NPCC 2020 New England Comprehensive Review of Resource Adequacy

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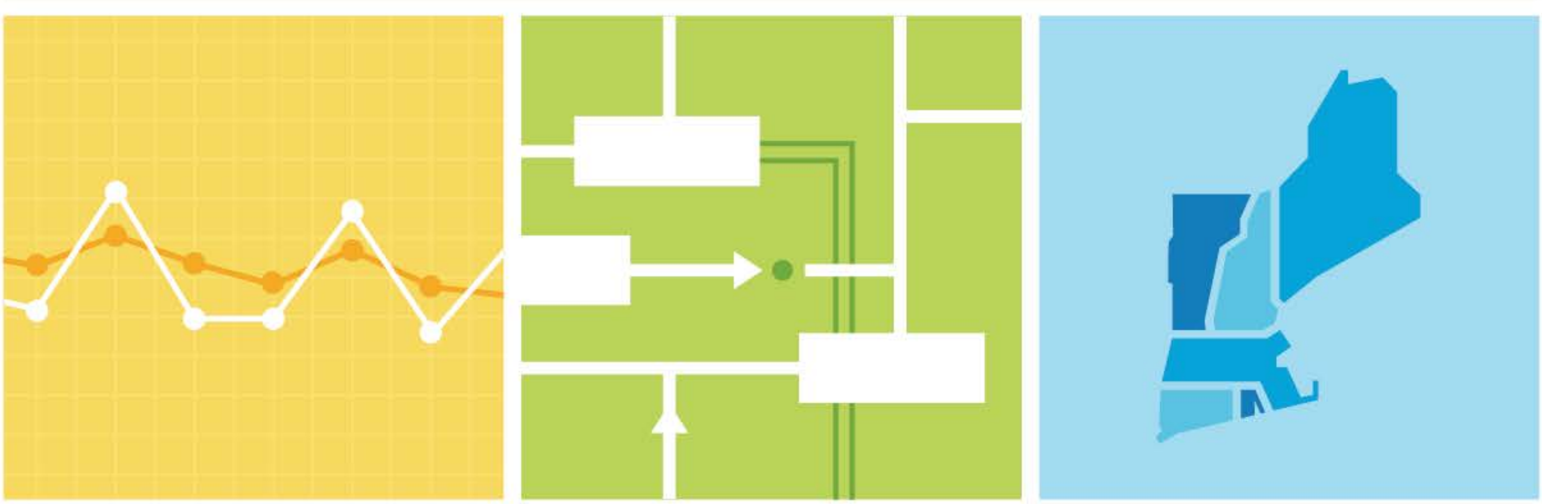

Section 1 Executive Summary

ISO New England Inc. (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 comprehensive planning of the regional power system. As part of its planning functions, ISO-NE is the Planning Coordinator for the New England Area of the Northeast Power Coordinating Council (NPCC). One of ISO-NE's responsibilities as a Planning Coordinator is to conduct studies and provide results to demonstrate that the New England Area bulk power system will meet the NPCC Resource Adequacy – Design Criteria as defined in NPCC Regional Reliability Reference Directory #1 –*Design and Operation of the Bulk Power System*[1].

This report of *2020 New England Comprehensive Review of Resource Adequacy*, covering 2021 through 2025, was prepared by ISO-NE to satisfy the NPCC compliance requirements on resource adequacy. This comprehensive review follows the guidelines specified in Appendix D of NPCC Directory #1 entitled *Guidelines for Area Review of Resource Adequacy*. This review supersedes the *2017 New England Comprehensive Review of Resource Adequacy*[2], which was approved by the NPCC Reliability Coordinating Committee (RCC) on December 3, 2017.

1.1 Major Findings

The findings of this comprehensive review are based on the results of a resource adequacy assessment of the New England bulk power system (BPS) using the General Electric Multi-Area Reliability Simulation Program (GE MARS) and results of other reliability studies conducted by ISO-NE for the ISO New England 2019 Regional System Plan (RSP19)[3].

The major findings of this comprehensive review are as follows:

- The anticipated resources are expected to be adequate to meet the NPCC Full Member Resource Adequacy Criterion of disconnecting firm load customers no more than 0.1 days/year for each year of the study period under the reference load forecast condition.

- Forward Capacity Market (FCM) auctions that were conducted have procured the requisite amount of resources to meet expected demand through 2023-2024. FCM continues to serve as the primary mechanism to create incentives to retain existing and attract new resources, and to incentivize improved availability/performance when dispatched during periods of system stress.

- As compared to the 2017 comprehensive review, this review's load forecast has been revised; downward for the summer peak demand, but slight upward for the winter peak demand and the annual energy. The gross peak summer load and net energy are forecast to grow by 0.9% and 1.0% over the next 5-year planning horizon respectively. Over the next 5-year forecast, regional energy efficiency is projected to grow at an average annual rate of ~300 MW per year. Photovoltaic (PV) resources reached 3,432 MWac (nameplate rating) by the end of 2019, and are expected to continue to grow to 6,505 MWac by 2025. New England's net summer peak load is decreasing while the annual

[1] https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/directories/directory1-design-and-oper-20200305.pdf
[2] A copy of this review can be found at: https://www.npcc.org/content/docs/public/library/resource-adequacy/2019-new-england-interim-review-rcc-approved-december-3-2019.pdf
[3] https://www.iso-ne.com/static-assets/documents/2019/10/rsp19_final.docx

net energy for load is projected to increase, after taking into consideration impacts from the energy-efficiency resources and the behind-the-meter (BTM) portion of PV resources (BTM PV).

- New England is currently fuel/energy constrained, which has been identified as the greatest "reliability-risk" to the region. Variable Energy Resources (VERs) (i.e., intermittent wind, solar, and hydro-electric resources) and natural gas-fired generators (with fuel related, operational limitations on their energy production during the winter) are replacing traditional nuclear, coal, and oil-fired resources. With its existing fuel infrastructure, New England has faced challenging operating conditions, particularly during long periods of extreme cold weather conditions. ISO-NE has already implemented near-term market and operational changes to address energy security risks, and in April 2020, filed is comprehensive, long-term market enhancements, known as "Energy Security Improvements (ESI)" that are necessary to address the fuel/energy security challenges facing the New England region. ISO-NE proposes to formalize the three new categories of operational capabilities into specific ancillary services, and allow Market Participants to compete to provide those capabilities within ISO-NE's Day-Ahead and Real-Time Energy Markets.

- Increasing compliance costs associated with procuring air emission allowances and mandated overhauls or retrofits required by new environmental regulations are affecting both existing and new generators in the region. Generator compliance obligations from existing and pending state, regional, and federal environmental requirements are not expected to pose reliability concerns during the study period, but they are a factor in retirement decisions.

- ISO-NE is actively enabling the reliable integration of renewable and distributed resources through improvements in regional planning, operations, and markets processes. The implementation of a new cluster study methodology as part of ISO-NE's interconnection process better facilitates the planning of new wind resources. ISO-NE has also improved its forecasting of wind and PV energy production and subsequently changed the dispatch methods used for operating the system. The region currently applies the voltage and frequency ride-through characteristics required by recently approved standards for interconnecting distributed energy resources (DERs). A number of improvements to the wholesale market structure now promotes resource responses, such as operational flexibility, that facilitate the transformation of the grid.

1.2 Summary of Major Assumptions and Results

Table 1 shows the major assumptions used in this comprehensive review and Table 2 summarizes the LOLE results. The detailed assumptions and results are documented in the later sections of this review.

The anticipated available resources are expected to be adequate to meet the NPCC resource adequacy criterion under the reference load forecasts for the study period from 2021 to 2025.

