revised Definition of Waters of the United States final rule. The 2023 rule went into effect on March 20, 2023, however, the revised definition is not operative in many states due to ongoing litigation. Project developers should take preemptive steps to discern if a property contains WOTUS, which WOTUS definition applies in which state, and if an activity would result in the discharge or addition of pollutant(s) from a point source to WOTUS, which may require a Clean Water Act permit.

1.4.3 Regional Greenhouse Gas Trends and Regional Initiatives

In addition to federal policy, state and regional policy and emissions targets will also have a significant impact on the power grid in the next decade and beyond. New England states have generally been more aggressive in their clean energy standards and emissions targets than federal policy dictates, and this trend has continued through 2023. The ISO expects generally that regional clean energy policy will continue to be more aggressive than federal policy in the coming years.



Every New England state with 2020 interim emission reduction goals has reportedly achieved those goals. New Hampshire does not have mandatory greenhouse gas targets.

States within the region continue to participate in programs designed to reduce carbon dioxide (CO_2) emissions and keep the New England states on target to meet their emissions goals. These programs include the Regional Greenhouse Gas Initiative and Renewable Portfolio Standards.

The Regional Greenhouse Gas Initiative is a market-based cap-and-trade program whereby affected generators within each participating state acquire and surrender CO_2 allowances equal to their CO_2 emissions over a three-year control period. Average costs for compliance rose sharply in 2022, increasing by 41%. This increase in price is likely attributable to several factors, including increased market participation, the continuation of the Emission Containment Reserve, and the initiation of a third program review with the adoption of a stricter cap.

Renewable Portfolio Standards are state laws that set the percentage of energy that load-serving entities must provide using renewable resources. These targets are shown in Figure 1-1. Changes in the last year include a revision of Rhode Island's target to 100% renewable energy by 2033.

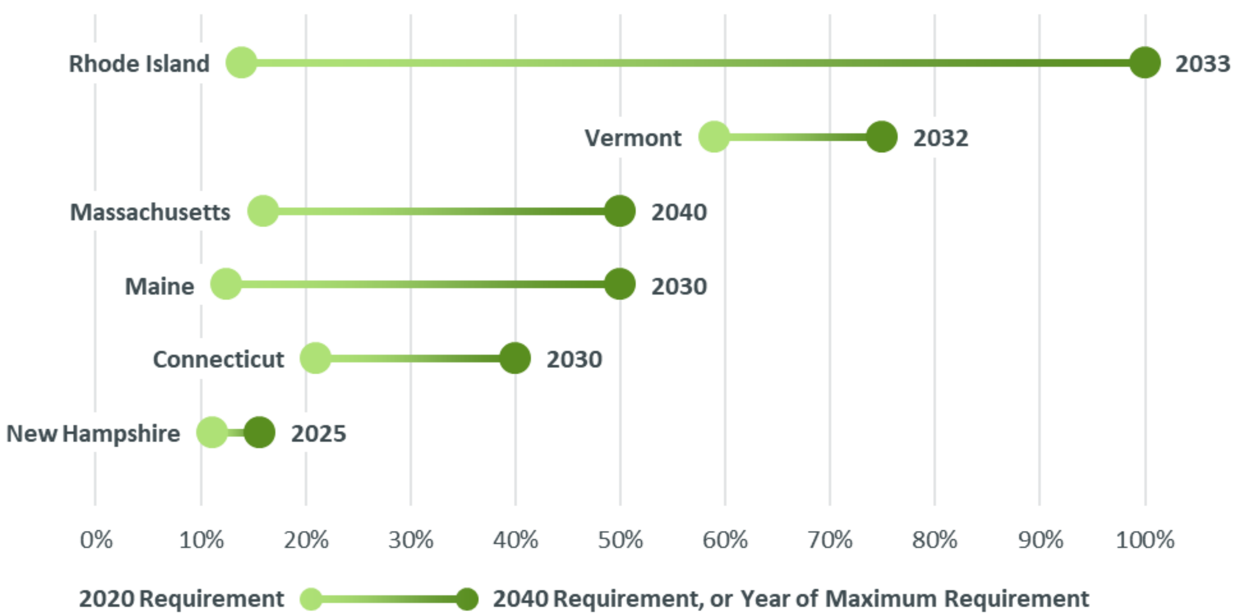


Figure 1-1: Renewable Portfolio Standards for New England States, 2020–2040

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 2012 through 2021, total system emissions decreased: nitrogen oxides by 39%, sulfur dioxide by 87%, and CO_2 by 20%.

1.5 Load Forecasting

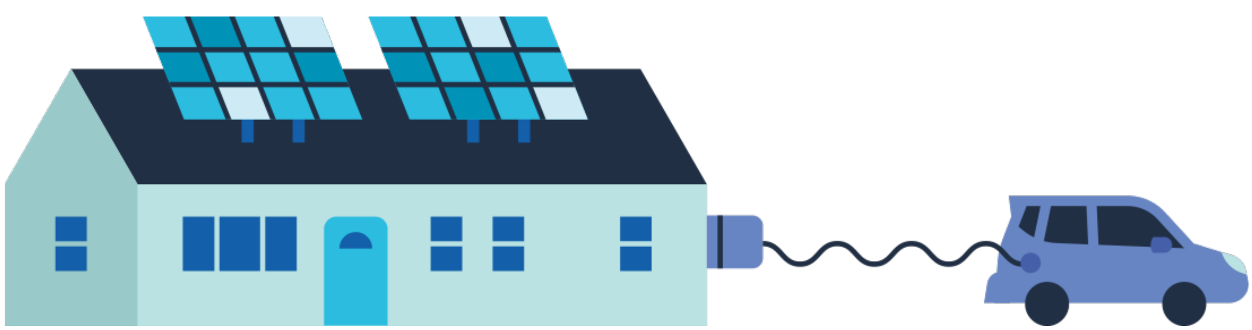
The expectation of significant transportation and heating electrification directly increases the region's annual energy, summer demand, and winter demand forecasts for the coming decade.[2] The ISO's Load Forecast uses historical loads, seasonal weather patterns, economic and demographic factors, and anticipated growth of distribution-connected resources and technologies to [forecast the peak and annual electric energy demand](). As the New England states incentivize the electrification of heating and transportation, overall growth in electrification will have an outsized impact on load in the region. Annual electricity use will increase in absolute terms, and seasonal and daily patterns of energy consumption, or load curves, will take vastly different shapes than they historically have. This transition is already underway, and the ISO expects it will accelerate rapidly in the coming decade.

The following section summarizes key findings related to the load forecast for RSP23. These findings are detailed further in Section 4.

1.5.1 Electrification Precipitating Shifts in Seasonal Peaks

By 2032, the regional impacts of electrification add 21,295 gigawatt-hours (GWh) of overall annual electricity use in New England as compared to 2022 levels, 2,415 megawatts (MW) of peak demand under typical summer peak weather conditions (known as the summer "50/50" demand), and 6,385 MW of winter peak demand under typical winter peak weather conditions (known as the winter "50/50" demand). Most of the growth in the energy and demand forecasts is attributable to electrification.

As shown in Figure 1-2, electrification is responsible for 14.2% of net energy in the 2032 annual electricity use forecast, 8.9% of net demand for the 2032 summer 50/50 demand forecast, and 24.3% of net demand for the winter 50/50 demand forecast.



[2] 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 peak load forecast for NMISA can be found in the Seven Year Adequacy Outlook.

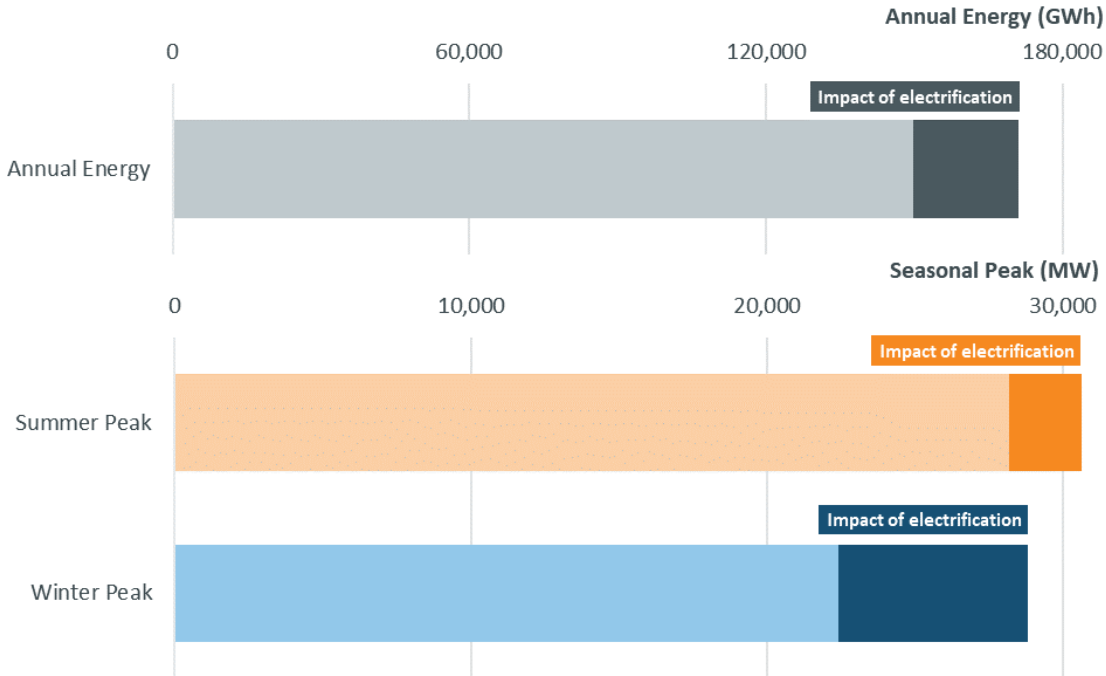


Figure 1-2: Impact of Electrification on Annual Energy Use and Seasonal Peak Demand in 2032

Electrification will also drive changes under the "90/10" forecast, which predicts what peak demand would be during unusually warm summers and unusually cold winters. Climate change is expected to make these historically rare seasonal patterns more common.

The ISO forecasts that by 2031, very cold winter weather and average summer weather occurring in the same year could cause the annual peak in demand in New England to occur in winter. By the mid-2030s, as a result of electrification, winter will become the typical peak season for electricity consumption. As this change in seasonality occurs, peak demand will likely also begin to occur in the morning, rather than the evening, as is currently the case.

1.5.2 Grid Operations Must Adapt to Growth in Distributed Photovoltaics

The ISO expects large increases in distributed photovoltaic (PV) resources by 2032. Distributed PV is either interconnected directly to the distribution system (i.e., solar farms) or interconnected behind the meter (i.e., solar rooftop installations on homes) and has a smaller nameplate capacity (usually less than 5 MW).

As shown in , by the end of 2022, all distributed PV resources in New England reached 5,473 MW_{ac} in nameplate capacity. The ISO forecasts this capacity to more than double in the next decade, reaching 11,913 MW_{ac} by 2032. Growth of distributed PV has already shifted summer net peak loads to later in the afternoon, when PV output is lower, and thus new distributed PV will play a lesser role in reducing summer peak demand than it has in previous years. The ISO expects this diminishing pattern to continue—future PV growth will be less useful in reducing forecast peaks in summer demand than it is today. As peaks in summer demand continue to occur later in the day, estimated reductions in summer peak demand due to behind-the-meter PV grow only marginally, from a 981 MW reduction in 2023 to a 1,117 MW reduction in 2032.

During the winter, peak demand occurs after sunset, which means that PV resources cannot assist in reducing the peak. However, recent study findings suggest solar resources can provide a winter reliability benefit. Their operation during the day will displace resources that use stored fuels, which will potentially make more of that stored fuel available at times when net demand is high and the grid is stressed.

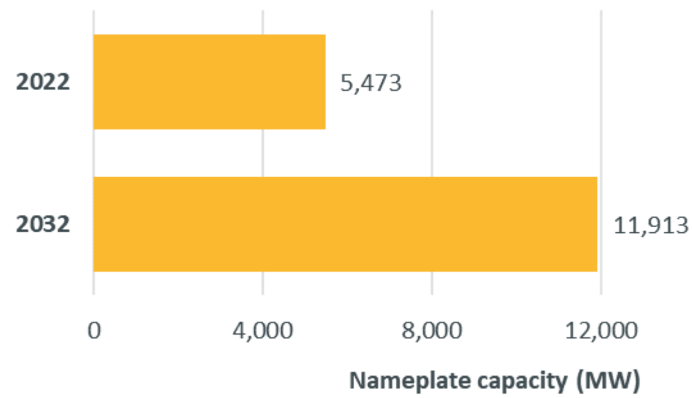


Figure 1-3: Growth in Distributed PV Resources in New England

Growing penetrations of distributed PV will also cause increasing volatility in net demand, since PV production is heavily affected by less predictable moment-to-moment factors like cloud cover. Increasing PV penetration will drive substantial PV production on sunny spring and fall days. However, spring and fall days rarely see high demand conditions, since the weather is largely milder than in summer and winter. The increase in days when solar production is high and demand drops to extremely low levels (severe light load conditions) may create challenges for the New England power grid, as spinning balancing resources will be kept offline in an unprecedented way due to the lack of net demand. The ISO predicts increasing severe light load conditions during the “shoulder seasons” over the next decade.

1.5.3 Fewer New Energy Efficiency Resources Lower Gross Load Forecasts

The implementation of new energy efficiency (EE) resources (e.g., LED bulbs) has continued to decrease since RSP21. This has resulted in a convergence between gross and net load forecasts and a proportionately lower EE forecast than in prior years. As EE resources reach a saturation point and related programs expire or pivot toward emerging priorities like heating electrification, the incremental impact of EE resources on demand is expected to continue to decrease, and gross and net loads will further converge.

1.6 Transmission Planning

Many recent trends in the electric power industry could significantly change the way that New England’s transmission system is planned. Transmission and related projects help maintain system reliability and enhance the region’s ability to support a robust, competitive wholesale power market by moving power from various internal and external sources to the region’s load centers. Transmission’s role in a reliable power grid is particularly crucial as the region implements large quantities of clean energy resources like solar, wind, and storage. With the changes in federal and regional policy outlined in Section 1.4 and the exponential growth of electrification and increase in distributed energy resources discussed in Section 1.5, uncertainty remains about how to consistently implement transmission projects with potential future needs in mind to right-size their design. The ISO’s Transmission Planning group works to ensure that the power system continues to operate reliably as grid conditions change.

Attachment N of the *Open Access Transmission Tariff* (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. Transmission upgrades resulting from system changes proposed by individual proponents include, for example, generator-interconnection-related upgrades and elective transmission upgrades. This section summarizes the transmission outlook and changes in the system since RSP21. More details on Transmission Planning, including more specific transmission upgrades, can be found in Section 5.

1.6.1 Transmission Planning for the Clean Energy Transition and Study Assumption Updates

Increases in renewable generation accompanied by certain load and weather conditions can create new power system conditions that have not previously been studied, and these conditions may limit system performance. Additionally, many clean energy resources proposed for interconnection into the New England system are inverter-based, rather than traditional thermal resources, whose spinning turbines provide inertia and reactive power and support the stability of the power system. A system with increasing numbers of inverter-based resources will have lower strength and could introduce new contingencies. The ISO's Transmission Planning department initiated the Transmission Planning for the Clean Energy Transition pilot study, published in January 2022, in order to study the effects of a changing resource mix on transmission planning.

Results of the study reveal that one of the most critical issues facing the transmission system in the clean energy transition is the potential loss of legacy distributed energy resources (DERs) during transmission system faults due to the inability of many legacy DER installations to "ride through" disturbances. This key result drove changes in study assumptions for future planning studies at the ISO, with a shift toward assumptions that better reflect the characteristics of these legacy DERs and their outsized effect on system performance.

1.6.2 Transmission Upgrades Since RSP21

A number of projects have been developed to address post-contingency overloads and voltage concerns since the publication of RSP21. Table 1-1 summarizes major transmission projects that are either underway or recently completed. A majority of these upgrades were completed in the urban areas surrounding Boston, where transmission density is higher than other, more rural areas of New England. The upgrades in Greater Boston addressed potential post-contingency overloads and voltage concerns and mitigated potential short circuit levels in the area. As of June 2023, the total estimated cost of reliability transmission upgrades was approximately $11.9 billion since 2002.

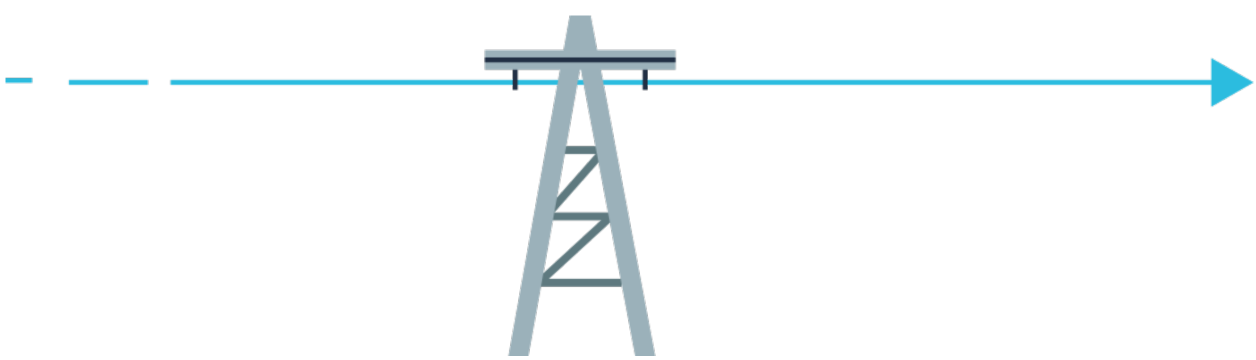


Table 1-1: Major Transmission Projects Completed since RSP21

Area or Name of Upgrade	Completion Status	Cost of Upgrade as of the June 2023 RSP Project List Update ($M)
Greater Boston Upgrade	Mostly completed; full expected in-service date March 2025	$1,200.0
Boston Area Optimized Solutions (BAOS)	Placed in service June 2023	$48.9
New Hampshire 2029 Upgrades	Expected in-service date March 2024	$155.7

In addition, 35 project components had either been planned, proposed, or were under construction as of June 2023. The ISO estimates a total of $1.5 billion in transmission project investment over the next few years, as shown in Figure 1-4.

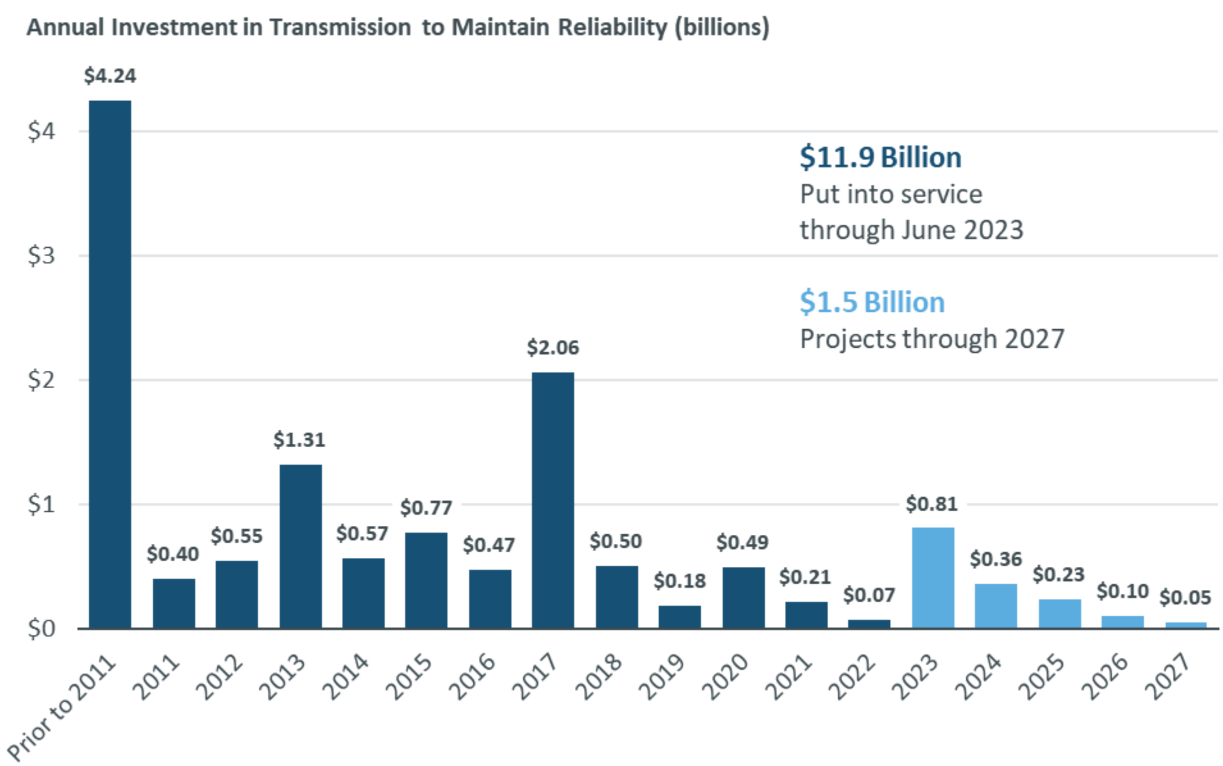


Figure 1-4: Transmission Investment by Year that Projects are In Service (Capital Costs)

1.6.3 2050 Transmission Study

At NESCOE's request and with assumptions provided by NESCOE, the ISO is conducting a 2050 Transmission Study in order to identify possible transmission system deficiencies in 2035, 2040, and 2050. Preliminary results indicate approximately 4,000 miles, or 50%, of New England's transmission line mileage could be overloaded by 2050. This study will be used to develop high-level transmission upgrade concepts and associated cost estimates to address these deficiencies. Input assumptions for this study are based on the "All Options" pathway in Massachusetts' *Energy Pathways to Deep Decarbonization* report. The high renewable penetration of this scenario is consistent with the level of renewable penetration required by the New England states' clean energy policies detailed in earlier sections.

1.6.4 Transmission Congestion

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. 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). The 2022 total for congestion resulting from transmission constraints was $51.0 million, and the total for voltage and second-contingency NCPC was $1.1 million. For context, the total wholesale electricity market value in 2022 was $16.7 billion.

1.7 Transmission Services and Resource Qualification

Changes in the way resources are qualified and interconnected will continue to add complexity to the New England power grid over the coming decades. As part of its role in administering transmission services to the region, and in accordance with provisions of the OATT, the ISO helps evaluate proposals for interconnections required for new or upgraded resources on the power grid. For example, a proposal for a new solar or wind farm in the region must run through ISO's interconnection request process. These proposals are evaluated in order of their submission to the Interconnection Request Queue. Since RSP21, the number of resources active in this queue has increased significantly, due in part to the incentives for clean energy related to the *Inflation Reduction Act* mentioned in Section 1.3.11.4. The ISO expects this trend to continue, and for the interconnection of distributed energy resources to increase the complexity of the power grid. To ensure a reliable grid, it is essential that the ISO continue to work closely with transmission owners to ensure the proper DER interconnection process is followed. More details on Transmission Services and Resource Qualification can be found in Section 6.

> ***353** generation projects are being tracked in the Interconnection Request Queue, up from **289** at the time of RSP21's publication*

1.7.1 Current Interconnection Queue

In total, 353 generation projects are being tracked in the Interconnection Request Queue, up from 289 at the time of RSP21's publication. Active projects are projects in any one of the stages of study, and remain in the queue until they achieve commercial operation or are withdrawn. Many projects withdraw due to lack of financing or inability to receive permitting. The ISO has observed that the length of the interconnection request process is not a common reason for project withdrawal. More common reasons are a lack of a power purchase agreement, permitting difficulties or supply chain/inflation concerns.

As of publication, the status of projects in the queue is as follows:

- **25** in the scoping stage
- **27** undergoing feasibility study
- **48** undergoing system impact study/optional interconnection study
- **4** undergoing facilities study
- **39** negotiating interconnection agreements
- **28** with interconnection agreements
- **193** non-FERC-jurisdictional distribution interconnections[3]

Resources active in the queue as of June 2023 are shown in Figure 1-5 (years represent expected in-service dates). Proposals for battery energy storage systems in particular have increased significantly. Though not all of these proposed generating resources will be built, transmission bottlenecks are likely, and additional transmission build-out may be required to reliably interconnect renewable resources currently in the queue.

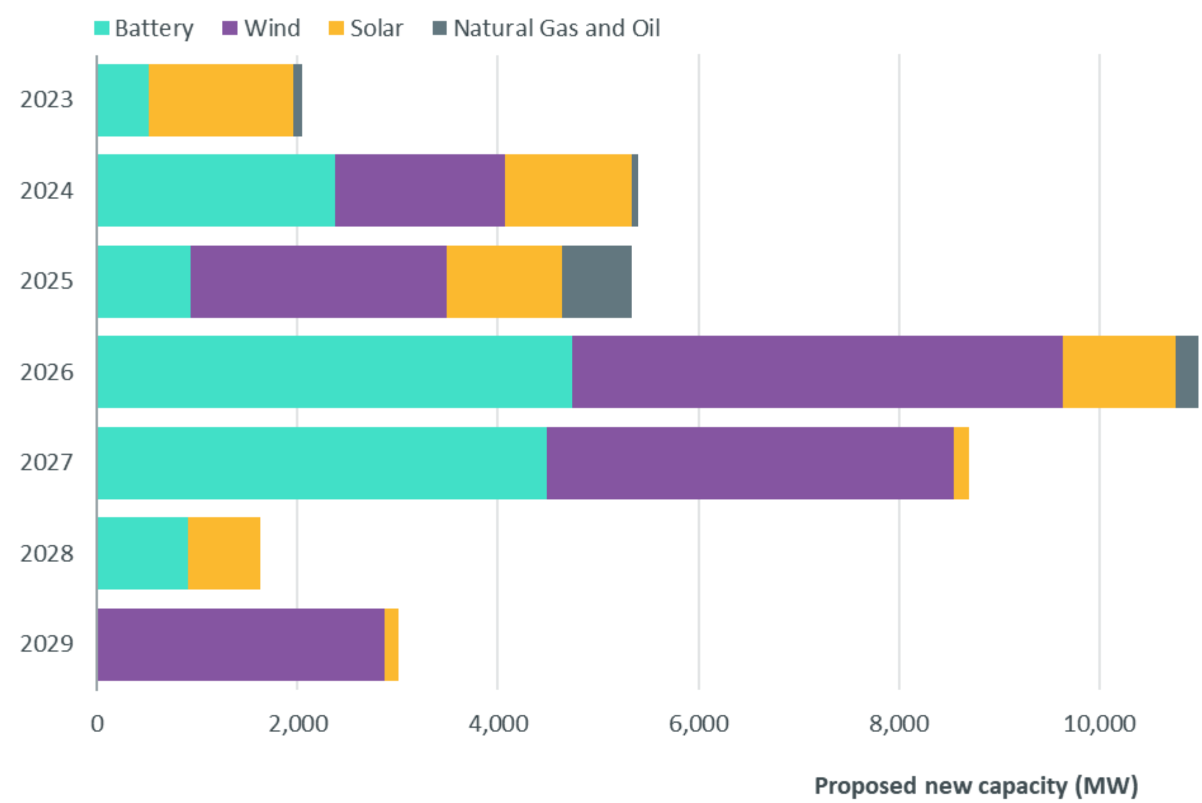


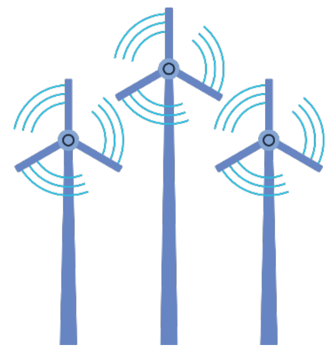
Figure 1-5: Resources Active in the ISO Interconnection Request Queue by Fuel Type, as of June 1, 2023

[3] These projects' interconnection processes are being administered by the local interconnecting Distribution Companies and only have ISO-NE queue positions for reporting purposes.

1.7.2 Outcomes of Recent Cluster Studies in Maine and Cape Cod

In certain circumstances, projects interconnecting through the FERC jurisdictional process can be studied in a *cluster.* A series of studies related to northern Maine (2016/2017 Maine Resource Integration Study or MRIS, the Second Maine Resource Integration Study completed in 2020, and a third MRIS currently underway) identified several required upgrades that are either completed or in progress. These upgrades could allow up to 1,200 MW of new generation to minimally interconnect.

System Impact Studies and Resource Integration Studies for offshore wind interconnecting to Cape Cod continue to reveal the likely need for significant new transmission infrastructure. Current infrastructure was developed to serve the area load and historically connected generation, and despite recent and proposed improvements, the ISO sees challenges related to queue length management with regard to the needs of proposed new offshore wind resources. Cluster studies can be an efficient way to manage challenges related to interconnections into complex areas of the New England Transmission system, especially Cape Cod.



1.7.3 Regional Integration of Wind, Photovoltaic, and Battery Resources

Limited transmission infrastructure in northern and western Maine poses the primary obstacle to interconnecting new onshore wind resources. Each new interconnection request in the area involves lengthy and complex study work, identifies significant transmission infrastructure needs, and leads to an inability or unwillingness on the part of individual project developers to make the required system upgrades. The ongoing Maine Resource Integration Study identifies major new transmission lines to integrate the proposed generation.

The ISO has taken a number of steps to prepare for the effects of large-scale solar development in New England. Existing solar resources have caused noticeable changes to system operation, and higher penetration will increase the system's need for regulation, ramping, reserves, and voltage support. New patterns of power flow from distribution substations onto (instead of out of) the transmission system when solar production is high have resulted in new uses of the transmission system and have increased the need for dynamic voltage support.

The addition of more battery energy storage systems to the region could present additional challenges, as demand could become less predictable. The interconnection of distributed energy resources within electric distribution systems has contributed to an overall decrease in net demand.

1.7.4 Required Generator-Interconnection-Related and Elective Transmission Upgrades

With the exception of the completed cluster studies, no significant transmission system upgrades have been proposed from the interconnection of generators. Most of the completed upgrades are modest in scope and fairly local to the point of interconnection of the generator. Identification of significant transmission upgrades for interconnection of a generator that is not part of a cluster study has often led developers to abandon their proposal and withdraw from the queue.

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. The queue includes proposals to import energy from other regions and from offshore wind and to increase internal transfer capabilities.

1.7.5 Resource Qualification for the Forward Capacity Market

The ISO runs a Forward Capacity Auction (FCA) each year to procure the resources needed to meet consumer demand for electricity three years in advance. FCA 17 was held on March 6, 2023, securing commitments for 31,370 MW of capacity to be available in 2026/2027. Of note, more than 5,000 MW of new and existing solar and wind generation, energy storage, and demand resources secured obligations in FCA 17, accounting for about 16% of all capacity clearing the auction.

1.8 Resource Adequacy and Accreditation

As part of its obligation to identify the quantities and locations of resources the New England power grid needs to operate reliably and effectively, the ISO determines the amount of capacity the system requires in a given year, called the Installed Capacity Requirement (ICR) and related values. The Forward Capacity Market (FCM) is designed to ensure our resource requirements are met each year. Along with the demand forecast detailed in Section 4 and Section 1.5, the ICR and FCM form what is known as the resource adequacy process. The ISO projects there will be sufficient resources for New England through the end of the 10-year horizon. However, this assumption is based on no additional resource retirements beyond those already planned, successful operation of all resources that have cleared the last FCA, addition of all Sponsored Policy Resources, and no significant changes in accreditation. Changes in any of those conditions could change the resource adequacy forecast for 2032.

The clean energy transition and its associated resource mix is rapidly changing the way the resource adequacy process must function. Since the publication of RSP21, the ISO has initiated the Resource Capacity Accreditation (RCA) project with stakeholders. This project is designed to account for the changing resource mix, the increase in winter risk, and changed daily demand profiles mentioned in Section 4 and Section 1.5. At the time of RSP23's publication, the final outcome of the RCA project was still undetermined. Any outcomes from its completion could significantly impact forecasts made in this section and Section 7.

This section summarizes the requirements for resource adequacy over the next decade, describes analyses the ISO has performed to determine both systemwide and local-area needs for ensuring resource adequacy, and discusses results of assessments of the system's resource adequacy under various stressed-system simulations. These assessments are described in further detail in Section 7.

1.8.1 Systemwide and Local Resource Requirements and Limits

In consultation with the New England Power Pool and other stakeholders, the ISO each year develops the ICR and related values, which are then reviewed and accepted by various committees and eventually FERC.

The region is expected to have decreasing net ICR requirements through the 2026/2027 capacity commitment period (CCP), but requirements are expected to begin rising again as the load forecast continues to increase. Expected reserve margins will start around 20% and settle out around 11% in the outer years of the planning horizon.

Given regional transmission constraints, the ICR alone is not sufficient to ensure New England's capacity needs will be met. More granular regional analysis must be performed. The Local Sourcing Requirement (LSR) helps determine the minimum amount of capacity each subarea of New England requires in order to meet the overall New England ICR. Conversely, the Maximum Capacity Limit (MCL) determines the maximum number of resources that can be located in an export-constrained subarea of New England.

The capacity zones for the last four auctions have remained fairly consistent. Southeast New England (SENE) required an LSR for FCAs 14–16, but this was removed for FCA 17 due to decreased loads and transmission system improvements. The capacity zones of Maine and Northern New England (NNE) required an MCL for the last four FCAs that has gradually declined as forecasted loads increase in the region.

1.8.2 Summer and Winter Operable Capacity

The ISO performs systemwide operable-capacity analyses to estimate future summer and winter operable-capacity margins at peak demand conditions under two scenarios, the 50/50 and 90/10 forecasts of peak load (as described in Section 1.5). The RCA project will change how resources are accredited, and thus post-RCA summers and winters (2028–2032) are subject to that change. The system will require ISO Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4) actions as soon as the summer of 2025 for a projected 50/50 peak and the upcoming summer of 2024 for a projected 90/10 peak. Assuming no new additional resources and an expectation that the region can achieve roughly 3,500–4,000 MW of demand relief from OP 4 actions, Operating Procedure No. 7, *Action in an Emergency* (OP 7) actions would not be necessary for 90/10 summer peak loads. The addition of Sponsored Policy Resources would reduce the need for OP 4 actions.

The region will need OP 4 actions starting in the winter of 2025/2026 for 50/50 forecasted winter peak loads, and this upcoming winter of 2023/2024 for 90/10 forecasted winter peak loads. Assuming no new additional resources and an expectation that the region can achieve roughly 3,500–4,000 MW of demand relief from OP 4 actions, OP 7 actions would not be necessary until the winter of 2031/2032 for 50/50 winter peak loads and the winter of 2028/2029 for 90/10 winter peak loads. The addition of Sponsored Policy Resources would reduce the need for OP 4 and OP 7 actions.

1.8.3 Tie Benefits

Interconnections with neighboring regions are a vital part of New England grid operations. Various interregional coordination efforts help ensure that New England's power grid functions efficiently with relation to its geographical neighbors. Interconnections with neighboring regions provide opportunities for exchanging capacity, energy, and mutual assistance during capacity-shortage conditions. Tie benefits have remained relatively constant over the last four FCAs, with steady increases the last three auctions. Imports cleared in the last four auctions have been more volatile, with significantly fewer imports clearing in FCA 17.

The ISO is revising tie benefits in the RCA project to incorporate seasonal values.

1.9 Economic Studies

The ISO has released one economic study since RSP21: the Future Grid Reliability Study Phase 1 of 2021, which was requested by the New England Power Pool. In 2022, the ISO commenced the Economic Planning for the Clean Energy Transition pilot study, which is underway. The ISO also conducts needs assessments of the New England power grid as they relate to the RSP process. The Economic Studies and Environmental Outlook group conducts these needs assessments in order to evaluate changes to the power grid that might affect total production costs or increase/decrease congestion on transmission lines. This section summarizes these studies and provides a short overview of the outlook for future economic studies. These studies are described in more detail in Section 8.

1.9.1 Future Grid Reliability Study Phase 1

Phase 1 of the Future Grid Reliability Study (FGRS) explored how our region might confront the significant challenges related to the transformation of our power grid and develop practical and innovative pathways forward given the emissions goals proposed by the New England states, described in Section 2 and Section 1.4. This innovative study analyzed 32 future scenarios, each a particular version of the 2040 grid, to determine key gaps and reliability issues. Though specific results for each scenario varied, the results showed that exclusive reliance on new wind, solar, and battery resources, coupled with expected increases in electrification, will pose significant reliability challenges. The main scenario explored in FGRS Phase 1, Scenario 3, was based heavily on Massachusetts' *Energy Pathways to Deep Decarbonization* report, which is also the basis for the 2050 Transmission Study detailed in Section 5.5.3 and Section 1.6.

KEY FINDINGS

>100%

Increase in 2040's assumed winter demand peak, compared to the grid's all-time peak.

36 Days

Frequency of natural gas demand exceeding pipeline supply in 2040.

6 Million Tons

Amount by which CO_2 emissions will exceed state goals due to the retirement of nuclear resources.

875%

Increase in electrification of heating and transportaton between 2031 (based on the latest Forecast Report of Capacity, Energy, Loads, and Transmission) and the 2040 study assumptions.

Specific observations from FGRS included challenges for energy adequacy, the need for resource and demand flexibility, and challenges from a changing resource mix. The study further highlighted the need for dispatchable resources as part of a reliable, renewables-heavy future grid, whether these dispatchable resources are carbon-emitting or not. In this same renewables-heavy future grid, demand on natural gas will likely exceed pipeline supply, precipitating a more urgent need for a dispatchable alternative. Proposed solutions like battery storage were not sufficient to meet these needs, as batteries were not able to charge sufficiently under predicted conditions. High electrification, aggressive retirement of existing dispatchable resources, and the difficulty in predicting the output of distributed energy resources will severely deplete reserves and regulation, and will increase reserve requirements by orders of magnitude.