Table 1 Major Assumptions

Assumptions	Description
Reliability Criterion	NPCC Criterion: no more than once in 10 years of firm load disconnection (LOLE of 0.1 days/year)
Load Model	Based on the load forecast from the 2020-2029 Forecast Report of Capacity, Energy, Loads, and Transmission (2020 CELT)[4], including the gross load forecast, the BTM PV forecast, and the electrification forecast
Reliability Model	GE MARS
Expected Existing Resources	Including generating resources, energy efficiency resources, active demand capacity resources, and capacity imports/exports as detailed in Section 3.2.2
Expected Resource Additions	Including the NERC Long-Term Reliability Assessment Tier 1 Resources that are under construction and/or has received approved planning requirements in Section 3.2.2
Expected Capacity Retirements	Resources with retirement requests approved and/or disconnected from the system as specified in Section 3.2.2
Resource Availability (EFORd and Scheduled Maintenance Requirements)	Generating resources based on their 5-year historical average (Jan 2015 through Dec 2019); Active demand capacity resources based on historical actual and audit performance from 2015 to 2019
Tie Benefits Assumptions from Neighboring Systems	Based on results of the latest tie benefits studies conducted for ISO-NE's Forward Capacity Markets as specified in Appendix 7.4
Emergency Operating Procedures (Load Relief from Voltage Reduction)	Assumed 1.0% of load relief from Voltage Reduction during OP-4[5] Actions 6 and 8
Internal Transmission Constraints	Subarea representation and the interface limits are shown in Appendix 7.8.

Table 2 LOLE Results

Year	Anticipated Available Resources[6] (MW)	Reference Load Forecast		High Load Forecast	
		Annual Peak[7] (MW)	LOLE (days/year)	Annual Peak[7] (MW)	LOLE (days/year)
2021	36,161	28,634	0.003	29,411	0.012
2022	35,912	28,843	0.003	29,892	0.018
2023	35,838	29,083	0.005	30,361	0.031
2024	33,741	29,303	0.100	30,783	0.314
2025	34,020	29,534	0.098	31,192	0.338

[4] https://www.iso-ne.com/system-planning/system-plans-studies/celt/
[5] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf
[6] Anticipated available resources include the existing and expected future generation resources, demand-side resources and capacity imports.
[7] These are the 50/50 peak load (net of the BTM PV) that has 50% chance of being exceeded.

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Section 3 Introduction

The Reliability Assessment Program established by NPCC requires its member Planning Coordinators to conduct their resource adequacy assessment on an annual basis. The purpose of this report is to document the results and findings of ISO New England's (ISO-NE) comprehensive resource adequacy studies, covering the period 2021 to 2025, for NPCC review and approval. The assessment is conducted in accordance with the guidelines specified in Appendix D[8] of NPCC Regional Reliability Reference Directory #1, entitled *Design and Operation of the Bulk Power System*. This assessment supersedes the *2017 New England Comprehensive Review of Resource Adequacy*, which was approved by the NPCC Reliability Coordinating Committee (RCC) on December 3, 2017.

3.1 Previous Comprehensive Review of New England's Resource Adequacy

The findings of the 2017 review showed that New England conformed with the NPCC Full Member Resource Adequacy Criteria over the study period under the expected load and resource conditions.

3.2 Comparison of Current and Previous Reviews

3.2.1 Load Forecast

ISO-NE annually updates its load forecast for the next ten years to reflect the impacts from the region's historical use of electric energy and peak loads, and incorporates the most recent economic and demographic forecasts, while making adjustments for resettlement that includes meter corrections. In 2019, ISO-NE incorporated three improvements to the peak demand and annual energy-models that better reflect peak-eliciting weather conditions. First, a second weather variable, cooling degree days ("CDD") was incorporated into the model specification in addition to weighted temperature-humidity index ("WTHI"). This improvement was made to mitigate forecast performance issues identified during extreme weather conditions. Second, for monthly peak demand modeling, separate July and August monthly models were developed. Third, the historical weather period used to generate the probabilistic forecast was shortened from 40 years to 25 years. The new 25-year period covers 1991 to 2015. These forecast updates affect both the annual peak values and the uncertainty distributions of the loads.

The load forecast used in this review is based on the 2020 CELT report, and consists of the following components:

1) *The Gross Load Forecast*: the seasonal gross peak load and energy forecasts fully accounts for historical energy efficiency, but does not reflect reductions in peak demand and energy consumption that result from passive demand resources (PDRs) that clear the Forward Capacity Auctions, the energy efficiency forecast, or the BTM PV forecast. Starting in this year, ISO-NE has also incorporated the electrification (both heating and transportation) forecast within its gross load forecast. Since the last review, ISO-NE has revised downward its summer gross peak demand forecast, while upward its winter gross peak demand forecast and the annual energy forecast slightly . The 2020 gross forecast expects the 5-year growth rate to be 0.9% per year for the summer peak demand, 1.0% per year for the winter peak demand, and 1.4% per year for the annual consumption of electric energy as compared with 2017 forecast values of 1.0%, 0.6% and 0.9%, respectively.

8 Entitled "Guidelines for Area Review of Resource Adequacy."

2) *The Behind-the-Meter (BTM) PV Forecast*: majority of the state-sponsored distributed solar resource installations installed in New England is connected to the distribution system, so the output of these resources is not directly “visible” to ISO-NE system operators, but it does reduce the overall system load observed in real-time. ISO-NE has developed a forecast of future BTM PV using a policy-based approach and through the stakeholder process, and their impacts on reducing demand are now reflected in this review. The BTM PV is expected to grow from ~2,600 MW (nameplate) in 2021 to ~3,600 MW in 2025. In this review, the BTM PV is modeled in an hourly profile with uncertainty incorporated to reflect its reliability impacts.

3) *The Energy Efficiency (EE) Forecast*: ISO-NE also develops a forecast of long-term savings in peak and energy use for each state stemming from state-sponsored energy-efficiency and conservation (EE) programs. EE measures include the use of more efficient lighting, motors, refrigeration, HVAC equipment, control systems, and industrial process equipment. ISO-NE’s forecast of EE resources is developed with stakeholder input from the Energy-Efficiency Forecast Working Group (EEFWG). Data used to create the EE forecast originates from state-regulated utilities, energy-efficiency program administrators, and state regulatory agencies. The EE forecast is based on averaged production costs, peak-to-energy ratios, and projected budgets of state-sponsored energy-efficiency programs. In this review, EE is modeled and represented as supply-side resources to reflect its impact on the peak demand. For the next five years, the peak load reduction impact from EE is expected to increase from ~3,650 MW in 2021 to ~4,880 MW in 2025.

This study assesses the New England system adequacy using both the reference and high load forecasts. The reference and high load forecasts were developed based on a "most likely" long-run economic and demographic forecast and a high growth long-run economic and demographic forecast, respectively, from Moody's Economy.com.

Tables 3 and 4 show the annual (summer) peak demand forecasts used in the 2017 and 2020 reviews for ease of reference and to facilitate comparison. Figure 1 shows these values in graphical form. The annual (summer) peaks are presented for both the reference and high load forecast scenarios. The peak loads shown in Table 3 and 4 have a 50% chance of being exceeded (50/50 peaks) due to weather uncertainty and are expected to occur at a weighted New England-wide, average temperature of 90.2 ºF. While Table 3 and 4 show the annual 50/50 peaks of the forecast, the inherent uncertainty of the forecast from weather variations is modeled within the LOLE calculation. As shown in Figure 1, the difference between the reference and the high economic load forecast is bigger in this review than the 2017 review. This is a result of more uncertainty associated with the long-run economic growth expected for the region in this review.

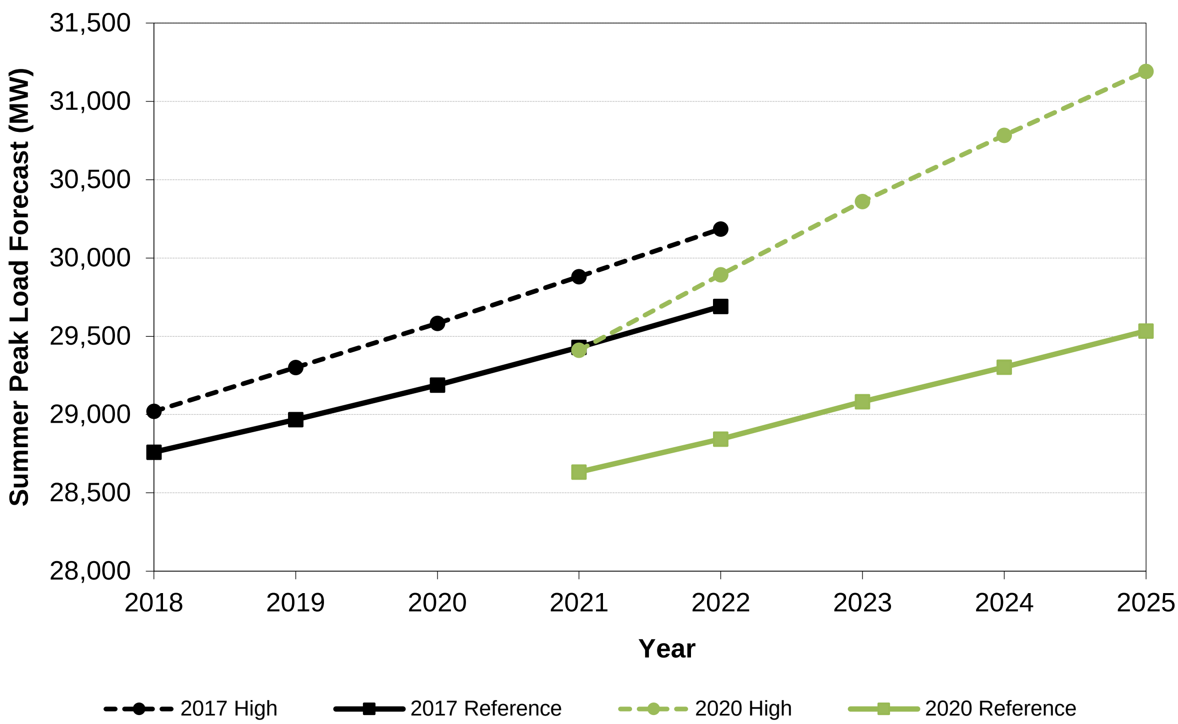
Table 3 Comparison of Annual Peak of Reference Load Forecasts

Year	2017 Review			2020 Review			2017 vs 2020 Difference of Gross Peak Net of BTM PV (MW)
	Gross Peak (MW)	BTM PV Peak Reduction (MW)	Gross Peak Net of BTM PV (MW)	Gross Peak (MW)	BTM PV Peak Reduction (MW)	Gross Peak Net of BTM PV (MW)	
2021	30,322	891	29,431	29,461	827	28,634	-797
2022	30,620	929	29,691	29,717	874	28,844	-848
2023	N/A	N/A	N/A	29,977	894	29,083	N/A
2024	N/A	N/A	N/A	30,241	938	29,303	N/A
2025	N/A	N/A	N/A	30,504	970	29,534	N/A

Table 4 Comparison of Annual Peak of High Load Forecasts

Year	2017 Review			2020 Review			2017 vs 2020 Difference of Gross Peak Net of BTM PV (MW)
	Gross Peak (MW)	BTM PV Peak Reduction (MW)	Gross Peak Net of BTM PV (MW)	Gross Peak (MW)	BTM PV Peak Reduction (MW)	Gross Peak Net of BTM PV (MW)	
2021	30,773	891	29,882	30,238	827	29,411	-471
2022	31,115	929	30,186	30,766	874	29,892	-294
2023	N/A	N/A	N/A	31,255	894	30,361	N/A
2024	N/A	N/A	N/A	31,721	938	30,783	N/A
2025	N/A	N/A	N/A	32,162	970	31,192	N/A

Figure 1 Comparison of Summer Peak Load Forecasts (net of BTM PV)



3.2.2 Resources

In New England, generating resources, measureable and verifiable demand side resources (including both passive and active demand resources), and capacity imports are all eligible to participate in ISO-NE's FCM and assume Capacity Supply Obligations to meet the region's Installed Capacity Requirements. This study uses these resources to assess the region's resource adequacy while reflecting the expected year-to-year variations from planned resource additions and expected retirements.

Since the last review in 2017, a number of generation resources have retired. The 1,535 MW Brayton Point Station, which consists of three coal-fired units and a dual-fuel (oil/gas) unit, retired in 2017. The Pilgrim Nuclear Power Station (~680 MW) retired in 2019. There are several major retirements expected during the next several years, including Bridgeport Harbor 3 (~370 MW) in 2021, Mystic 7 (~540 MW) in 2022, and Mystic 8 & 9 (~1,400 MW) in 2024.

Over 3,000 MW of new resources have been added to the New England system since 2017, offsetting some of these earlier and planned retirements. These new capacities consist primarily of natural gas-fired generation, of which the largest projects include the Footprint Combined Cycle Plant (674 MW), the CPV Towantic Energy Center (725 MW), PSEG's Bridgeport Harbor Expansion (484 MW), and the Canal 3 unit (333 MW), Wallingford units 6 & 7 (200 MW), and Medway Jet unit 4 & 5 (~200 MW).

The ratings of generating resources used for the review are based on the 2020 CELT. Active demand capacity resources that participate in the FCM are modelled as supply-side resources within the study. For 2021 through 2023, the study modelled the actual amount of capacity resources procured under FCM. As the capacity auctions for 2024 and 2025 have not been conducted, the capacity values for 2024 and 2025 are assumed to remain constant at the 2023 level.

External capacity import resources are based on known FCM Capacity Supply Obligations, which amount to 1,305 MW in 2021 and decrease to 1,058 MW in 2023. For 2024 and 2025, only the grand-fathered capacity imports of 82 MW are assumed.

Table 5 and Figure 2 compare the capacity (MW) values of resources assumed for the 2017 and 2020 reviews. The increase in the total amount of resources in this review for the two common years is mainly attributed to the higher energy efficiency forecast (~450 MW) and more capacity import resources procured in the forward capacity auctions (~1,200 MW). Table 6 provides the breakdown of resources by category for the 2020 review, and the reasons for the year-to-year change.

The NPCC Full Member Resource Adequacy Criterion (R4) allows the use of load and capacity relief from the implementation of emergency operating procedures (EOPs) to meet peak system capacity needs. Specifically, the tie benefits assumed available from the neighboring transmission interconnections and load relief from implementing voltage reductions are used in meeting the 0.1 days/year LOLE, but are not reflected as resources in Tables 4 and 5 and Figure 2. The tie benefits assumptions are detailed in Appendix 7.4. The load relief from implementing a 5% voltage reduction was assumed to be a 1.0% reduction from the corresponding peak demand.

Table 5 Comparison of 2017 vs. 2020 Resources Assumptions (MW)[9]

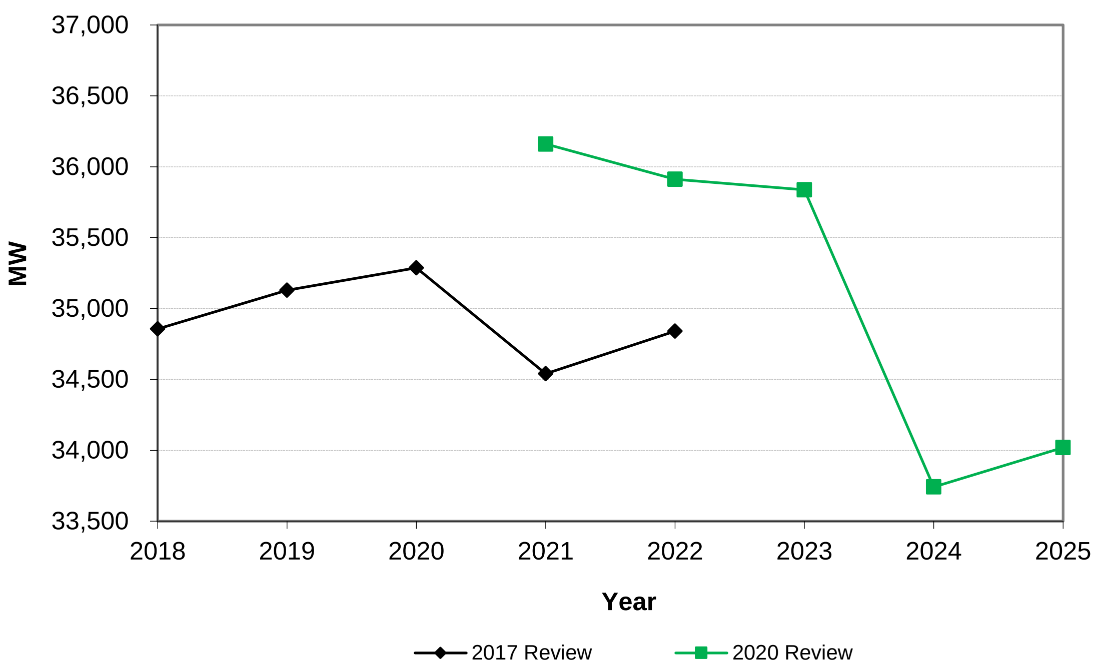
Year	2017 Review	2020 Review
2021	**34,540**	**36,161**
2022	**34,840**	**35,912**
2023	**N/A**	**35,838**
2024	**N/A**	**33,741**
2025	**N/A**	**34,020**

[9] Demand resource values include an 8% transmission and distribution loss gross-up.