FGRS Phase 1 also allowed the ISO to identify ways to improve future economic studies using new software tools and analyses. Phase 2 has been incorporated in the Economic Planning for the Clean Energy Transition pilot study, detailed in the next section.

1.9.2 Economic Planning for the Clean Energy Transition

In April 2022 the ISO proposed the Economic Planning for the Clean Energy Transition (EPCET) pilot study. This pilot study is intended to achieve three main objectives: serve as a dry run for a new economic study framework under development by the ISO and its stakeholders, enable review and testing of input assumptions for economic planning analyses, and provide experience in the features and capabilities of new planning software. The new framework was based on lessons learned during FGRS Phase 1 and introduces a biennial process that provides a cohesive, repeatable study framework based on defined reference scenarios, with additional stakeholder-requested sensitivities. It was accepted by FERC in March 2023.

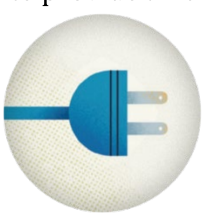
A key component of EPCET is the test of new software (PLEXOS) designed to better reflect the assumed resource mix of the future grid explored in FGRS Phase 1. The main benefit of the PLEXOS software is the ability to run capacity expansion scenarios, which was not possible with the previous software. With capacity expansion modeling capabilities, resources can be added and/or retired from the modeled grid based on production *and* capital costs, which allows for a more complete picture of the rapidly changing resource mix of the future New England grid.

The new economic study framework includes three reference scenarios: a *benchmark scenario*, a *market efficiency needs scenario (MENS),* and a *policy scenario*. The *benchmark scenario* models the previous calendar year and compares it to historical system performance as a way to evaluate software performance; *MENS* models future years in the existing Tariff-mandated 10-year planning horizon; and the *policy scenario* models future years beyond the 10-year horizon as a means to inform regional and other energy and climate policies.

Initial EPCET results include benchmark scenario and MENS results, with policy scenario results expected throughout the rest of 2023.

1.10 Regional System Plan Inputs

The functions of the RSP are to provide updates on power system needs and system planning, and to provide a 10-year planning outlook. Stakeholders responsible for developing needed resources



can use the RSP to assess their options for satisfying these needs and commit to developing market resource projects. For example, developers can build a new generating resource to provide additional system capacity and produce electric energy. Similarly, market participants can provide demand resources to reduce the amount of electricity drawn from the bulk power system. They also can develop and independently fund the interconnection to the ISO system of a new transmission facility. These transmission upgrades, along with supply and demand resources, could result in modifying, offsetting, or deferring proposed regulated transmission upgrades.

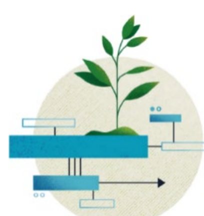
If stakeholder responses are not adequate to meet identified system needs, the transmission planning process requires the ISO either to acquire transmission solutions through a competitive process or to work with existing transmission owners to develop their own transmission solutions. All transmission upgrades must meet reliability performance requirements. More about the transmission planning process can be found in Section 4. An overview of the inputs for RSP23 development is shown in the appendix to RSP23. Aspects of these inputs are described in detail in later sections of this RSP and include **State and Federal Initiatives** (Section 2), **Environmental Regulations** (Section 3), **Load Forecasting** (Section 4), **Transmission Planning** (Section 5), **Interconnection** (Section 6), **Resource and Energy Adequacy** (Section 7), and **Economic Studies** (Section 8).

1.10.1 Planning Studies Conducted for and Summarized in RSP23

The ISO continually conducts numerous regional and local-area studies during all stages of planning in order to ensure 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. Major studies and initiatives performed by the ISO, as well as those conducted by other entities, are detailed in this report. These major studies and initiatives are consistent with the regional planning process and include:

- Studies of the economic and environmental performance of the bulk power system including the 2050 Transmission Study, Transmission Planning for the Clean Energy Transition pilot study, Economic Planning for the Clean Energy Transition pilot study, and Future Grid Reliability Study Phase 1
- Forecasts through 2032 of seasonal gross peak load and annual gross electric energy use
- Ten-year forecasts for distributed solar power, energy efficiency, and electrification of the heating and transportation sectors
- Net forecasts of annual and peak electric energy use
- Analyses of the amount and locations of needed energy, capacity, and operating reserves to ensure resource adequacy
- A summary of the most recent Forward Capacity Market results and representative future operating-reserve requirements
- Assessment of the implications for the transmission system of generator retirements and interconnection of distributed energy resources
- Assessment of the effects of compliance with environmental regulations on generator operating requirements and the need for remediation measures
- Preparation 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
- Assessments of systemwide and local-area needs (i.e., needs assessments), and transmission solutions to meet these needs[4]
- Interregional studies and initiatives
- Consideration of federal, state, and regional initiatives and governmental activities and policies affecting the planning process

While each Regional System Plan represents a snapshot in time, the planning process is continuous and adaptive, seeking to meet planning objectives in an open and transparent manner with interested stakeholders for the 10-year planning horizon. 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.



[4] Refer to the OATT, Attachment K, Section 4.1 and 4.2 for complete definitions for needs assessments and solutions studies.

1.10.2 Working with the Planning Advisory Committee, Other Committees, and Stakeholders

To conduct the system planning process, the ISO holds a transparent stakeholder forum with the Planning Advisory Committee (PAC).[5] Meetings are open to members of the public, including state regulators or agencies and the New England States Committee on Electricity. PAC attendees typically include representatives from state and federal agencies, participating transmission owners, ISO market participants, other New England Power Pool members, consulting companies, manufacturers, and other organizations, such as universities and environmental groups.

Other committees like the Reliability Committee, the Transmission Committee, and the Markets Committee are also involved in the system planning process. Additionally, 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.

The ISO provides various types of information designed to assist stakeholders. In addition to publishing the RSP and specific needs assessments and solutions studies, the ISO issues RSP Project Lists and Asset Condition Lists. The RSP Project List includes the status of transmission upgrades during a project's lifecycle, and the Asset Condition List.[6] Both lists are updated several times per year.

Additionally, the ISO posts on its website detailed information supplemental to the RSP process, such as the Regional Electricity Outlook, Annual Markets Report, Wholesale Markets Project Plan, presentations, and other reports. The ISO also makes available reliability criteria and assessment practices used in its analyses and related information required to perform simulations consistent with FERC policies and ISO *Information Policy* requirements pertaining to both confidential information and Critical Energy Infrastructure Information requirements.[7] Stakeholders can use this information and data to conduct their own independent studies.

1.10.3 Meeting All Requirements

In addition to complying with the *Open Access Transmission Tariff*, which reflects the requirements of FERC orders, RSP23 complies with North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council (NPCC) criteria and standards, as well as ISO planning procedures and operating procedures.

1.11 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 RSP subareas (or System Planning subareas), load zones, reserve zones, demand-resource dispatch zones, and capacity zones. These categories are included in discussions throughout the RSP. Commonly used maps and diagrams related to ISO New England's operation of the region's electric power system and settlement of the wholesale electricity marketplace are available on the ISO-NE website.

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[5] More information on the PAC can be found in the ISO Tariff, Section II (Open Access Transmission Tariff), Attachment K: Regional System Planning Process.

[6] Stakeholder presentations to the PAC on the condition and management of assets are available at the ISO-NE's website.

[7] Stakeholders also can obtain publicly available power flow base cases, maps and diagrams of the transmission system network through the FERC 715 process. ISO New England Information Policy (2020) contains the requirements for controlling the disclosure of CEII and confidential information.

1.12 Conclusion and Future Outlook

The ISO is committed to helping the region adequately plan for the clean energy transition. The New England states have set aggressive targets to reduce greenhouse gas emissions to nearly zero by 2050. The ISO supports the states' environmental objectives in its role as the region's Independent System Operator—and as New England's grid operator, the ISO has an important role to play in securing the region's clean and reliable energy future. However, the challenge ahead is large.

To that end, the ISO has identified four pillars that are critical to maintaining a reliable decarbonized grid: **large quantities of clean energy**, **balancing resources, energy adequacy**, and **robust transmission.** Key results of the RSP23 relate to each of these four pillars.

As the region's policymakers work to address climate change through laws aimed at decarbonizing the electricity sector, it is imperative that the ISO, the states, and all other stakeholders continue working together to adequately plan for the clean energy transition and to ensure the strength of these pillars.

As detailed in this executive summary, various conditions precipitated by the clean energy transition will create unprecedented shifts in the operation of the New England power grid. For example, the ISO's studies consistently show the need for significant transmission development and sufficient amounts of dispatchable resources that can run independent of weather variation. Today, such dispatchable resources use fossil fuels. Successfully navigating a transition to clean, high-density, dispatchable energy sources—such as generators powered by hydrogen or other clean fuels—will depend on technological advancements, as well as maintaining some natural gas infrastructure.

How quickly will these advancements come? How will the region maintain infrastructure that may be seldom used, but will be absolutely critical to fill energy gaps over days or weeks when weather-dependent resources are not available? These are just some of the questions and engineering and economic realities the region must contend with as we work together toward decarbonization. Other variables, from the pace of resource retirements to rising costs, supply chain issues, and siting challenges that could slow or threaten the build-out of new clean energy infrastructure are also in play. Some variables will fall within the scope of the ISO's responsibilities and authority. Others will call for state action. Others will involve global economic forces.

A significant increase in the demand for electricity is coming. New England residents and communities are turning to electrification to reduce their carbon footprints. Harnessing New England's vast renewable energy potential to meet this new demand—and achieving the states' decarbonization goals while maintaining reliability—will require significant investment and creative, collaborative problem-solving.

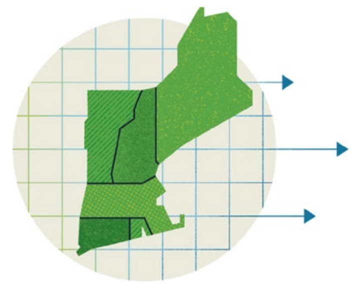
ISO New England is committed to working with the region to plan, prepare and execute changes to meet the challenges ahead.

The ISO has a successful track record of integrating regional policy objectives into system operations, planning, and wholesale markets. In order to ensure our future energy markets and grid deliver the fairly priced and reliable electricity consumers have come to expect, the ISO draws upon its quarter century of experience planning the region's power system, and in collaboration with the industry at large, continues to develop innovative and flexible solutions. To meet the challenges of an evolving grid, the ISO is enhancing its work in several key areas: revising assumptions in transmission studies, conducting long-term transmission and extreme weather studies, performing follow-up work to FGRS, and exploring new approaches to markets and accreditation, among others.

> *As detailed in this executive summary, various conditions precipitated by the clean energy transition will create unprecedented shifts in the operation of the New England power grid.*

Efficient, reliable, clean energy is possible, but it requires innovative technology development and significant investment. ISO New England, NEPOOL and other stakeholders, and the states will continue to collaborate on viable pathways to a clean, reliable, and economical future grid in this decade and beyond.

Section 2: State and Federal Initiatives



The ISO's External Affairs department engages with public officials, policymakers, regulators, consumer representatives, and environmental agencies regarding important initiatives affecting the energy sector. These initiatives include projects and key study areas aimed at developing and integrating new technologies, improving operating and planning procedures, and updating the wholesale markets to enhance system reliability. Stakeholders include the New England Conference of Public Utilities Commissioners (NECPUC), the New England States Committee on Electricity (NESCOE), and the Consumer Liaison Group (CLG).

A number of policies and programs at the state and multistate levels have a significant impact on the wholesale electricity markets and transmission, specifically regarding the timing, type, and location of resources and transmission infrastructure. Additionally, policies of many of the six New England states aim to encourage electrification of heating and transportation, which is projected to have impacts on total load and load profiles throughout the coming decade and beyond. Federal efforts, by the Federal Energy Regulatory Commission (FERC), the US Department of Energy (DOE), Congress, and the White House, also have implications for the sector. The ISO closely monitors federal and state activity to inform various stakeholder and study processes.

2.1 ISO New England Collaboration with New England States on Policy Goals

The ISO continues to engage with market participants and state entities, including NESCOE, to assess the future of the regional power system in light of state energy and environmental laws and explore potential pathways forward to ensuring a reliable, efficient, and sustainable clean energy grid.

In 2022 the ISO finalized Phase 1 of the *Future Grid Reliability Study* (FGRS), described in greater detail in Section 8, a stakeholder-led assessment designed to evaluate how a 2040 grid could perform with the predicted shift in both predominant resource type and increased demand. Studies that build on results in FGRS include the *Pathways to the Future Grid Study* and the *2050 Transmission Study*, described in greater detail in Section 5. These studies provide critical information and analysis as state policymakers and regulators determine how to accomplish current clean energy and climate policy objectives.

The ISO also provides technical assistance to the New England states, including answers to questions about the Tariff, qualitative feedback on project proposals, and interconnection procedures. For example, ISO staff provided technical feedback on draft proposals as the New England states pursued DOE funding opportunities, described in Section 2.3.1.

2.2 Incorporating Federal Policy

The ISO monitors federal government activity closely to determine potential impacts to the New England planning processes. In 2021 and 2022, Congress passed legislation with significant implications for the energy and electricity industries, including various opportunities for federal funding to support renewable energy and transmission development.

2.2.1 Congressional Activities

In late 2021, President Biden signed into law the *Infrastructure Investment and Jobs Act* (IIJA), a $1.2 trillion investment that contains a number of electricity and transmission provisions. These provisions include, but are not limited to, enhancing the backstop siting authority of FERC, and creating several mechanisms for DOE to incentivize electric transmission planning and development. The bill also contains components that support existing nuclear generation, energy efficiency, and cybersecurity.

In August 2022, President Biden signed legislation, known as the *Inflation Reduction Act,* that similarly contains a number of fiscal incentives for a host of clean energy technologies, including wind and solar, energy storage, energy efficiency, and the electrification of transportation and heating. It includes a $370 billion, 10-year investment plan that seeks to lower energy costs, reduce greenhouse gas (GHG) emissions, accelerate investment in and deployment of clean energy resources, and invest in domestic energy production and manufacturing.[8]

2.2.2 FERC Initiatives and Recent Notices of Proposed Rulemaking

A number of recent FERC efforts have targeted issues related to the integration of renewable energy generation and electric transmission planning and development, including the creation of a joint federal-state task force with the National Association of Regulatory Utility Commissioners to discuss the ways in which state commissioners can collaborate with FERC to move transmission projects forward. FERC has also issued notices of proposed rulemaking and final rules, described below, that will change various aspects of planning and transmission development.

On April 21, 2022, FERC issued a notice of proposed rulemaking (NOPR), *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022)*, to address the Commission's concerns that existing transmission policies do not allow for the development of transmission infrastructure at an adequate rate to meet the needs of the changing resource mix and demand. This NOPR proposes significant reforms to the existing transmission planning process and transmission cost allocation requirements established initially in Order No. 1000. The major reforms include:

- Establishing a new long-term (over 20 years), scenario-based planning process that anticipates the evolving resource mix and demand, and gives the states a decision-making role in cost allocation for longer-term transmission facilities selected in that process
- Restoring incumbent transmission owners' right of first refusal to build regional transmission projects, as long as they establish joint ownership of those projects with unaffiliated entities
- Increasing transparency in local transmission planning and "right-sizing" aging infrastructure replacements to more efficiently and cost-effectively address regional transmission needs in the long-term planning process
- Sharing of information regarding transmission needs in the long-term planning process in the identification and joint evaluation of interregional transmission facilities

On June 16, 2022, FERC issued a NOPR, *Improvements to Generator Interconnection Procedures and*

[8] "Inflation Reduction Act Guidebook", The White House, accessed August 9, 2023

Agreements, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 (2022), proposing reforms to the standard large and small generator interconnection procedures and agreements. The proposed reforms build on the Commission's Orders No. 2003, 2006, and 845 to address interconnection queue backlogs, improve certainty, and prevent undue discrimination related to new technologies, primarily wind, solar, and storage.

This NOPR was prompted by the growth of new resources seeking to interconnect to the transmission system and the challenges related to differing characteristics of those resources for the generator interconnection process. These challenges result in large interconnection queue backlogs and uncertainty regarding the costs and timing of interconnecting to the system, which could increase consumer costs. The NOPR recognizes that the surge of interconnection requests coupled with limited transmission capacity to interconnect them to the system will continue to increase and, absent reforms, further intensify interconnection queue backlogs. These backlogs create reliability issues, as they hinder the ability of necessary new generating facilities to achieve commercial operation.

On July 28, 2023, FERC issued *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, the final rule adopting many of the reforms to the interconnection process proposed in the NOPR.

The final rule's major reforms include:

- Replacing the "first-come, first-served" interconnection study process with a "first-ready, first-served" cluster study process, and allocating costs among interconnection customers in the cluster using a proportional impact method
- Improving the speed of interconnection queue processing by imposing firm study deadlines for the completion of interconnection studies, including penalties for late studies
- Incorporating technological advancements in the interconnection process for the benefit of new technology (i.e., nonsynchronous wind, solar, and storage) interconnections
- Requiring interconnection customers with nonsynchronous generating facilities to include models needed for accurate interconnection studies in the interconnection request

2.3 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 NESCOE. NESCOE is governed by a board of managers appointed by the governors of the six New England states and is active in matters related to resource adequacy and system planning. NESCOE's forward-looking priorities are highlighted in its annual report. NESCOE and individual state representatives are active in the regional stakeholder processes and discussions about the ISO's Annual Work Plan.

The ISO also works collaboratively with NECPUC, the New England governors' offices, state energy offices, and the states' consumer advocates, providing monthly updates to the states on regional stakeholder discussions regarding regional planning processes and the wholesale electricity markets.[9]

2.3.1 Regional Coordination to Pursue Department of Energy Funding

The *Infrastructure Investment and Jobs Act*, also known as the *Bipartisan Infrastructure Law* (BIL), invests more than $1 trillion over the next five years into transportation, broadband, and utilities. The BIL allocates funding to DOE to create new programs and expand funding for research, development, demonstration, and deployment. The states, utilities, and developers are seeking funding through various programs of the BIL.

The New England states have coordinated on multistate and individual applications to pursue funding through programs including the Grid Resilience and Innovation Partnership's Grid Innovation Program. The Grid Innovation Program has $5 billion to allocate over the next five years to support innovative approaches to transmission, storage, and distribution infrastructure that will enhance grid resilience and reliability. ISO staff provided technical assistance to the states as they prepared their proposals for the first round of funding.

2.3.2 Northern Maine Procurement

Legislation enacted in Maine in June 2021 required the Maine Public Utilities Commission (PUC) to conduct a request for proposals (RFP) for a transmission line from Northern Maine to ISO territory, and for northern Maine renewable energy resources that will utilize the new transmission line. The RFP was issued in November 2021 and conditionally selected both generation and transmission projects in November 2022. The selected projects are a ~100 mile, 1,200 megawatt (MW), 345 kilovolt (kV) double circuit transmission line from LS Power and a 1,000 MW King Pine wind project from Longroad Energy. The commission initially delayed a final decision to await possible cost sharing opportunities.

In response, in December 2022, the Massachusetts Department of Energy Resources, in consultation with the Massachusetts Office of the Attorney General, directed Massachusetts electric distribution companies to enter into long-term contracts for 40% of both the generation and transmission costs. The Maine PUC commissioners determined that the 60% cost share for Maine ratepayers was in the public interest and in January 2023 directed utilities to move forward with long-term contracts.

2.3.3 NECEC Transmission Line

In 2016, Massachusetts passed renewable energy legislation that, in part, resulted in a renewable energy solicitation and selection of the New England Clean Energy Connect (NECEC) transmission line.[10] The NECEC line is a Central Maine Power-proposed 145-mile HVDC transmission line intended to bring 1,200 MW of large-scale hydropower from Hydro-Québec in eastern Canada to Maine and the ISO system. After a series of litigation and other challenges resulting in delays, a stop-work order was lifted in May 2023, allowing for the resumption of construction.

2.3.4 Hydrogen Hub

In spring of 2023, Connecticut, Maine, Massachusetts, Rhode Island, and Vermont joined New York and New Jersey in a proposal submission to DOE seeking $1.25 billion in funding for development

[9] Most consumer advocates are members of NEPOOL.

[10] [MA General Court, An Act to Promote Energy Diversity, Chapter 188 of the Acts of 2016 (August 8, 2016)]()

of a Northeast Regional Clean Hydrogen Hub. The proposal includes more than a dozen projects across the participating states designed to advance clean electrolytic hydrogen production, consumption, and infrastructure projects for hard-to-decarbonize sectors, including transportation and heavy industry. Awards are anticipated in the fall of 2023.

2.3.5 Consumer Liaison Group

In 2009, the ISO and regional stakeholders created the Consumer Liaison Group (CLG). This forum is open to the public and meets quarterly to facilitate information flow between the ISO and consumers.[11] The CLG comprises representatives from state offices of consumer advocates and attorneys general, large industrial and commercial consumers, chambers of commerce, environmental organizations, individual ratepayers, and others. With the input of CLG members, a Coordinating Committee establishes CLG meeting agendas and discussion topics and selects panel speakers. The ISO posts meeting materials and summaries on its website.

On March 30, 2023, the CLG Coordinating Committee (CLGCC) and the ISO summarized the group's 2022 activities in the *2022 Report of the Consumer Liaison Group*. The report was updated in May 2023 with input from the CLGCC on their priorities and future initiatives.

The report also provides an update on ISO activities and initiatives, as well as information on wholesale electricity costs and retail electricity rates.[12]

2.4 Individual State Initiatives, Activities, and Policies

The New England states work together continually to identify, discuss, and address energy issues of common interest. Each state also has a unique set of energy policy objectives and goals. This section briefly discusses Renewable Portfolio Standards (RPS) and carbon reduction policies and summarizes additional actions taken by the individual New England states related to regional system planning. Many of the New England states pursue initiatives that support reduced energy costs, accelerate electrification of heating and transportation, and advance the adoption of renewable energy generation. This section aims to highlight energy policies passed during the 2022 and 2023 legislative sessions, since the issuance of RSP21, and is not intended to be a comprehensive review of all enacted state policies and initiatives.

2.4.1 Renewable Portfolio Standards

To support the development of renewable energy resources, state RPS policies require electricity providers (electric distribution companies and competitive suppliers) to serve a minimum percentage of their retail load using renewable energy. All six New England states have differing RPS requirements and goals, expressed as a percentage of retail electric sales, with varying definitions of renewable resources. Figure 2-1 shows the RPS for each New England state for new renewable energy resources.

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[11] The end-user sector in the New England Power Pool (NEPOOL) stakeholder process also includes consumer interests and provides information and advice to the ISO through the NEPOOL process.

[12] US Energy Information Administration, Electric Power Monthly, Table 5.6.B Average Price of Electricity to Ultimate Customers by End-Use Sector, by State (Through Dec. 2022); 2022 Report of the Consumer Liaison Group. The New England all-in wholesale electricity price is derived by dividing total wholesale electricity costs by real-time load obligation (presented for illustrative purposes; does not reflect actual charge methodologies).

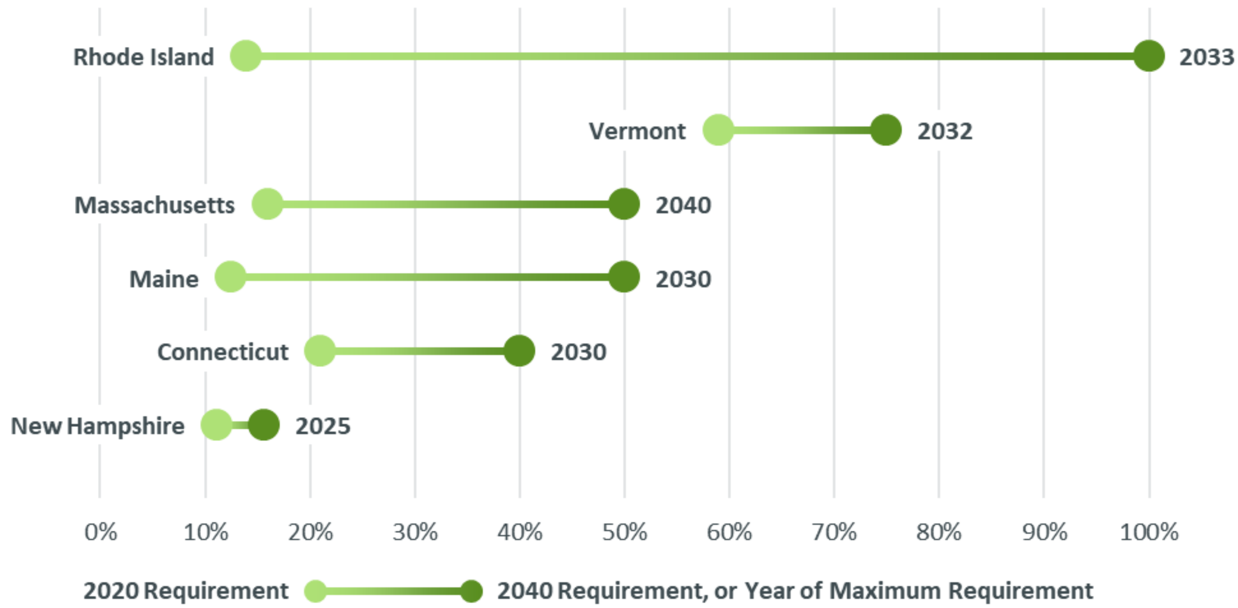

Figure 2-1: Renewable Portfolio Standards for New England States, 2020–2040

Source: ISO-NE, Resource Mix.[13]

2.4.2 Connecticut

Connecticut's 2022 legislative session included the enactment of energy legislation concerning the state's goal to achieve a zero-carbon electricity grid, energy storage project regulations, the state's clean energy tariff program, and transportation-related emissions. Governor Ned Lamont signed into law climate change legislation in 2022, originally established under an executive order in 2019, which requires the state to eliminate greenhouse gas emissions from electricity supplied to electric customers in the state by January 1, 2040.

Additional legislation passed in 2022 expands the state's clean energy tariff programs, making adjustments to both the non-residential energy solutions (NRES) and shared clean energy facilities (SCEF) programs. The statutory changes increase the yearly amount of capacity available for zero-emissions NRES projects (e.g., solar facilities), raise the aggregate cap for NRES and SCEF projects,

[13] State RPS requirements promote the development of renewable energy resources by requiring electricity providers (electric distribution companies and competitive suppliers) to serve a minimum percentage of their retail load using renewable energy. Connecticut's Class I RPS requirement plateaus at 40% in 2030. Maine's Class I/IA 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 2024, 3% each year between 2025 and 2029, 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 reaches 100% in 2033. 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.

raise the cap on eligible project size, and allow megawatt allocations to roll over to the next program year.

In the spring of 2023, Connecticut announced its intent to pursue additional clean energy procurements to support the state's progress in achieving greenhouse gas emissions reductions and decarbonization of the electric sector. Two draft procurements released in July 2023 target both new zero-carbon electricity generating resources and offshore wind. The state is also in process of issuing a solicitation for energy storage to support grid reliability.

2.4.3 Maine

Maine passed legislation in 2022 directing the PUC to lead a stakeholder initiative, requiring Maine's utilities to undergo an integrated grid planning process for developing a reliable electric grid that supports a transition to clean energy at the lowest possible cost. This planning process is currently underway at the Maine PUC. Additionally, legislation enacted in 2023 directs the Maine Governor's Energy Office to conduct a two-part study regarding the establishment of a distribution system operator.

Related to the Northern Maine Renewable Energy Development Program described in Section 2.3.2, Maine enacted legislation that directs the PUC to procure additional generation projects in northern Maine to utilize the remaining capacity on the 1200 MW transmission line selected through the initial procurement. The PUC is directed to consider the timing of the procurement in an effort to enable the selected project(s) to seek inclusion in the ISO's Third Maine Resource Integration Study and subsequent cluster system impact study.

In 2023, Governor Janet Mills signed legislation that establishes a state goal of 3,000 MW of offshore wind capacity installed by 2040 and creates the Maine Offshore Wind Renewable Energy and Economic Development program. Among other provisions, the bill directs the Maine Governor's Energy Office to establish a schedule for competitive solicitations for offshore wind development. The PUC may then issue competitive solicitations for offshore wind for no less than 600 MW per solicitation starting no later than January 2026, and authorizes the PUC to conduct one or more competitive solicitations for offshore transmission development.

2.4.4 Massachusetts

Massachusetts passed legislation in 2022 to stimulate clean energy development, support transportation and heating electrification, and promote decarbonization and economic development. A Clean Energy Investment Fund was established at the Massachusetts Clean Energy Center (MassCEC) to advance clean energy research, technology, and deployment to achieve the commonwealth's GHG reduction mandates. The legislation created a Clean Energy Transmission Working Group to study the regional transmission upgrades that may be necessary to deliver the state's procured clean energy and allowed the state to solicit for and procure independent offshore wind transmission. In addition, the legislation authorized the commonwealth to coordinate with one or more New England states on a competitive solicitation for clean energy generation, transmission, or capacity. Additionally, a Massachusetts Offshore Wind Industry Investment Trust Fund was established to promote offshore wind development and associated economic activity.

In June 2022, the Massachusetts Executive Office of Energy and Environmental Affairs (EEA) issued a revised Massachusetts Clean Energy and Climate Plan (CECP) for 2025 and 2030. The plan outlines the programs the state is undertaking, will adopt, and is considering in order to achieve its

GHG emissions reduction mandates of 33% below 1990 levels by 2025 and 50% below 1990 levels by 2030.

The EEA additionally released the 2050 CECP in December 2022, which details how the state plans to meet its statutory requirements to achieve net-zero GHG emissions by 2050. The plan sets sector-specific emissions limits that equal the required gross greenhouse gas emissions reductions of at least 85% below 1990 levels, and proposes carbon sequestration goals to supplement reductions and meet the net-zero requirement.

In August 2023, the Massachusetts Department of Energy Resources (DOER) and electric distribution companies (EDCs) jointly issued an RFP for the commonwealth's fourth and largest offshore wind solicitation to date. The RFP seeks to procure up to 3,600 MW of offshore wind.[14]

2.4.5 New Hampshire

In 2022, two bills were enacted that impact the site evaluation process for energy infrastructure proposals. The first bill creates a study committee to determine the feasibility of replacing the site evaluation committee with an office of energy siting, located in the New Hampshire Department of Energy (NH DOE). The second bill made a number of technical changes to the existing site evaluation process, including lowering the number of attendees to create a quorum, enhancing funding, and allowing for financial penalties for violations of issued certificates.

A bill was enacted in 2022 to create the Office of Offshore Wind Development within NH DOE. The office will develop recommendations for wind generation in the Gulf of Maine and the purchase of power by New Hampshire utilities. Additional legislation was passed to ensure that various potential impacts to resources and the environment are considered when developing plans for offshore wind.

Two key energy bills passed the General Court during the 2023 regular session and were signed by Governor Christopher Sununu. The enacted legislation allows electric distribution companies to solicit proposals by June 30, 2025, for long-term power purchase agreements for new generation of up to 2 million megawatt-hours (MWh) per year. Legislation was also enacted that contains various energy provisions, including transferring monitoring and enforcement duties related to energy facility siting to NH DOE. It additionally repeals the requirement for electric and natural gas distribution utilities to submit least-cost integrated resource plans.

2.4.6 Rhode Island

In 2022, Rhode Island enacted legislation increasing the state's renewable energy standard (RES), now requiring 100% of electricity to be met or offset by renewable energy in 2033. If the state meets this requirement, Rhode Island would become the first state in the country to achieve 100% renewable energy.

Enacted legislation additionally required Rhode Island Energy to issue a request for proposals for 600–1,000 MW of new offshore wind capacity by October 2022 and submit a final decision by March 2024. The subsequent RFP was issued in October 2022 and resulted in one bid submission announced in spring of 2023, a joint proposal between Ørsted and Eversource for an 884 MW Revolution Wind 2 offshore wind project. In July 2023, Rhode Island Energy, the state Office of

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[14] https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/17868278

Energy Resources, and the Division of Public Utilities and Carriers announced that they will not move forward with a contract for Revolution Wind 2.

2.4.7 Vermont

The Vermont state budget for fiscal 2022 allocated nearly $130 million of American Rescue Plan Act funds to climate change mitigation initiatives. Funding for energy-related initiatives include implementation of advanced metering infrastructure, electrification of heating and transportation, and energy efficiency.

In 2023, the Vermont legislature overrode a governor's veto to enact a bill known as the Affordable Heat Act. The legislation requires entities that import heating fuels into Vermont to reduce their GHG emissions each year as determined by VT PUC, either through emission reductions or the purchase of "clean heat credits." VT PUC is directed to bring the legislature a final rule for the program, which is expected to be voted on in January 2025.

2.5 Summary

The ISO conducts system planning on behalf of the region with input from the six New England states. The ISO is also engaged in planning activities 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 regional system planning in New England. Over the last few decades, significant investments in transmission have focused on meeting reliability-driven needs. Current and future regional transmission planning is now also focused on aiding in the accomplishment of state policy objectives. The ISO continues to provide technical support and long-term planning to the New England states and will need ongoing state input to support a reliable clean energy transition.

Section 3: Environmental Regulations and Goals Affecting the Power System

In addition to the initiatives described in the previous section, federal and state environmental laws, regulations, and goals, and multistate initiatives for controlling pollution, emissions, or discharges, have a large impact on various elements of the power system. These limits are intended to protect human health and the environment. Siting and environmental permitting requirements for new and existing generation can be complex and may involve multiple federal, state and local regulatory entities, depending on the generation technology, site location, and transmission needs. Generation and transmission projects may be required to modify design specifications, or adjust construction timelines or operating schedules. In the upcoming planning horizon, new generation technologies are shifting from predominantly natural-gas-fired resources to wind, solar, and storage resources. Electricity generating resources, both fossil and renewable, are required to meet regulations regarding siting and construction, and may also include requirements regarding operation and decommissioning. Mitigation may involve major capital investments for new, existing, or modified projects, as well as remediation measures, or operational changes at existing or modified facilities.

System reliability could suffer if such compliance efforts limit generator energy production, reduce capacity output, or contribute to unit retirements. However, in several recent rulemakings and permitting decisions, federal and state regulators have provided compliance options that recognize the reliability value of low-capacity-factor fossil steam generators (primarily oil-fired units).

This section summarizes the current environmental regulations affecting various types of energy resources, the federal and state efforts to promote the development of renewable resources, and regional air emissions from the New England states' generation and net imports.

The ISO's Environmental Advisory Group provides quarterly updates on the environmental performance of the regional electric generating system and regulatory and policy developments that may affect current or future operations.

3.1 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. Existing and new electric generating resources (coal, natural gas, oil, refuse, and wood) in New England generally operate advanced pollution-control technologies that reduce air emissions and wastewater discharges. Hydro, wind, and solar generators are subject to land-use and wildlife protection requirements, with additional evolving requirements for offshore wind energy projects. Within the next planning period, changes in applicable air, water, wildlife protection, and greenhouse gas (GHG) emission standards, including those for carbon dioxide (CO_2), could affect the economic performance of existing generators by imposing seasonal or year-round operational constraints or resulting in additional capital costs for installing environmental remediation measures. Wind, solar, and hydro generators may also experience operational constraints due to evolving wildlife, wildlife habitat, and water quality protection requirements.

The US Environmental Protection Agency (EPA) will likely undertake many regulatory actions in the upcoming years pursuant to President Biden's *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*, which directed agency heads to review rules published between 2017 and 2021 to ensure laws reflect the best available science, improve public health, and protect the environment. Significant programmatic and budgetary changes at various federal departments and agencies with environmental oversight responsibilities affecting the power sector are under consideration or implementation.[15] The key regulatory actions that could affect the power industry were included in EPA's Fall 2022 Unified Agenda of Regulatory and Deregulatory Actions, and are summarized below.

3.1.1 Hazardous Air Pollutants

EPA is required under Section 112 of the Clean Air Act to regulate hazardous air pollutants from industrial facilities in two phases: a technology-based phase and a risk-based phase. The first phase is focused on developing the maximum achievable control technology standards based on emissions levels already being achieved by lower-emitting sources in their respective industries. As part of the second phase, within eight years of establishing the standards, EPA is required to assess any remaining health risks from each source category and determine whether more stringent health-protective standards are needed. These phases are commonly referenced together as the Residual Risk and Technology Review. EPA is required to review and revise the standards every eight years. For electric generating units, Congress also requires EPA to determine whether it is "appropriate and necessary" to regulate emissions of mercury and other hazardous air pollutants from power plants under Clean Air Act Section 112.

In 2020, the Trump administration reversed prior determinations and stated that it was "not appropriate and necessary" to regulate this source. On March 6, 2023, EPA issued a final action revoking the 2020 rule and reaffirming that it is "appropriate and necessary" to regulate electric generating units (EGUs).[16]

The current National Emission Standards for Hazardous Air Pollutants for coal- and oil-fired EGUs, commonly known as the Mercury and Air Toxics Standards, limit emissions of mercury; acid gas such as hydrogen chloride and hydrogen fluoride; nonmercury metals including nickel, lead, and chromium (with an option to comply with a filterable particulate matter surrogate standard); and organic hazardous air pollutants such as formaldehyde and dioxin/furan. EPA estimated that, since the promulgation of the standards in 2012, 2021 mercury emissions from the power sector were 86% lower than pre-standards levels. The industry also saw 96% reduction in acid gas emissions and 81% reduction in nonmercury metals emissions compared to 2010.

EPA reviewed the 2020 Mercury and Air Toxics Standards Residual Risk and Technology Review in accordance with the executive order and proposed amendments to strengthen some emission

[15] 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 EPA.

[16] *"National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units – Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding. 88 FR 13956"*, Federal Register, last modified on March 6, 2023.

limits based on the results of the technology review.[17] EPA did not propose any changes to the 2020 residual risk review. The proposed rule is focused on reducing the emission standard for filterable particulate matter, tightening emission limits for mercury for certain coal plants, and strengthening emissions monitoring requirements. The compliance period for proposed emission limits will be three years after the effective date of the final rule, which is expected next year. EPA estimates that the proposed rule would result in numerous control upgrades, the retirement of 500 megawatts (MW) of coal-fired capacity nationally by 2028, and up to a 0.1% increase in energy prices nationally.

The Reclassification of Major Sources as Area Sources under Section 112 of the Clean Air Act was promulgated on November 19, 2020, allowing a "major source" of hazardous air pollutants to reclassify as an "area source" at any time upon reducing its emissions and "potential to emit" to below the major source thresholds. Major sources have higher emissions of hazardous air pollutants than area sources. Therefore, they are subject to different requirements that only apply to major sources. In general, an area source is any source of hazardous air pollutants that is not a major source. Pursuant to the executive order, EPA is reviewing the final rule and plans to publish for comments a notice of proposed rulemaking either suspending, revising, or rescinding the 2020 rule.

3.1.2 Clean Air Act Section 111

New Source Performance Standards for new, modified, and reconstructed stationary sources require that any new power plant be subject to a performance standard for CO_2 emissions. Section 111(d) of the Clean Air Act is generally interpreted to require EPA to regulate CO_2 from existing sources as well once it finalizes standards for new sources under Section 111(b). Each state must submit a plan for EPA approval that establishes standards of performance for the existing sources in the category, and provides for their implementation and enforcement. On May 23, 2023, EPA proposed emission limits and guidelines for CO_2 from the following sources:

- Existing fossil-fuel-fired, steam-generating EGUs (coal, oil, and gas units) with nameplate capacity of at least 25 MW and a minimum baseload rating of 260 GJ/h or 250 MMBtu/h heat input of fossil fuel
- Existing fossil-fuel-fired stationary combustion turbines (primarily natural gas units) with nameplate capacity greater than 300 MW and capacity factor greater than 50%
- New and reconstructed fossil-fuel-fired stationary combustion turbines (primarily new natural gas units)[18]

The proposed limits are based on technologies such as carbon capture and sequestration/storage (CCS), low-GHG hydrogen co-firing, and natural gas co-firing.[19] EPA also proposed to repeal the Affordable Clean Energy (ACE) rule finalized during the Trump administration and replace it with the proposed rule. The final rule is expected to be published in June 2024 after EPA reviews public comments. The standards and compliance schedule for covered coal-fired generating units are based on the plant's operating horizon, or dates for electing to retire.

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[17] *"Mercury and Air Toxics Standards",* EPA, last modified on May 15, 2023.

[18] *"Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants"*, EPA, last modified on May 26, 2023.

[19] EPA's proposed definition of "low-GHG hydrogen" is that produced with an overall emissions intensity of less than 0.45 kg CO2e/kg H2 from well-to-gate, consistent with the Congressional definitions provided in section 45V(b)(2)(D) of the Inflation Reduction Act.

As illustrated in Figure 3-1, coal units that commit to retire by 2032 are not subject to any additional emission reduction requirements as long as they do not exceed the current emission rate. For units with longer-term operating horizons, that do not plan to retire until 2035 or beyond, EPA's proposed best systems of emission reduction (BSER) are operational and fuel changes or CCS to comply with EPA standards.

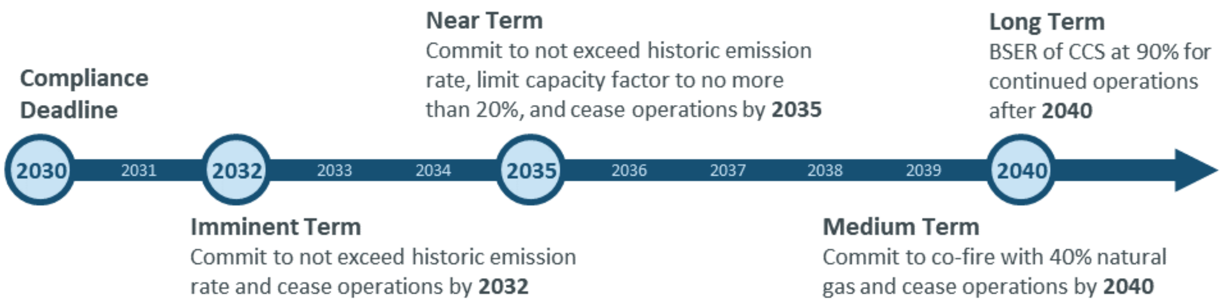

Figure 3-1: Proposed Standards and Compliance Deadline for Existing Coal-Fired Units

Source: ERM, EPA Unified Agenda: Regulatory Update

EPA offers two compliance pathways, illustrated in Figure 3-2, for covered existing natural gas combined cycle (NGCC) units to comply with the proposed standards. The first pathway involves the use of CCS to capture 90% of the CO_2 emissions by 2035. The second pathway would require units to co-fire with increasing amounts of low-GHG hydrogen by 2032 and 2038. Alternatively, units can choose to operate below the thresholds to avoid triggering compliance requirements.

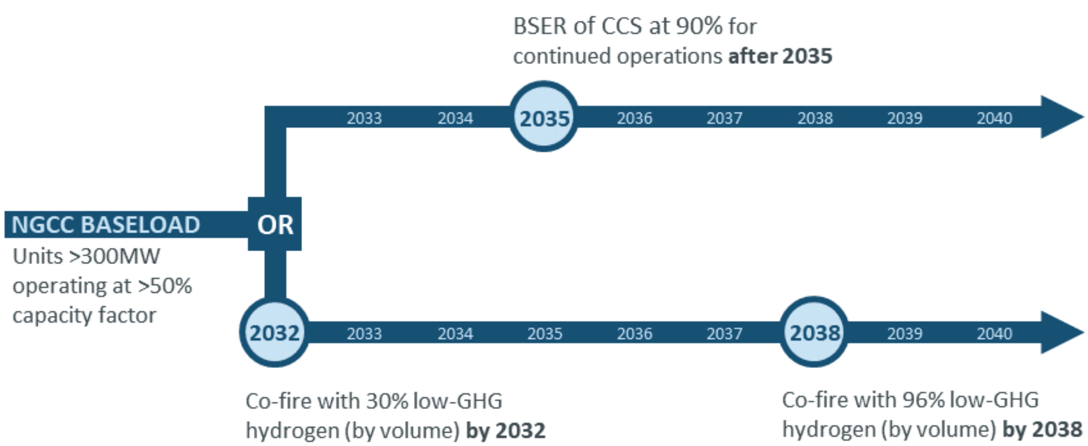

Figure 3-2: Proposed Standards and Compliance Deadline for Existing Natural Gas Units

Source: ERM, EPA Unified Agenda: Regulatory Update

The proposed new source performance standards for new and reconstructed natural gas units are divided into three subcategories based on capacity factor: low load/peaking units, intermediate load, and base load. EPA is proposing the use of lower-emitting fuels for low load/peaking units operating at less than 20% capacity factor. For intermediate and base load units, EPA is proposing a two- to three-phase approach using a combination of highly efficient generation and, depending on the subcategory, use of CCS or co-firing with increasing amounts of low-GHG hydrogen. In the first phase, the BSER for intermediate load units includes highly efficient simple cycle combustion turbine technology with an associated standard of performance of 1,150 lb CO_2per megawatt-hour (MWh). For baseload units, the proposed BSER includes highly efficient combined cycle turbine technology with standards ranging from 770 lb CO_2/MWh to 900 lb CO_2/MWh, depending on their base load rating. Figure 3-3 shows the first phase standard of performance for affected facilities followed by more stringent standards in phases two and three, which involves the use of CCS and low-GHG hydrogen at specified compliance deadlines in the future. EPA proposes these standards to apply at all times and compliance to be determined on a 12-operating-month rolling average basis.

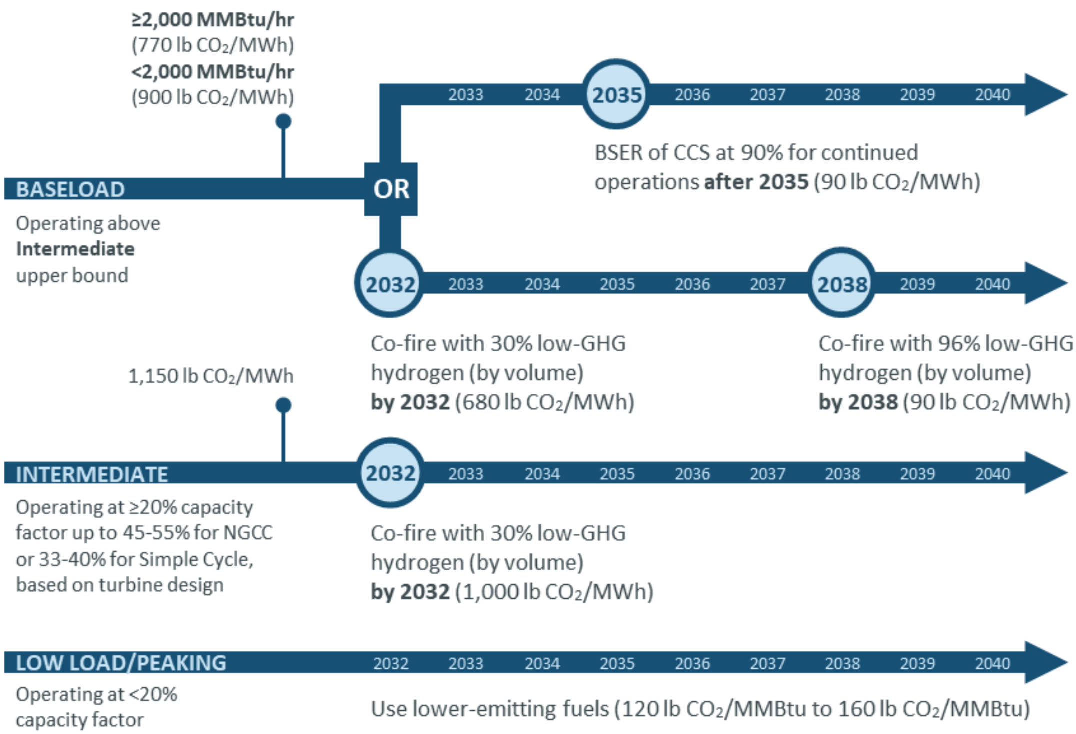

Figure 3-3: Proposed Standards and Compliance Deadline for New Natural Gas Units

Source: ERM, EPA Unified Agenda: Regulatory Update

EPA is also proposing emission guidelines for natural-gas- and oil-fired steam-generating units with a compliance deadline of 2030. For baseload units operating at greater than 45% capacity factor, the proposed emission limit is 1,300 lbs CO_2/MWh. For intermediate units with capacity factors between 8% and 45%, the emission limit is 1,500 lbs CO_2/MWh. The proposed BSER for both natural-gas- and oil-fired steam-generating units are routine operation and maintenance and a degree of emission limitation of no increase in emission rate.

Once EPA issues the final rule, states are required to submit a State Implementation Plan to achieve emission reduction at least as stringent as EPA's proposed limits. Under the proposed rule, states would have 24 months from the date of the final rule to submit state plans. The proposal allows states to exempt specific units based on the state's determination of their remaining useful life and operations.

3.1.3 Wastewater Discharges

EPA promulgated the Steam Electric Power Generating Effluent Guidelines and Standards in 1974. These were last amended in 2020. The standards regulate wastewater discharges from power plants operating as utilities under National Pollutant Discharge Elimination System permits. These regulations are based on the performance of existing wastewater treatment technologies. On March 29, 2023, EPA released a proposed rule to impose stricter wastewater discharge standards for three types of wastewaters generated at coal-fired power plants: flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate.[20] Under the proposed rule, existing sources that discharge directly to surface water are subject to the following requirements:

- A zero-discharge limitation for all pollutants in flue gas desulfurization wastewater and bottom ash transport water
- Combustion residual leachate is not to exceed average 30-day limits of 8 μg/L arsenic and 356 ng/L of mercury or maximum for any day of 11 μg/L arsenic and 788 ng/L mercury

The compliance date for the proposed limitations is as soon as possible, but no later than December 31, 2029. EPA also proposed to eliminate the less stringent requirements for two subcategories established from the 2020 rule: high-flow facilities and low-utilization electric generating units. Under the proposed rule, the waste streams from these subcategories would be subject to the otherwise applicable requirements for the rest of the industry. EPA identified the GSP Merrimack LLC in New Hampshire as one of two known facilities with low-utilization electric generating units. However, for plants opting to retire early in 2032 or "early adopters," the rule would retain the less stringent 2020 rule requirements, rather than require the new proposed zero-discharge requirements for flue gas desulfurization wastewater and bottom ash transport water.

EPA also issued a direct final rule to extend the deadline for power plants to apply for the 2028 early retirement. [21] Power plants have until June 27, 2023, to opt in for early retirement to be eligible for less stringent wastewater pollution limits retained from the 2020 rule.

Several of these federal environmental regulations and policies affecting power generators have 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.

3.1.4 Revised Definition of Waters of the United States

The *Clean Water Act of 1972* established federal jurisdiction over navigable bodies of water that are defined as Waters of the United States (WOTUS). The *Clean Water Act* does not define WOTUS. Instead, it authorizes the US Department of the Army and EPA to define WOTUS in regulations. Many Clean Water Act programs are only applicable to WOTUS, including the Section 402 National

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[20] *"Steam Electric Power Generating Effluent Guidelines - 2023 Proposed Rule"*, EPA, last modified March 8, 2023.

[21] *"Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category-Initial Notification Date Extension"*, Federal Register, last modified March 29, 2023.

Pollutant Discharge Elimination System and Section 404 Permitting Discharges of Dredged or Fill Material. [22]

The definition of WOTUS has been revised several times since the 1970s and has been the subject of continuous litigation since its inception. In response to the executive order, the definition was revised once again in the 2023 Revised Definition of Waters of the United States final rule.[23] The final rule restores the 1986 definitions that includes "tributaries," "adjacent wetlands," "impoundments," and "other waters" as WOTUS. The revised definition also includes the "relatively permanent" and "significant nexus" standards to determine which US waters are protected under WOTUS.

In the 2006 Supreme Court case *Rapanos v. United States*, the court interpreted WOTUS to include *relatively permanent* and continuously flowing bodies of water with a continuous surface connection to a *relatively permanent* body of water that is connected to a traditional US navigable water or any waterbodies that possess a *significant nexus* to a navigable water. The significant nexus standard qualifies any water as WOTUS if it has a significant impact on the chemical, physical, and biological integrity of a traditional navigable water. The 2020 Navigable Water Protection Rule only included the relatively permanent standard, which narrowed the definition of WOTUS and declassified many previously jurisdictional waters. The most affected waters were the ones located in dry climate that may not have a typical water year. The new rule repealed the 2020 rule and extended the definition to include both standards, but it concluded that the significant nexus standard provides a better criterion for defining jurisdictional waters.

The 2023 rule went into effect on March 20, 2023, however, the revised definition is not operative in many states due to ongoing litigation. In particular, the recent Supreme Court decision in the case of *Sackett v. EPA* presented a major setback to EPA's jurisdiction over certain wetlands.[24] In 2004, a couple (the Sacketts) purchased a residential lot near Idaho's Priest Lake and were in the process of filling the lot for development. EPA later issued an administrative compliance order stating that the property contained a wetland that was protected under the Clean Water Act and required the Sacketts to cease all operations and restore the site. The Sacketts were subject to $40,000 per day penalty should they fail to comply immediately. The Sacketts initially argued to the Ninth Circuit Court of Appeals that their wetland would not be considered part of WOTUS under the relatively permanent standard because the Sacketts' lot did not contain any surface water connection to any water body. The site is separated from the nearest water by a county road, on the other side of which runs a drainage ditch. However, the Ninth Circuit disagreed and upheld the significant nexus standard as the controlling authority. In 2021, the Sacketts petitioned to the Supreme Court for review, and on May 25, 2023 the court decided that the Clean Water Act extends only to waters or wetlands with a continuous surface connection to WOTUS, referencing the relatively permanent standard. The lengthy and costly litigation process demonstrated by the 15-year-long case of *Sackett v. EPA* underscores the significant impact that WOTUS can have on the siting and permitting of development projects, including construction of transmission lines and power plants. Project developers should take preemptive steps to discern if a property contains WOTUS, which WOTUS definition applies in which state, and if an activity would result in the discharge or addition of pollutant(s) from a point source to WOTUS, which may require a Clean Water Act permit.

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[22] *"Clean Water Act Programs Utilizing the Definition of WOTUS"*, EPA, last modified August 12, 2022.

[23] *"Current Implementation of Waters of the United States",* EPA, last modified May 30, 2023.

[24] *"Michael Sackett, et ux., Petitioners v. Environmental Protection Agency, et al.",* Supreme Court, last modified May 25, 2023

As result of the *Sackett v. EPA* decision, EPA is interpreting WOTUS consistent with the court's interpretation. In states where the 2023 rule is not operative due to other ongoing litigation, EPA is interpreting WOTUS consistent with the pre-2015 definition, commonly referred to as the 1986/1988 regulations.[25] The EPA website provides a map detailing which states have implemented the 2023 rule. New Hampshire is the only state in New England that has not implemented the revised definition. This information is subject to change as litigation continues.

3.1.5 Regional and State Greenhouse Gas Regulations and Goals

Limiting and eventually removing CO_2 and other GHGs from the regional power sector has been a goal of many New England policymakers for more than a decade, as some renewable portfolio standards (RPS), clean energy standards, and GHG emission limits have increased. Table 3-1 shows the New England states' economy-wide goals for reducing these emissions over the next several decades.

Table 3-1: New England State Goals for Reducing in GHG Emissions (Percentage Reduction in GHGs in 2020, 2025, 2030, 2040, 2045, and 2050)

State	2020 Interim Target/Goal	Interim Target/Goal	2050 Target/Goal
Connecticut[26]	10% below 1990 levels	2040: 0% from electric sector 2030: 45% below 2001 levels	2050: 80% below 2001 levels
Maine[27]	10% below 1990 levels	2045: Carbon neutral 2030: 45% below 1990 levels	2050: 80% below 1990 levels
Massachusetts[28]	25% below 1990 levels	2040: 75% below 1990 levels 2030: 50% below 1990 levels 2025: 33% below 1990s level[29]	2050: achieve at least net-zero but do not exceed 85% below 1990 levels
New Hampshire	N/A	N/A	N/A
Rhode Island[30]	10% below 1990 levels	2040: 80% below 1990 levels 2030: 45% below 1990 levels	2050: net zero
Vermont[31]	N/A	2030: 40% below 1990 levels 2025: 26% below 2005 levels	2050: 80% below 1990 levels
Carbon zero, carbon neutral or net zero refers to achieving net zero CO_2 emissions by balancing GHG emissions with removal (through carbon offsetting) or simply eliminating CO_2 emissions altogether. Carbon zero status can be achieved in two ways: (1) Balancing CO_2 emissions with carbon offsets, often through carbon offsetting—the process of reducing or avoiding GHG emissions or sequestering (removing) CO_2 from the atmosphere to make up for emissions elsewhere (2) Reducing carbon emissions to zero through changing energy sources and industry processes; also includes other GHGs, measured in terms of their CO_2 equivalence			

Note: Massachusetts' emission limit for 2050 is net zero statewide emissions annually, limited to 85% below 1990 levels. New Hampshire has not established a GHG emission reduction target.

[25] "*Pre-2015 Regulatory Regime*", EPA, last modified May 30, 2023.

[26] *Conn. Gen. Stat. Sec. 22a-200a*

[27] *38MRS§576-A*

[28] "*An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy*", State of Massachusetts, accessed June 7, 2023.

[29] *"Massachusetts Clean Energy and Climate Plan for 2025 and 2030"*, State of Massachusetts, accessed March 13, 2023.

[30] R.I. Gen. Laws § 42-6.2-9

[31] "*Vermont Global Warming Solutions Act of 2020*", State of Vermont, accessed June 7, 2023.

By 2021, five New England states, New York, and several Canadian Maritime provinces adopted GHG-reduction requirements that establish either economy-wide or economic sector charges on the distribution or sale of GHG-emitting items, including electricity.[32]

Every state with 2020 interim emission reduction goals has reportedly achieved those goals. In its Maine Won't Wait progress report, state officials reported that, as of 2019, gross GHG emissions in Maine were 25% below 1990 levels, surpassing the state's 2020 interim goal of 10%. Maine is 75% of the way toward its goal of 100% carbon neutrality in 2045 (i.e., 75% of GHG emissions are offset by sequestration). Massachusetts also reported a decreasing trend in emissions, citing an estimated emissions reduction of 31.4% below 1990 levels in 2020, satisfying its 2020 emissions limit of 25% below 1990 levels.[33] The state recently released its Clean Energy and Climate Plan for 2025 and 2030, which provides a roadmap to achieve its interim emission reductions. On April 14, 2021, Rhode Island enacted the *2021 Act on Climate* that updated the GHG emission reduction goals in the previous *2014 Resilient Rhode Island Act* to meet the new goal of net zero emissions by 2050. Key findings from the *2019 Rhode Island Greenhouse Gas Emissions Inventory* showed that in 2019, the state achieved a 19.6% reduction in total net GHG emissions and 15.3% reduction in total gross GHG emissions, achieving its 2020 GHG emissions reduction mandate of 10% below 1990 levels.

The *1990–2021 Connecticut Greenhouse Gas Emissions Inventory* was released in April 2023. It revealed that the state has met its 2020 emission reduction target and saw a decrease of 13.9% from 1990 levels in 2019. The state's top emitting sectors from highest to lowest are transportation, residential, and electricity. As of 2020, the residential sector emissions were reduced by 10% since 1990, however, it has since replaced the electricity sector as the second-largest emitter. Most of the emission reductions in recent years were in the electricity sector. The report emphasized that in order to meet its GHG emission reduction goals, Connecticut must achieve deeper emission reductions in these sectors, particularly in the transportation and building sectors.

The New England states are assessing, developing, and implementing other requirements, initiatives, and incentives to reduce GHGs. In aggregate, these GHG-reduction initiatives are affecting both individual combustion electric generators and the regional transmission system. The ISO continues to evaluate the impact of the states' various initiatives to reduce CO_2 and other emissions, including updates to the Regional Greenhouse Gas Initiative, individual state CO_2 power sector caps, changes to RPSs, related new clean energy generation standards, and nascent efforts to electrify the transportation and heating sectors. These existing and emerging efforts are summarized in the subsections below, in Section 4.2, and discussed in more detail in presentations and reports presented regularly to the Environmental Advisory Group.

3.1.6 Regional Greenhouse Gas Initiative

Since 2009, the New England states have participated in the Regional Greenhouse Gas Initiative (RGGI), a market-based cap-and-trade program to reduce CO_2 emissions from the power sector across participating New England and Mid-Atlantic states.[34] Based on the RGGI Model Rule, each participating state's individual CO_2 Budget Trading Program operates in aggregate to limit CO_2

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[32] See, *"Greenhouse Gas Emissions Reduction Targets and Market-based Policies"* National Conference of State Legislatures, last modified March 11, 2021.

[33] *"Statement of Compliance with 2020 Greenhouse Gas Emissions Limit"*, State of Massachusetts, accessed March 13, 2023.

[34] *"Elements of RGGI",* RGGI Inc., accessed March 14, 2023. In 2023, the participating RGGI states include: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia.

emissions from affected generators. One CO_2 allowance represents the right to emit one short ton (US ton) of CO_2. RGGI-affected generators within each state acquire and surrender RGGI CO_2 allowances equal to their CO_2 emissions over a three-year control period (the current fifth control period runs from January 1, 2021, to December 31, 2023).

The original 2009 cap was 188 million short tons of CO_2 per year in the first three years of the program, 2009 through 2011. In those years, actual emissions averaged 126 million short tons per year, or one-third less than the cap. The cap was lowered in 2012 and 2014, but emissions have consistently been less than the caps. The RGGI Model Rule has been periodically reviewed and updated by the participating states, most recently in 2017. The Third Program Review was initiated in 2021 and the RGGI states are continuing to review public input on its objectives and timeline. On July 5, 2022, RGGI published an updated timeline to allow more time to conduct additional public engagement. The updated timeline states that the Third Program Review will likely conclude by December 2023.[35] In 2022, the RGGI cap for the 11 participating states was 116,112,784 CO_2 allowances and the adjusted cap was 97,022,454 CO_2 allowances. Pennsylvania did not release any allowances during 2022 because its RGGI regulation was under a court injunction.

According to the ISO's Internal Market Monitor, the average estimated costs of the RGGI program increased 41% for most fossil-fuel-fired generators year-to-year from 2021 to 2022: natural gas ($4.36/MWh to $6.15/MWh), coal ($9.85/MWh to $13.89/MWh), No. 6 oil ($8.73/MWh to $11.69/MWh), and No. 2 oil ($9/MWh to $12.70/MWh). Since natural gas generators set price for most of the load (~80% in 2022), one would expect that the impact on energy prices will be most closely related to their CO2 cost.[36]

Figure 3-4 shows a sharp increase in the estimated RGGI costs for generators of all fuel types in 2021 that eventually flattened out over 2022. This increase is likely due to several factors:

- The continuation of the Emission Containment Reserve (ECR), which allows participating states to withhold allowances to secure additional emission reductions if prices are below an ECR trigger price
- Increased market participation as Pennsylvania and North Carolina are set to join RGGI
- Initiation of the Third Program Review that could place another emission cap similar to the 2017 Second Program Review
- Increased futures trading activity and investor participation

[35] RGGI Third Program Review: Updated Timeline RGGI Inc., last modified July 5, 2022.

[36] 2022 Annual Markets Report ISO Internal Market Monitor, last modified June 5, 2023

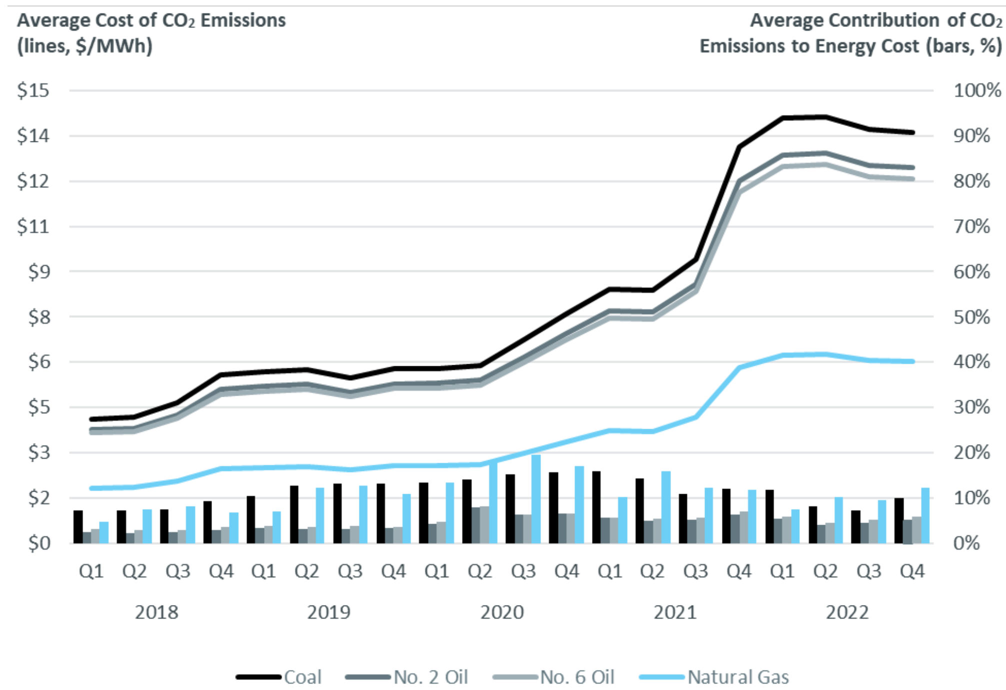


Figure 3-4: Estimated Average Cost of RGGI CO_2 Allowances and Contribution of Emissions to Energy Production

Note: The average CO_2 cost is estimated using average heat and emission rates. Additional CO_2 costs from the Massachusetts *Global Warming Solutions Act* are not included in this figure. RGGI accounts for nearly all of emissions costs.
Source: ISO New England Internal Market Monitor, 2022 Annual Markets Report.

3.2 Environmental Justice

Environmental justice is a priority for federal agencies, and at the time of publication, five New England states have enacted environmental justice laws or policies. While the ISO does not have a direct role in siting or permitting energy infrastructure, it is important to maintain awareness of environmental justice issues as they relate to system planning responsibilities and market administration. Although the decarbonization of the New England power grid has been underway for years, transitioning the region's homes, vehicles and economy to run on clean electricity will require significant new electrical infrastructure throughout the region—transmission lines, substations, generating resources—and regulators and policymakers have begun to consider the voices of historically disadvantaged communities in siting these critical grid investments. The ISO's vision—to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy—overlaps with environmental justice goals to improve the equity of the power system by expanding access to reliable, emission-free, and cost-effective electricity.

During a September 2021 meeting with New England states, the ISO offered to be a resource to the states on matters related to the regional power system as they evaluate equity and environmental justice issues. To this end, the ISO's External Affairs department tracks state and federal environmental justice policy and goals, and in May 2023, External Affairs staff presented to the ISO's Environmental Advisory Group (EAG) about the role of ISO New England and power system planning in the context of environmental justice. ISO staff also produce digestible write-ups on *ISO Newswire*, maintain user-friendly data portals in ISO-to-Go and ISO Express, host public webinars on important ISO studies, and have worked with the states to reimagine annual and semi-annual documents—such as this Regional System Plan—to promote public engagement and eliminate jargon. These efforts support procedural environmental justice goals to effectively communicate technical information in a way that is understandable regardless of the audience. ISO committees and groups including the EAG, Planning Advisory Committee (PAC), and Consumer Liaison Group provide additional opportunities for the public to learn and engage in discussions on regional energy matters. Further, the regional system planning process offers opportunities, primarily through PAC, for stakeholders to provide input or feedback.

The regional power system is experiencing a time of historic change, and while the ISO is a pivotal player, other entities play important roles in achieving the region's goals. The ISO remains committed to actively engaging New England stakeholders in its work for the region, and looks forward to continued environmental justice discussions with ratepayers, public officials and policymakers, transmission owners, consumer representatives, generators, and energy and environmental regulators.

3.3 Regional Emissions Trends and Compliance Costs

Emissions CO_2, nitrogen oxides (NO_X), and sulfur dioxide (SO_2) from the region's generators are presented below. The increased use of lower-emitting fuels, energy efficiency, wind and solar photovoltaic resources, imports from neighboring systems, and added environmental controls could decrease regional power sector emissions further.

3.3.1 ISO Tracking of Emissions Trends

The ISO tracks the system emissions, rates, and trends for CO_2, NO_X, and SO_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 *2021 ISO New England Electric Generator Air Emissions Report,* provides detailed historical trends and emissions rate data using methodologies developed with input from stakeholders. Figure 3-5 shows the regional annual emissions from native generation and imports from 2012 to 2021.

Regional 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 2012 through 2021, total system emissions decreased (NO_X by 39%, SO_2 by 87%, and CO_2 by 20%). The current emissions trends result from the regional shift away from older oil- and coal-fired generation toward more efficient natural-gas-fired and non-emitting native renewable generation, as well as increasing reliance on imports from adjacent control areas.

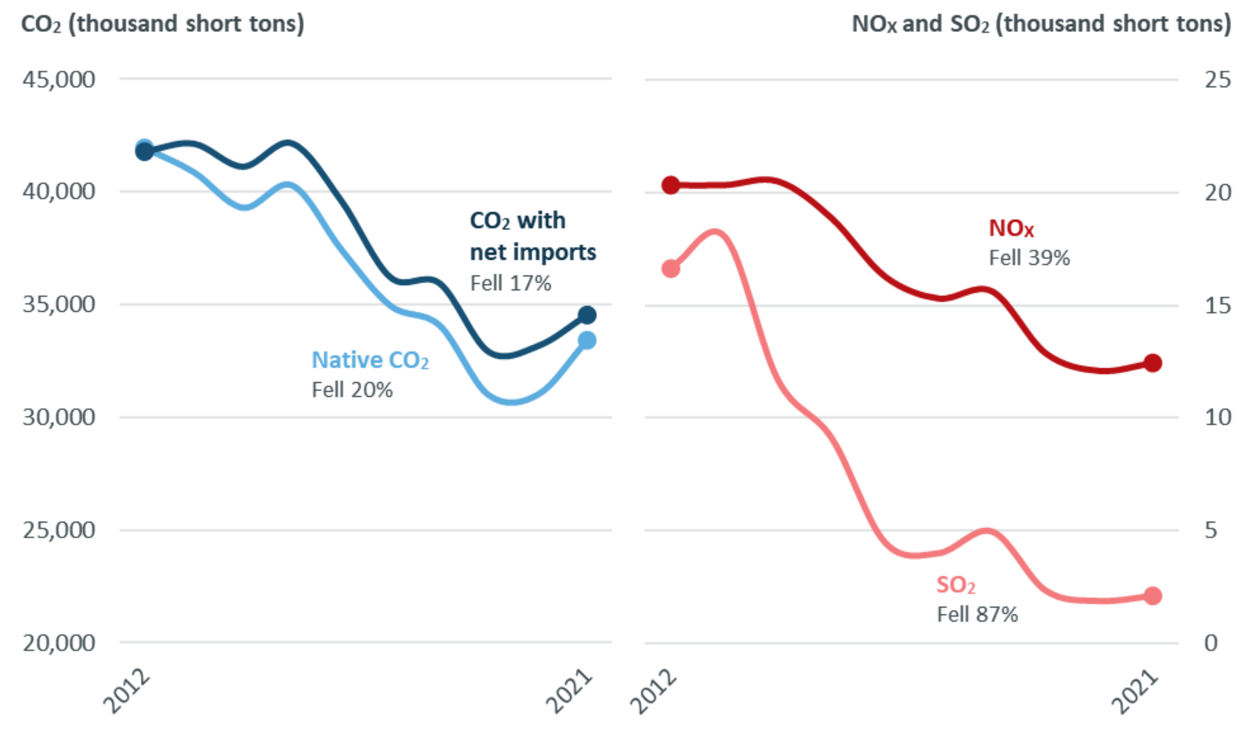


Figure 3-5: New England System Annual Emissions of NO_X, SO_2, and CO_2, 2012–2021 (Thousand Short Tons)[37]

Source: ISO-NE, *2021 ISO New England Electric Generator Air Emissions Report* (April 2023).

3.3.2 Cost of Compliance with Environmental Regulations

Environmental compliance costs for generating units vary by age, economics, location, and readiness of commercially available control technologies. Such costs make up a small but growing portion of operating and maintenance production costs, compared to variable fuel costs.

The costs for CO_2 emission allowances under the Regional Greenhouse Gas Initiative and the Massachusetts *Global Warming Solutions Act* (GWSA) are the largest individual factor in environmental compliance costs for combustion generators in New England. RGGI allowance prices increased by 41%, from $9.56/short ton CO_2 in 2021 to $13.48 in 2022, due to a variety of factors discussed in Section 3.1.6. Since natural gas generators set the price for most of the load (~80%) in 2022, the impact on energy prices will be most closely related to their CO_2 cost. However, the impact of the higher RGGI allowance prices in 2022 was diminished by a 101% increase in natural gas prices from the previous year. The average estimated costs of the Massachusetts GWSA program increased by 19% from 2021 to $4.23/MWh in 2022 for the average natural gas combined cycle generator. This increase was driven by expectations of tighter conditions in future years. Figure 3-6 highlights that CO_2 allowance costs under RGGI and GWSA have a relatively small impact on overall generation costs and consequently do not have a major impact on the economic merit order of generation, although emission costs have grown in recent years. The impact of GWSA on New England energy prices is unclear since the GWSA is only applicable to generators in Massachusetts.

[37] The ISO provides a comprehensive analysis of New England electric generator air emissions (NO_X, SO_2, and CO_2) and a review of relevant system conditions, focused on direct emissions emitted by all solid, gaseous, and liquid fuel combusting generators in New England and includes emissions associated with net imports to serve load in New England.

Other variable environmental compliance costs related to air pollution include control catalyst replacement, ammonia reagent (for catalyst operation), and water treatment and discharge.

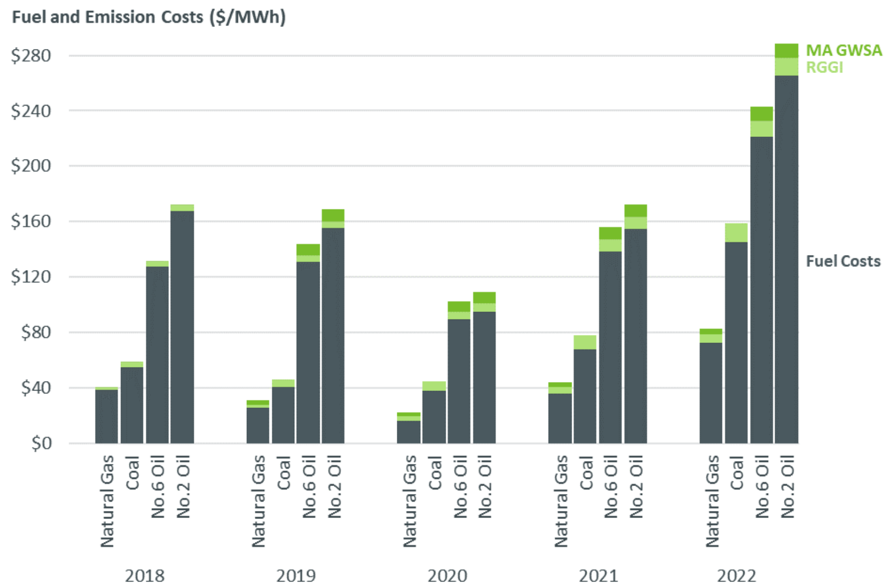


Figure 3-6: Annual Estimated Average Costs of Generation and Emissions, 2018–2022 ($/MWh)[38]

Source: ISO-NE, *2022 Annual Markets Report*

3.4 Summary

Existing and pending federal and state environmental regulations and multistate initiatives may require generators to consider adding air pollution control devices, modify or reduce water use and wastewater discharges, and limit operations. The actual compliance timelines and costs will depend on the timing and length of the permit reviews, implementation of any final state and federal regulations, and the condition of the electric generating facilities involved. As a result, some generator owners may determine certain resources are uneconomical and retire such facilities instead of making major investments in environmental compliance measures.