Table 6 Breakdown of 2020 Review Resources Assumptions by Category (MW)

<table>
<tr><th>Year</th><th colspan="2">Generating Resources</th><th colspan="2">Demand Resources</th><th colspan="2">Net Purchase and Sale</th></tr>
<tr><td>2021</td><td>30,547</td><td rowspan="5">Major changes:
- Bridgeport Harbor 3 (370 MW) retirement in 2021
- Mystic 7(~540 MW) retirement in 2022
- South Meadow units 11-14 (~150 MW) retirement in 2023
-Mystic 8&9 (~1,400 MW) to retirement in 2024
-</td><td>4,308</td><td rowspan="5"><u>Energy Efficiency:</u>
~300 MW annual increase
<u>Active DR:</u>
Known FCM Capacity Supply Obligations for 2021 to 2023; 2024 and 2025 assumed the same as 2023</td><td>1,305</td><td rowspan="5">Known FCM Capacity Supply Obligations for 2021 to 2023;
Only grandfathered imports for 2024 and 2025</td></tr>
<tr><td>2022</td><td>30,059</td><td>4,665</td><td>1,188</td></tr>
<tr><td>2023</td><td>29,886</td><td>4,894</td><td>1,058</td></tr>
<tr><td>2024</td><td>28,469</td><td>5,191</td><td>82</td></tr>
<tr><td>2025</td><td>28,469</td><td>5,470</td><td>82[10]</td></tr>
</table>

Figure 2 Comparison of 2017 vs. 2020 Resource Assumptions



[10] These grandfathered imports expires on 8/31/2025.

Section 4 Resource Adequacy Criterion

4.1 The New England Resource Adequacy Planning Criterion

The New England resource adequacy planning criterion can be found in Section III.12 of the ISO New England Market Rule 1[11] – Standard Market Design (Market Rule 1). It states that "The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period." Section III.12 of Market Rule 1 also details the calculation methodology and the guidelines for the development of input assumptions. The New England resource adequacy planning criterion, as stated in Market Rule 1, is consistent with the NPCC Full Member Resource Adequacy Criterion (Resource Adequacy R4) which reads:

"Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.

> *R4.1 Make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."*

4.2 Application of New England Resource Adequacy Planning Criterion

The New England resource adequacy planning criterion is used to determine the amount of installed capacity resources needed to reliably satisfy system demand. In calculating the amount of resources needed, New England also takes into account the tie benefits that are assumed available from neighboring systems. The tie benefits from Québec, New Brunswick (Maritimes), and New York have been modeled within this reliability review.

To properly capture the intended operation of the system, the emergency operating procedures that are implemented during periods of capacity deficiencies are also modeled in the form of the amount of load relief that is assumed obtainable. It is assumed that the system operators will always maintain at least some minimum level of operating reserve to ensure control over transmission loadings.

Table 7 documents the actions of ISO New England Operating Procedure No. 4 (OP-4) – *Action During A Capacity Deficiency*[12]. In actual practice, these actions may be implemented in a different order to reflect the situation and the magnitude of the expected deficiency experienced at the time. Actions 1, 2, 5, 6 and 8 were modeled as load relief in this review. OP 4 Actions 3, 4, 7, 9, 10 and 11 were not modeled and are therefore listed as contingency resources. The amount of capacity assistance obtainable through OP 4 Action 5 is modeled as tie reliability benefits and those assumed benefits are shown in Appendix 7.4.

[11] https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.
[12] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4a_rto_final.pdf.

Table 7 Estimate of Additional Generation and Load Relief from System Wide Implementation of Actions in ISO New England Operating Procedure NO. 4 - Action During a Capacity Deficiency Based on a 25,000 MW System Load [13]

Action #	Description	MW
1	Implement Power Caution and advise Resources with a Capacity Supply Obligation to prepare to provide all associated capacity. Notify Settlement Only Resources with a Capacity Supply Obligation(CSO)to monitor the status of reserve pricing to meet those obligations. Begin to allow the depletion of 30-minute reserve.	0 0 About 600 MW
2	Declare Energy Emergency Alert (EEA) Level 1[14]	0
3	Voluntary Load Curtailment of Market Participants' Facilities	40[15]
4	Implement Power Watch	0
5	Schedule Market Participant-submitted EETs Arrange to purchase Control Area-to-Control Area emergency capacity and energy or energy only (if capacity is not available)	Variable (could be between 0 and 1,000 MW)
6	Implementation of 5% VR Requiring More Than 10 Minutes Declare EEA Level 2 Alert NYISO that sharing of reserves within NPCC may be required	125[16]
7	Request Generating Resources not subject to a Capacity Supply Obligation to voluntarily provide energy for reliability purposes.	Variable (could be between 0 and 1,500 MW)
8	Implementation of 5% VR Requiring 10 Minutes or Less Declare EEA Level 2	250[16]
9	Transmission Customer Generation Not Contractually Available to Market Participants During a Capacity Deficiency Voluntary Load Curtailment by Large Industrial and Commercial Customers	5 200[13]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning Declare EEA Level 2	200[13]
11	Request State Governors to Reinforce Power Warning Appeals Declare EEA Level 2	100[13]
Grand Total		1920 - 4020

4.3 Resource Adequacy Studies Conducted Since the 2017 Comprehensive Review

Since the 2017 Comprehensive Resource Adequacy Review, ISO-NE has conducted two interim NPCC Resource Adequacy Reviews and two NERC Long Term Reliability Assessments (LTRAs). Results of these resource adequacy studies indicated that New England would meet or expects to meet the NPCC Member Resource Adequacy Criterion covering the respective study periods.

In addition, the planning process in New England includes the periodic preparation of a Regional System Plan (RSP) in accordance with the ISO's Federal Energy Regulatory Commission approved *Open Access Transmission Tariff* (OATT) and the *Transmission, Markets, and Services Tariff* (the ISO TMS tariff). Regional System Plans meet the tariff requirements by summarizing planning activities that include the following:

[13] http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4a_rto_final.pdf. Estimated MW values are shown in this table for illustration purposes. The amount of load relief obtainable and the sequence of implementing these actions may vary depending on actual system conditions.
[14] EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011-Emergency Operations.
[15] The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
[16] The MW values are based on a 25,000 MW system load and the most recent voltage reduction test % achieved.

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

The RSP also summarizes 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 other information that can be used for improving reliability and the design of the regional wholesale electricity markets. In addition to these requirements, RSPs identify other actions taken by ISO-NE, state officials, regional policymakers, participating transmission owners (PTOs), New England Power Pool (NEPOOL) members, market participants, and other stakeholders to meet or modify the needs of the system.

In 2019, ISO-NE published the 2019 Regional System Plan (RSP19[17]), which identifies the region's electricity needs and plans for meeting these needs for 2019 through 2028.

[17] https://www.iso-ne.com/static-assets/documents/2019/10/rsp19_final.docx

Section 5 Resource Adequacy Assessment

5.1 Based On Reference Load Forecast

Table 8 summarizes the LOLE results under the reference load forecast using the resource assumptions detailed in Section 3.2. As shown, New England will meet the NPCC Full Member Resource Adequacy Criterion of disconnecting firm load customers no more than 0.1 days/year during the study period.

Table 8 LOLE Results Based on Reference Load Forecast

Year	Resources Assumed (MW)	Reference Load Peak Forecast net of BTM PV (MW)	LOLE (days/year)
2021	36,161	28,634	0.003
2022	35,912	28,844	0.003
2023	35,838	29,083	0.005
2024	33,741	29,303	0.100
2025	34,020	29,534	0.098

5.2 Based On High Load Forecast

ISO-NE also has analyzed the system resource adequacy under a higher than expected load forecast, which would be primarily driven by higher economic growth. Table 9 shows the LOLE results based on the high load forecast, while using the same resource assumptions as for the reference load forecasts.