The passage of the landmark *Inflation Reduction Act* will accelerate the transition to renewable energy sources and make the future of clean energy more economical. The law includes a $370 billion investment in energy security and climate change programs over the next 10 years. The clean energy tax credits and other provisions under the IRA could position the US to achieve its Paris Agreement 2030 target with additional actions from the federal, state, local, and private sectors.

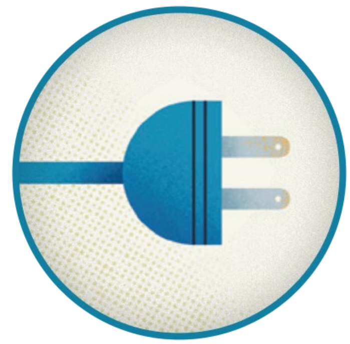
[38] The bar chart shows the costs of the RGGI and the Global Warming Solutions Act (GWSA), only in Massachusetts, CO_2 cap-and-trade programs for generators by fuel type (with typical efficiencies) relative to their fuel costs. The Massachusetts Electricity Generator Emissions Limits under GWSA began in 2018, but 2018 costs are excluded due to limited available market information regarding the value of allowances resulting in varied bid prices. The MA GWSA costs are a trade-weighted average of auction clearing prices and secondary trades for a given year. MA GWSA was removed for coal because there are currently no coal generators affected by the program. ISO-NE Internal Market Monitor standard generator heat rates and fuel emission rates are used to convert $/ton CO_2 prices to $/MWh generation costs.

The electric grid will see an influx of renewable energy resources in the future due to individual states' emission reduction mandates and other climate policies and initiatives. All of the New England states have RPS targets for the amount of electric energy provided by renewable resources. Some of the states also have issued requests for proposals for renewable energy development. The increased use of various types and amounts of renewable resources may displace traditional fossil-fuel-fired generators as the marginal resource type in the future. Resulting higher variable operations and maintenance costs may increase the likelihood of retirement for such generators.

The New England states take part in the RGGI for limiting CO_2 emissions by power plants as well as 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 decreasing percentage share of 2021 annual energy production—native natural gas, nuclear, net imports, other renewables (landfill gas, methane, refuse, solar, steam, and wood), hydro, wind, oil, and coal. Higher emissions, however, occur during the winter months because of greater reliance on solid- and liquid-fuel-fired combustion generators when natural gas is more expensive or in limited supply. The retirement of nuclear units would tend to increase regional emissions, while the addition of low- or zero-emitting resources would tend to reduce longer-term emissions.

Section 4: Forecasts of New England's Peak Demand and Annual Use of Electric Energy

ISO's load forecasting provides foundational assumptions for ISO markets and studies related to changes in end-use electricity consumption in New England. Combatting climate change is a top priority of many New England states, and both state and federal policies have significant impacts on regional electric energy consumption. Over the 10-year forecast horizon, policies will further stimulate energy efficiency (EE) measures and distribution-connected photovoltaics (PV), as well as trigger significant electrification of the transportation and heating sectors. Methodological improvements and innovation will be required to enable forecasts to keep pace with these emerging trends.



This section discusses the forecasts of gross and net annual energy and seasonal peak demand for 2023 through winter 2032/2033, including the ISO's component forecasts of transportation electrification, heating electrification, EE, and distribution-connected PV. Electrification will drive an increase in the amount of electricity the system will need to provide, which is expected to more than offset any decreases in demand due to EE and distribution-connected PV. The forecasts discussed in this RSP and published in the 2023–2032 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report) provide key inputs for determining the region's resource adequacy requirements for future years and evaluating the reliability and economic performance of the electric power system (Section 7), as well as for planning needed transmission improvements (Section 5).

The ISO's net forecasts are projections of energy and demand after reductions from EE and behind-the-meter (BTM) PV, and define the baseline load characteristics for evaluation in most non-FCM (Forward Capacity Market) planning studies. Net forecast corresponds to observed load. The ISO's gross forecasts are projections of the amount of electric energy the New England states will need annually and during seasonal peak hours, absent savings from EE resources that participate in Forward Capacity Auctions (FCAs) and savings from BTM PV. Gross load forecasts help to ensure appropriate demand-side modeling in FCM studies (e.g., the Installed Capacity Requirement calculation). Since passive demand capacity resources (the majority of which are EE resources) are compensated as supply in the FCM, they need to be addressed in the load forecast in a manner that avoids double-counting. Both gross and net forecasts are inclusive of the forecast impacts of electrification.[39]

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[39] Forecast accounting for RSP23, including treatment of all component forecasts in gross and net load forecasts for the region and states, is detailed in the 2023 Forecast Itemization spreadsheet (April 28, 2023). A high-level summary of existing methodology is contained in a Load Forecast Committee presentation Long-Term Load Forecast Methodology Overview (September 23, 2022). Additional 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. The energy and demand modeling methodology is described in the 2023 *Forecast Modeling Procedure* (April 28, 2023). All final forecast values are published in the 2023 Forecast Data spreadsheet. All resulting energy and peak models are documented in a spreadsheet (i.e., 2023 Regional and State Energy & Peak Model Details, April 28, 2023). The Load Forecast Materials webpage includes the 10-year hourly forecasts in electronic export information (EEI) format (e.g., hourly 2023 forecasts for the region, RSP subareas, and load zones). The Load Forecast Committee webpage contains materials on relevant stakeholder discussions.

4.1 ISO New England Gross Forecasts

The ISO's forecasts of gross annual electric energy use and seasonal peak demand are driven by historical loads, macroeconomic and demographic factors, and anticipated electrification trends. The 2023 forecasts of gross annual energy use, and both summer and winter gross seasonal peak demand, increase over the 2023–2032 forecast horizon, with much of the growth attributable to anticipated increases in electrification. Figure 4-1 shows the forecast for all three components over the forecast horizon.

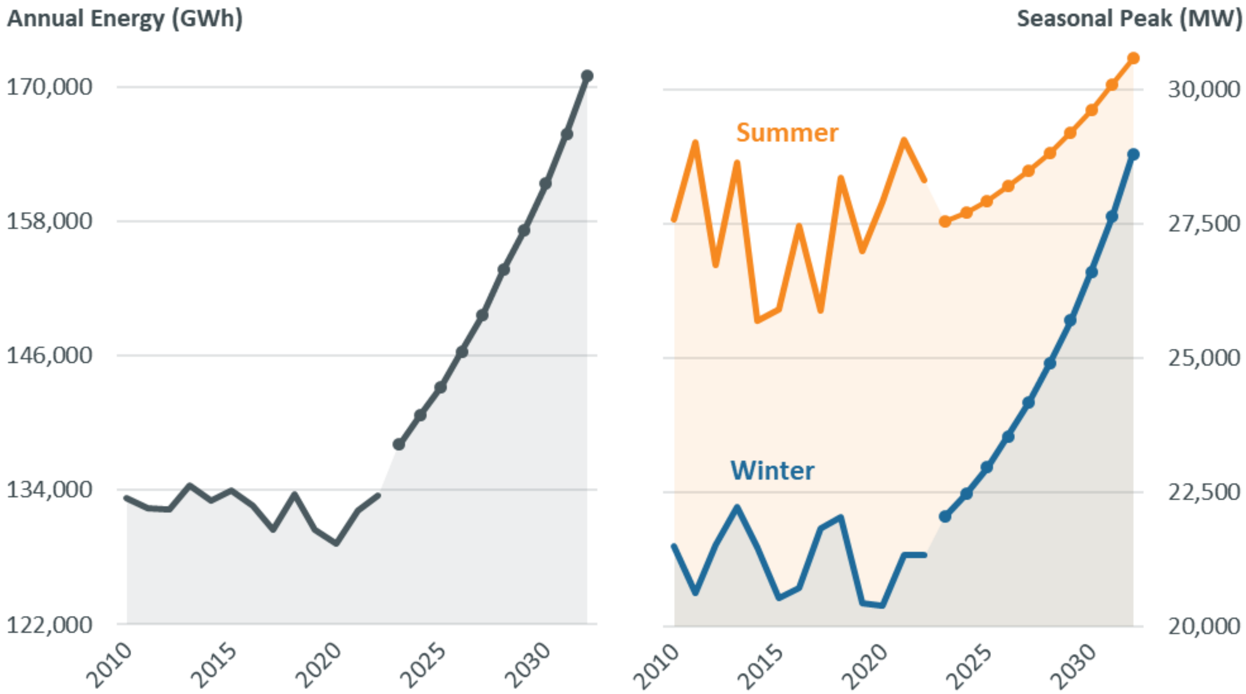

Figure 4-1: Forecast of Annual Gross Energy, Summer Gross 50/50 Peak Demand, and Winter Gross 50/50 Peak Demand

4.2 Electrification Forecasts

Strategic electrification initiatives targeting economy-wide reductions in greenhouse gases continue to take shape across New England. Both the 2023 gross and net forecasts include the energy and demand impacts of heating and transportation electrification initiatives across the region. These initiatives encourage consumers to adopt emerging technologies (e.g., electric vehicles and electric heat pumps) in order to replace conventional primary fuel sources. The maturing stages of electrification growth over the 2023–2032 forecast horizon will add considerable new demand for electricity across the region. Key inputs and feedback provided by representatives from each of the New England states, including state policymakers and regulators, helped guide the development of the 2023–2032 electrification forecasts.

4.2.1 Heating Electrification Adoption

The heating electrification forecast for RSP23 projects the incremental energy and demand impacts (relative to the base year 2022) of residential and commercial heat pump adoption for space and water heating over the next 10 years.[40] This forecast reflects heat pumps installed to provide heat for more than 1 million additional households and approximately 630 million square feet of additional commercial space across New England over the following decade. Heating electrification will increase electricity consumption mostly from October through April.[41]

Figure 4-2 shows the growth in the cumulative share (on a percent basis) of electrified residential and commercial building stock, based on total number of households and total square feet, respectively. The future electrified shares plotted are based on the total building stock that was using legacy fossil fuel heating sources at the end of 2022. The dark blue portion of the plots represents the relative share of buildings for which heat pumps will supply all of the heat (i.e., "full" heating). The light blue portion of the plots represents heat pump installations that supply most of the heat (i.e., "partial" heating), assuming a non-electric backup heating source at temperatures below 20°F.

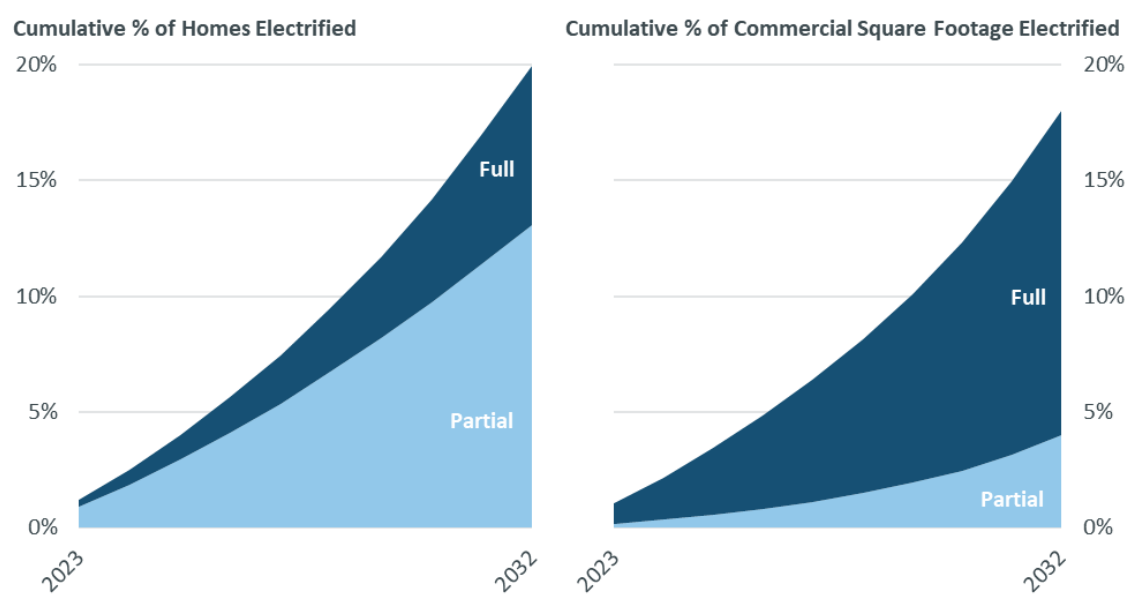

Figure 4-2: Projection of Heating Electrification in Residential and Commercial Building Stock, 2023–2032

4.2.2 Transportation Electrification Adoption

The transportation electrification forecast for RSP23 projects the incremental energy and demand impacts (relative to the base year 2022) of adoption of electric vehicles (EVs) throughout the six New England states over the next 10 years.[42] Figure 4-3 illustrates the outlook for cumulative regional adoption (as a percentage of total vehicle stock) of electrified light-duty personal vehicles, light-duty fleet vehicles, medium-duty delivery vehicles, school buses, and transit buses.[43] The

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[40] A full explanation of the methodology used for the heating electrification forecast is available in the file Final 2023 Heating Electrification Forecast (April 28, 2023).

[41]The heating forecast includes residential and commercial water heating, which will add a relatively small amount of electricity consumption during cooling months.

[42] A full explanation of the methodology used for the transportation electrification forecast is available in the file Final 2023 Transportation Electrification Forecast (April 28, 2023).

[43] Adoption values illustrated are based on total non-electrified vehicle stock at the end of 2022.

adoption forecast reflects the electrification of more than 3 million vehicles, or approximately 25% of all vehicle stock across New England, by 2032. Electric vehicle stock in 2020 was less than 1%.[44]

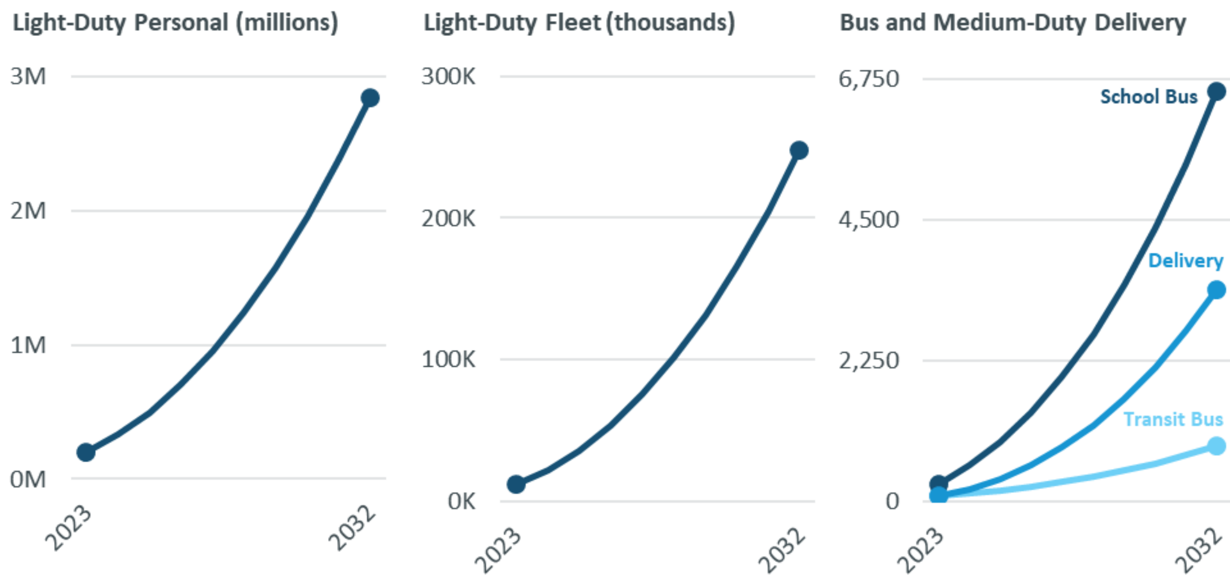

Figure 4-3: Projection of Share of Electrified Transportation Across Various Vehicle Classes, 2023–2032

4.2.3 Electrification Impacts to Electric Energy and Demand

Figure 4-4 illustrates the regional impacts of both heating and transportation electrification over the next 10 years. By 2032, the regional impacts of electrification add 21,295 gigawatt-hours (GWh) of overall annual electricity use in New England as compared to 2022 levels, 2,415 megawatts (MW) of peak demand under typical summer peak weather conditions (known as the summer "50/50" demand), and 6,385 MW of winter peak demand under typical winter peak weather conditions (known as the winter "50/50" demand). Most of the growth in the energy and demand forecasts is attributable to electrification. Electrification is responsible for 14.2% of net energy in the 2032 annual electricity use forecast, 8.9% of net demand for the 2032 summer 50/50 demand forecast, and 24.3% of net demand for the winter 50/50 demand forecast.

[44] Cited historical EV penetration values are estimates based on data provided by the New England states. Future 2032 values are based on the 2023 EV adoption forecast.

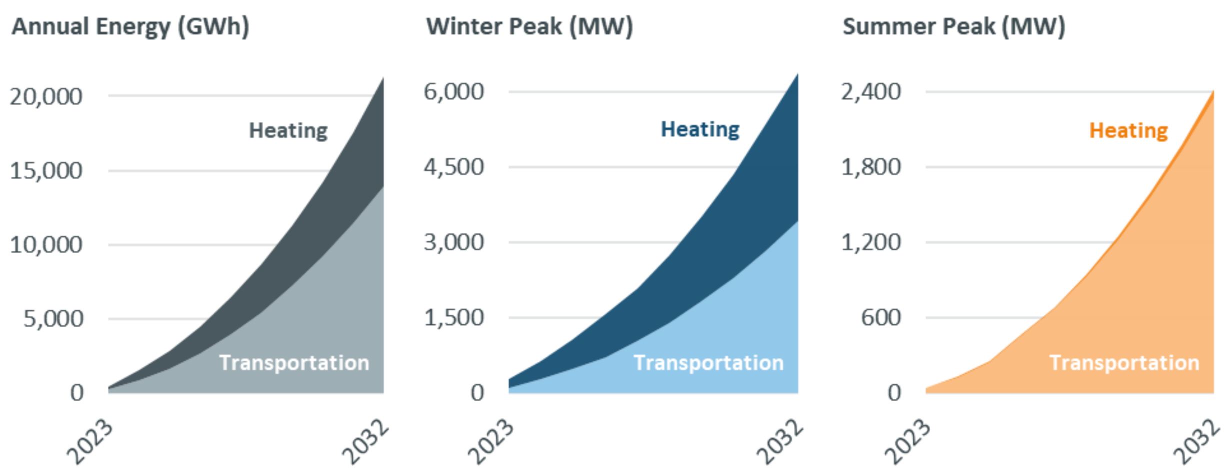

Figure 4-4: Total Electrification Impacts to Regional Annual Energy and Seasonal 50/50 Peak Demand, 2023–2032

4.3 Energy Efficiency Forecast

The energy efficiency forecast provides the ISO with an understanding of additional energy and demand savings from EE resources expected to participate in the FCM over the next 10 years. Forecasts are made using EE program performance and budget data from individual program administrators and state regulatory agencies in collaboration with the ISO's Energy Efficiency Forecast Working Group. Significant amounts of EE resources have taken on obligations in FCAs since their initial introduction, but this trend has shifted in more recent FCAs, with fewer new EE resources taking on obligations and many existing EE measures expiring.[45] As a result, the gross load forecast now primarily captures load reductions from the historical EE resources. This shift has lowered both the magnitude and rate of growth of the forecast, with the outlook for future EE much lower than it was just a few years ago. Figure 4-5 shows the impact of EE savings on annual energy, summer demand, and winter demand over the 2023–2032 forecast horizon. The degree to which EE measure expiration reduces the gross load forecast's growth rate is explicitly accounted for in the EE forecast. This reduction is characterized as expiring measures that are already "embedded" in the gross load forecast, and are consequently netted out of the final EE forecast (red bars in Figure 4-5). The amount of embedded expiring measures varies across seasons, and is the primary source of the difference between the summer and winter EE forecasts illustrated in Figure 4-5. As EE resources reach a saturation point and related programs pivot toward emerging priorities like heating electrification, the incremental impact of EE resources on demand is expected to continue to decrease.

[45] The amount of total passive demand capacity resources taking on obligations decreased from approximately 3,327 MW in FCA 14 to 2,317 MW in FCA 17, reflecting a decrease of more than 30%.

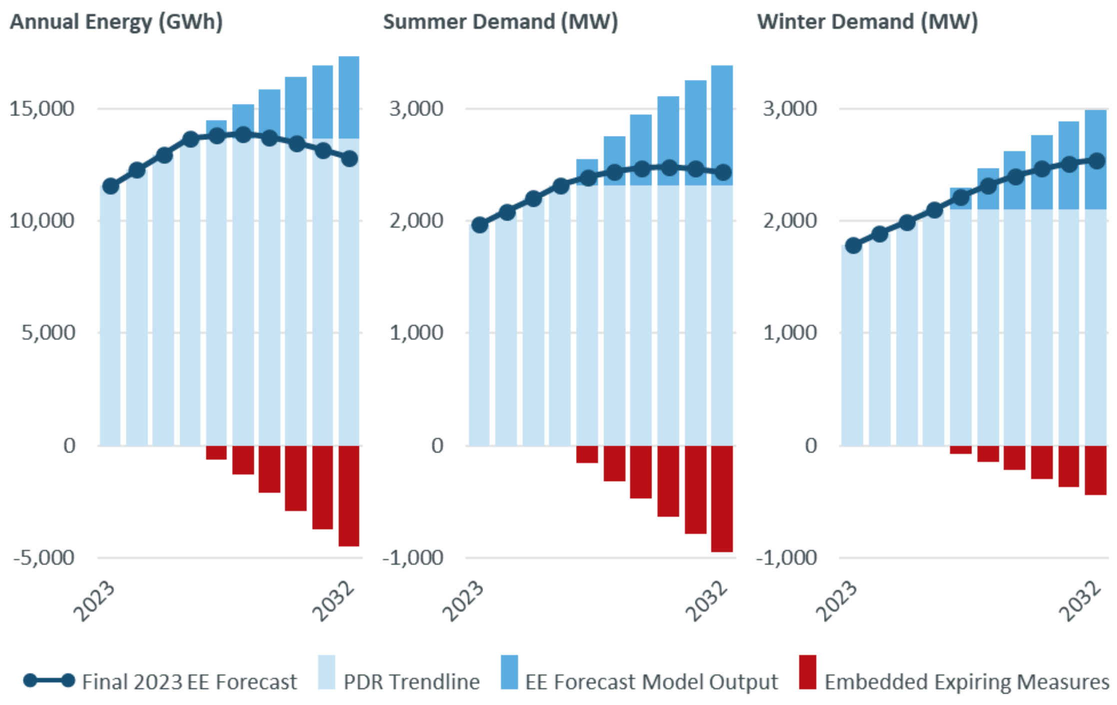

Figure 4-5: Forecast of Annual Energy and Seasonal Demand Savings from EE, 2023–2032

4.4 Distributed Photovoltaic Generation Forecast

This section describes the outlook for growth in distribution-connected PV resources in New England.[46] Distributed photovoltaics have grown substantially in New England since 2012, and have already significantly altered the region's seasonal load profiles. The 2023–2032 forecast shows distributed PV resources more than doubling over the next decade. As penetrations of these PV resources increase, so will the need for resource ramping to serve the increasing fluctuations in net demand and the severity of light-load conditions during the shoulder seasons, since much of this PV is embedded in load. [47]

As part of PV forecasting, the ISO first develops state-by-state forecasts of the growth in PV nameplate capacities (MW_{ac} [megawatts of alternating current] ratings) through the 10-year planning horizon.[48] To ensure proper accounting, the ISO classifies PV into three types, each of which is treated differently in system planning studies:

[46] A full explanation of the methodology used for the PV forecast is available in the file Final 2023 PV Forecast (April 28, 2023). The ISO continues to monitor the growth of non-PV distributed generation, including BTM energy storage facilities, to determine whether separate forecasts of these resources may eventually be warranted.

[47] 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.

[48] The forecast reflects distributed 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.

- FCM resources with capacity supply obligations
- Energy-only resources (EORs), which are generation resources that participate in the wholesale energy markets but choose to not participate in the FCM[49]
- BTM PV, which does not participate in wholesale markets and reduces the load the ISO observes

Figure 4-6 shows how the FCM, EOR, and BTM PV contribute to the total PV nameplate capacity forecast for 2023–2032.

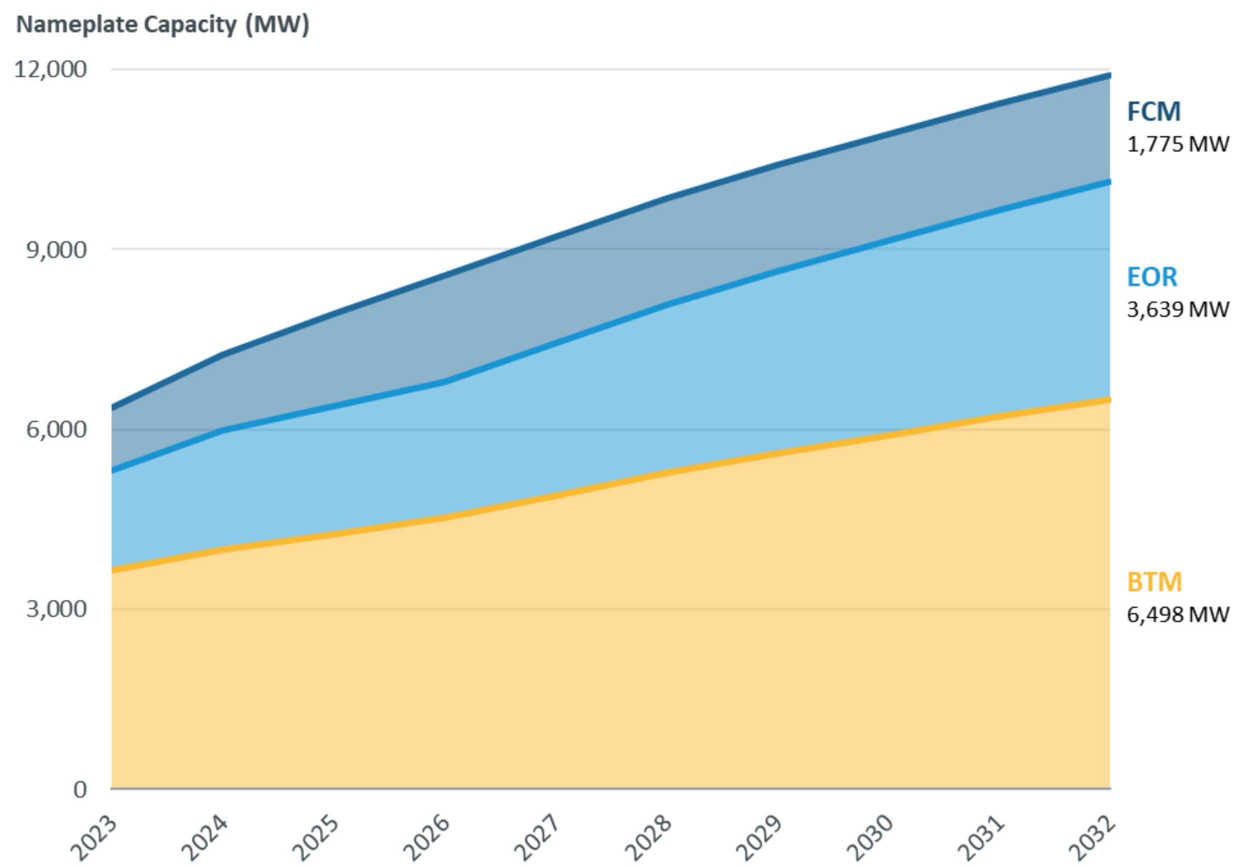

Figure 4-6: Classification of 2023–2032 Cumulative PV Nameplate Capacity Forecast

4.4.1 Forecasts of Behind-the-Meter Photovoltaic Energy and Summer Peak Demand Reductions

Using the nameplate BTM PV forecast and other available data, the ISO develops forecasts of BTM PV energy and corresponding reductions in summer peak demand. Higher PV penetrations are associated with diminishing incremental peak demand reductions.[50] Future PV growth will be less useful in reducing forecast peaks in summer demand than it is today. As peaks in summer demand

[49] 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.

[50] The ISO's detailed analysis and resulting methodology for estimated summer peak load reductions is available in Estimating Summer Peak Demand Reductions from Behind-the-Meter Photovoltaics

continue to occur later in the day, estimated reductions in summer peak demand due to BTM PV grow only marginally, from a 981 MW reduction in 2023 to a 1,117 MW reduction in 2032. Figure 4-7 shows the values of regional annual energy savings and summer peak demand reductions from the 2023 forecast of BTM PV.

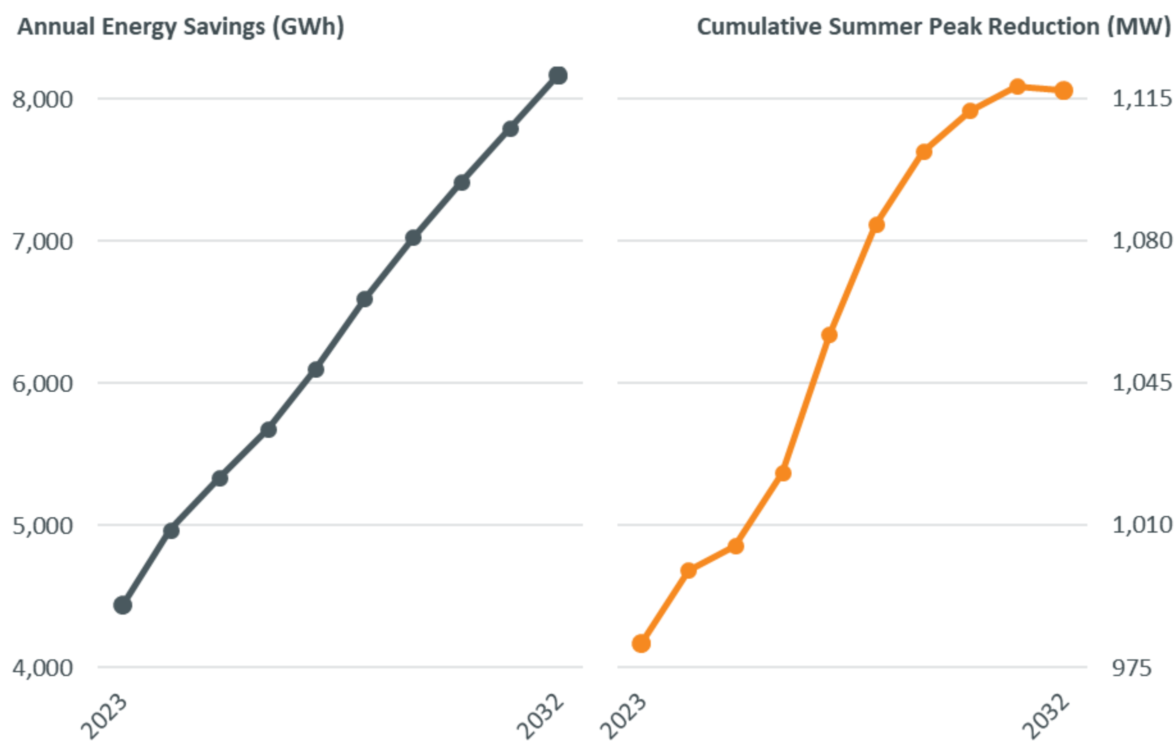

Figure 4-7: Forecast of BTM PV Annual Energy and Estimated Summer Peak Demand Reductions, 2023–2032

4.5 Net Demand Forecast

The ISO's net demand forecast is the gross demand forecast, inclusive of electrification, lowered by the BTM PV forecast and EE forecast. Figure 4-8 shows the net demand forecasts of annual energy, summer 50/50 peak demand, and winter 50/50 peak demand. All net forecasts show growth over the forecast horizon, largely as a result of increasing electrification.

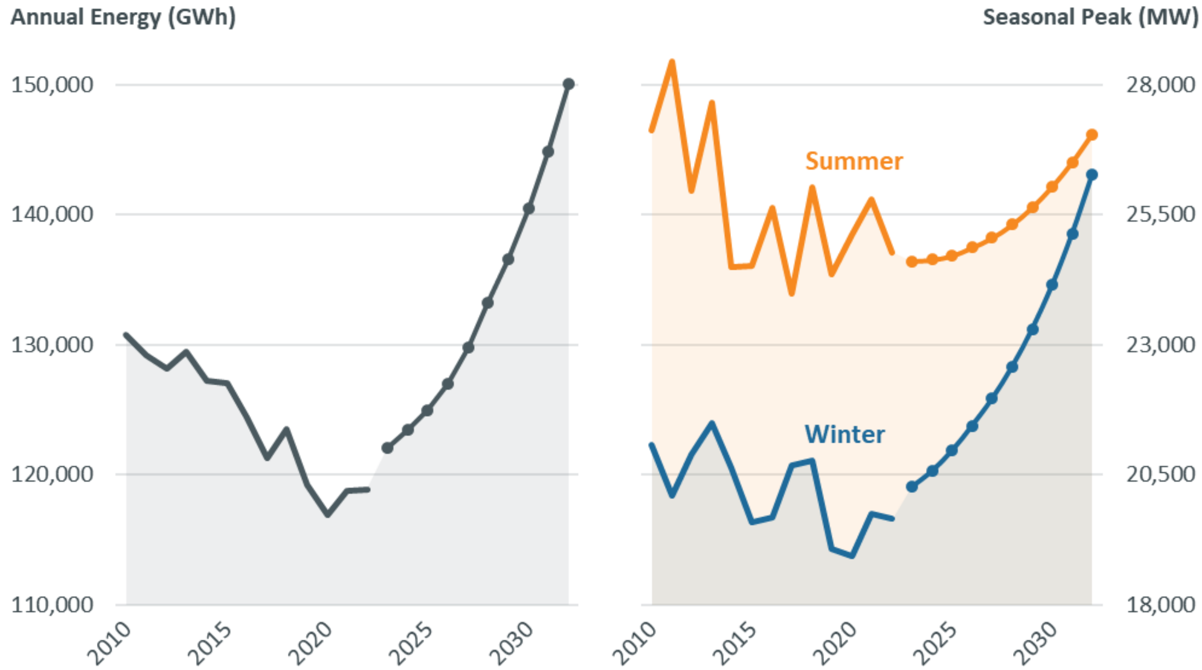

Figure 4-8: Forecast of Annual Net Energy, Summer Net 50/50 Peak Demand, and Winter Net 50/50 Peak Demand

The net systemwide load factor is the ratio of the average hourly load for a year to peak hourly load, based on the net 50/50 demand and annual energy forecasts. This load factor increases over the forecast horizon from 56.6% to 63.3%. While the forecast indicates that summer will remain the typical peak season over the forecast horizon, the anticipated impacts of electrification are driving a predicted increase in load factor, since electrification will predominantly affect winter demand and energy use versus summer.

Figure 4-9 shows the winter (in blue) and summer (in red) peak demand forecast distributions over the 10-year planning horizon, illustrating the degree to which the forecast impacts of electrification will drive a convergence in summer and winter peak demand magnitude. The 50/50 net summer peak forecast grows by 2,441 MW (~10%) from 2023 to 2032, while the 50/50 net winter peak forecast grows by 5,998 MW (~29%) over the same time period. Over the forecast horizon, the difference in these forecasts shrinks from 4,336 MW in 2023 to 779 MW in 2032.

The 90/10 net summer peak forecast, which represents demand during a particularly hot summer heat wave, grows by 2,553 MW (~10%) between 2023 and 2032. However, the 90/10 net winter peak forecast, which represents demand during a particularly significant cold snap, grows by 7,036 MW (~33%) over the same time period. Over the forecast horizon, the difference in these forecasts shrinks from 5,389 MW in 2023 to 906 MW in 2032.

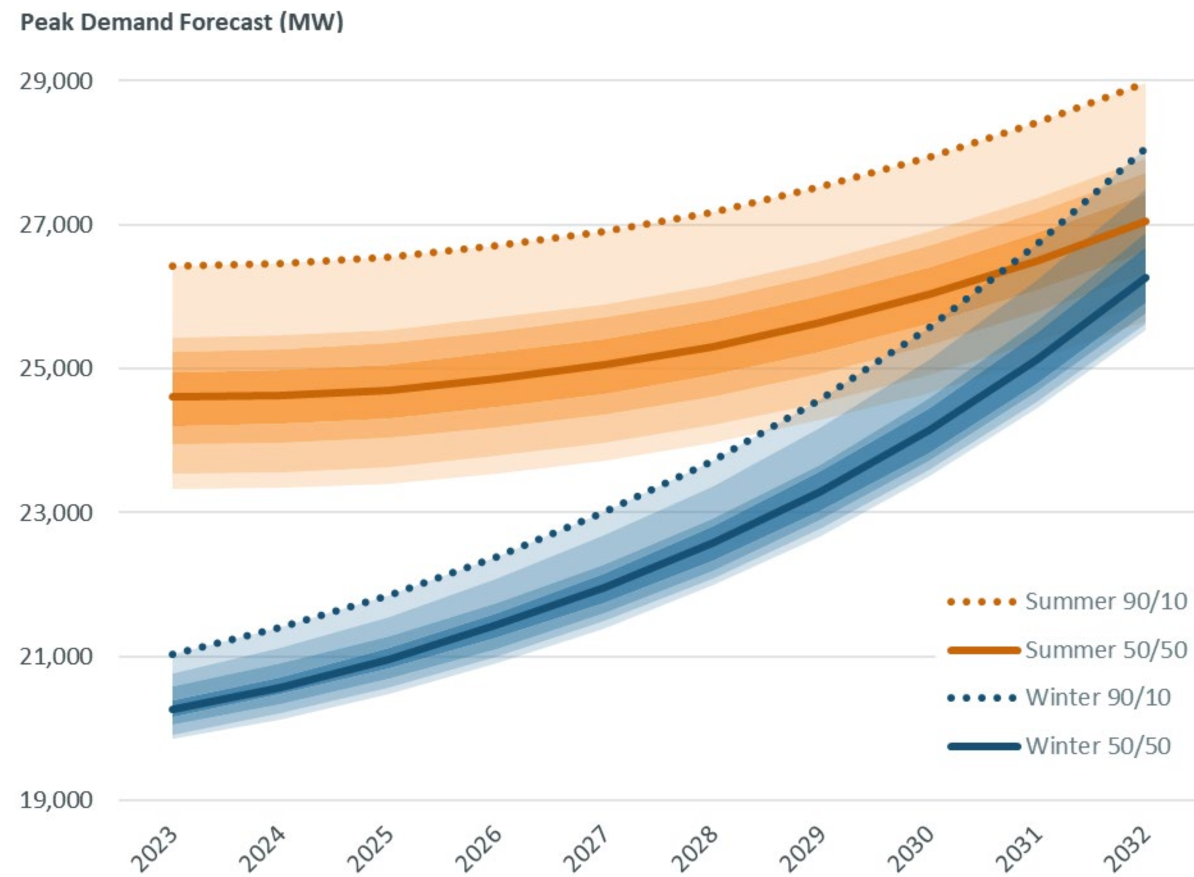

Figure 4-9: Forecast Summer and Winter Seasonal Net Peak Demand Distributions, 2023–2032

Figure 4-10 shows the combined hourly winter demand profile of the heating and transportation electrification forecasts during typical winter peak weather. The significant morning peak exhibited by the plot suggests that as electrification (particularly of heating) increases, it will likely cause the timing of the winter peak to occur in the morning, rather than its current evening timing.

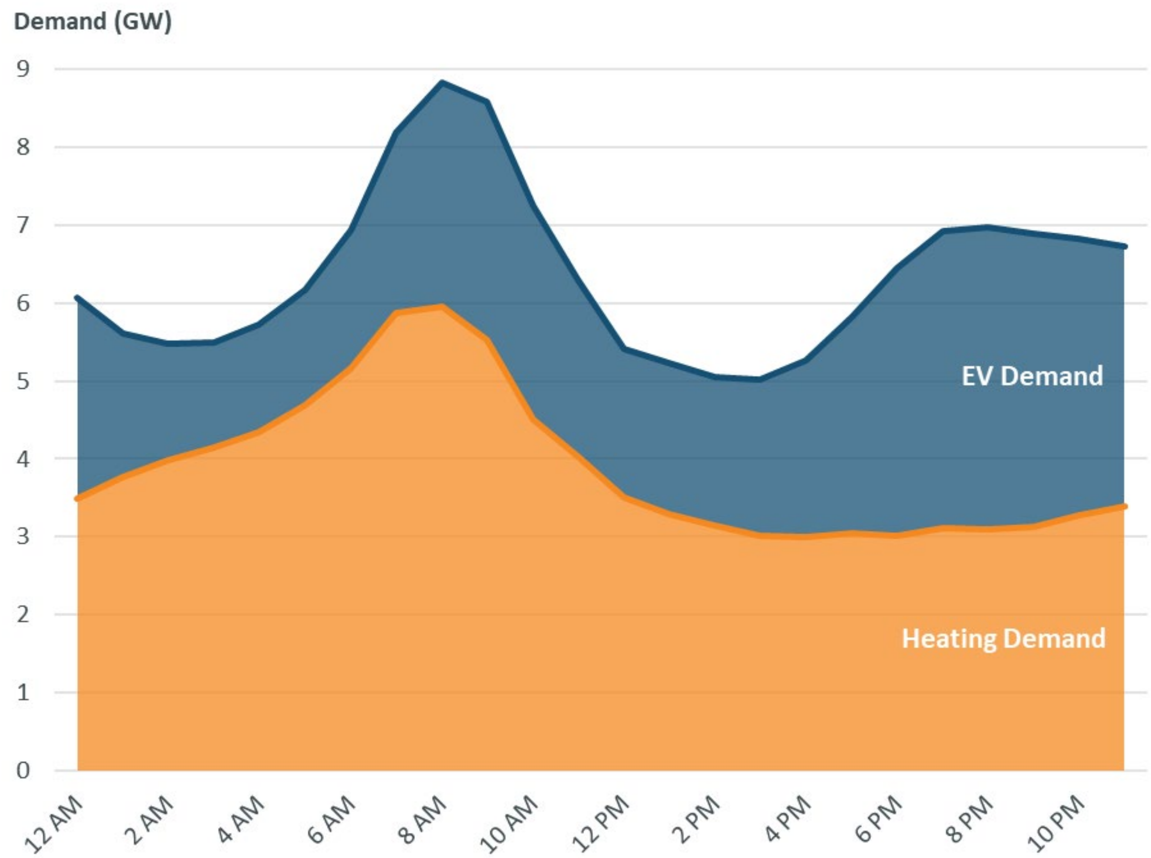

Figure 4-10: Projection of Hourly Demand Due to Heating and Transportation Electrification on a Typical Winter Peak Day, January 2033

4.6 Summary

The ISO's annual forecasts of annual energy use and peak loads are key inputs in establishing the system needs discussed throughout RSP23. Significant growth in the region's annual energy, summer demand, and winter demand forecasts over the following decade will be driven by an increase in transportation and heating electrification. Electrification will also drive a significant convergence in the magnitude of summer and winter peaks over the 10-year planning horizon. By 2031, the "90/10" net winter demand forecast exceeds the "50/50" net summer demand forecast, suggesting that by that year, if the region experiences very cold winter weather and milder summer weather, the region could experience its highest loads in the winter. Beyond the forecast horizon, by the mid-2030s, winter will become the typical peak season for electricity consumption. As this change in seasonality occurs, peak demand will likely also begin to occur in the morning, rather than the evening, as is currently the case.

Fewer EE resources took on obligations in FCA 17, aligning with recent trends. This has resulted in a convergence between gross and net load forecasts and a proportionately lower EE forecast than in prior years. The degree of EE participation expected in future FCAs is expected to decrease due to saturation of EE savings and pivots toward other initiatives like electrification. If recent trends persist, there will be a further convergence of gross and net load in the future.

Growth of distributed PV has already shifted summer net peak loads to later in the afternoon, when PV output is lower, and thus new distributed PV will play a lesser role in reducing summer peak demand than it has in previous years. The ISO expects this diminishing pattern to continue—future PV growth will be less useful in reducing forecast peaks in summer demand than it is today. Growing penetrations of distributed PV will be associated with increasing volatility in net demand and more severe light-load conditions, especially in the shoulder seasons.

Increased electrification and penetrations of distributed energy resources will significantly change the region's load characteristics, and are a key consideration as the New England grid evolves. The ISO's forecast methodology must keep pace with these changes in order to provide timely insights necessary for establishing future system needs.

Section 5: Transmission System Performance Needs Assessments and Upgrade Approvals

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

This section provides an overview of the New England transmission system, updates on the performance of the system, and the status of several key transmission planning studies.[51] The progress of major transmission projects and various types of transmission upgrades in the region as of June 2023 is also discussed.[52] The transmission planning studies account for known plans for resource additions and attritions (see Section 7) and the material effects of the energy efficiency (EE), photovoltaics (PV), and electrification forecasts (see Section 4).

The Transmission Planning department at the ISO ensures that the power system continues to operate reliably as conditions on the grid change. In addition, the department oversees transmission driven by other needs. Upgrades to the transmission system can be identified and procured under a number of different criteria, as described below, pursuant to Attachment K of the *Open Access Transmission Tariff* (OATT).

- Reliability transmission upgrades ensure that system reliability criteria set by the North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and ISO New England are met. This includes assessments of transmission system reliability and solutions developed through the solutions study process or the competitive transmission process.
- Competitive transmission upgrades are applied when needs assessments reveal a non-time-sensitive need or when market efficiency or public policy needs are identified. The ISO conducts a request for proposals process to identify competitive solutions to solve these needs.
- Market efficiency transmission upgrades are identified by the ISO to provide a net reduction in total production cost to supply system load that exceeds the cost of the transmission upgrade.
- Public policy transmission upgrades are improvements of or additions to the regional transmission system designed to meet state, federal, and local (e.g., municipal and county) public policy requirements identified as driving transmission needs.
- Longer-term transmission studies are requested by the New England States Committee on Electricity (NESCOE) to identify high-level concepts of transmission infrastructure that could meet a state's energy policy, mandate, or legal requirement based on state-identified scenarios and timeframes, which may extend beyond the 10-year planning horizon.

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[51] For further detailed analyses associated with transmission planning, see previous RSPs and various Planning Advisory Committee (PAC) presentations, and other ISO reports.

[52] For further details about individual transmission projects, refer to the latest RSP Project List or Asset Condition List.

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 standards and details the criteria and assumptions used in transmission planning studies.

5.1 Overview of New England's Transmission System

The power system in New England provides electricity to diverse areas, ranging from rural agricultural communities to densely populated cities, and integrates widely dispersed and varied types of power supply resources. Geographically, approximately 23% of New England's peak loads are in the northern states of Maine, New Hampshire, and Vermont, and 77% are in the southern states of Massachusetts, Connecticut, and Rhode Island.[53] Although the land area in the northern states is larger than that in the southern states, the greater urban development in southern New England creates greater demand and corresponding transmission density. Transmission flows on the system are primarily from west to east and from north to south. However, flows change throughout each day, and the predominant flows may change significantly with future installation of distributed energy resources and offshore wind.[54] Because the demands on the New England transmission system can vary widely, the system must at all times be able to reliably operate under the wide range of conditions that may occur in the region—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, 230, and 345 kilovolt (kV) transmission lines, which are generally longer and fewer in number in northern New England than in southern New England. 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 megawatt (MW), ±150 kV high-voltage direct-current (HVDC) tie, the Cross-Sound Cable interconnection. New England and the Canadian Maritimes (New Brunswick Power Corporation) are connected through two 345 kV alternating current (AC) ties.[55] New England also has two HVDC interconnections with Québec (Hydro-Québec or HQ). One is a 120 kV AC interconnection with a 225 MW back-to-back converter station (Highgate in northern Vermont), which converts AC 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 (Phase II).

5.2 New Challenges for Transmission Planning

Various changes related to increasing electrification and a shifting resource mix present new challenges for transmission planning in the New England power grid. These shifts began before RSP23 and have continued to influence the ISO's approach to transmission planning in the years since.

[53] Peak loads can vary from month to month, day to day and hour to hour. Values cited are seasonal approximations.

[54] See historical flow estimates of the hourly flows and limits on New England's thermal interfaces for additional detail.

[55] One exception is that Aroostook County and part of Washington County in Maine receive electricity service from New Brunswick.

5.2.1 Treatment of Energy-Only Resources in Transmission Planning Studies

In light of the changing resource mix, in 2021, the ISO revisited the language in Attachment K that defines which resources can be relied upon in needs assessments and public policy transmission studies. These resources were defined at a time when large, conventional generation (typically steam-driven or gas turbines) was the norm. Today's Interconnection Request Queue includes large volumes of wind, PV, and storage resources. Since these resources have virtually no marginal cost of operation (such as fuel costs), they are likely to run regardless of whether they have a capacity market obligation. Attachment K of the OATT originally limited resources that could be relied upon in needs assessments (NAs) and public policy transmission studies (PPTSs) to those that have an obligation through the Forward Capacity Market, are contractually bound by a state request for proposals (RFP), or have a financially binding obligation pursuant to a contract. The ISO therefore revised Attachment K so that all existing resources, except for those with a planned retirement before the year under study, can be relied on in needs assessments and public policy transmission studies. The ISO filed the Attachment K resource assumption changes with the Federal Energy Regulatory Commission (FERC) on November 11, 2021, and FERC accepted the changes on January 4, 2022.

5.2.2 Longer-Term Transmission Studies

In the *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid*, NESCOE identified a need for changes in transmission system planning, and recommended that the ISO identify process changes to allow for a routine transmission planning process to help "inform all stakeholders of the amount and type of transmission infrastructure needed to cost-effectively integrate clean energy resources."

In response, the ISO revised Attachment K to incorporate a new transmission planning process designed to look beyond the current 10-year planning horizon. The first phase of the effort established the rules that will allow New England states to request that the ISO perform scenario-based transmission planning studies on a routine basis. The ISO filed the Attachment K longer-term transmission study changes with FERC on December 27, 2021, and FERC accepted the changes on February 25, 2022. The 2050 Transmission Study discussed in Section 5.5.3 is the first example of this kind of longer-term transmission study. The second phase of the effort will develop a process to enable a state or states to consider moving policy-related transmission projects forward and help determine the associated cost allocation. This effort is anticipated to begin by October 2023.

5.2.3 Storage as Transmission-Only Assets

In response to stakeholder requests, the ISO has developed a process to allow for storage facilities to be considered as transmission-only assets (SATOAs).[56] This would allow storage to be considered as a solution in both the solutions study process and the competitive solution process in needs assessments and public policy transmission studies, subject to certain limitations. In developing the proposal, two overarching principles were observed as necessary to the process: 1) the introduction of a SATOA cannot compromise reliability by introducing unmanageable operating burdens into the control room, and 2) it cannot have a significant impact on the markets. The ISO filed this Tariff revision with FERC on December 29, 2022.[57] On June 14, 2023, the ISO provided

[56] A SATOA is an energy storage device connected to the PTF at 115 kV or higher which can inject stored power to address transmission system concerns.

[57] https://www.iso-ne.com/static-assets/documents/2022/12/satoa_filing_part_1.pdf and https://www.iso-ne.com/static-assets/documents/2022/12/satoa_filing_part_2.pdf

additional information in response to FERC's deficiency letter dated May 15, 2023. As of July 2023, FERC had yet to accept the ISO's filing. The region will revisit the limits and approaches to storage over time.

5.2.4 RFP Improvements

Based on the results of the Boston 2028 RFP, the ISO launched a lessons- learned process to discuss potential improvements to the competitive transmission solution process. After several discussions at the Planning Advisory Committee (PAC), the ISO proposed changes to Attachment K Sections 4.3 and 4A and clarifications to the RFP materials and other ISO documentation. Two of the major proposed changes allowed for a subset of needs to be solved by a qualified transmission project sponsor and for non-incumbent joint proposals, other than the backstop transmission solution. Previously, only the incumbent transmission owners required to provide a continued reliability solution were permitted to submit joint proposals. The ISO filed the proposed Tariff changes with FERC on December 28, 2021, and FERC accepted the changes on February 25, 2022.

5.2.5 New BPS Testing

On March 27, 2020, NPCC revised Regional Reliability Reference Criteria A-10, *Classification of Bulk Power System Elements*, which changed the assumptions used to conduct bulk power system (BPS) testing.[58] System stress conditions were revised to represent at least the 98th percentile of historical flows, adjusted for known future system changes. In the past, study cases were created under the assumption that major interfaces were stressed up to their limits. The ISO conducted a BPS classification study and shared the results with the PAC in October 2022.[59] Based on the results, 19 existing buses were removed from the NPCC BPS List.

These changes to Document A-10 also separated transfer limits from BPS testing. As discussed in the FCA 18 capacity zone development preview at the December 2022 PAC meeting, transfer capabilities of the Orrington South and Surowiec South interfaces may be impacted by the separation of transfer limit testing from BPS testing.[60]

5.2.6 Changes in Loss of Source Limit

As the interconnection of large-scale renewables such as offshore wind resources accelerates, project developers may identify proposals larger than 1,200 MW, and recent trends in Europe have suggested this as a strong possibility.[61] Agreements are in place that require both PJM Interconnection and New York ISO to operate such that New England's real-time loss of source limit will be at least 1,200 MW, but also allow the limit to be reduced to 1,200 MW at any time. Upon loss of a large source in New England, inertial pickup prompts increased flows through both the New York and PJM systems. Under certain conditions, these increased flows may have the potential to cause voltage collapse, compromising the reliability of the New York and/or PJM systems and could, at worst, lead to widespread blackouts. The ISO's loss of source limit was established to ensure

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[58] The object of NPCC Regional Reliability Reference Criteria A-10, *Classification of the Bulk Power System Elements* is to provide the methodology to identify the bulk power system elements or parts thereof, of the interconnected NPCC Region, for NPCC criteria applicability.

[59] ISO New England, New England Bulk Power System List Updates, presentation (October 19, 2022)

[60] https://www.iso-ne.com/static-assets/documents/2022/12/a07_fca_18_capacity_zone_development_preview.pdf

[61] To take advantage of economies of scale, wind developers in Europe are developing projects at the 2,000 MW level and higher, which will influence the size of offshore wind projects in the United States.

reliability in both the New York and PJM systems. In March 2023, the ISO made a request to the Joint ISO/RTO Planning Council (JIPC) to evaluate the loss of source limit. The purpose of this request was to assess whether the current system could already allow the minimum loss of source limit to be raised above 1,200 MW, and if it could, to what level.[62] If the minimum loss of source limit within the existing system was still below 2,000 MW, the ISO would request an additional assessment to determine the potential upgrades, including estimated cost, necessary to support a 2,000 MW minimum loss of source limit.[63] JIPC agreed to support the requested system evaluations and directed the ISO to lead the effort. PJM and NYISO would support the necessary evaluations to identify the feasibility and the benefits for each system. JIPC anticipates this complex study effort involving three RTOs will require approximately 18–24 months to complete.

5.2.7 Future Use of EMT Studies

The region's evolving power system will include an unprecedented proportion of nonsynchronous resources and increasing HVDC and flexible alternating-current transmission system (FACTS) devices. Traditional transient stability study tools may not be able to adequately identify system issues that could arise with high penetrations of inverter-based resources.

To ensure continued reliability, electromagnetic transient (EMT) studies must now be incorporated in planning studies. Unlike traditional dynamic models, EMT models can represent the power system at all frequencies as well as individual phase quantities. These models are used to study the ride-through of distributed energy resources (DERs) for major grid disturbances, interactions between controllers, and weak grid instability, to name a few areas of concern. The ISO is working to identify and determine the feasibility of an EMT Transmission Planning pilot study and develop the necessary foundation to perform such a study. Lessons learned from the pilot study would be incorporated in EMT analysis in future transmission planning studies. The ISO anticipates the pilot study will be completed in 2024.

5.2.8 DOE National Transmission Planning Study and NREL Atlantic Offshore Wind Transmission Study

Members of the ISO's Transmission Planning group are represented on the power system modeling subcommittee of the US Department of Energy (DOE) National Transmission Planning Study (NTPS) Technical Review Committee (TRC).[64] Through regularly scheduled coordination meetings, the ISO provides feedback on study approaches and assumptions, both alone and coordinated with other Eastern Interconnection Planning Collaborative members. The NTPS is anticipated to conclude in the fall of 2023.

In addition, members of the ISO Transmission Planning and Planning Services groups are represented on the National Renewable Energy Laboratory (NREL) Atlantic Offshore Wind Transmission Study.[65] Members gave input on generator redispatch assumptions and modeling data, and the ISO provided feedback on modeling and study criteria. The Atlantic Offshore Wind Transmission Study is anticipated to conclude in the fall of 2023.

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[62] https://www.iso-ne.com/static-assets/documents/2023/03/jipc_loss_of_source_limit_final.pdf

[63] If the upgrades needed to raise the loss of source limit to 2,000 MW is cost prohibitive, the ISO would work with PJM and NYISO to determine a new limit greater than 1,200 MW that would be cost favorable.

[64] https://www.energy.gov/gdo/national-transmission-planning-study

[65] https://www.nrel.gov/wind/atlantic-offshore-wind-transmission-study.html

5.3 Completed Major Projects

A number of recent projects have addressed potential post-contingency overloads and voltage concerns. Additionally, projects in Greater Boston have mitigated potential short circuit levels in the area. Since RSP21 the following major projects have been completed or are near completion:

- Greater Boston projects included 345 kV upgrades, which included installing new lines, an autotransformer, and reactive support to maintain voltage; 230 kV upgrades, which included installing an autotransformer; 115 kV upgrades, which included installing a new station, lines, and reactive support to maintain voltage; and several other upgrades. The suite of projects also included the addition of a ±200 megavolt-ampere reactive (MVAR) static synchronous compensator (STATCOM) in Maine.[66] The majority of upgrades are in service, with the exception of the installation of a 345 kV cable from Woburn to Wakefield Junction and the installation of a second 115 kV cable from Mystic to Woburn to create a bifurcated line, with an anticipated in-service date of December 2023, and the installation of a new 115 kV line from Sudbury to Hudson, with an anticipated in-service date of March 2025.
- The Boston Area Optimized Solutions project included the installation of two 345 kV series reactors at North Cambridge in December 2021, the installation of a direct transfer trip scheme on the 345 kV line between Ward Hill and West Amesbury in April 2022, and the installation of a ±167 MVAR STATCOM at Tewksbury with an in-service date of June 2023.
- New Hampshire 2029 Upgrades included the installation of two 50 MVAR capacitors called the Browns River station on Line 363 near Seabrook Station with an anticipated in-service date in November 2023, the installation of a +127/−50 MVAR synchronous condenser at Amherst, with an anticipated in-service date in March 2024, and a +55/−32.2 MVAR synchronous condenser at Huckins Hill, and a +55/−32.2 MVAR synchronous condenser at North Keene with an anticipated in-service date of March 2024.

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

5.4 Key Study Area Updates

Study efforts are 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.

A new effort has re-evaluated transmission planning assumptions on a forward-looking basis (see Section 5.5). New assumptions arising from this effort will be incorporated into future transmission planning studies.

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

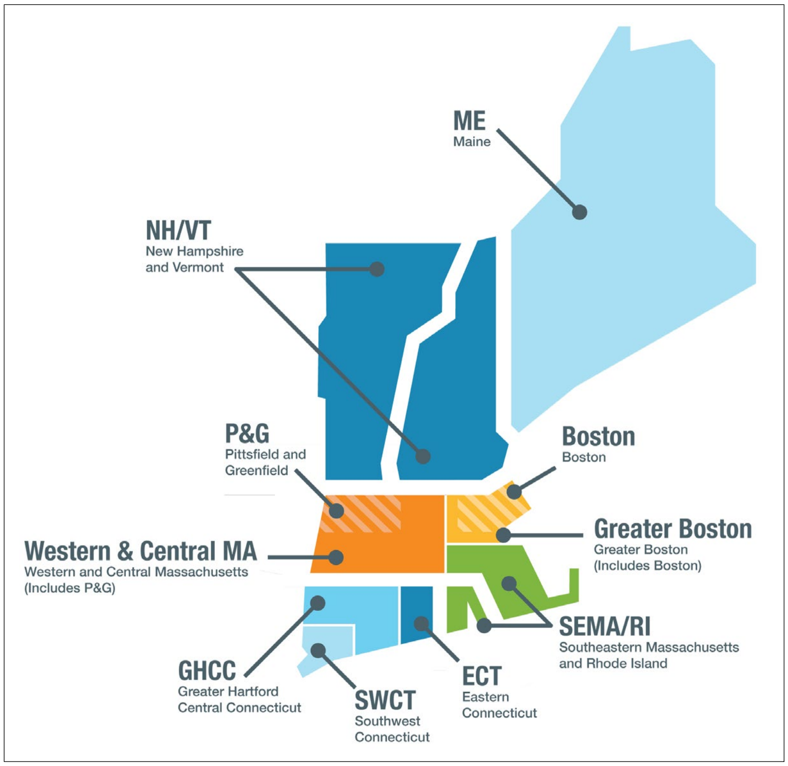

Figure 5-1: Key Study Areas in New England

5.4.1 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.

The SWCT 2027 study was the latest study work completed in the SWCT study area. The *SWCT 2027 Needs Assessment* was posted in July 2018 and the *SWCT 2027 Solutions Study Update* was presented at the September 24, 2020, PAC meeting.

Although high voltage violations were identified at the minimum load level due to contingency events that included the loss of reactive devices in SWCT, those needs were mitigated by an Eversource asset condition project that replaced and removed the single point of failure of the Glenbrook STATCOMs.[67] The Glenbrook STATCOMs asset condition project was completed in May 2021.

5.4.2 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. The GHCC study area represents about 35% of the Connecticut load.

[67] Eversource Energy, *Glenbrook Station STATCOM Asset Condition Replacement*, presentation (July 22, 2020).

The latest study work completed in the GHCC study area was the *SWCT 2027 Needs Assessment* posted in July 2018, which included a minimum-load assessment for the entire state of Connecticut.

No needs were identified in the GHCC study area.

5.4.3 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. 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 2029 study was the latest study work completed in the ECT study area. The *Eastern Connecticut (ECT) 2029 Needs Assessment* was posted in November 2019 and the *Eastern Connecticut (ECT) 2029 Solutions Study* was posted in June 2020. The preferred solution from the ECT 2029 Study comprised a 345/115 kV autotransformer and 115 kV upgrades that include the conversion of a line from 69 kV to 115 kV, the reconductoring of a line, and the installation of a synchronous condenser, a series reactor, a capacitor, and two series breakers. In addition, a station will be upgraded to meet bulk power system standards. The projected in-service date of the last solution component is December 2024.

5.4.4 Western and Central Massachusetts Key Study Area

The Western and Central Massachusetts (WCMA) Key Study Area is bound 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. 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.

The WCMA 2029 study was the latest area-wide study work completed in the WCMA study area. The *Western and Central Massachusetts (WCMA) 2029 Needs Assessment Addendum* was posted in November 2021.

Although voltage violations were identified along the A1/B2 69 kV lines between Pratts Junction in Massachusetts and Vernon in Vermont under peak load conditions, those needs are mitigated by a National Grid asset condition project that rebuilds and reconductors the A1/B2 lines.[68]

A focused study was completed to assess the D-4 115 kV line protection system. The *D-4 Protection System Needs Assessment* was posted in May 2022 and the *D-4 Protection System Solutions Study* was posted in July 2022. The preferred solution is to install a permissive overreaching transfer trip protection system on the D-4 line.

5.4.5 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.

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[68] National Grid, *A-1 & B-2 69kV Line Asset Condition Project*, presentation (September 22, 2021).

The Boston 2028 study was the latest area-wide study work completed in the Greater Boston study area.[69] The Boston 2028 Needs Assessment Addendum was posted in October 2019 and the Boston 2028 Solutions Study—Mystic Retirement was posted in September 2020. The preferred solution, referred to as the Boston Area Optimized Solution (BAOS), was placed in service in June 2023.

A focused study was completed to assess the benefits of operating a 345 kV breaker at K Street as normally open. The *Update on K Street 345 kV Breaker Proposal and Impact on Transfer Capability* was presented to PAC on April 28, 2022, and concluded that opening the 103S breaker at K Street will result in a 300 MW increase to the Boston import interface N-1-1 limit. The opening of the 103S breaker at K Street was completed in September 2022.

The Boston 2032 study began with the *Notice of Initiation of Boston 2032 Needs Assessment* posted on November 16, 2022. The *Draft Boston 2033 Needs Assessment Scope of Work* was posted in June 2023.[70] This assessment will examine whether needs exist for the Boston study area by taking into account updated transmission planning assumptions and will identify the time-sensitivity of any identified needs.

5.4.6 Southeastern Massachusetts and Rhode Island Key Study Area

The Southeastern Massachusetts and Rhode Island (SEMA/RI) Key Study Area focuses on the SEMA and RI load zones, which encompass the areas within Massachusetts south of Boston and the entire state of Rhode Island.

The SEMA/RI 2030 study was the latest area-wide study work completed in the SEMA/RI study area. The *Southeastern Massachusetts and Rhode Island (SEMA/RI) 2030 Minimum Load Needs Assessment* was posted in November 2021. This needs assessment did not identify any needs to be addressed through the regional planning process.

Since 2015, the SEMA/RI study area has undergone a number of needs assessments and solutions studies that have culminated in many projects. The major components of the preferred solutions for addressing the needs are included in the latest version of the RSP Project List.

5.4.7 Maine Key Study Area

The Maine Key Study Area examines the entire state of Maine. In recent needs assessments, the Maine study area was divided into two halves: Upper Maine and Lower Maine. Upper Maine was roughly defined as the area north of the Coopers Mills substation, and is distant enough from the New England Clean Energy Connect (NECEC) HVDC project's point of interconnection to be unaffected by upgrades associated with that project. Lower Maine was roughly defined as the rest of the Maine study area.

The Lower Maine 2030 study was the latest study work completed in the Lower Maine study area. The *Lower Maine (LME) 2030 Needs Assessment* was posted in May 2021. This needs assessment did not identify any needs to be addressed through the regional planning process.

The Upper Maine 2029 study was the latest study work completed in the Upper Maine study area. The *Upper Maine (ME) 2029 Needs Assessment* was posted in March 2020 and the *Upper Maine (UME) 2029 Solutions Study* was posted in June 2021. The preferred solution from the UME 2029

[69] The Boston study area is a subset of the Greater Boston area approximately bounded by the Boston import interface.

[70] The study horizon changed from 2032 to 2033 to account for the new CELT data in the study files.

Solutions Study comprised rebuilding a 115 kV line, converting a substation to a breaker-and-a-half configuration, and installing one 115 kV capacitor, two 115 kV reactors, two 115 kV +50/–25 MVAR synchronous condensers, and three remotely monitored and controlled switches.

5.4.8 New Hampshire and Vermont Key Study Area

The New Hampshire and Vermont (NH/VT) Key Study Area includes the states of New Hampshire and Vermont.

The New Hampshire 2029 study was the latest study work completed in the NH/VT study area. The *New Hampshire (NH) 2029 Needs Assessment* was posted in December 2019 and the *New Hampshire (NH) 2029 Solutions Study* was posted in August 2022. The preferred solutions are anticipated to be in service by March 2024.

The Vermont 2032 study began with the *Notice of Initiation of Vermont (VT) 2032 Needs Assessment* posted on November 16, 2022, and the *Vermont (VT) 2033 Needs Assessment Scope of Work* was posted in July 2023.[71] This assessment will examine whether needs exist for the Vermont study area by taking into account updated transmission planning assumptions and will identify the time-sensitivity of any identified needs.

5.4.9 New England-Wide Geomagnetic Disturbance

The New England-Wide Geomagnetic Disturbance Key Study Area was established in 2022 and covers the entire region.

NERC Standard TPL-007-4, requirements 4 and 8 (R4 and R8), directed the ISO to conduct a benchmark and supplemental geomagnetic disturbance (GMD) vulnerability assessment based on the needs assessment process outlined in Attachment K. If necessary, the ISO was required to identify corrective action plans to address vulnerability issues under R7 and R11 based on the solutions study or competitive solutions process described in Attachment K.

The Geomagnetic Disturbance 2026 Needs Assessment was the latest study work completed to comply with NERC Standard TPL-007-4. The *NERC TPL-007-4 Benchmark and Supplemental Geomagnetic Disturbance (GMD) 2026 Needs Assessment* was posted in August 2022. The results of the needs assessment showed the New England transmission system meets R4 for the steady state benchmark GMD event and R8 for the steady state supplemental GMD event. Therefore, no corrective action plans are needed and R7 and R11 are automatically met. In addition, the ISO specified the criteria for steady-state voltage performance in GMD studies in order to comply with R3.

5.5 Forward-Looking Transmission Planning Efforts

Many current trends in the electric power industry could significantly change the way that New England's transmission system is planned. Substantial increases in renewable generation and certain load and weather conditions are creating new, unstudied power system conditions, and these conditions may limit system performance. Additionally, many of the resources currently proposed for interconnection into the New England system are inverter-based, such as wind, solar, and imports across HVDC lines, rather than traditional synchronous machines. Reduced

[71] The study horizon changed from 2032 to 2033 to account for the new CELT data in the study files.

synchronous generation, coupled with increases in inverter-based generation, leads to lower system strength, and may change the system's response to contingencies and other unexpected events.

The ISO is leading or supporting a number of transmission planning study efforts to address these trends and ensure continued reliability. These efforts explore whether the existing transmission system and planning practices adequately accommodate the future power system, and examine the necessity of reinforcements to the transmission system or changes to study practices. These studies are not intended to be, or take the place of, needs assessments, solutions studies, or requests for proposals for competitive transmission projects. Rather, they are intended to give a high-level view of some of the challenges that New England will face, and the scope of the transmission system upgrades that might be required.

5.5.1 Transmission Planning for the Clean Energy Transition

The first of these forward-looking transmission planning studies is *Transmission Planning for the Clean Energy Transition (TPCET)*. This effort was initiated in order to ensure that, as renewable and DER integration leads to shifts in the most critical conditions for reliability, these critical conditions are studied adequately in transmission planning assessments. This pilot study was conducted from September 2020 to August 2021 with periodic presentations to PAC.[72] The final report was released in January 2022.

TPCET results showed that one of the most critical phenomena to be examined in future transmission planning studies is the loss of legacy DERs following transmission system faults, due to transient low voltage and the inability of many DER installations interconnected in compliance with IEEE Standard 1547-2003 to "ride through" disturbances. Further refinements were made to the DER modeling assumptions, based on research into manufacturers' inverter settings and DER performance during actual system events. Further detail on these refinements may be found in the following section.

Based on preliminary TPCET results, in September 2021 the ISO updated the *Transmission Planning Technical Guide* to reflect the changes in study assumptions for needs assessments and associated solution development.

5.5.2 New Study Assumptions Developed in Response to the TPCET Pilot Study

After TPCET's completion, the ISO further refined its assumptions for future planning studies. The first new study assumption change is designed to align maximum power ratings for resources used in steady-state and stability studies. Prior to this assumption change, all stability analysis utilized winter network resource capability (NRC) ratings, independent of the load level assessed. With the assumption change, stability analysis conducted at summer peak load levels will reflect de-rated output levels that are expected under summer peak load conditions.[73] Additionally, winter NRC values will be used for all resources for off-peak load scenarios in steady-state and stability analyses. These new study assumptions were discussed at PAC on June 15, 2022.

[72] All documentation related to this effort can be accessed on the ISO's website by searching "TPCET"

[73] Winter NRC rating is used to represent the nameplate value for renewable and energy storage resources. These resources are dispatched at a de-rated output level in these studies.

Another study assumption change is designed to align assumptions for pumped storage hydroelectric resources with the existing assumptions for battery energy storage systems (BESS). This topic was discussed at PAC on March 17, 2021.

TPCET revealed that the response of DERs (especially legacy DERs installed under IEEE Standard 1547-2003) to voltage disturbances on the transmission system is a major factor in system performance. In response to this finding, the ISO continued working on refinements to assumptions related to DER protection settings and the expected lifetime of legacy DER installations. These assumption refinements were presented to PAC on May 18, 2022, and August 24, 2022.

Generator outage and intra-area transfer assumptions were updated to utilize transparent, public, and stable input data. The new study assumptions replaced the previous methodology based on a megawatt unavailable threshold and focused on the number of units out of service, rather than number of megawatts. In addition, the new study assumptions considered economic dispatch of generation in the development of study conditions. These new study assumptions were discussed at PAC on June 15, 2022, and August 24, 2022.

Finally, load distribution at minimum load was established. The new study assumptions updated the daytime and nighttime minimum load distributions and are based on real-time minimum load distributions among the load zones. This new study assumption was documented in the 2022 Transmission Planning Base Case Library release.

The *Transmission Planning Technical Guide* was further updated in March 2023 to reflect these new study assumptions.

5.5.3 2050 Transmission Study

The ISO is conducting a 2050 Transmission Study in order to identify possible transmission system deficiencies in serving load in 2035, 2040, and 2050, and to develop high-level transmission upgrade concepts and associated cost estimates to address these deficiencies.

The input assumptions for the 2050 Transmission Study are based on the All Options Pathway in the *Massachusetts 2050 Decarbonization Roadmap* report. These input assumptions include the development of significant new offshore wind, solar, and battery resources; the retirement of significant portions of the fossil-fueled generation fleet, including all oil and coal generators, by 2035; and large increases in electric load due to the electrification of transportation and heating. The 2050 Transmission Study will examine summer peak loads of approximately 40 gigawatts (GW) by 2050, and winter peak loads of approximately 57 GW by 2050.