Table 9 LOLE Results Based on High Load Forecast

Year	Resources Assumed (MW)	High Load Peak Forecast net of BTM PV (MW)	LOLE (days/year)
2021	36,161	29,411	0.012
2022	35,912	29,892	0.018
2023	35,838	30,361	0.031
2024	33,741	30,783	0.314
2025	34,020	31,192	0.338

The results of the high load forecast show that New England would also be able to meet the NPCC Full Member Resource Adequacy Criterion for the first years from 2021 to 2023. Additional resources are needed for 2024 and 2025 should the high load forecast materialize. The jump in the LOLE results in 2024 is the result of a reduction of resources resulting from the retirement of Mystic 8&9, and less capacity imports assumed for the years beginning in 2024.

5.3 Mechanisms to Mitigate Potential Reliability Impacts of Uncertainty

Under the FCM, the Installed Capacity Requirement is forecast and procured three years ahead of the commitment period, based on ISO-NE's assumed topology and system conditions three years into the future. The FCM design recognizes that system conditions can change and uncertainties exist in load forecasts, resource ratings and availability, as well as transmission topology. The FCM construct provides measures to mitigate the reliability impacts that might be caused by these potential uncertainties through a series of "reconfiguration auctions" conducted prior to each commitment period. These annual reconfiguration auctions are held in each subsequent year after the initial FCA for each commitment period. For each reconfiguration auction, ISO-NE recalculates the Installed Capacity Requirement using the updated forecast of loads, resources, and transmission topology. If the recalculated capacity needs are higher than the latest amount of resources purchased for the designated period, ISO-NE will attempt to procure additional resources to meet the revised needs within these reconfiguration auctions.

Section 6 Planned Resource Capacity Mix

New England's capacity and electric energy production in 2019 indicates that the region is highly dependent on natural gas-fired generation. As shown in Figure 3, more than 50% of the region's capacity in 2019 was natural gas-fired generation. This is more than twice as large as oil-fired capacity, which was the next largest type of generation resource in the region. Figure 3 also shows that natural gas power plants contributed ~49% to the region's electric energy production in 2019. Nuclear generation supplied ~30% of the electric energy while each of the other types of generating resources produced less than 8%.

Figure 4 depicts the regional generation capacity mix assumed during the study period by primary fuel type[18]. This is expressed in terms of summer capacity ratings (MW and associated percentages). Natural gas-fired generation represents the largest fleet at more than ~50% of total generation capacity, and of all the natural gas-fired generation, less than one-third has dual-fuel capability (fuel oil). Oil-fired generation is the second largest component at approximately ~20%. Nuclear generation accounts for 3,321 MW, or approximately 11%. Coal-fired generation accounts for less than 2% at about 533 MW. Conventional hydro (~1,370 MW) comprises approximately 5%. Pumped-storage (~1,785 MW) makes up over 6% of the total installed generation capacity. Other renewable resources, including landfill gas (LFG), other biomass gas, refuse (municipal solid waste), wood and wood-waste solids, wind, and tire-derived fuels, etc. represent about 3.5% of the total installed generating capacity.

[18] Demand resources and capacity import resources are not reflected in the mix.

Figure 3 New England's summer seasonal claimed capability (MW, %) and electric energy production (GWh, %) by fuel type for 2019

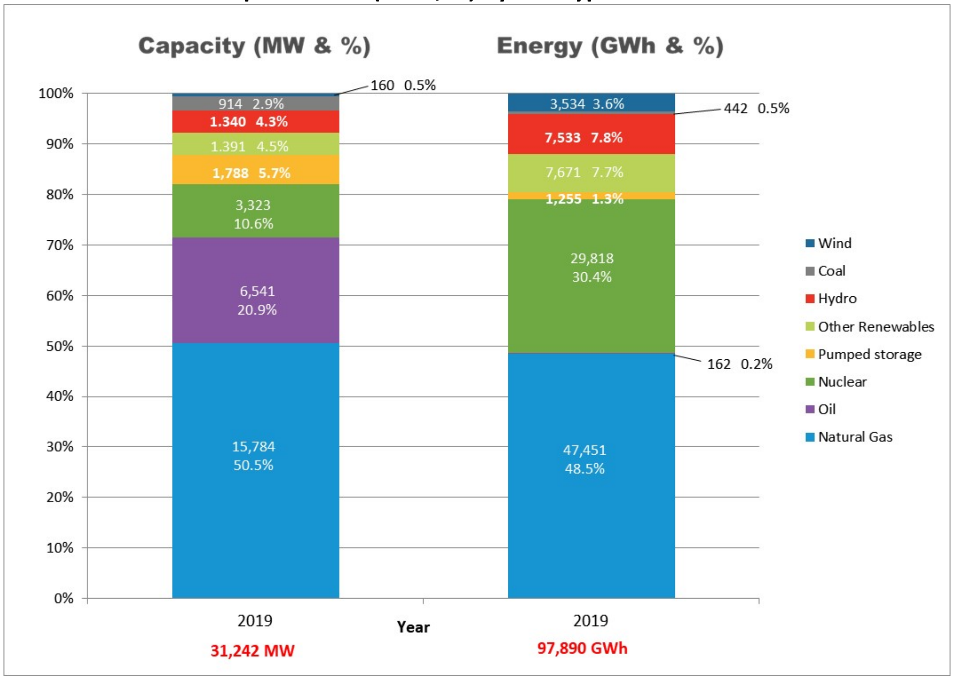
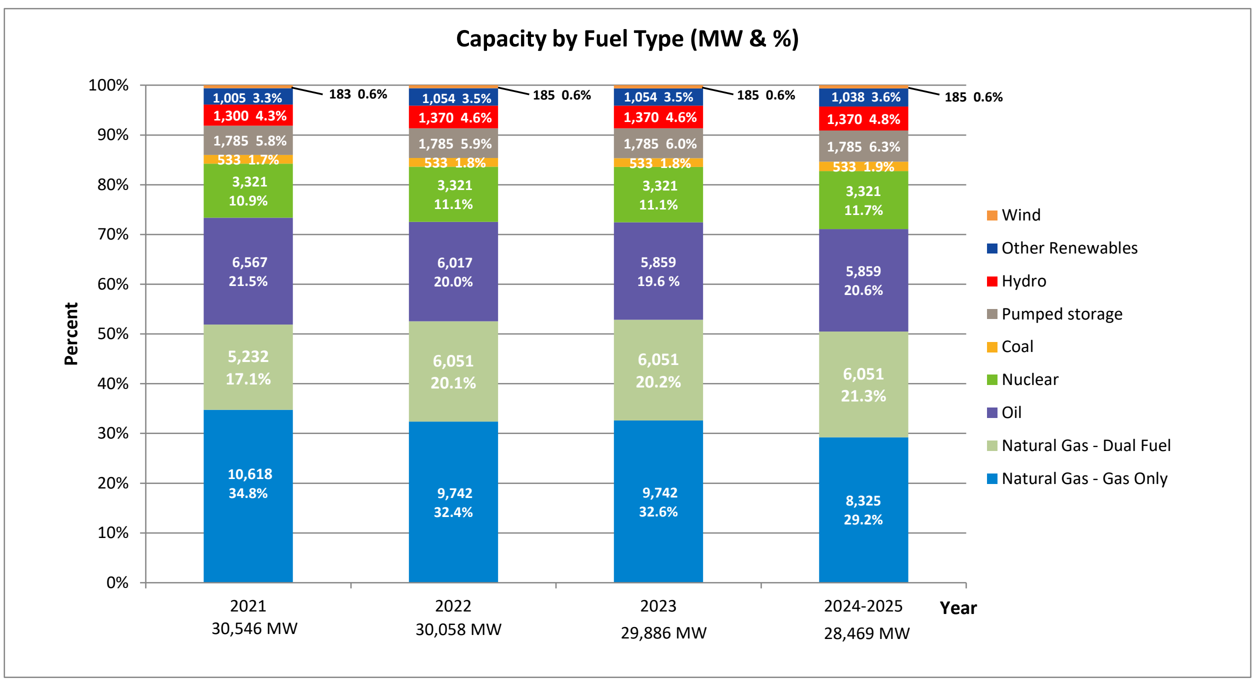


Figure 4 Expected Future New England's summer generation capacity mix by primary fuel type (MW[19] and %)



[19] Based on resources' summer claimed capability, not nameplate ratings.

6.1 Discussion of Energy Security Risks to System Reliability

Risks to current and future power system reliability hinges on the deliverability of fuel to New England's power generators so that they can provide the electric energy needed for meeting system demand. The operational challenges experienced during recent cold spells highlight the need for ISO-NE to manage energy-production limitations. During extremely cold weather, regional gas-fired power plants' lack of firm fuel contracts limits the operational availability of these generators. Inclement weather can also hamper fuel oil and LNG deliveries into and throughout the region. The inability of natural gas pipelines to serve coincidental gas and electric sector demands results in the need for replacement resources.

Expanding the region's fuel infrastructure would benefit New England, but major improvements are not currently planned. Siting new gas pipelines in New England can be a long and difficult process and will not address short-term needs. Siting and permitting operationally flexible dual-fuel generators also remains challenging.

Variable generation from renewable resources complicates both fuel availability and energy security concerns. Renewable generators generally can help supply the demand for energy and displace the traditional fuels that have been generating it, but the output of wind and solar facilities depends on the weather and time of day. For example, solar panels can reduce the consumption of natural gas and oil during sunny winter days, so more oil and gas are available later to generate electricity to meet the daily winter peak demand which occurs at night. Solar energy cannot help directly with the winter peak, however. Similarly, wind generation can reduce consumption of fossil fuels but can reduce to 0 MW during extraordinarily low or high wind conditions.

ISO-NE has implemented near-term market and operational changes to address energy security risks. Some of these improvements are as follows:

- Enhancing Operating Procedure No. 21, which developed new situational awareness and forecasting tools for system operators to confirm fuel availability (via surveys) for all fossil-fueled generators along with a new 21-Day Energy Forecast.
- Increasing awareness through improved communication and coordination with interstate pipeline operators

On April 15, 2020, ISO-NE submitted to FERC proposed revisions (Energy Security Improvements, or ESI) to the ISO-NE Transmission, Markets and Services Tariff reflecting improvements to its market design to better address regional fuel security concerns. Specifically, ISO-NE proposed three day-ahead ancillary service products: 1) Energy Imbalance Reserve, to compensate all generators that work to satisfy ISO-NE's load forecast; 2) Generation Contingency Reserve, to parallel the existing real-time operating reserve products; and 3) Replacement Energy Reserve, to restore depleting operating reserves within reliability standards' prescribed timeframes and to address load forecast errors realized during the operating day. In conjunction with this proposed ESI, ISO-NE proposed to sunset two interim out-of-market programs (Fuel Security Retention Mechanism and the Inventoried Energy Program) that were designed to bridge the gap prior to the implementation of ISO-NE's long-term energy security market design, for the Capacity Commitment Period 2024-2025, coincident with the ESI's implementation date.

On October 30, 2020, FERC issued an order[20] rejecting ISO-NE's proposed ESI tariff revisions citing that the ESI proposal unjust and unreasonable. In light of this outcome, FERC also rejected ISO-NE's associated proposal to sunset the Fuel Security Retention Mechanism and the Inventoried Energy Program one year earlier than currently provided in the ISO-NE tariff.

Given this recent FERC decision, ISO-NE is reviewing the decision, and will discuss next steps with stakeholders. ISO-NE remains committed to finding market-based solutions to solving the region's energy security challenges.

6.2 Discussion of Potential Reliability Impacts Due to Environmental Regulations

Existing and pending federal and state environmental regulations and multistate initiatives may require generators to consider adding air pollution control devices; modifying or reducing water use and wastewater discharges; and, in some cases, limiting operations. The actual compliance timelines and costs will depend on the timing and substance of the final regulations and site-specific circumstances of the electric generating facilities. Based on these and other economic factors, some generator owners may determine certain resources are uneconomical and retire their facilities instead of making major investments in environmental compliance measures.

All the New England states have Renewable Portfolio Standard (RPS) targets for the amount of electric energy load-serving entities must provide by renewable resources; individual state targets for 2020 require LSEs to provide between 10% to 59% of the energy they procure from renewable resources, which has driven new proposals for renewable energy. Some of the states also have issued requests for proposals for renewables development. The increased use of various types and amounts of renewable resources may require operational modifications or retrofits, resulting in additional environmental compliance costs. Additionally, the units are likely to experience higher operations and maintenance costs.

The New England states also take part in the Regional Greenhouse Gas Initiative (RGGI) for limiting carbon dioxide emissions by power plants and other emission-reduction efforts. Regional generator air emissions remain relatively low compared with historical levels, due to the generation fuel mix, including (in order of percentage share of 2017 annual energy production) natural gas, nuclear, hydro, wind, other fuel type (landfill gas, methane, refuse, solar, steam and wood), oil, and coal. Higher emissions, however, occur during the winter months because of the burning of fuel oil by generators when natural gas is either more expensive or in limited supply. The retirement of nuclear units would tend to increase regional emissions, but the addition of low- or zero-emitting resources would tend to reduce longer-term emissions. A combination of thermal generator retirements and the decreased use of remaining fossil thermal capacity has decreased overall water consumption for power generation compared with historical levels.

6.3 Integration of Variable Energy Resources

New England's electric power grid is rapidly changing, in response to public policies. The growth of inverter-based resources and demand resources provides many advantages of reduced energy costs, lower emissions,

[20] Please use the following link if you wish to review the FERC order: https://www.iso-ne.com/static-assets/documents/2020/10/er20-1567-000_order_rejecting_esi_10-30-2020.pdf

and less dependence on natural gas-fired generation. However, it also increases the complexity of real-time operations, regional planning, and the economic performance of the system.

ISO-NE and outside organizations have performed research and conducted analyses that have helped frame grid-transformation issues and work toward possible solutions. ISO-NE economic studies show the effects of the large-scale development of inverter-based technologies and build upon work provided by NREL and other organizations. For example, ISO-NE economic studies rely on NREL data sets which are critical for modeling hypothetical wind and PV resources within its planning studies. ISO-NE will continue to track industry research and monitor the effects that increased amounts of VERs have on system performance.

The development of renewables is facilitated by advances in transmission technologies (e.g., FACTS, HVDC, and adaptive protection). Analysis tools for more accurate forecasting of the state of the system and accounting for its probabilistic nature in studies can improve the overall operations and planning of the system. The application of phasor measurement units (PMUs) and modern analysis techniques also provide improved measurements of key data, more accurate state estimation, and resultant security analyzes.. Special controls, especially on inverter-based technologies and demand response, can help achieve more reliable and economic performance of the system.

ISO-NE is actively enabling the reliable integration of renewable and distributed resources through improvements in regional planning, operations, and markets processes. The implementation of a new cluster study methodology as part of the ISO's interconnection process better facilitates the planning of new wind resources. ISO-NE also improved its forecasting of wind and PV production and subsequently changed the dispatch methods used for operating the system. The region currently applies the voltage and frequency ride-through characteristics required by recently approved standards for interconnecting distributed energy resources. A number of improvements to the wholesale markets promote resource responses, such as operational flexibility, that facilitate the transformation of the grid.

Demand resources and new storage technologies hold the promise of providing needed system flexibility. Cyber- and physical security requirements must be constantly met to ensure a secure operation independent of any potential changes in the industry structure.

Operational coordination between the wholesale market (bulk power) and retail-level distributed resources and microgrids is complex. It will remain important for all resources that provide wholesale grid reliability services to have the same obligations and performance incentives. At present, ISO-NE relies on (market) aggregators to integrate small-scale, distributed resources into large enough quantities to participate in the wholesale market, similar to demand-response providers. For example, ISO-NE's integration of demand response paved the way for the full integration of storage and microgrids. Non-FERC-jurisdictional cluster studies administered by distribution owners should facilitate the interconnection of new distributed energy resources.

Section 7 APPENDIX

7.1 Description of Resource Reliability Model

GE MARS uses a sequential Monte Carlo simulation to compute the reliability of a power system comprised of a number of interconnected areas containing generation and load. This Monte Carlo process simulates the year repeatedly (multiple replications) to evaluate the impacts of a wide range of possible random combinations of generator outages. The transmission system is modeled in terms of transfer limits (constraints) on the interfaces between interconnected areas. Chronological system histories are developed by combining randomly generated operating histories of the generating units and inter-area transfers with the hourly chronological loads. For each hour of the year, the program computes the isolated area margins based on the available capacity and demand in each area. GE MARS then uses a transportation algorithm to determine the extent to which areas with negative margin can be assisted by areas having positive (excess) margin, subject to the available transfer constraints between the two areas. The program collects the statistics for computing the reliability indices, and proceeds to the next hour. After simulating all of the hours in the year, the program computes the annual indices and tests for convergence. If the simulation has not converged to an acceptable level, it proceeds to another replication of the current study year; otherwise, it moves on to the next study year.