Over the past two years, the ISO has presented progress made on the study to PAC. These presentations are summarized below:

- November 17, 2021—Study scope and assumptions are detailed, including snapshots to be studied, source of assumptions, and load and generation data.[74]

[74] ISO New England, https://www.iso-ne.com/static-assets/documents/2021/12/draft_2050_transmission_planning_study_scope_of_work_for_pac_rev2_clean.pdf, presentation (November 17, 2021, revised December 22, 2021)

- March 16, 2022—Preliminary first and second contingency results show approximately half (by mileage) of the pool transmission facility (PTF) lines in New England and more than half of the PTF transformers were overloaded.
- April 22, 2022—Sensitivity results related to load reductions and resource relocation are discussed. The study shifts focus to development of possible solution roadmaps from a winter peak of 57 GW to 51 GW.[75]
- July 20, 2022—Results are updated due to some modeling corrections. These corrections did not have a significant impact on the results. The ISO also provides information regarding the possible duration of overloads.[76]
- December 13, 2022—An update is provided on solution development and on lessons learned.[77] The lessons learned are:
    - Increasing capacity of existing lines is effective
    - 345/115 kV transformers are critical
    - Generator sizes and locations can affect overloads
    - Solutions are sensitive to load distribution
- April 20, 2023—The development of cost estimates, solutions being considered, and defined "high-likelihood" concerns are discussed.[78] High-likelihood concerns are those that would appear under a wide variety of conditions, including conditions that do not exactly match those examined in the 2050 Transmission Study.
- July 25, 2023—Key takeaways and transmission development roadmaps are presented.[79]

The final outcomes of this study, expected in November 2023, will help inform stakeholders about the amount and type of transmission infrastructure needed to cost-effectively serve load over the next three decades in light of electrification, accelerated development of renewable resources, and retirement of a significant portion of New England's fossil-fueled generation fleet. The 2050 Transmission Study is conducted in coordination with NESCOE, and in response to the NESCOE recommendation for a comprehensive long-term transmission planning study contained in the *New*

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[75] ISO New England, https://www.iso-ne.com/static-assets/documents/2022/05/a13_2050_transmission_study_sensitivity_results_and_solution_development_plans.pdf, presentation (April 22, 2022)

[76] ISO New England, https://www.iso-ne.com/static-assets/documents/2022/07/a7_2050_transmission_study_updated_results_and_approximate_frequency_of_overloads_1.pdf, presentation (July 20, 2022)

[77] ISO New England, https://www.iso-ne.com/static-assets/documents/2022/12/a04_2050_transmission_study_soultion_development_update.pdf, presentation (December 13, 2022)

[78] ISO New England, https://www.iso-ne.com/static-assets/documents/2023/04/a07_2023_04_20_2050_transmission_study_solutions_update.pdf, presentation (April 20, 2023)

[79] ISO New England, https://www.iso-ne.com/static-assets/documents/2023/07/a10_2023_07_25_pac_2050_study.pdf, presentation (July 25, 2023)

England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid. This study work is being performed under the provisions for longer-term transmission studies that were added to the Tariff in 2022.[80]

5.6 Public Policy

FERC Order No. 1000 directs regions, such as New England, to establish a process to identify public policy requirements that drive a transmission need and, if necessary, evaluate potential solutions to those needs. In January 2023, the ISO initiated the public policy process.[81] The ISO solicited input from stakeholders and the New England states about potential transmission upgrades to address public policies. Through NESCOE, the states requested that the ISO not initiate a public policy transmission study since there were no state or federal public policy requirements "driving transmission needs relating to the New England Transmission System."[82] The ISO did not identify any federal or local public policy requirements and concluded a public policy transmission study will not be conducted for 2023.[83]

5.7 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 non-PTF system. While LSP projects are designed to serve the needs of the non-PTF system, they typically involve PTF components. These components are not eligible for cost regionalization since the upgrade is due to a non-PTF need. Information regarding LSP projects is provided to stakeholders through Transmission Owner Planning Advisory Committee (TOPAC) meetings.[84]

5.8 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, primary owner, transmission upgrades and their status, and estimated cost of the PTF portion of the project. The RSP Project List includes the status of reliability transmission upgrades (RTUs), market efficiency transmission upgrades (METUs), elective transmission upgrades (ETUs), public policy transmission upgrades (PPTU), and generator interconnection transmission upgrades. 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 PAC on transmission upgrades, including study schedules, scopes of work, assumptions, draft and final results, and project costs. Projects are considered part of the Regional System Plan consistent with their status and are subject to transmission cost allocation (TCA) for the region. RSP23 incorporates information from the June 2023 RSP Project List.

[80] Section 16 in Attachment K.

[81] ISO *Public Notification for Public Policy Requirements Submittals* memo (January 13, 2023)

[82] See NESCOE Submission Regarding Transmission Needs Driven by State and Federal Public Policy Requirements (April 28, 2023).

[83] See 2023 Public Policy Transmission Upgrade Process presentation (June 15, 2023)

[84] Links to the most recent LSPs are included on the ISO's RSP Project List.

5.8.1 Reliability Transmission Upgrades

As of June 2023, the total estimated cost of reliability transmission upgrades currently proposed, planned, or under construction was approximately $1.5 billion. The upgrades are described in further detail in the Final RSP Project List and Asset Condition List and shown in Figure 5-2. Since 2002, 858 project components have been placed in service across the region to fortify the transmission system. In addition, 35 project components have a status of proposed, planned, or under construction. Overall, the estimated investment in New England to maintain reliability has been $11.9 billion from 2002 to June 2023. The ISO maintains a spreadsheet listing all projects where a TCA application has been submitted, and identifies costs the ISO deemed as localized in accordance with Schedule 12C of the OATT.

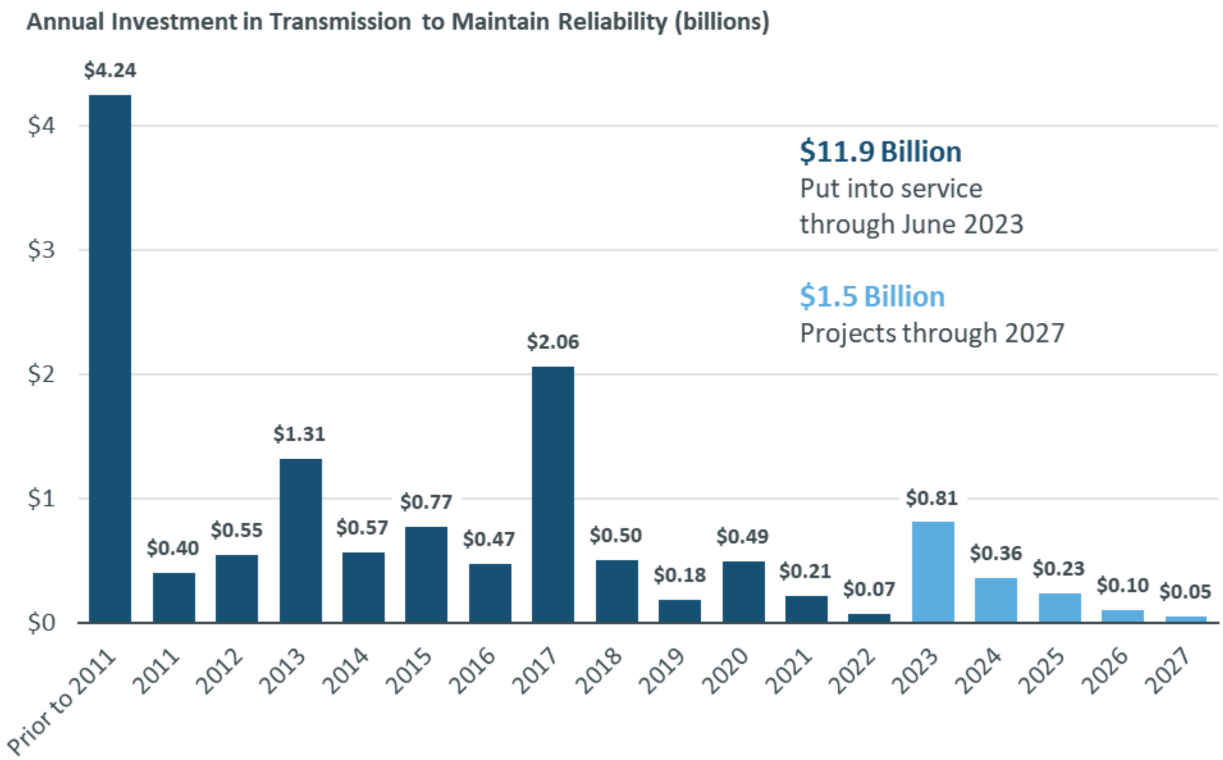

Figure 5-2: Transmission Investment by Year that Projects are In Service (Capital Costs)

Source: ISO New England RSP Project List, June 2023

Note: Estimated future investment includes projects under construction, planned, and proposed.

The Participating Transmission Owner (PTO) Administrative Committee provides an annual informational filing to FERC on the current and upcoming regional transmission service rates and annual updates to the ISO and the New England Power Pool.

Table 5-1 shows actual rates for recent years and upcoming rates for the next year.[85]

Table 5-1:
Actual and Forecast Regional Transmission Service Rates, 2024–2028[(a)]

		1/1/2024	1/1/2025	1/1/2026	1/1/2027	1/1/2028
1	Estimated RNS Rate Impact ($/kW-Yr) (Line (5) / CY Load [(2)] held constant)	$ 11	$ 11	$ 11	$ 11	$ 11
2	Estimated RNS Rate Forecast ($/kW-Yr)	$ 154[(3)]	$ 163[(4)]	$ 174	$ 185	$ 196
3	Estimated RNS Rate Forecast ($/kWh) (Assumes a 54.5% [(5)] Load Factor)	$ 0.024	$ 0.025	$ 0.027	$ 0.029	$ 0.030
4	Estimated Incremental Additions In-Service and CWIP ($ in Millions) [(6)]	$ 1,382[(7)]	$ 1,384	$ 1,253	$ 1,295	$ 1,275
5	Forecasted Revenue Requirement ($ in Millions) (Line 4 * Carry Charge Factor)	$ 195	$ 210	$ 195	$ 209	$ 194

(1) Forecasted rates for 2025-2028 are preliminary and for illustrative purposes only. Estimated data is consistent with the March 2023 RSP and does not reflect revised ISO forecasts. The forecast calculations performed were based on estimated data, and do not contain all the provisions set forth in Attachment F of the ISO-NE OATT.
(2) Source: *RNS Rate Forecast Overview*, PTO-AC Rates Working Group presentation at the RC/TC Summer Meeting (July 18, 2023).
(3) 2022 12CP Average Monthly RNL (kW) = 18,431,168 (kW)
(4) Forecasted RNS Rate effective January 1, 2024 to be filed with FERC on July 31, 2023 utilizing Attachment F of the ISO-NE OATT.
(5) January 1, 2025 RNS Rate excludes $2 kW-Yr related to the prior true-up and PTO-specific prior year adjustments.
(6) ISO-NE Internal Market Monitor: 2022 Annual Markets Report
(7) Forecasted incremental additions for 2025 through 2028 are the forecasted Regional additions projected in the respective year without considering averaging as PTOs do not forecast long range additions by quarter.
(8) January 1, 2024 RNS Rate includes the incremental change in 2023 forecasted Regional plant in-service and CWIP additions (as compared to the 2023 5Q average Regional plant in-service and CWIP additions included in the January 1, 2023 RNS Rate), plus the 5Q average 2024 forecasted Regional plant in-service and CWIP additions.

Wholesale costs and the rates for residential retail power supply can vary dramatically among the states and from year to year, primarily because wholesale electricity markets and retail electricity markets are used to obtain different products. Wholesale markets reflect the short-term spot market for electric energy, whereas retail rates reflect longer-term, fixed-price contracts. The relationship between wholesale costs and retail rates will also vary with each utility and state's procurement practices for retail power.

According to the *2022 Report of the Consumer Liaison Group*, from 2021 to 2022, wholesale market costs increased 58.5% to 63.0% across the New England states, largely due to higher

[85] Regional transmission service is composed 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 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.

demand and higher natural gas prices following Russia's invasion of Ukraine. All the states saw a significant increase in retail power supply rates in effect on January 1, 2023, compared with retail power supply rates in effect on January 1, 2022. A review of actual transmission rates for residential retail consumers in Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island in effect on January 1, 2022, shows that transmission represents 7.9% to 15.3% of total residential retail electricity rates.

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

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

- RTUs have resulted in significant market efficiency benefits, particularly by reducing out-of-merit operating costs
- 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 cCommitment-Period Compensation (NCPC)[86]

Improvements to the Tariff realted to economic study processes have incorporated a METU needs scenario to better help identify market efficiency issues and needs that could lead to future METUs.[87]

5.8.3 Transmission Congestion

Recent experience has demonstrated that the regional transmission system has low levels of congestion, as illustrated in Table 5-2.[88] At approximately −$51 million in 2022, the total day-ahead and real-time congestion costs remain small, and mitigation by additional transmission upgrades does not appear warranted based on the current system and resource mix. Real-time congestion costs on the system were −$2 million. Planned RTUs could reduce congestion costs further, as well as reduce transmission system losses.

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[86] 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.

[87] https://www.iso-ne.com/static-assets/documents/2023/01/improvements_to_economic_study_process_in_att_k.pdf

[88] A hub is a specific set of predefined pricing nodes for which locational marginal prices are calculated and which are used to establish reference prices for electric energy purchases, the transfer of day-ahead and real-time adjusted load obligations, and the designation of Financial Transmission Rights (FTRs)

Table 5-2:
ISO New England Transmission System Day-Ahead, Real-Time, and Total Congestion Costs and Credits, 2003–2020 ($)[(a)]

Year	Day-Ahead Congestion[(b, c)]	Real-Time Congestion[(b, d)]	Total Congestion[(b, e)]
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	−$4,596,349	−$38,868,759
2017	−$39,213,542	−$2,171,319	−$41,384,861
2018	−$67,792,715	$3,260,035	−$64,532,680
2019	−$34,376,058	$1,435,764	−$32,940,294
2020	−$29,709,216	$631,623	−$29,077,593
2021	−$51,068,637	$1,020,155	−$50,048,481
2022	−$48,876,423	−$2,101,125	−$50,977,547

(a) Values subject to change as a result of resettlement.

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

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

(d) 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.

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

In 2022, the highest mean annual positive difference in the congestion component of locational marginal prices (LMPs) was $0.002 per megawatt-hour (MWh) at the Central Massachusetts/Northeastern Massachusetts (CMA/NEMA) and Western Massachusetts (WMA) RSP subareas relative to the Hub.[89] The Northeastern Maine (BHE) RSP subarea had the highest mean negative congestion difference at $4.23/MWh. Portions of the system remote from load centers, especially in northern Maine, have relatively high negative loss components.

5.8.4 Transmission Improvements to Load Pockets Addressing Reliability Issues

The performance of the transmission system depends on well-located 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 certain generating units are unavailable to provide system support, especially when combined with normal levels of unplanned or scheduled outages of generators or transmission facilities. This transmission system dependence on local-area generating units can typically result in reliability payments associated with out-of-merit unit commitments. These reliability payments were a small portion of the overall $16.7 billion wholesale electricity market costs in New England in 2022.

Generating units in load pockets may receive second-contingency or voltage-control payments for must-run situations. Table 5-3 shows the NCPC by type and year. There has been a general decline in payments since 2013, with 2021 and 2022's average ($4.0 million) at only 7% of the 2013 figure. In 2022, no area of the system had an NCPC in excess of $330,000. RTUs typically improve the economic performance of the system, however, upgrading transmission solely to reduce NCPC has not yet been justified by economic analysis.

[89] See the ISO's Real-Time and Historical Data for Informed Market Decisions webpage.

Table 5-3:
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	38.6
2015	42.7	5.4	48.1
2016	31.1	1.5	32.6
2017	12.5	3.4	15.9
2018	15.0	2.7	17.7
2019	7.3	0.5	7.8
2020	4.0	0.6	4.6
2021	6.8	0.0	6.8
2022	1.1	0.0	1.1

(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 used where proposed generating or demand resources have not relieved transmission system performance concerns. The ISO is studying 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. RTUs were used to address these system performance concerns, which contributed to a substantial reduction in out-of-merit operating costs.

5.8.5 Required Generator-Interconnection-Related Upgrades

See Section 6.8.

5.8.6 Elective Transmission Upgrades

See Section 6.9.

5.9 Interregional Coordination

Interconnections with neighboring systems allow for the exchange of capacity and energy, facilitating access to a diversity of resources, compliance with environmental obligations, and more economic, interregional operation of the system. New England is well situated for interregional coordination, given the seasonal diversity of demand in neighboring regions, especially the winter-peaking Canadian provinces.[90] As our system becomes dual-peaking toward the end of the next 10 years and then winter-peaking in the mid-2030s, this diversity in demand will diminish and a well-coordinated interregional system will become even more crucial.

The ISO coordinates its planning activities with neighboring systems and across the Eastern Interconnection (EI) 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 and participates in studies that aim to address other common issues affecting the planning of the overall system.

The ISO participates in numerous interregional planning activities with DOE, NPCC, and NERC. The overriding purpose of these efforts is to enhance the overall reliability of the interregional electric power system.

5.9.1 Eastern Interconnection Planning Collaborative Studies

In 2009, most of the electric power planning coordinators of the EI, including ISO New England, formed the Eastern Interconnection Planning Collaborative (EIPC) to analyze the combined regionally planned, interconnection-wide system. Since that time, 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.[91] EIPC is developing its updated version for publication in late 2023.

EIPC has performed analyses to verify that the combined regional plans function well together to maintain bulk power system reliability throughout the EI, and to identify potential constraints

[90] Interconnecting different time zones provides additional diversity. The Atlantic time zone used by the Canadian Maritime provinces is an hour later than the Eastern time zone used by New England.

[91] See EIPC, *State of the Eastern Interconnection* report and Eastern Interconnection Planning Collaborative Completes Report on the State of the Eastern Interconnection press release.

resulting from interconnection-wide power-flow interactions, providing feedback to inform and enhance regional plans.[92]

EIPC entities responsible for system planning have developed power flow and production cost models of the EI for a base scenario and a high penetration of renewables scenario to identify potential EI-related issues that may need to be addressed in future analysis.

The addition of inverter-based, nonsynchronous generation and planned synchronous resource retirements may affect the ability of the EI to maintain frequency. In support of NERC, EIPC conducted an analysis that showed acceptable system performance over the next five years. Updates to this analysis are expected every two years.[93]

EIPC has established a working group to liaise with planning coordinators and their representatives in the Multiregional Modeling Working Group (MMWG) on assembling network models of the EI, in pursuit of improved model quality and model development processes.

EIPC representatives prepared testimony and spoke at the FERC Technical Conference on interregional transfers on December 5–6, 2022, in Washington, DC. EIPC and its representatives are involved in the technical review committees for many of the current DOE studies, such as the National Transmission Planning Study and the Atlantic Offshore Wind Transmission Study.

5.9.2 Electric Reliability Organization Overview

NERC is the FERC-designated Electric Reliability Organization. NERC issued its annual *Long-Term Reliability Assessment* (LTRA), analyzing reliability conditions across the North American continent, in December 2022. This report discusses transmission additions, generation projections, and reserve capability by reliability council area. This edition of the LTRA, as with past reports, included a note regarding the heightened risk in New England, among other regions, of vulnerabilities associated with natural gas delivery to generators.

5.9.3 NPCC Studies and Activities

NPCC 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 (BPS) or bulk electric system (BES).[94,95] NERC has authorized NPCC to create regional standards to maintain and enhance the reliability of the international, interconnected BES in northeastern North America. As a member of NPCC, ISO New England 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. The ISO assessments demonstrate full compliance with

[92] Final reports from work undertaken with the support of DOE is available on the EIPC webpage.

[93] See EIPC *Frequency Response Working Group 2020 Final Report*, Public Version. The next report is expected in the last half of 2023.

[94] The six NERC regional entities are: the NPCC, Southeastern Reliability Corporation (SERC), ReliabilityFirst (RF), Midwest Reliability Organization (MRO), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).

[95] NERC uses the term BES; NPCC uses BPS.

NERC and NPCC requirements for meeting resource adequacy and transmission planning criteria and standards.

NPCC activities also include the issuance of several special reports and updating guidelines and criteria. One ongoing project will assess the future reliability risk to the NPCC BPS of a significant gas contingency during periods of increased reliance on natural gas, including electrical nonpeak/shoulder month periods. Another evaluates the reliability impacts of NPCC balancing authority areas' resource adequacy scenarios to address societal decarbonization objectives established by the American states and Canadian provinces within the NPCC footprint.

5.9.4 Northeastern ISO/RTO Planning Coordination Protocol

Each Independent System Operator/Regional Transmission Organization (ISO/RTO) develops individual system reliability plans, production cost studies, and interconnection studies, with the potential for significant interregional impacts in mind. JIPC and the Interregional Planning Stakeholder Advisory Committee (IPSAC) were established to facilitate interregional coordination and communication among all interested parties.[96] 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. [97]

Recent planning activities among ISO New England, New York ISO, and PJM Interconnection, discussed with IPSAC, include the interregional planning process, regional needs, and projects meeting the regional needs. [98] The planning 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 have addressed interconnection queue studies with potential interregional impacts and coordinated data sharing among regions related to the influx of offshore wind proposals. 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.

5.10 Asset Condition Process and Right-Sizing

As discussed in Section 5.8.1, $11.9 billion of reliability transmission upgrades have been placed in service in New England through June 2023, with another $1.5 billion of investment anticipated through 2027. This substantial investment has added to or improved the transmission system to serve the load in the region. However, this figure does not include investments needed to repair and replace aging elements of the transmission system. Most reliability transmission upgrades have involved the construction of new transmission facilities, which, in combination with the existing transmission facilities, increase the capabilities of the system. These new facilities work in concert with the existing system; however, they generally do not replace it. Many system assets are reaching the end of their useful life and require significant repair or replacement, and spending to address these concerns has increased significantly over the past few years. This spending can be

[96] See ISO New England Interregional Planning Stakeholder Advisory Committee (IPSAC) website

[97] See ISO New England, NYISO, and PJM, *Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol*

[98] The PJM Interconnection is a regional transmission organization operating an electric transmission system serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

reviewed in the New England Asset Management Key Study Area, a repository for all asset-condition-related PAC presentations.[99,100]

Although asset condition projects are not under the ISO's purview (as defined in Attachment K), beginning in 2016 the ISO created a New England Asset Condition Update List to capture all asset-condition PAC presentations. The list is updated three times a year, coincident with the RSP Project List.[101] Since the list's creation, 389 projects have been added for a total of $7.7 billion as of June 2023. Of the 389 projects, 257 are in service, for a total of $3.4 billion. The remaining projects are conceptual, proposed, planned, or under construction.[102] Investment in asset condition projects is illustrated in Figure 5-3.

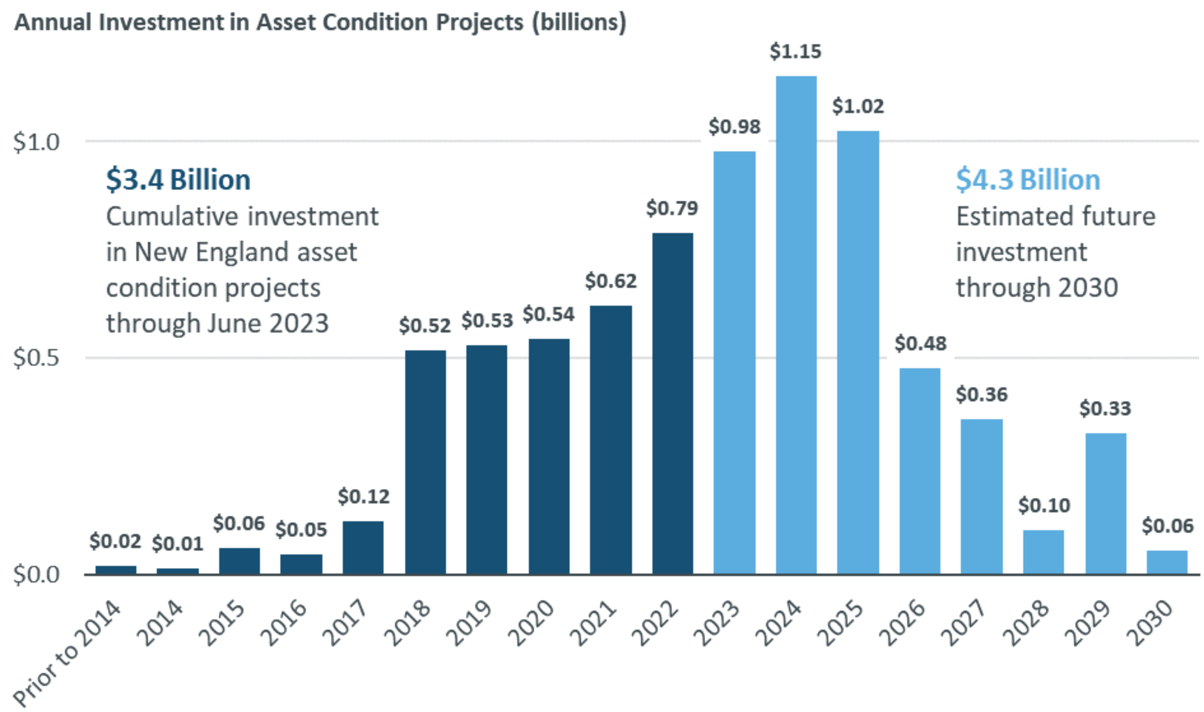

Figure 5-3: Asset Condition Project Costs By Year

Spending on asset condition projects far outpaces the spending on reliability transmission upgrades. As a result, and coupled with ISO's lack of jurisdiction in this area, NESCOE has proposed several process enhancements to improve the transparency, predictability, and cost discipline of asset condition projects. These proposals were communicated through memorandums submitted to

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99 A PAC presentation is required for all asset-condition-related work where the cost estimate is greater than or equal to $5 million.

100 https://www.iso-ne.com/system-planning/transmission-planning/transmission-owner-asset-management/

101 ISO New England, Regional System Plan Transmission Projects October 2015 Update, presentation (October 22, 2015) – Slide 4 discusses the separation of asset condition related projects from the RSP Project List which prompted the initiation of the Asset Condition List beginning with the March 2016 RSP Project List Update.

102 Projects under the status of "concept" are not included.

PAC in February and July 2023.[103] NESCOE recommended that New England Transmission Owners should:

- Develop asset condition project spending plans that include one-, two-, and five-year forecasts
- Work with ISO-NE to develop and maintain an asset condition database that will include all information necessary to guide and inform holistic asset condition prioritization and decision-making
- Provide a description of how select asset condition projects could support right-sizing
- Develop an asset condition and guidance document that will promote a more criteria-based decision-making approach to asset condition projects
- Make certain improvements to the process for stakeholder review of proposed asset condition projects

The New England Transmission Owners (NETO) responded with an Asset Condition Projects Update presentation made to stakeholders in late July.[104] In addition, the NETO presented their proposed guidelines for asset condition project presentations and an overview of their cost estimating processes at the PAC meeting on August 16, 2023.[105,106,107]

NESCOE, NETO, the ISO, and stakeholders continue to coordinate on improvements to the asset condition process. Improving the asset condition process to increase transparency and predictability is a necessary precursor to developing a process to right-size asset condition projects as part of the region's decarbonization build-out. These changes must be planned holistically to allow for efficient transmission investment at the pace and scale needed to meet the region's clean energy future.

As part of the asset condition and right-sizing conversation, the ISO reviewed a number of recent transmission cost allocation applications and found that materials are typically 10% or less of the total project costs for overhead transmission line rebuilds. This suggests, for example, that an incremental increase in the size of a conductor would have a minimal impact on the overall project costs for overhead transmission. This type of evaluation should inform the decision-making process when selecting the optimal overhead transmission line conductors for future reliability and asset condition line rebuild projects.

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103 NESCOE, https://www.iso-ne.com/static-assets/documents/2023/02/2023_02_08_nescoe_asset_conditions_letter.pdf, memorandum (February 8, 2023)

NESCOE, https://www.iso-ne.com/static-assets/documents/2023/07/2023_07_17_nescoe_asset_condition_request_netos.pdf, memorandum (July 14, 2023)

104 NETOs, https://www.iso-ne.com/static-assets/documents/2023/07/a08_2023_07_25_rns_and_asset_condition_project_update.pdf, presentation (July 25, 2023)

105 New England Transmission Owners, https://www.iso-ne.com/static-assets/documents/2023/08/a07_2023_08_16_pac_proposed_guidelines_asset_condition_project_presentations.pdf, presentation (August 16, 2023)

106 New England Transmission Owners,https://www.iso-ne.com/static-assets/documents/2023/08/2023_08_16_pac_tos_asset_condition_guidelines_draft.pdf, report (August 16, 2023)

107 New England Transmission Owners, https://www.iso-ne.com/static-assets/documents/2023/08/a06_2023_08_16_pac_overview_of_new_england_transmission_owner_cost_estimating_process.pdf, presentation (August 16, 2023)

The efforts outlined above are designed to serve in the development of guidelines for right-sizing future transmission projects.

5.11 Summary

Since the publication of RSP21, the Greater Boston Upgrades, Boston Area Optimized Solutions, and NH 2029 Upgrades were either placed in service or are nearing completion.

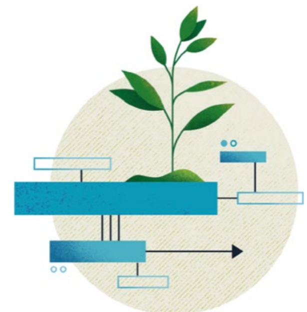
The continued development of renewable resources and DERs will ultimately require some transmission build-out to successfully interconnect and maintain system reliability. The ISO has developed new study assumptions, largely through the Transmission Planning for the Clean Energy Transition effort, and work utilizing the new study assumptions has started in the Boston and Vermont study areas.

The 2050 Transmission Study is nearing its conclusion. This effort will help to inform stakeholder discussions to lay out a high-level direction and potential costs for the transmission system to deliver clean energy resources to load centers and may help to inform the selection of solutions for nearer-term needs.

Engagement with the states, stakeholders, and neighboring regional transmission operators is in progress to tackle important issues facing the evolving transmission system, such as:

- Phase two of the longer-term transmission study effort that would enable a state or states to consider moving policy-related transmission projects forward and with an associated cost allocation
- Right-sizing to determine where more robust transmission upgrades may address broader potential future scenarios than the immediately identified need
- A study to potentially increase the current 1,200 MW loss of source limit

Section 6: Interconnection Requests and Generating Resources in the Interconnection Queue



In order to provide energy and/or capacity in New England, new resources must interconnect to the administered transmission system. The ISO studies proposed interconnections in order to ensure that system reliability criteria and standards for no adverse impact are met. Studies in the Interconnection Request Queue are typically performed serially according to the order in which the requests are received. Section 2.2.2 describes the recent FERC rule change related to the interconnection process in more detail. Cluster studies are not listed in the queue; these are described in Section **Error! Reference source not found.**. The interconnection process begins when developers evaluate where they would like to build a new resource or determine if they would like to modify an existing resource. This section describes the general makeup of the Interconnection Request Queue at the time of RSP23's publication, and what that makeup means for the New England power grid.

In accordance with provisions of the *Open Access Transmission Tariff* (OATT), interconnection studies include proposals for generator and elective transmission upgrade interconnections and supplemental transmission service for New England's grid. Studies typically consist of thermal, voltage, stability, and short-circuit analyses, with electromagnetic transient (EMT) analysis also performed for inverter-based resources. Certain factors can affect the time taken to complete each interconnection study, such as the location on the system, the extent of accumulation of requests, and the quality and finality of the modeling information provided by developers.

Proposed projects in the ISO's Interconnection Request Queue reflect the type of new generation capacity developers in the region are currently interested in building.[108] Recent years have seen large growth in wind and storage proposals as solar power's share of the queue recedes, while new natural gas proposals are near zero.

At the time of publication, 353 total generation projects are being tracked by the ISO, totaling approximately 35,400 megawatts (MW):

- 25 in the scoping stage
- 27 undergoing feasibility study
- 48 undergoing system impact study/optional interconnection study
- 4 undergoing facilities study
- 39 negotiating interconnection agreements
- 28 with interconnection agreements
- 193 non-FERC jurisdictional distribution interconnections

[108] The ISO provides monthly updates on the status of active generation interconnection requests, *NEPOOL Participant Committee Chief Operating Officer (COO) Report for Monthly Updates* (Monthly COO Report). For an example, see the June 2021 monthly COO Report.

Figure 6-1 shows resources in the queue by fuel type. Years shown represent the developers' target in-service dates for proposed resources. Though not all of these proposed new generating resources will be built, transmission bottlenecks are likely, and additional transmission build-out may be required to reliably interconnect renewable resources currently in the queue.

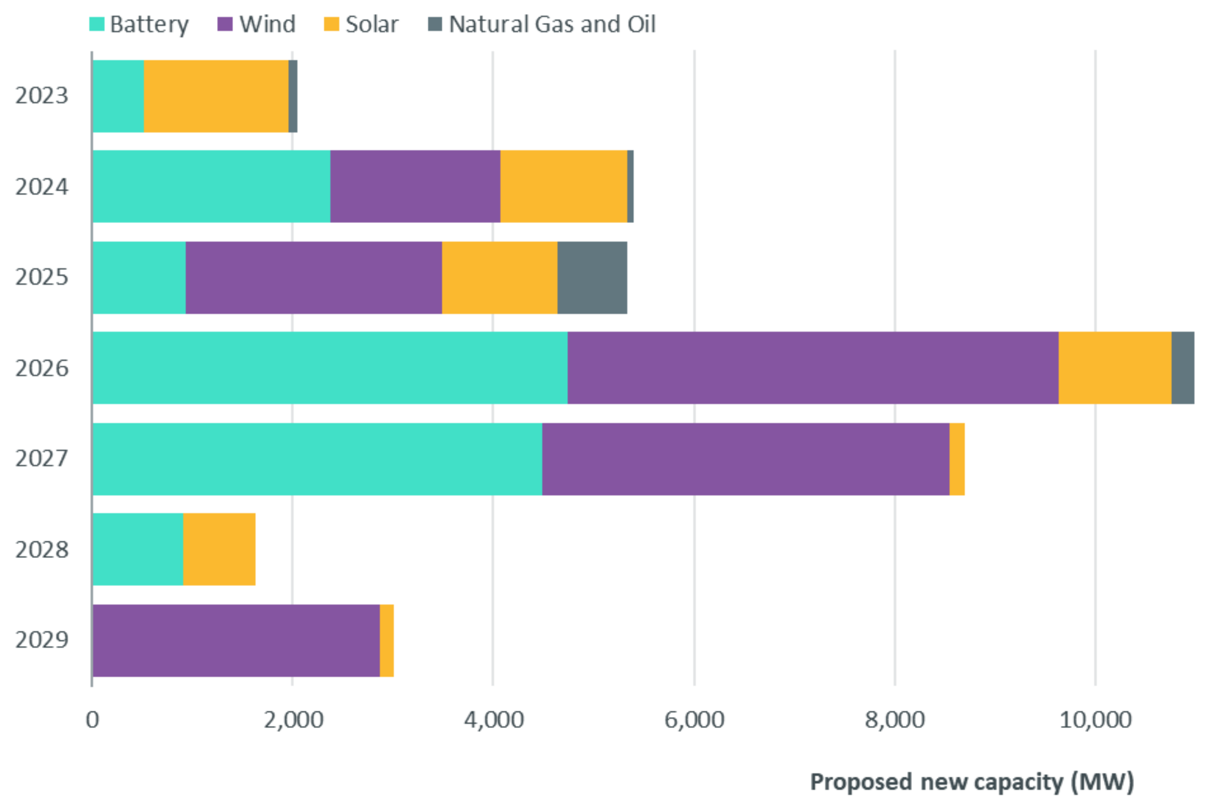


Figure 6-1: Resources Active in ISO Interconnection Request Queue by Fuel Type, as of June 1, 2023

Note: The "Other Renewables" category includes biomass/wood waste and fuel cells.

6.1 Interconnection Process

The interconnection of distributed energy resources (DERs) will continue to add complexity to the power grid and in particular the ISO-administered transmission system. In recent years, more and more small resources are seeking to interconnect to the distribution system and participate in the wholesale markets. [109] As more DERs interconnect, it is essential that the ISO continue to work closely with transmission owners to ensure the proper DER interconnection process is followed and grid reliability is maintained.

[109] Distribution system facilities are low-voltage electric power lines (typically < 69 kV); which can be either FERC jurisdictional or state jurisdictional. The state interconnection process will apply if a DER is interconnecting to a FERC non-jurisdictional facility.

6.2 Cluster Studies

In accordance with Schedules 22, 23, and 25 of the OATT, certain projects interconnecting through the FERC jurisdictional process can be studied in a *cluster*. The study reports and other related materials for projects that are evaluated as part of a cluster are described in this section.

6.2.1 Maine Cluster Studies

The *2016/2017 Maine Resource Integration Study* (MRIS) identified transmission upgrades necessary for interconnecting proposed resources in northern and western Maine. A *Second Maine Resource Integration Study* (Second MRIS) was completed in October 2020 and identified transmission upgrades necessary to enable the interconnection of proposed new resources in northern Maine. A Third Maine Resource Integration Study is currently underway.

These studies have found that a new 345 kilovolt (kV) line will need to extend from Aroostook County in northern Maine to a new substation on the existing 345 kV Orrington–Albion 3023 line in the vicinity of Pittsfield. In addition, a new 345 kV line will be required between Pittsfield and Coopers Mills. The addition of a second 345 kV Coopers Mills–Maine Yankee 392 line was identified as a required upgrade for Queue Position 639, and this upgrade is a contingent facility for the cluster. These upgrades could allow up to 1,200 MW of generation to interconnect in a manner that meets the Network Capability Interconnection Standard. The upgrades would not enable the generation to connect in a way that meets the Capacity Capability Interconnection Standard if earlier-queued projects proceed and interconnect according to this standard.

Elective transmission upgrades (ETUs) were also identified as eligible to participate in this Second MRIS. These ETUs themselves constitute significant new transmission line infrastructure rated at or above 115 kilovots (kV) alternating current (AC).

6.2.2 Cape Cod and Offshore Wind Cluster Studies

As of April 1, 2021, system impact studies were completed for 1,600 MW of offshore wind interconnecting to Cape Cod.[110] Cape Cod is just one of the areas within New England where offshore wind interconnections have been proposed due to the completed auction of US Bureau of Ocean Energy Management (BOEM) lease areas. These lease areas are found off the shores of Massachusetts and Rhode Island, and in Wind Energy Areas (WEAs) on the outer continental shelf.[111]

Significant potential offshore wind in southern New England is the subject of another cluster study. The *First Cape Cod Resource Integration Study* (CCRIS) was completed on July 30, 2021. The study sought to identify the transmission upgrades necessary to enable the interconnection of proposed new offshore wind resources to Cape Cod. The transmission infrastructure that serves the Cape Cod area was developed to serve the area load and historically connected generation, particularly Canal Station and Pilgrim Station. Significant amounts of offshore wind resources are now projected to

[110] All interconnection requests require a System Impact Study, which is an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the transmission system. If a proposed project is eligible for study in a cluster, the ISO will inform the project sponsor accordingly. At the discretion of the ISO, clustering is triggered when both of the following conditions exist: (1) There's a backlog of two or more interconnection requests in the same part of the transmission system and (2) The ISO has determined that none of proposed projects in that part of the transmission system are able to interconnect, either individually or in a cluster, without the use of common significant new transmission line infrastructure.

[111] Interconnections for offshore wind have also been proposed to Boston, Plymouth, and Somerset in Massachusetts, eastern Rhode Island, and southern Connecticut.

interconnect to the region. Offshore lease areas have been established to the south of Martha's Vineyard and Nantucket. Cape Cod is one of the closer landing points from these lease areas and, as a result, several projects have proposed to connect to this part of the system. Current infrastructure was developed to serve the area load and historically connected generation, and despite recent and proposed improvements, the ISO sees challenges in meeting the needs of proposed new offshore wind resources. Significant new transmission infrastructure is likely needed to interconnect all of the proposed resources in Cape Cod.

6.3 Regional Integration of Inverter-Based Resources and Technologies

The effect of an increase in inverter-based technologies on power grid system events must be understood and reflected within planning and operating studies. These events 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, photovoltaic (PV), storage, demand response, and high-voltage direct current and flexible alternating current transmission system devices. The ISO has implemented several updates to planning and operations and the wholesale electricity markets to assist with the integration of inverter-based resources and technologies into the grid. Several of the technology developments affecting the planning of the region involve integrating grid-transformation equipment, improving operator awareness and system modeling, and using phasor measurement units.

6.4 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.[112]

Limited transmission infrastructure in northern and western Maine poses the primary obstacle to interconnecting new onshore wind resources. Current generator interconnections leave this part of the transmission system at its performance limit with little to no remaining margin. Each new interconnection request in the area involves lengthy and complex study work, identifies significant transmission infrastructure needs, and leads to an inability or unwillingness on the part of individual project developers to make the required system upgrades. The interconnection clustering methodology can allow for more than one project to be grouped together to contribute to the costs of the significant upgrades. The ongoing Maine resource integration studies, for example, have identified major new 345 kV lines to allow integration of the proposed generation.

6.5 Regional Integration of Photovoltaic Resources and Other Distributed Generation Resources

As noted in Section 4, New England has experienced significant growth in the development of solar resources over the past few years, and continued growth of PV is anticipated. Current PV has already caused noticeable changes to system operation and, as it grows, is 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

[112] 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 inverter-based resources.

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 of non-PV DERs. Future demand could become less predictable, since to date the region has not experienced the large-scale growth of other types of DERs, such as energy storage, which would present challenges similar to behind-the-meter (BTM) PV technologies and time-varying retail rates in predicting demand. The ISO continues to monitor this situation and actively seeks to improve its demand forecasts. This includes applications of modern analysis techniques like big data analysis and artificial intelligence.

Distribution company owners are reviewing and improving processes and methodologies for integrating DERs. These activities include cluster analyses for non-FERC-jurisdictional resources, providing information on the hosting capacity of distribution circuits, and making better use of smart inverters. Electric distribution owners are also modernizing distribution system equipment to better accommodate the large-scale development of DERs. In Massachusetts, the Technical Standards Review Group is discussing the next phase of implementation for the IEEE 1547 Standard.[113]

6.6 Energy Storage Resources

Grid-scale, or in-front-of-the-meter, battery storage resources are integrated into the New England power system and are successfully participating in regional electricity markets. Most new proposals for energy storage resources make use of inverter-based technologies. For the ISO to efficiently process interconnection requests for these technologies, requests must include appropriately robust equipment. The power system models are required to perform well in the network study analysis, and the equipment must meet established performance requirements, such as power factor, ride-through, and frequency requirements.

6.7 Distributed Energy Resources

The New England states have increased targets for renewable energy, resulting in an influx of generator interconnection requests to the ISO and to transmission providers. The interconnection of DERs within electric distribution systems has contributed to a decrease in net demand. This, combined with continuing state decarbonization policies, points to significant changes in the region's resource mix over the next 15–20 years.

Development of renewable energy resources and DERs will continue to add complexity to the power grid. Small DERs, including those coupled with energy storage, usually have limited observability and controllability because they do not participate in the New England markets. Without adequate knowledge about where and/or when these types of resources will operate, operational complexity increases. The ISO is conducting several studies to identify ancillary service requirements, such as regulation, ramping, reserves, and voltage support, that are associated with a

[113] Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems

clean energy future, and seeks to identify and address operational challenges associated with the expected influx of small DERs.[114]

Regulatory changes may also influence how reliability and operability standards will be met. FERC Order No. 2222 directly impacts resource integration and market participation by requiring Independent System Operators/Regional Transmission Organizations to remove entry barriers for DER aggregations in their wholesale markets. Thousands of megawatts of DERs are currently participating in New England's electricity markets under existing participation models. However, the ISO does not currently have participation models to allow DERs to participate in the markets using heterogeneous aggregations of DER asset types. To address this gap, the ISO is proposing new participation models for DER aggregations. Discussions will continue with the affected New England Power Pool committees throughout 2023.

6.8 Required Generator-Interconnection-Related Upgrades

With the exception of the larger cluster studies, no significant transmission system upgrades have 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 found in the RSP section of the ISO website identifies the pool transmission facility (PTF) upgrades to be built to accommodate new generation, and ETUs that have satisfied the requirements of the Tariff.

Several wind-generating plants have participated in clustering studies that expedite the consideration of two or more interconnection requests and allocate interconnection upgrade costs among the interconnection customers, including the MRIS and Cape Cod studies identified in Section 6.2.1 and Section 6.2.2.

6.9 Elective Transmission Upgrades

A number of new ETUs have been added to the Interconnection Request Queue. Many of these are focused on delivering zero- or low-carbon resources to or within New England. The queue currently includes proposals to import energy from other regions and from offshore wind, and to increase internal transfer capabilities. As of July 1, 2023, seven projects are under study as ETUs, and five have received approval of their proposed plan applications.

6.10 Resource Qualification for the Forward Capacity Market

The ISO runs an auction each year to procure the resources needed to meet future consumer demand for electricity. The annual auction of the Forward Capacity Market is held three years before each capacity commitment period to provide time for new resources to be developed. Capacity resources can include traditional power plants, renewable generation, imports, and demand resources such as load management and energy efficiency measures. Resources that clear in the auction receive a monthly capacity payment in that future year in exchange for their commitment to provide power or curtail demand when called upon by the ISO. Resources that fail to meet their capacity commitment during a capacity scarcity condition must refund part of their capacity payment. This refunded money goes to resources that over-perform during the event. The capacity market is separate from the energy market, where resources with and without capacity commitments compete each day to provide power and are paid for the electricity they produce.

[114] Studies include the Future Grid Reliability Study, Pathways to the Future Grid, Transmission Planning for the Clean Energy Transition (TPCET) Pilot Study, and the New England states' 2050 Transmission Study.

Held on March 6, 2023, the 17th Forward Capacity Auction (FCA 17) closed after four rounds of competitive bidding. The auction secured capacity commitments of 31,370 megawatts (MW) to be available in the 2026–2027 commitment period, at a preliminary price of $2.590 per kilowatt-month (kW-month) in all zones and import interfaces except the New Brunswick interface, which cleared at $2.551/kW-month.

Almost 750 MW of capacity of new renewable energy, energy storage, and demand-reducing resources secured obligations in FCA 17, as illustrated in Figure 6-2. New and existing solar and wind generation, energy storage, and demand capacity resources secured obligations totaling more than 5,000 MW, accounting for about 16% of all capacity clearing the auction. New solar generation and energy storage resources, or facilities combining the two, secured obligations totaling 519 MW. This accounted for the majority of new generating resources, which also included wind and a small amount of hydroelectric resources. More than 350 MW of new and existing wind resources cleared the auction.

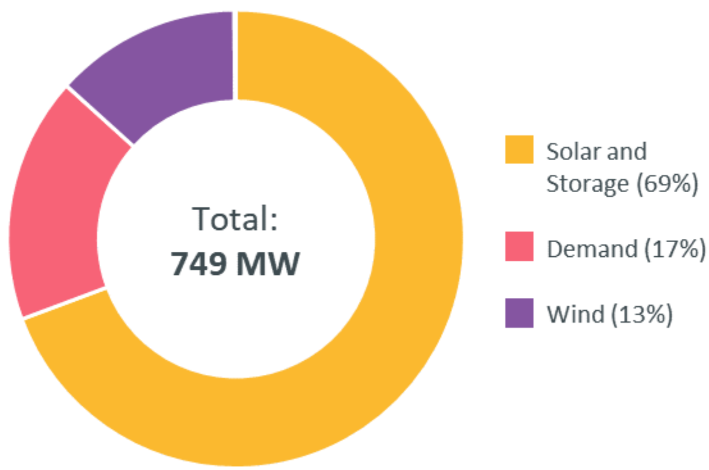


Figure 6-2: New Native Resources Securing Capacity Supply Obligations in FCA 17[115]

Approximately 37,500 MW of resources, including about 32,500 MW of existing capacity and 5,000 MW of new capacity, qualified to participate in the auction. Capacity clearing the auction totaled 31,370 MW, including:

- 27,864 MW of generation, including 619 MW of new resources
- 2,940 MW (including 130 MW new) of demand resources, including energy efficiency, load management, and distributed generation resources
- 567 MW of imports from New York, Québec, and New Brunswick

Prior to the auction, the ISO proposed—and FERC accepted—a net installed capacity requirement of 30,305 MW to meet reliability requirements for New England's power system. The auction rules allow the region to acquire more or less capacity based on demand curves set by the capacity requirement. This provides flexibility to acquire additional capacity and enhanced reliability at a cost-effective price.

[115] Total includes less than 1 MW of new hydro. Percentages do not add to 100 due to rounding.

6.11 Summary

The Interconnection Request Queue has seen significant growth and change in resource types over the past decade. Resources like wind and storage have increased significantly. Various cluster studies conducted over the past five-plus years have shown the value in this type of study, where developers can benefit from collaborating with other developers to ensure proposed resources are interconnected in a way that ensures grid reliability. The ISO expects growth in DER interconnection requests to continue and that these resources will continue to add complexity to the New England grid.

Section 7: Resource and Energy Adequacy—Resources, Capacity, and Reserves

The ISO's system planning process identifies the quantity of capacity resources the system needs for ensuring resource adequacy. Needed resources are then procured through the Forward Capacity Market (FCM). The 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 to provide operating reserves for the system and local areas addresses contingencies, such as unplanned outages. Collectively, the forecasts of future electricity demand (see Section 4), 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 (RA) process.

Beginning in the summer of 2021, the ISO initiated the Resource Capacity Accreditation project with stakeholders. The resource mix is rapidly evolving from resources with significant stored energy on-site that were available for dispatch during stressed conditions to a mix of resources with many different operating characteristics, including sources of intermittent "fuel" to produce power. Combined with changing market conditions, a wholesale review of how the ISO accredits capacity was needed.

Capacity accreditation allows all resources—which have disparate features that may have different reliability contributions toward resource adequacy per nameplate megawatt—to sell the same uniform product in the FCM. The accreditation process should yield accredited capacity that is substitutable across resources. Substitutability implies that small changes in the accredited capacity of different resources have approximately the same impact on resource adequacy.

The ISO expects to file new Tariff rules to implement the RCA project for the 19th Forward Capacity Auction (FCA 19) for the 2028/2029 capacity commitment period (CCP). As of publication of RSP23, these rules are not yet finalized. As a result, RA analyses in this section that include CCPs beyond FCA 18 are based on existing rules. Details on how the RCA project could affect future ICR values and resource accreditation are available in the materials presented at the Markets and Reliability Committees and on the ISO website.

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

- Results of the net operable-capacity assessments of the system under a variety of deterministic stressed-system conditions[116]

Capacity and reserve requirements form the basis for determining future systemwide needs. The planning process also determines the need for localized capacity, accounting for the export and import transmission capabilities (or limitations) of these capacity zones. The annual FCAs and annual and monthly reconfiguration auctions are intended to procure the systemwide needed capacity and capacity for identified capacity zones. In addition to the availability of capacity resources to meet the region's actual demand for electricity, the system needs a certain amount of resources that can provide operating reserves. This section provides the results of the systemwide and local-area analyses for the planning period.

Energy adequacy is a growing area of interest in the industry. After the quantity of resources (i.e., "iron in the ground") has met resource adequacy criteria, the system also requires enough stored "fuel" or energy (i.e., water in the pond for pumped storage, electrical energy stored in a battery, gas from a pipeline or liquefied natural gas terminals for a combustion turbine, etc.) to run the installed generation during times of system stress. This is referred to as energy adequacy. The ISO is exploring this area in several ways detailed later this section.

7.1 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 reviews the values developed by the ISO. The Reliability Committee and the Participants Committee then review, discuss, and vote on the values before they are filed with the Federal Energy Regulatory Commission (FERC).

Figure 7-1 shows the actual and representative ICR values for the 10-year planning horizon. It should be noted that CCPs starting in June 2028 through the end of the planning horizon will be affected by the proposed RCA project. Results published in this RSP23 are based on the current market rules, in place through FCA 18.

[116] 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.

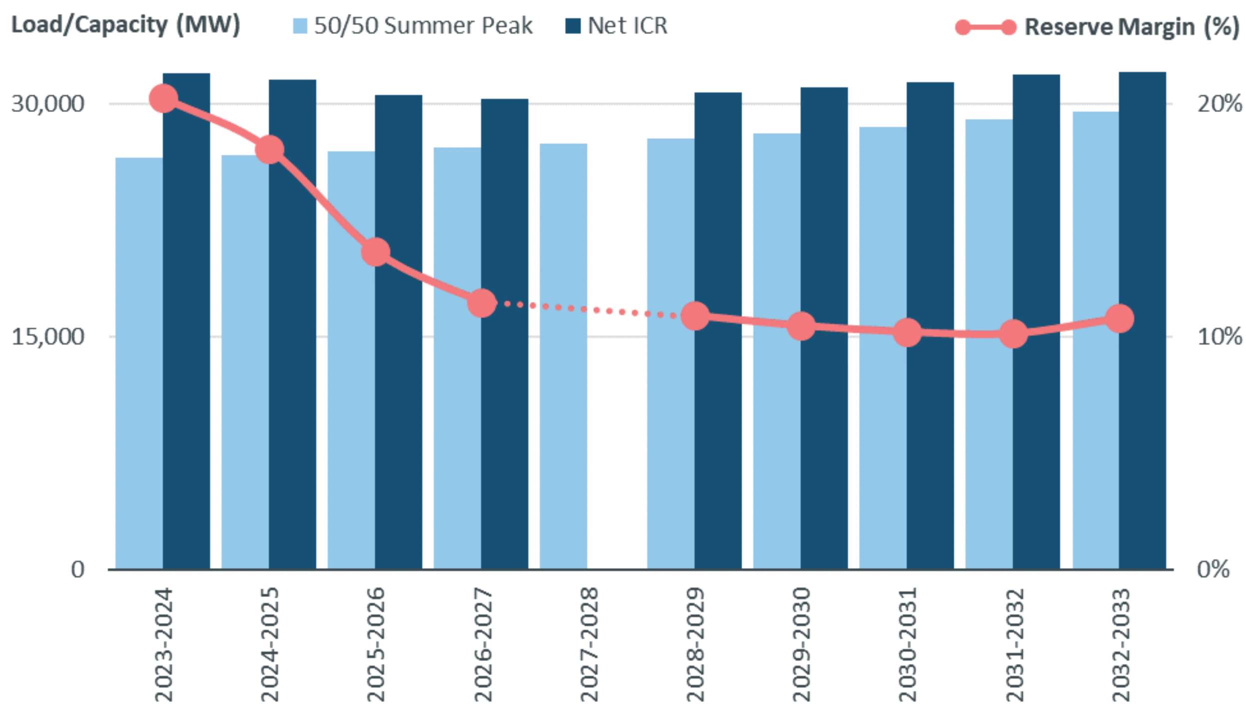


Figure 7-1: Actual and Representative New England Net ICR and Resulting Reserves (MW, %)

Net ICR requirements are expected to decrease through the 2026/2027 CCP, then afterward rise in line with the load forecast due to increased electrification of heating and transportation. Expected reserve margins will start around 20% and decrease to around 10% to 11% in the later years of the planning horizon based on current installed capacity quantities.

7.2 Local Resource Requirements and Limits

The ICR addresses New England's total capacity requirement using the assumption that the system overall has no transmission constraints. However, in reality certain subareas are limited in their ability to import or export power. To address the impacts of these constraints on subarea reliability, the ISO determines the local sourcing requirement (LSR) and maximum capacity limit (MCL) for certain subareas. An LSR is the minimum amount of electrical capacity that must be located within an import-constrained capacity zone to meet the net ICR. A MCL is the maximum amount of electrical capacity connected in an export-constrained capacity zone that can be used to meet the net ICR. Before each FCA, areas that meet certain objective criteria for zonal modeling are designated as capacity zones and assigned an LSR or MCL.[117] Figure 7-2 shows the LSRs and MCLs for capacity zones for the last four auctions. Values have remained fairly consistent from FCA 14 through FCA 17. Southeast New England (SENE) required an LSR for FCAs 14–16, but this was removed for FCA 17 due to reduced load and transmission improvements in the region. The Maine and Northern New England (NNE) zones required an MCL for the last four FCAs that has gradually

[117] 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 CCP. Capacity zones are developed pursuant to ISO Tariff, Section III.12.4.

declined as forecasted loads increase in the region. FCA 18 will continue to require an MCL for the zones of Maine and Northern New England; final values will be filed with FERC in November 2023.

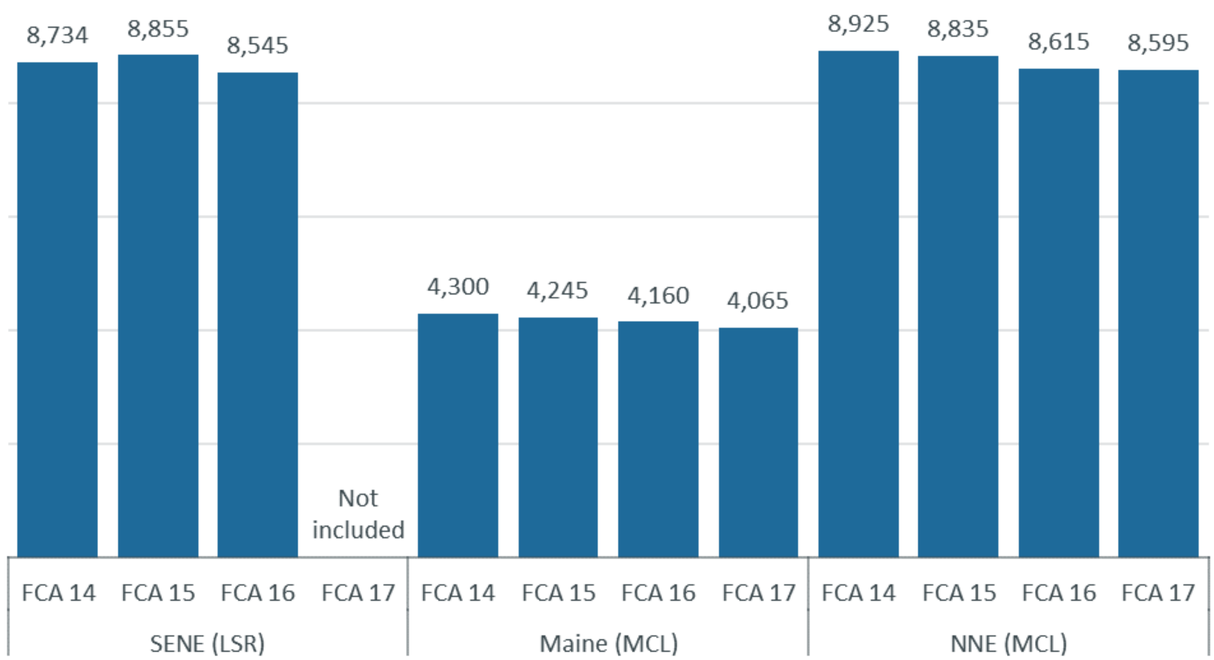


Figure 7-2: Actual LSRs and MCLs for FCAs 14–17

7.3 Tie Benefits and Capacity Imports

Interconnections with neighboring regions provide opportunities for exchanging capacity, energy, reserves, and mutual assistance during capacity shortage conditions. The tie-reliability benefits reflect the amount of mutual assistance assumed to be available from interconnections with neighboring control areas in the event of a capacity shortage in New England. These benefits lower the ICR. Capacity imports help New England meet the ICR and enhance competition in the capacity and energy markets. Imports also provide resource diversity and can lower regional generation emissions, especially imports of energy from renewable resources.

The historical tie benefits and imports from the last four FCAs are shown in Figure 7-3. Tie benefits have remained relatively constant over the last four FCAs. Imports cleared in the last four auctions have been more volatile, with significantly fewer imports clearing in FCA 17.

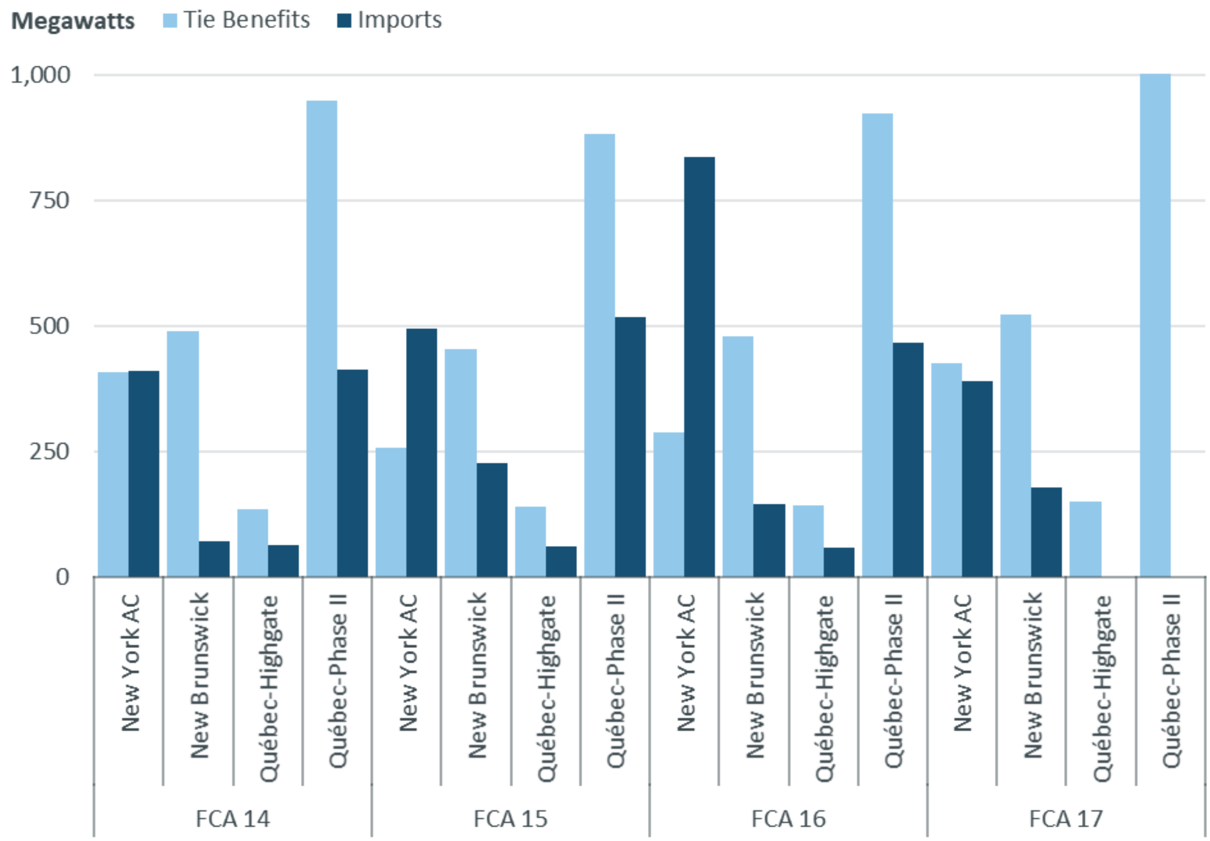


Figure 7-3: FCA 14–17 Tie Benefits and Imports

As part of the RCA project, the ISO is reviewing the feasibility of incorporating seasonality into tie benefit forecasts. The ISO is also committed to reviewing its tie benefit methodology to ensure the contribution of tie benefits is adequately reflected in resource adequacy studies. Related discussions with stakeholders are expected to begin in late 2023 and continue into 2024.

7.4 Capacity Supply Obligations from the Forward Capacity Auctions

Figure 7-4 illustrates the results of the past four FCAs, FCA 14 through FCA 17, and provides the capacity supply obligation (CSO) totals at the conclusion of each auction.[118]

[118] The values in this figure do not include adjustments from any ARAs that have occurred since the primary FCA.

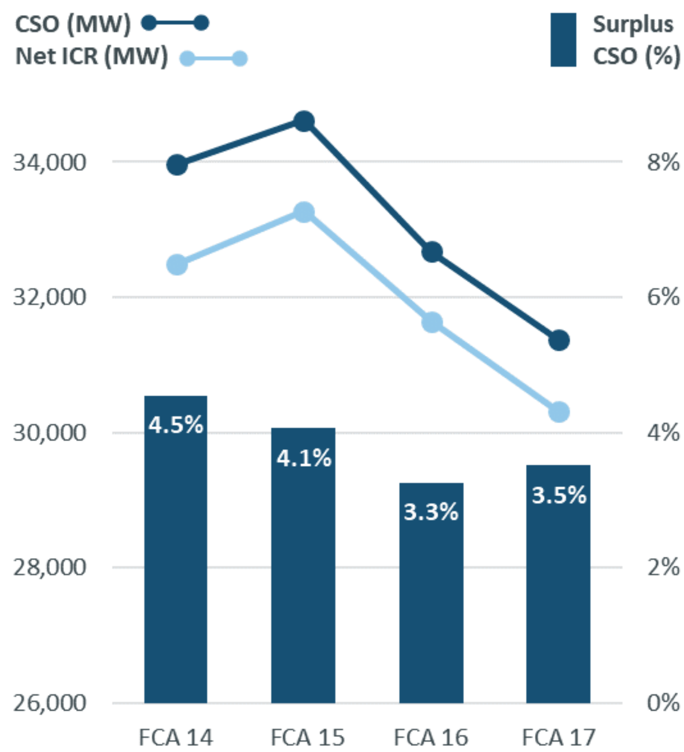


Figure 7-4: Summary of FCA Net ICR and CSOs

The net ICR increased from FCA 14 to FCA 15 after 2020's Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report) incorporated electrification forecasts for the first time. From FCA 15 to FCA 16, after the Passive Demand Response (PDR) reconstitution methodology was introduced in the 2021 CELT Report, the net ICR decreased. The net ICR continued to decrease in FCA 17 from additional effects of the PDR reconstitution methodology. Additionally, behind-the-meter photovoltaics (BTM PV) applied downward pressure on net ICRs for the last four auctions, while Hydro-Québec Interconnection Capacity Credits (HQICCs) remained fairly constant over the same time period. The auctions continue to acquire more capacity than needed as a function of marginal reliability impact demand curves.

Figure 7-5 illustrates, by resource type, the amounts of new capacity procured during the last four FCAs. Imports declined significantly in FCA 17 compared to historical procured amounts. New demand response has declined over the last four auctions, with very little active demand capacity resources clearing in three of the four previous auctions.

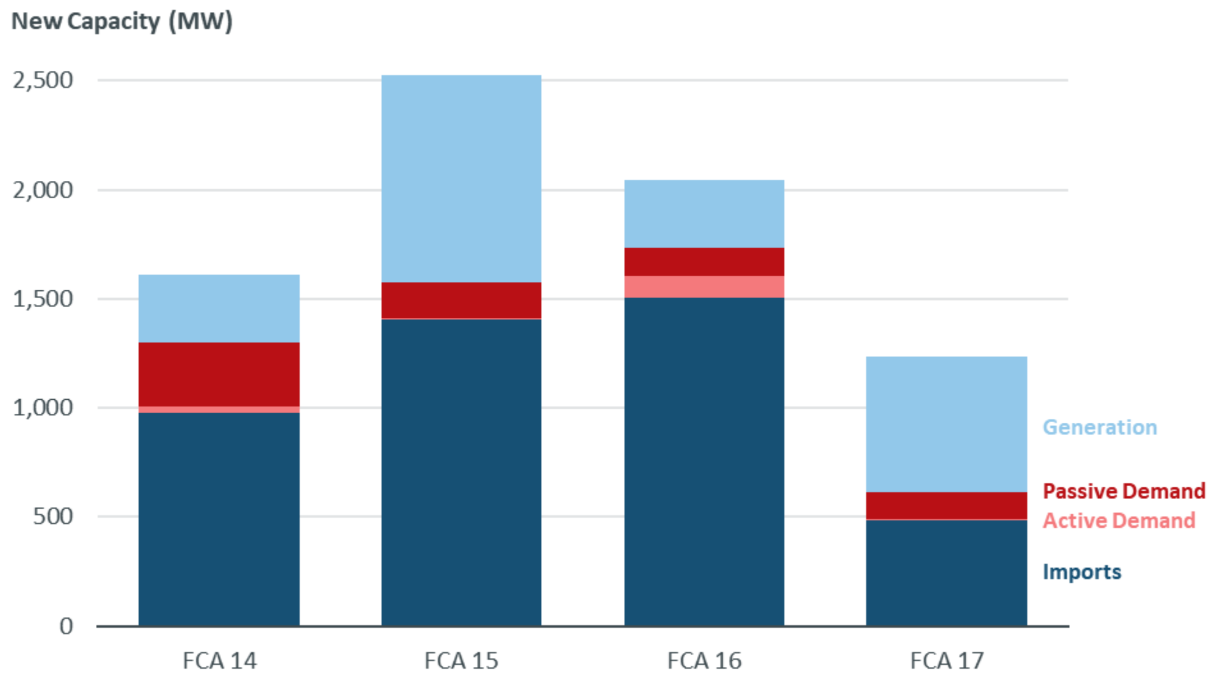


Figure 7-5: New Capacity Procured during FCAs 14–17

7.5 Representative Systemwide Resource Needs

The representative net ICR values for future years provide expected systemwide capacity needs. Figure 7-6 compares these systemwide needs with the resources procured in FCA 17 and Sponsored Policy Resources, and accounts for future levels of BTM PV and energy efficiency (EE) resources (see Section 4).

Accounting for resources that have cleared FCA 17, Sponsored Policy Resources, and projected growth of BTM PV and EE, the region is expected to have sufficient capacity through the end of the planning horizon.

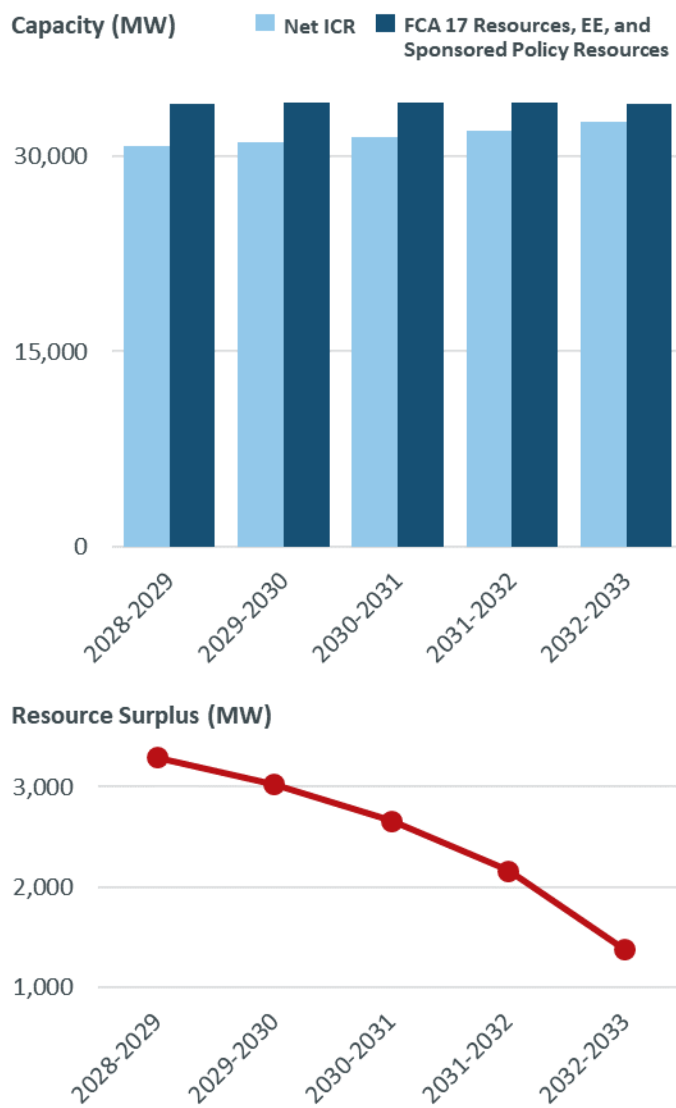


Figure 7-6: Future Systemwide Needs

The RCA project will change how resources are accredited to meet the ICR and may influence the ICR for future auctions. The values described in this report are based on the current market rules in effect for FCA 18. Details on how the RCA project could affect future ICR values and resource accreditation are available in the materials presented at the Markets and Reliability Committees.

7.6 Analyzing Operable Capacity

The ISO has performed systemwide analyses to estimate future summer and winter operable-capacity margins at peak demand conditions under two scenarios: the 50/50 and 90/10 forecasts of peak load.[119] These analyses assume that gross peak demand conditions are reduced to reflect the effect of BTM PV. It also assumes that in order to meet the forecast seasonal peak demand plus

[119] Tie Benefits are not included in operable-capacity analyses. Tie Benefits may contribute to reduce capacity deficiencies identified in the winter period.

operating reserve requirements, the capacity in New England will equal the net ICR. The net ICR is probabilistically determined. It includes some portion of load and capacity relief benefits available from implementation, by system operators, of certain actions of ISO Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4), in order to meet the one-day-in-10-years loss-of-load expectation (LOLE).[120] A forecast of negative operable-capacity margins indicates the extent to which possible mitigation actions would be required through predefined operational protocols, as prescribed in OP 4 or implementation of Operating Procedure No. 7, *Action in an Emergency* (OP 7).

7.6.1 Summer Operable Capacity

Figure 7-7 illustrates the operable-capacity analyses for summer periods associated with FCA 15 (summer 2024) through FCA 17, under the 50/50 and 90/10 demand scenarios.

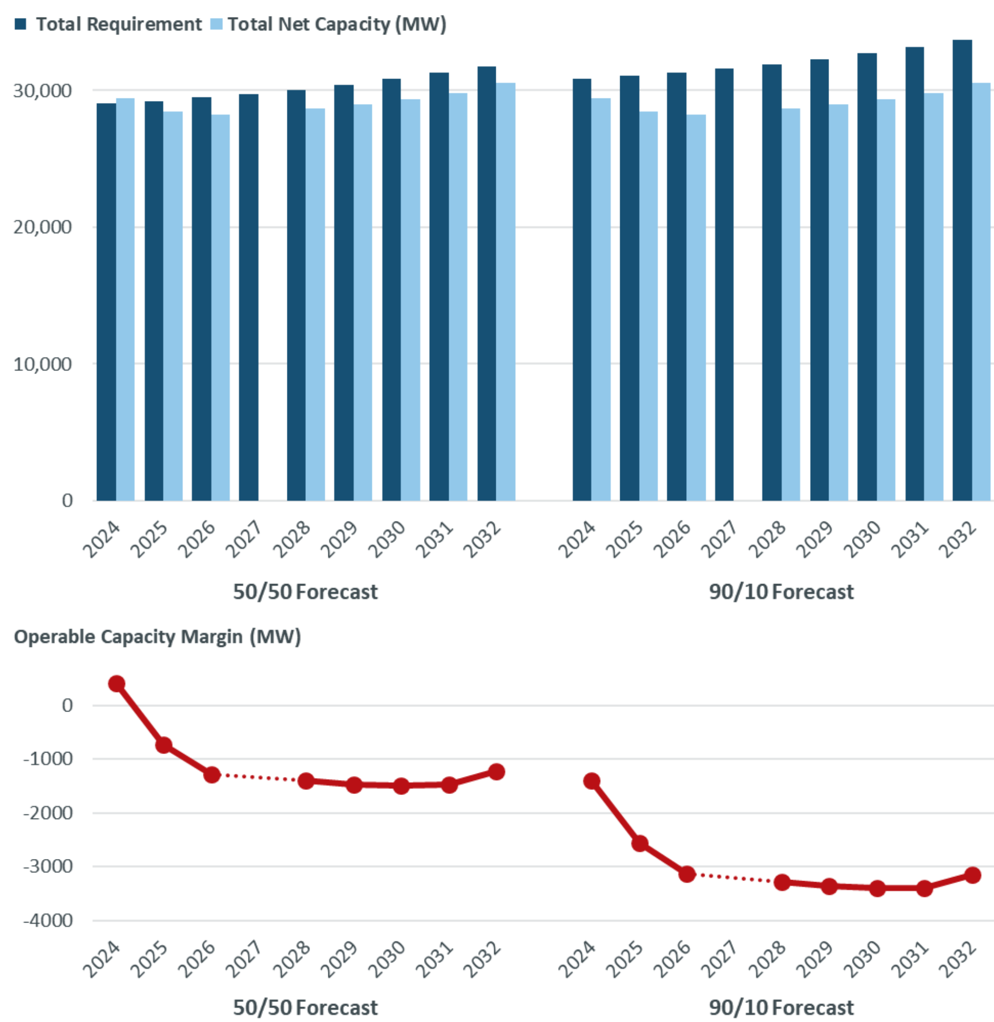


Figure 7-7: Forecast of New England's Operable-Capacity Analysis for Summer 2024–2032 Assuming 50/50 and 90/10 Peak Summer Demands

[120] An LOLE analysis is a probabilistic analysis used to identify the amount of installed capacity 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.