7.2 Load Model

7.2.1 Hourly Loads

GE MARS employs an 8,760-hour chronological sub-area load model. The load model currently relies on actual historical load profiles from the year 2002. This model is then scaled up to the summer peak for the future years being analyzed.

7.2.2 Load Forecast Uncertainty

The load forecast uncertainty was modeled on a seasonal basis, which accounts for the uncertainty due to weather variations.

7.2.3 Demand of Entities that are Not Members of NEPOOL

All the demands of entities within NEPOOL are modeled. The Maine Public Service (MPS) Company's demand (in the northeastern-most area of Maine) is not modeled in this review because it is currently not a part of the ISO Planning Coordinator area.

7.2.4 Demand Side Management Programs

The demand side programs included in this assessment include regional conservation and energy efficiency programs, the BTM distributed solar, and active demand capacity resources that participate in New England's FCM.

The BTM PV, including residential and commercial rooftop solar, comprises approximately two-thirds of the total PV capacity and is treated by ISO-NE as a reduction to demand. The BTM PV resources are interconnected to the distribution system, not the bulk power system, and the installation and locational data were historically not available to ISO-NE. As part of long-term forecasting improvement efforts, ISO-NE has established a process to collect town-level installed capacity data from the region's distribution utilities, and applied a policy approach to develop a 10-year forecast of the BTM PV for the region. The link to the 2020 PV forecast: https://www.iso-ne.com/static-assets/documents/2020/03/final_2020_pv_forecast_corrected.pdf

Each year, ISO-NE also develops an energy-efficiency (EE) forecast that reflects the long-term savings in peak demand (MW) and energy (MWhr) use for the New England system and for each state stemming from state-sponsored energy-efficiency programs. Examples of EE measures include the use of more efficient lighting, motors, refrigeration, HVAC equipment, control systems, and industrial process equipment. ISO-NE's forecast of EE resources is developed with stakeholder input from the Energy-Efficiency Forecast Working Group (EEFWG). Data used to create the EE forecast originates from state-regulated utilities, energy-efficiency program administrators, and state regulatory agencies. The EE forecast is based on averaged production costs, peak-to-energy ratios, and projected budgets of state-sponsored energy-efficiency programs. The 2020 EE forecast can be found using the following link:
https://www.iso-ne.com/static-assets/documents/2020/04/eef2020_final_fcst.pdf

Active Demand Capacity Resources provide real-time peak load relief at the request of ISO-NE System Operators. These resources participate in the FCM, and are fully integrated and co-optimized? within the energy and reserve markets.

7.3 Resource Unit Representation

7.3.1 Unit Ratings

7.3.1.1 Definition

The ratings of resources were based upon their Seasonal Claimed Capabilities and Qualified Capacity values that are determined in accordance with ISO-NE's FCM market rules.

7.3.1.2 Procedure for Verifying Ratings

Seasonal Claimed Capability (SCC) of Generating Units

ISO-NE has the authority to initiate audits of all generating units to verify their Seasonal Claimed Capability (MW output). Audits are initiated by ordering the generator output to be increased from its current operating level (if that level is below SCC) to its SCC. The unit is then required to hold the output at its SCC for a predefined time period. The required duration for a claimed capability audit is at least two hours and no more than eight hours, depending on the Capability Period and type of unit. In order to pass a claimed capability audit, a unit must demonstrate it can achieve average output greater than or equal to its Claimed Capability. Full details of the audit process can be found in the ISO New England Operating Procedure No. 23 – Generator Resource Auditing located at:. http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op23/op23_rto_final.pdf.

Qualified Capacity Value under FCM

The determination of the Qualified Capacity value of a resource for participation in the FCA is outlined in Section III. 13 – Forward Capacity Market of Market Rule 1 located at: http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

The summer Qualified Capacity of a Generating Resource is calculated as the median of the most recent five summer Seasonal Claimed Capability ratings with only positive, non-zero ratings included in the calculation.

The seasonal Qualified Capacity for Intermittent Power Resources, is calculated as the median of the net output during the Seasonal Intermittent Reliability Hours of the most recent five years.

The summer Qualified Capacity of a Demand Resource is rated using the summer seasonal Demand Reduction Value calculation which is dependent upon the Demand Resource type.

7.3.2 Unit Unavailability Factors

7.3.2.1 Unavailability Factors Represented

Forced outage rates, planned outages, and maintenance outages are represented for each resource in the reliability assessment.

7.3.2.2 Sources of Unavailability Factors

A 5-year, historical average of unit-specific, forced outage assumptions is determined for each generating resource, using its individual unit data of monthly EFORd[21] values from the North American Electric Reliability Corporation's (*NERC*) Generating Availability Data System (GADS). NERC GADS data submitted by generators to ISO-NE for the months of January 2015 through December 2019 is used to create an EFORd value for each unit that submits such data. NERC Class Average data is used as a substitute for units that do not submit GADS data.

Energy efficiency resources are considered 100% available in the reliability model. The availability factors of Active Demand Capacity Resources are based on their performance measured by the actual response during historical events or during audits.

A weekly representation of a generator's planned outages is calculated for each unit, based on a 5-year historical average.

7.3.2.3 Maturity Consideration

NERC Class Average data is used as a substitute for immature units and new resource additions.

7.3.2.4 Tabulation of Unavailability Factors

Table 10 and 11 show the average unavailability factors used in this reliability review by unit type.

Table 10 Generating Resource EFORd and Maintenance Weeks by Category[22]

Unit Type	Assumed Weighted EFORd (%)	Assumed Weighted Maintenance Weeks
Fossil	15.4	5
Combined Cycle	4.1	5
Diesel	8.3	2
Combustion Turbine	10.2	3
Nuclear	1.2	3
Hydro	2.1	5
Others	13.1	6
System	6.4	5

[21] The calculation methodology of EFORd can be found in Appendix F of the NERC GADS Data Reporting Instructions at http://www.nerc.com/pa/RAPA/gads/Pages/Data%20Reporting%20Instructions.aspx.
[22] https://www.iso-ne.com/static-assets/documents/2020/08/a02_pspc_2020_08_25_review_fca15_icr_values.pptx

Table 11 Demand Resources EFORd Assumptions by Category

Type	Assumed Weighted EFORd (%)	Assumed Maintenance Weeks
Energy Efficiency	0	0
Active Demand Capacity Resource	5	0

7.3.3 Imports and Exports Representation

Table 12 summarizes the capacity imports and exports with neighboring systems assumed for this assessment.

Table 12 Net of Capacity Import Assumptions (MW)

	2021	2022	2023	2024	2025
Total Import	1,305	1,188	1,058	82	82

7.3.4 Retirements & Deactivations

Retirements assumed in this review are detailed in Section 3.2.2.

7.4 Representation of Interconnected Systems

New England's directly interconnected neighboring bulk power systems of Quebec, Maritimes, and New York provide tie benefits (emergency assistance) and capacity/energy imports in this comprehensive review.

The tie benefits are derived based on results of studies conducted with the GE MARS program. In these tie benefit studies, all the interconnected Areas are assumed to be at the 0.1 days/year resource adequacy criterion simultaneously. The Area's load, resources (including load and/or capacity relief assumed available from implementing emergency operating procedures) and transmission interface transfer limits are based on data that each Area has provided to NPCC for its regional studies. ISO-NE updates its tie benefit studies whenever it deems necessary. The tie benefit assumptions used in this review for 2021 to 2024 are based on the results of the latest tie benefits studies. Since no tie benefits study has been conducted for 2025, the 2024 values are assumed to be held constant for 2025 within this assessment. Table 13 summarizes the tie benefit assumptions for this reliability review. The tie benefits assumed in this assessment are within the range of tie benefits available to New England as estimated in the 2019 NPCC tie benefits study.

The capacity imports, summarized in Table 12 above, are based on FCM Capacity Supply Obligations and the transmission import capability of the external interconnections after accounting for tie benefits. In other words, the amount of capacity imports that clear in the FCM auctions cannot exceed the transmission import capability of the external interconnections after accounting for emergency assistance assumed available over the external interconnections.