The system will require OP 4 actions as soon as the summer of 2025 for a projected 50/50 peak and the upcoming summer of 2024 for a projected 90/10 peak. Assuming no new additional resources and an expectation that the region can achieve roughly 3,500–4,000 megawatts (MW) of demand relief from OP 4 actions, OP 7 actions would not be necessary for 90/10 summer peak loads. The addition of Sponsored Policy Resources would reduce the need for OP 4 actions.

7.6.2 Winter Operable Capacity

Figure 7-8 illustrates the operable-capacity analyses for winter periods associated with FCAs 14–17, under the 50/50 and 90/10 demand scenarios.

Figure 7-8: Forecast of New England's Operable-Capacity Analysis for Winter 2024/2025 to 2032/2033 Assuming 50/50 and 90/10 Peak Winter Demands

The region will need OP 4 actions starting in the winter of 2025/2026 for 50/50 forecasted winter peak loads, and this upcoming winter of 2023/2024 for 90/10 forecasted winter peak loads. Assuming no new additional resources and an expectation that the region can achieve roughly 3,500–4,000 MW of demand relief from OP 4 actions, OP 7 actions would not be necessary until the winter of 2031/2032 for 50/50 winter peak loads and the winter of 2028/2029 for 90/10 winter peak loads. The addition of Sponsored Policy Resources would reduce the need for OP 4 and OP 7 actions.

7.7 Locational Reserve Needs for Major Import Areas

To further maintain system reliability, the ISO allocates minimum 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 the projected load levels of both the system and the subarea, and the economic and physical operating characteristics of the generators within the subarea and the rest of the system. 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.

Representative future operating-reserve requirements for the Northeastern Massachusetts (NEMA)/Boston area are based on the same methodology used to calculate the requirements for the locational Forward Reserve Market (FRM).[121] The representative values are given as a range in order to reflect the load and resource uncertainties associated with future system conditions. The NEMA/Boston Reserve Zone is expected to need 50–450 MW of local reserve in the summers of 2024 through 2026, after the Wakefield–Woburn 345 kilovolt (kV) line is built, Mystic 8 and 9 retire, and the Boston Area Optimized Solution goes in service. It is worthwhile to note that the proposed Day-Ahead Services Initiative (DASI) is expected to make changes to the locational FRM.

7.8 Energy Adequacy

The ISO is exploring the area of energy adequacy in several ways. For example, the RCA project is considering including potential energy and fuel limitations in the determination of resource accreditation. As part of the RCA framework, the proposed requirement for number of hours to continuously operate during a stressed day, number of days to operate during a cold weather event, and total hours of storage for a winter season are all used to determine the amount of firm capacity the unit can submit into the FCM. The amount of energy stored (battery storage size, oil tank size, firm gas supply, etc.) for a resource will have a significant effect on the marginal contribution the resource can have on the system.

Additionally, the ISO's Operational Impacts of Extreme Weather study, currently underway, is a probabilistic analysis of energy adequacy in the operational time frame under extreme weather events. The study aims to develop a framework to quantify the magnitude of energy adequacy risk. The study's current focus is the years 2027 and 2032, but this framework could be extended to examine the effects of significant resource mix change and demand side changes as part of the clean energy transition.

[121] 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.

Initial results for 2027 presented to stakeholders in May indicated that in the near term the energy shortfall risk over a 21-day period appears manageable. Baseline studies of 2032 winter events indicate an energy shortfall risk profile similar to that of the 2027 winter event studies. The ISO plans to use the newly developed energy adequacy platform to study the system as it continues to evolve.

Additional exploration of energy adequacy concerns was completed in the Future Grid Reliability Study Phase 1, described in Section 8.1.

7.9 Summary

Sufficient resources to meet the resource adequacy planning criterion are projected for New England through the 10-year planning horizon, assuming no additional retirements, the successful commercialization of all new resources that have cleared the FCM in FCA 17, and the installation of Sponsored Policy Resources. However, it is important to note that the pending RCA project could significantly change how the New England resource mix's contribution toward resource adequacy is assessed.

This planning analysis accounts for new resource additions that have responded to market improvements and 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 for future years.

Section 8: Economic Studies

ISO New England provides the region with information and data on possible evolutionary changes to the power grid. Changes to the grid impact the general public, and the implications of these changes must be explored and shared widely in order to educate and inform. Since the ISO is a Regional Transmission Organization, it possesses sensitive market information about system resources and Critical Energy Infrastructure Information (CEII) that cannot be shared broadly. However, the ISO can use this unique access to data to produce publicly available studies to inform future development.

Attachment K of the Tariff instructs the ISO to conduct needs assessments as they relate to the regional system planning process. Attachment K also allows stakeholders to request these needs assessments in order to evaluate changes to the power grid that might reduce total production costs or reduce congestion on transmission lines. These types of needs assessments are also known as economic studies.

The ISO has released one economic study since RSP21: the Future Grid Reliability Study (FGRS) Phase 1 of 2021, which was requested by the New England Power Pool (NEPOOL). No stakeholder requests were made in 2022, however, the ISO engaged in the Economic Planning for the Clean Energy Transition (EPCET) pilot study currently underway. These two studies are described in further detail in the following sections. EPCET is piloting the economic study process changes to the Tariff that were recently approved by the Federal Energy Regulatory Commission (FERC). These changes, prompted in part by FGRS lessons learned, bring a repeatable study structure to the previous process, allowing for trending over multiple studies and a framework in which stakeholders can easily request single assumption adjustments to scenarios.

8.1 Future Grid Reliability Study Phase 1

As part of the March 2020 Participants Committee meeting, NEPOOL proposed the Transition to Future Grid initiative in order to assess and discuss the future state of the regional power system in light of state energy and environmental policies.

The resulting study, FGRS Phase 1, was an exploration of how our region might confront the significant challenges related to the transformation of our power grid and develop practical and innovative pathways forward. In recent years, five of the six New England states have committed to reducing their carbon dioxide emissions by at least 80% (relative to mostly 1990 levels) in the next 20–30 years. These policies will result in major changes in the ways New England sources energy, as illustrated in Figure 8-1.

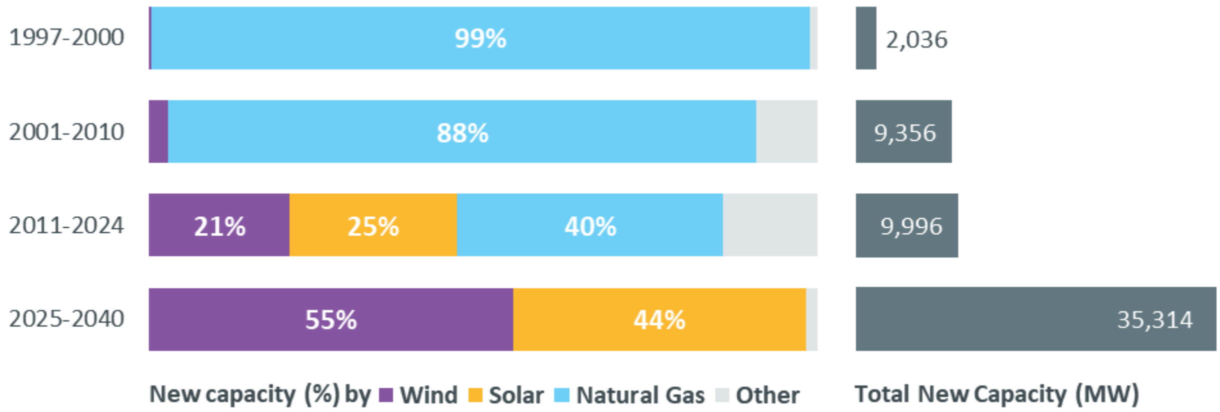


Figure 8-1: Historical and Anticipated New Resource Capacity by Fuel Type, 1997 Baseline

In addition, large increases in the electrification of heating and transportation will dramatically increase total load, as illustrated in Figure 8-2. FGRS Phase 1 explored the impact of these concurrent transformations on the future grid using traditional production cost, resource adequacy, and ancillary services analyses. Resource adequacy analysis was performed using both the traditional resource adequacy screen (RAS) and an additional probabilistic resource availability analysis (PRAA). Using both RAS and PRAA helped evaluate the reliability of different future resource mixes and explore whether today's RAS approximations will still be valid for a future grid with significant amounts of variable resources.

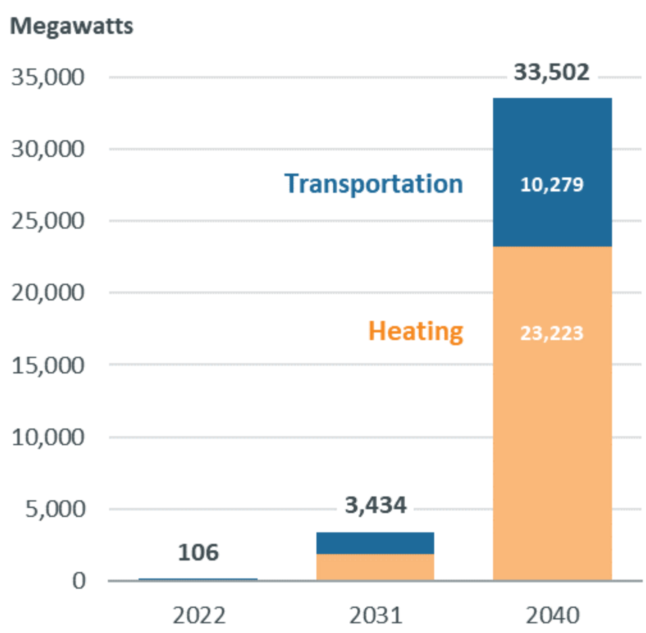


Figure 8-2: Current and Projected Peak Electrification Loads Using CELT Forecast for 2031

8.1.1 FGRS Scenarios and Key Takeaways

FGRS Phase 1 evaluated how a 2040 grid could perform with both the expected shift in supply resources and increased demand. This innovative study analyzed 32 future scenarios, each a particular version of the 2040 grid, to determine key gaps and reliability issues. Although specific results for each scenario varied, the results of the study showed that exclusive reliance on new wind, solar, and battery resources as a pathway toward a carbon-neutral economy will pose significant reliability challenges.

Key takeaways for FGRS fell under the following categories: *energy security*, *resource and demand flexibility*, and *resource mix diversity*. All takeaways from FGRS reinforced the central idea that a reliable future grid depends upon innovative approaches to decarbonization.

8.1.1.1 Challenges for Energy Security

- The 2040 grid will require an amount of gas or stored fuels beyond what is possible under current supply levels and infrastructure. The stored fuels of the future may not necessarily be carbon-emitting, but they must be dispatchable. As home heating is electrified, oil, propane, and other high-emission systems are likely to be the first systems replaced before natural gas heating. This will drive demand for electricity, which will subsequently increase natural-gas-fired resource usage and continue the grid's reliance on gas pipeline capabilities during these peak winter periods.
- The large amounts of battery energy storage systems (BESS) in the 2040 grid will not be able to charge sufficiently under predicted load curves. Solar resources are not helpful in meeting the winter early morning and evening periods of high demand, and potential wind lulls and droughts could prevent wind resources from supplementing these gaps.
- Retirement of the region's nuclear generators poses a challenge to grid reliability and conflicts with the region's commitment to decrease carbon emissions.

8.1.1.2 Problems with Resource and Demand Flexibility

- High electrification, aggressive retirement of existing dispatchable resources, and the difficulty in predicting output of variable renewable resources will severely deplete available backup energy (reserves and regulation). The grid has traditionally relied upon this backup energy to maintain balance and ensure reliability.
- Flexibility in both supply and demand would help preserve balance in the system. Flexible electric vehicle (EV) charging, for example, could help flatten overall demand and supply variability by directing portions of the region's EV fleet to charge at specific times.

8.1.1.3 Changing Resource Mix Diversity

- As the proportion of variable energy resources increases, and as the grid becomes winter-peaking, rules and regulations related to grid operation, as well as modeling assumptions related to all types of resources, will need to change and remain fluid.
- Rapid decarbonization of the grid will increase the reserve margin—i.e., how much extra installed capacity is needed to keep the system reliable in times of stress—by orders of magnitude by 2040.

In addition to these key takeaways, FGRS helped the ISO identify possible pathways to improve future economic studies using new software tools and analyses. These new pathways will be explored in the EPCET study, detailed in the next section.

8.2 Lessons Learned from FGRS and the Necessary Evolution of Economic Studies

While the ISO has performed economic studies for over a decade, FGRS represented a sea change in studies of this nature. At the beginning of the study, the renewable generation and demand electrification in Scenario 3 was perceived by the stakeholder body as an aggressive assumption, but by the completion of the study it was generally accepted as a likely path forward.

FGRS stretched the limits of software modeling tools, the assumptions used in previous economic studies, and current practices of the ISO. While the assumptions of FGRS deviated significantly from previous economic studies, it showed the need for further deviations and creative thinking to meet these new challenges. Shortcomings of previous study methodologies include:

- Limitations of a single weather year
- Need for modeling of neighboring regions
- Limitations in modeling energy storage
- Oversimplification of wind and solar resource modeling
- Uncertainties in future load shapes
- Demand resource modeling

Some of the key takeaways of this study related to the function and scope of economic studies themselves, and to the limitations of current software. Based on ISO's experience with this study, several improvements were suggested for future economic study frameworks. While the original focus of this study involved identifying reliability and revenue gaps, the ISO discovered as the study evolved that current industry study tools and processes are not sufficient to fully explore what such a shift in resource supply and demand patterns will require.

Lessons learned were identified and the ISO has since moved to replace its analysis software, enhance the economic study process, and implement many of these lessons learned.

8.2.1 Sequence of Production Cost, Ancillary Services, and RAS/PRAA Analyses

In future economic studies, it would be beneficial to run the RAS and PRAA first before performing other types of analysis. In FGRS, RAS and PRAA were performed after the production cost and ancillary services analysis. When some scenarios showed supply shortage issues in the production cost and ancillary services analyses, FGRS reran these scenarios with altered assumptions to test the effects of changed resource mixes. If the RAS/PRAA had been run first, adequate resource mixes would have been used in the production cost and ancillary services analyses, and this step could have been avoided.

8.2.2 Limitations of a Single Weather Year

Studies like FGRS use a concept called a "weather year" to inform production from renewable resources and demand for electricity. While the use of a single weather year has been a common industry practice, this method is not as useful or representative in scenarios with high penetrations of wind and solar resources. In these scenarios, weather impacts not just demand, but also supply. Additionally, in a future with increasingly electrified heating, the severity of a particular winter will affect demand more than in previous years with less electrification. In future studies, it would be beneficial to model multiple weather years instead of one. Through parallel work with an outside consultant, the ISO has worked to develop several years of historical correlated wind, solar, and load data, which it plans to leverage for future studies.

8.2.3 Need for Modeling of Neighboring Regions

In FGRS and other past studies, historical diurnal (daily) profiles have been used to model supply from neighboring regions. However, interregional exchange of power will become increasingly important as other regions electrify, decarbonize, and diversify. Additionally, the simplification of using historical import profiles may not reflect future interregional transfer patterns. Expanding upon the modeling of neighboring regions using simulated supply and demand instead of historical data will lead to more insightful model results.

8.2.4 Other Assumptions

FGRS results also identified other assumptions that could benefit from revision, including:

- *Out-of-market revenues.* These external sources of compensation allow emission-free resources to lower their energy-market offers. In FGRS, threshold prices were a proxy for these revenues and informed the curtailment order during times of oversupply.
- *Modeling colocated energy storage.* FGRS modeled storage units as discrete from the wind and solar resources whose energy they store. The actual behavior of colocated units may help lessen variability by producing a fixed output value, instead of the variable values produced by wind and solar without storage.
- *Modeling of the transmission system.* Nodal modeling would replace the 13 zone "pipe and bubble" model with a more detailed and comprehensive bus-level model of the New England power system.
- PRAA is a better reliability representation than the RAS approach, using reliability hours to estimate qualified capacity.

As a result of the lessons learned from FGRS, the ISO is testing some of these assumption changes in EPCET.

8.2.5 Limitations in Modeling Energy Storage

One frequent problem was related to the study's modeling of energy storage. Most of the software tools assumed the use of storage for price arbitrage, but price arbitrage becomes complicated during sustained periods of low or negative locational marginal prices (LMPs). FGRS found that modeling storage with the objective of price arbitrage did not fully address the needs of the overall future power grid. With larger penetrations of renewables, modeling longer periods (such as seasonal storage) may be necessary. It is also plausible that energy storage will be used to provide reserves or regulation, but the software used in FGRS could not adequately model these uses.

The ISO has shifted to new simulation software that is more flexible and able to better reflect commonly imagined future uses for storage, and thus improve the evaluation of BESS's usefulness to the future grid.

8.2.6 Simplification of Wind and Solar Resources

Treatment of wind and solar resources was also simplified to fit current software tools. Some software was designed to model large amounts of traditional dispatchable generators, with wind, solar, and energy storage as added features. When large portions of energy are supplied from variable resources and storage, the software lacks the complexity to fully model and dispatch these resources. When wind and solar were a small portion of the resource mix, a constant value was sufficient to model their effect. However, as renewables become a larger part of the resource mix, this simplification can sometimes overstate their production. PRAA modeling allows for historical variable profiles, which shows more realistic output from these resources, including lulls in production.

8.2.7 Uncertainties in Future Load Shapes

Uncertainty regarding future demand also affected the FGRS results. EV and heating load shapes were created for the study based on stakeholder-provided data, but it is unclear how representative these shapes are of future load patterns. Figure 8-3 illustrates the generic implementation of flexible EV charging in the scenarios and the significant changes to demand that resulted. The software could only accept a static load profile and had limited ability to model flexible loads.

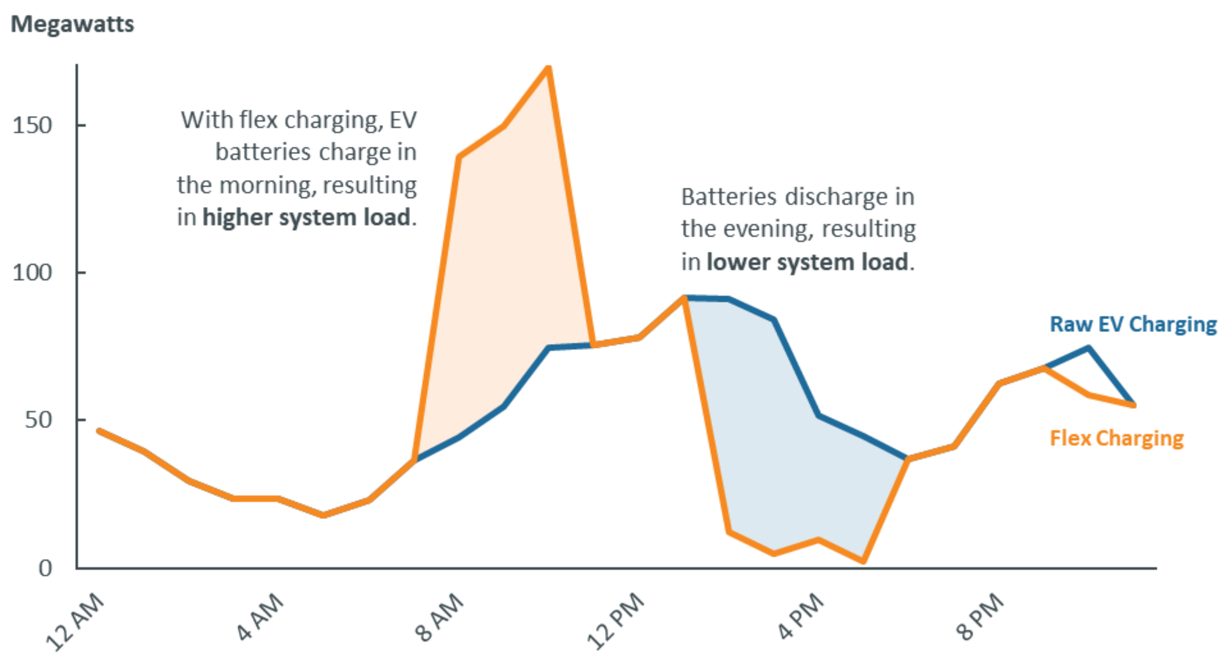


Figure 8-3: Implementation of Flex EV in Production Cost Analysis of FGRS Scenarios

The ISO continues to perform research in this area. In 2021, the ISO worked with a consultant to improve existing light-duty electric vehicle profiles and add medium-duty electric vehicles to the annual forecast process.

8.2.8 Demand Response Modeling

Active demand response, where customers may curtail their power use at the request of utility providers, has a limited role in this analysis. The electrified heating and transportation load shapes had a large impact on the results of the study, so continued modeling improvement through research will be important. Post-FGRS, the ISO is beginning to utilize new modeling that could incorporate active demand response.

8.3 Economic Study Process Changes

The ISO has historically conducted economic studies under Attachment K of its Tariff, which permits stakeholders to request studies every April 1. While this process allowed for many useful studies, it also required stakeholders to provide a whole suite of assumptions for, at times, just one specific question. Recent studies have averaged 18 months, and this timeline meant that often the previous year's study was unable to inform the current year's requests, while the overlap strained ISO resources. Some requests were very narrow while others were quite broad. The tight timeline also limited the ability to coordinate with neighboring regions or answer more complex questions.

Year-to-year and study-to-study variations in assumptions limited any ability to observe trends over multiple years or make comparisons between studies. Stakeholders indicated interest in moving beyond the capabilities of the initial studies; current production cost modeling with stakeholder-led assumptions is of less interest. Stakeholders have asked the ISO to take more leadership in identifying necessary studies, and want to see more variety in analyses, further integration of various models, and an eye toward "big picture" observations.

In response to these lessons learned and stakeholder feedback, the ISO has altered its study framework to include three repeating reference scenarios in addition to a stakeholder requested scenario and sensitivity requests. The reference scenarios cover the baselines of the current plans for the clean energy transition. Using the same reference scenarios, updated with the region's most recent projects and policies on a repeating cycle, will provide more insight into system trends, and should aid stakeholders in formulating requests for more targeted analysis based on those trends. Additional benefits of the economic study process changes include:

- A longer timeline, allowing for more detailed modeling (for example: move from zonal to nodal simulations)
- Better alignment of economic studies with other studies within System Planning, providing predictable and consistent usage of internal ISO resources
- The ability to include additional probabilistic resource studies in the overall process (for example: PRAA or equivalent)
- Opportunities to explore new modeling methods for the evolving grid during the study cycle (e.g., colocated storage, electric/gas co-simulation during winter peaks, etc.)
- The opportunity to incorporate neighboring regions' detailed models in simulations

The process changes also follow models of repeated studies used by New York ISO and other regional operators.

To reflect these changes, in January of 2023, the ISO filed Tariff revisions for Phase 1 of the economic studies process with FERC. These changes were approved in March 2023 and will be implemented in 2024.

8.4 Economic Planning for the Clean Energy Transition

In April 2022 the ISO proposed the Economic Planning for the Clean Energy Transition (EPCET) pilot study. It is intended to achieve three main objectives: perform a dry run for a new economic study framework, review and test input assumptions for economic planning analyses, and gain experience in the features and capabilities of new planning software.

Although EPCET itself is not a formally requested economic study per Attachment K of the Tariff, the overall goal of the study is to prepare models, tools, and processes such that informative and actionable results can be more readily produced in future economic studies that will be subject to the new Tariff provisions.

8.4.1 Employing PLEXOS Software in Economic Studies

After identifying certain gaps in the software tools used during FGRS, the ISO began to explore new software options for future economic studies. In the fall of 2022, the ISO performed an extensive evaluation of Energy Exemplar's PLEXOS software, obtained a license for the program, and is, at the time of this RSP's publication, running simulations of grid scenarios using PLEXOS.

8.4.1.1 Capacity Expansion Modeling in PLEXOS

The main benefit of the PLEXOS software is the ability to run capacity expansion scenarios, which was not possible under old software models. With capacity expansion modeling capabilities, resources can be added and/or retired from the modeled grid based on production *and* capital costs, which allows for a more complete picture of the rapidly changing resource mix of the future New England grid.

The ISO foresees some challenges related to the use of capacity expansion modeling. Since this type of modeling is new to the ISO, multiple iterations and false starts are expected. Two inputs are expected to have an outsized effect on capacity expansion results: state CO_2 emission reduction targets and economics. Emissions targets will directly influence expansion (i.e., more aggressive emissions targets will drive an accelerated building of new resources), while economics will influence the type of additions and the sequence of their addition. Since these variables have a drastic effect on how units are built, the ISO expects a wide array of possible capacity expansion build-outs in the EPCET results. The dispatchability of possible build-outs is of particular interest, since dispatchability was a key concern of FGRS Phase 1. Possible new generators must have the dispatchability required to meet the needs of the future grid.

8.4.2 Scenarios Modeled in EPCET

EPCET will perform trial runs of the three main scenarios proposed in the January 2023 Tariff revisions:

- *Benchmark scenario.* This scenario models the previous calendar year and compares it to historical system performance in order to test the overall fidelity of PLEXOS models against historical performance and improve the inputs for future scenarios.
- *Market Efficiency Needs scenario (MENS).* This scenario models future years in the existing Tariff-mandated 10-year planning horizon to identify market efficiency needs.
- *Policy scenario.* This scenario models future years beyond the existing Tariff-mandated 10-year planning horizon based on regional and other energy and climate policies.

As of July 2023, the ISO has performed initial modeling of the benchmark scenario and the MENS scenario. For more information, please visit the ISO's Economic Studies website.

8.4.2.1 Benchmark Scenario Results

In initial runs of the benchmark scenario, actual historical metrics from 2021 were compared to a PLEXOS model run of the same year. The evaluation outputs included average and annual LMPs, production by fuel type, and interface flows.

PLEXOS modeling runs produced lower LMPs for 2021 than the observed 2021 LMPs, primarily due to the way in which the real system dispatches based on submitted offers, while PLEXOS dispatches to estimated costs. These can differ for a variety of reasons. In addition, historical minimum and maximum LMPs were more variable than the modeled PLEXOS prices, again due to a variety of differences between real-world offers and estimated costs. Model generation by fuel type and interface flows closely followed historical observations, and congestion was observed in historically constrained areas. Discrepancies between modeled results and historical observations could be explained by additional revenue streams and transmission outages, which were not included in the model. One critical factor in aligning model results with observed historical patterns was implementation of daily gas prices by pipeline.

8.4.2.2 MENS Scenario Results

Two MENS scenario models were run in PLEXOS: an *unconstrained* model and a *constrained* model with interface limits. As in prior economic studies, running both an unconstrained and constrained model of a possible future grid can reveal the impact of constraints and congestion on LMPs, production cost, emissions, and dispatch by fuel type. These results provide insight into the economic and environmental impacts of congestion on a 10-year planning horizon.

The *constrained* modeling showed slightly reduced hydro, wind, and solar generation, which resulted in slightly more gas, oil, and coal generation. LMPs were 0.8% lower in the constrained model due to increased curtailment in export-constrained zones. Though LMPs were slightly higher in unconstrained zones due to more expensive generation running outside of the constraint, LMPs went sharply negative in export-constrained zones during hours with curtailment. The net effect was a slight decrease in average LMPs. Average LMPs were reduced by $2.40 per megawatt-hour (MWh) in 2032 ($43.86/MWh) compared to historical 2021 LMPs ($46.26/MWh). The 2032 resource mix modeled in the MENS contained future offshore wind, energy storage, and photovoltaic (PV) generators as well as the new New England Clean Energy Connect tie line. These zero-cost, zero-emission resources helped displace fossil fuel generation and reduce production costs, emissions, and LMPs.

Production costs were 0.3% higher and CO_2 emissions were 0.07% higher in the constrained model versus the unconstrained model, since interface limits resulted in congestion, and thus more expensive carbon-emitting resources were used to quickly dispatch energy to the grid when needed. However, modeled CO_2 emissions were reduced by 10.4 million tons in 2032 compared to the modeled 2021 system (33.1 million tons).

8.4.2.3 Policy Scenario Results

While work on the policy scenario is ongoing, an initial set of results has been released. Specifically, a capacity expansion model was run that attempts to reach annual carbon emissions of 1 million tons per year (from gas, oil, and coal) by 2050. The capacity expansion model adds and retires units in response to changing input parameters. The model was given a 51 gigawatt (GW) winter peak to meet, as well as large amounts of candidate wind, PV, and energy storage resources. Retirements will be implemented in future modeling, but no retirements were modeled in the initial run.

The capacity expansion model achieved 1.6 million tons of emissions while building 97 GW of new capacity. The marginal cost of carbon and Renewable Energy Certificates (RECs) was found to be high ($3,113/ton and $2,076/MWh). Upon further investigation, it was found that generator additions in the 2045–2050 timeframe were only being used for ~10% of the year. As a result, the generators would need to be compensated more per megawatt-hour of zero-carbon energy than generators built during earlier years.

With the calculated REC and carbon costs, additional production cost models were run that investigated different pricing methods for new resources. Specifically, a REC model, a carbon pricing model, and a hybrid model (with 50% each of REC and carbon prices). The main difference in the scenarios revolved around where the money to compensate the generators was coming from. While a carbon price kept the money in the energy market, a REC price significantly deflated the energy market and relied heavily on out-of-market revenues.

Despite aggressive additions of energy storage, all of the modeled scenarios had large amounts of curtailed energy. New England was found to be a net exporter for 65% of the year and curtailing energy for 44% of the year; 46 terawatt-hours (TWh) of the available 229 TWh was curtailed. Because most carbon emissions only occurred in the winter months, extremely long duration storage was needed to be able to shift extra energy from the spring, summer, and fall into the winter.

Even with the 97 GW of new capacity, it was found that there were some hours with significant amounts of dispatchable emitting generation (gas, oil, and coal) online. When the build-out was run through 20 weather years of load/weather data, every weather year had at least 16 GW of dispatchable emitting generation online during some hours. One weather year had more than 20 GW of dispatchable emitting generation online for one hour. For high winter load scenarios, it is extremely difficult to build enough wind, PV, and energy storage to displace all gas, oil, and coal.

8.5 Energy Adequacy and ISO Studies

8.5.1 FGRS Energy Adequacy

Most FGRS scenarios assumed retirement of all legacy coal- and oil-fired units, and restricted dual-fuel units to only burn gas. Though it is very difficult to know to what extent fuel constraints will continue to exist in 2040, the observed levels of gas generation in winter months may exceed the amount of gas that New England would realistically have available in the pipelines. In particular, the Scenario 3 system was found to frequently rely on liquefied natural gas (LNG) or completely exceed the amount of pipeline gas and LNG that would be available. The tool used to calculate LNG contributions also assumed a continued existence of the Everett LNG terminal, whose future is uncertain following the expiration of the Mystic cost of service agreement in 2024. Without retention of some stored fuel capabilities, the 2040 system would frequently experience emergency conditions during the winter period.

8.5.2 EPCET Energy Adequacy

Within EPCET, the ISO had the ability to explicitly model daily pipeline gas/LNG availability and fuel switching within the model. The scenarios of most interest covered a 2032 system with moderate increases in electrified load and deployment of PV, offshore wind, and a new tie line with Hydro-Québec. The analysis covered 20 weather years of load, wind, PV, and temperature data. Just as with the FGRS fuel analysis, this 2032 model assumed the Everett LNG terminal was providing fuel. Despite the new generation sources, the increased wintertime demand due to electrification led to a significant need for stored fuel resources. Compared to the past four historical years, the average generation from coal and oil was expected to almost double, with the worst-case weather year burning nearly four times as much oil as the 2019–2022 average. This scenario only included generator retirements that have been announced so far, and did not assume the loss of any additional stored fuel units. Despite the overall reductions in CO_2 emissions compared to the current system, modeling indicates a significant need to retain stored fuel units for the winter period.

8.5.3 Fuel Drawdown

A critical limitation not modeled in EPCET was the inventory size of stored fuel resources. The majority of oil inventory is stored at a subset of heavy oil generating stations, while the more numerous light oil and dual-fuel generators tend to have smaller fuel supplies. Both FGRS and EPCET observed a need for more dispatchable generation during the wintertime. Because the modeled oil drawdowns were not limited in the FGRS or EPCET energy adequacy studies, the reliability risks could be potentially understated. Though refueling is a normal part of the winter operation of these plants, individual tanks could be depleted before being refilled, leading to less winter capacity. Because heavy oil and coal units, which currently have the largest fuel inventories in New England, tend to be older than dual-fuel units, units with the largest access to stored energy may be at risk of retiring first.

8.5.4 Reliability of External Areas during Winter Conditions

Another potential gap in the FGRS and EPCET analysis was the performance of external areas in winter conditions. Both models assumed that Hydro-Québec and New Brunswick were able to send significant amounts of energy around the clock (FGRS Scenario 3 also assumed significant imports from NYISO). While external areas may have energy to send throughout most of the year, experience from recent weather events, trends in electrification, and changing resource mixes across the Eastern Interconnect should be of concern when evaluating New England's reliance on external areas during extreme cold conditions.

During Winter Storm Elliott in 2022, cold temperatures led to a number of unexpected generator outages in New England and the declaration of ISO Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4). This was driven in part by significantly smaller-than-expected imports from other areas in the Day-Ahead Energy Market. Other control areas within the US faced significant generator outages, and some were forced to implement controlled outages to maintain the stability of the grid. During the February 2023 cold snap, the New England system operated reliably under extreme cold conditions, but exported energy to Québec for the first time since 2016. During both of these cold weather conditions, oil generation provided about 33% of the region's energy needs when gas generators could not obtain needed fuel due to pipeline constraints.

It is hard to predict the reliability of neighboring regions in 10 or 20 years, but recent experience has shown that extreme winter conditions can affect large portions of North America at the same time. These regions will likely face challenging periods at the same time as New England as they undergo green transitions of their own.

8.5.5 Operational Impacts of Extreme Weather Events Key Project

ISO Operations is also working with the Electric Power Research Institute (EPRI) to conduct a probabilistic energy-security study and develop a framework for the ISO to assess operational energy-security risks associated with extreme weather events. This is a collaborative opportunity for industry leaders and regional stakeholders to learn about how extreme weather events in the future may affect the evolving power system and to prompt thinking about how best to prepare.

8.6 Future Outlook for Economic Studies

The EPCET study is the pilot of the economic study process Tariff revisions. These Tariff revisions are in part a response to stakeholder requests for the ISO's study results to be clearer and more actionable. Under the new Tariff language, results from the MENS scenarios of the economic studies could trigger a request for proposals for new transmission. The policy scenarios will now also illustrate possible paths to a future grid that meet objectives outlined in regional or state clean energy policies.

Due to lessons learned in FGRS, Scenario 3 data was also used in the 2050 Transmission Study and Pathways to the Future Grid. FGRS results have provided greater insight into resource adequacy with higher renewable penetrations, triggered a white paper on the socioeconomic impacts on vehicle electrification, and helped prompt related work at universities and other ISOs. In its transition to new modeling software, the ISO is also developing a public case and Economic Studies Technical Guide that will make the work of the future-looking studies more accessible to stakeholders and the broader public.

As the ISO moves to further support the clean energy transition, previously isolated study areas now frequently overlap. In response, the ISO is fostering the utilization of multiple study tools and organization-wide expertise, and continues to work closely with other ISOs to develop study assumptions and share results and data.

8.7 Summary

The ongoing changes in economic studies are emblematic of the changes occurring in the industry, within the power grid, and at the ISO. For much of the ISO's economic study history, modeling was designed to simulate an approximation of the New England power grid and provided directional rather than granular results. These studies used many simplifications and historical assumptions, due in part to computational constraints and the nature of grid operations changing at a relatively slow rate. Simplifications were sufficient to model a grid that stayed largely the same from decade to decade.

However, as changes to state and federal policy prompt significant changes to the future grid, potential grid operation has deviated far enough away from historical precedent that past assumptions become less useful. To perform relevant and insightful analysis, the ISO is improving the accuracy and detail of its modeling to identify barriers to reliable and efficient grid operation.

Modeling in FGRS dispensed with many previous historical assumptions, and a number of possible variable futures were investigated instead. After FGRS, the ISO retired several more assumptions, and is continuing to do so in its EPCET work and economic study process Tariff changes. Current and future studies will investigate an evolving resource and demand mix, changes to grid operations, and the practicality of meeting emissions targets, and they will provide actionable results, including transmission construction recommendations.

The expanded focus of current economic studies requires close coordination with other areas of System Planning, the ISO, and with outside organizations, such as other ISOs and RTOs. ISO staff has increased its cross-collaboration as the organization and industry focuses on new challenges and goals.

As the grid continues to evolve, forward-thinking strategies and innovative solutions will be crucial to providing the reliable and economical electricity that consumers have come to expect from the

New England grid. The Economic Studies department and the ISO at large are committed to a flexible, inventive approach to ensuring the clean energy transition is smooth and successful.