Table 13 Assumed Tie Benefits From Neighboring System (MW)

Neighboring System	2021[23]	2022[24]	2023[25]	2024[26]	2025
Québec	987	1,118	1,077	1,023	1,023
New Brunswick	469	516	501	454	454
New York	209	366	362	258	258
Total	1,665	2,000	1,940	1,735	1,735

7.5 Modeling of Limited Energy Sources

New England's pumped storage and hydro-electric units were considered available to meet daily and monthly peak loads except when they are on planned maintenance or forced outages.

7.6 Modeling of Demand Side Management (DSM)

A description of the DSM programs was presented in Section 7.2.4.

7.7 Modeling of Resources

Modeling of resources was described within the above sections.

7.8 Other Assumptions

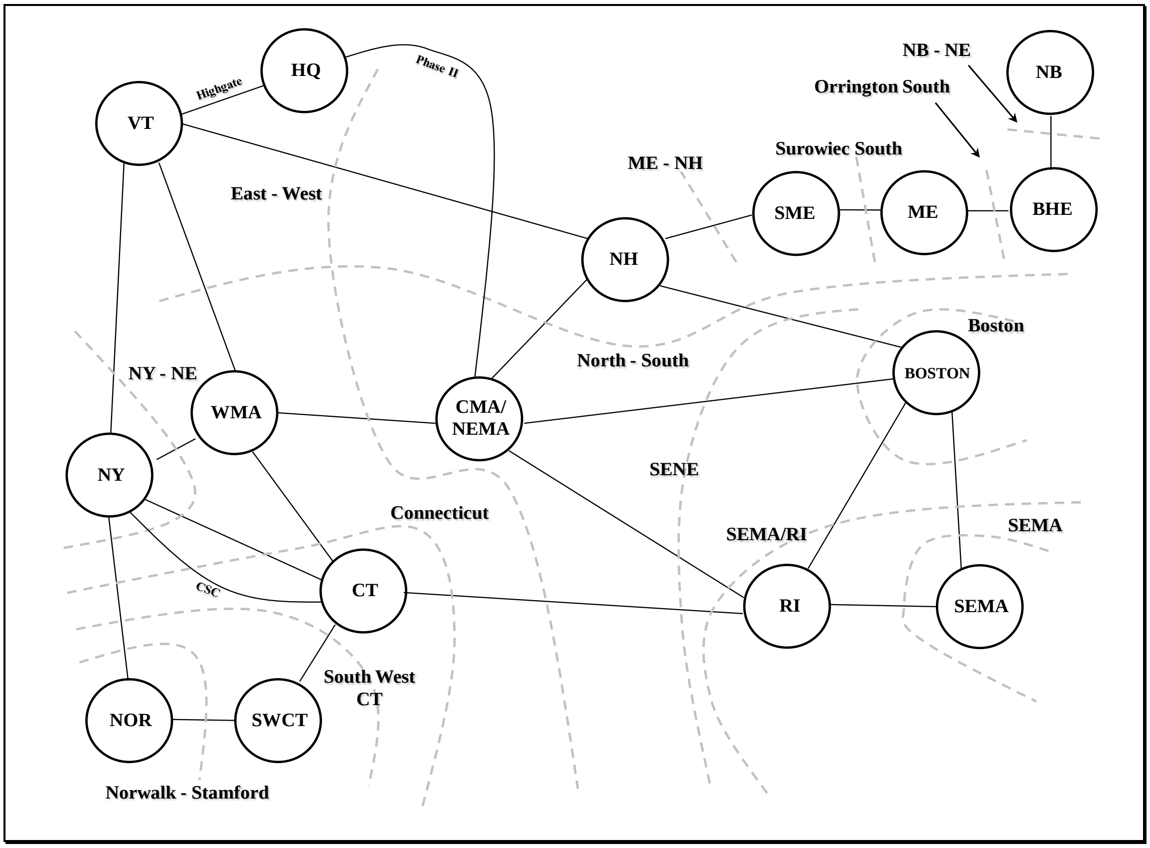
Consistent with the ISO-NE's Regional System Plan, the New England system was modeled as 13 interconnected sub-areas, with predefined transmission interface limits between them. The transmission interface transfer capabilities between these sub-areas have been determined based on established ISO-NE and NPCC reliability criteria. These criteria are described, respectively, in ISO-NE's Planning Procedure No. 3[27], entitled *Reliability Standards for the New England Area Pool Transmission Facilities*, and NPCC Regional Reliability Reference Directory #1, entitled *Design and Operation of the Bulk Power System.* These criteria require that the interconnected bulk power supply system be designed for a level of reliability such that the loss of a major portion of the system, or unintentional separation of any portion of the system, will not result from reasonably foreseeable contingencies. Therefore, the system must be designed to meet representative contingencies as defined in those criteria. Contingencies are simulated to assess the potential for widespread cascading outages due to overloads, instability, or voltage collapse. New England's bulk power supply system must remain stable during and following the most severe of the contingencies specified in the criteria, with due regard to re-closing facilities and before making any manual system adjustments. Voltages, line loadings, and equipment loadings must be within normal limits for pre-disturbance conditions, and within applicable emergency limits following the contingencies specified in the criteria. Disturbances in New England must not adversely affect other NPCC Control Areas and vice versa. Conversely, the loss of small portions of the system may be tolerated, provided the reliability of the overall interconnected system is not jeopardized.

The transmission interfaces used in this reliability review represent potential limiting areas of New England's transmission system, which may become constrained under a variety of system demands, generation patterns, or transmission topology. The most limiting transmission facility (limiting element) and critical contingency which limits the transmission interface transfer, may change depending on unit dispatch, load

[23] https://www.iso-ne.com/static-assets/documents/2020/09/a02_pspc_2020_09_16_prop_assumptions_tie_benefit.pptx
[24] https://www.iso-ne.com/static-assets/documents/2018/07/a41_pspc_propsd_tiebenfits_fca13_07262018.pdf
[25] https://www.iso-ne.com/static-assets/documents/2019/07/pspc_a05_tiebenefitswithandwithoutmystic89.pptx
[26] https://www.iso-ne.com/static-assets/documents/2020/08/a02_pspc_2020_08_14_.results_tie_benefits.pptx
[27] https://www.iso-ne.com/static-assets/documents/2017/10/pp3_r8.pdf

level, load distribution, and transmission configuration. For modeling purposes, these interface limits are shown as static. Interfaces composed of one or more transmission facilities have been defined to gauge the amount of power which can be transferred between or through various areas before a transmission limitation is reached. Figure 5 shows the New England sub-area representation.

Figure 5 New England Sub-Area Representation



Sub-areas

BHE	-	Northeastern Maine
ME	-	Western & Central Maine / Saco Valley, New Hampshire
SME	-	Southeastern Maine
NH	-	Northern, Eastern, & Central New Hampshire / Eastern Vermont & Southwestern Maine
VT	-	Vermont / Southwestern New Hampshire
BOSTON	-	Greater Boston, including North Shore
CMA/NEMA	-	Central Massachusetts / Northeastern Massachusetts
WMA	-	Western Massachusetts
SEMA	-	Southeastern Massachusetts / Newport, Rhode Island
RI	-	Rhode Island / bordering Massachusetts
CT	-	Northern and Eastern Connecticut
SWCT	-	Southwestern Connecticut

NOR - Norwalk / Stamford, Connecticut

NB, HQ and NY represent the New Brunswick, Québec and New York balancing authority, respectively.

Interface Limits (MW)[28]

Interface or Interface Group	Interface Limit (MW)
New Brunswick to NE	700
Orrington South	1,325
Surowiec South	1,500
Maine – NH	1,900
North to South	2,725
Boston Import	5,400
	5,700 (Year 2021)
	5,150 (Year 2024)
SEMA / RI Export	3,400
SEMA / RI Import	1,280
	1,800 (Year 2023)
East to West	3,500
West to East	2,200
	3,000 (Year 2023)
Connecticut Import	3,400
Southwestern CT Import	2,500
	2,800 (Year 2021)
Norwalk / Stamford Import	9,999
South East New England Import	5,400
	5,700 (Year 2021)
	5,150 (Year 2024)
New York / New England Import	1,400
HQII Import	1,400
Highgate Import	200
Cross Sound Cable Import	0

[28] https://www.iso-ne.com/static-assets/documents/2020/03/a08.0_rc_2020_03_17_presentation.pdf