NPCC 2019 New England Interim Review of Resource Adequacy

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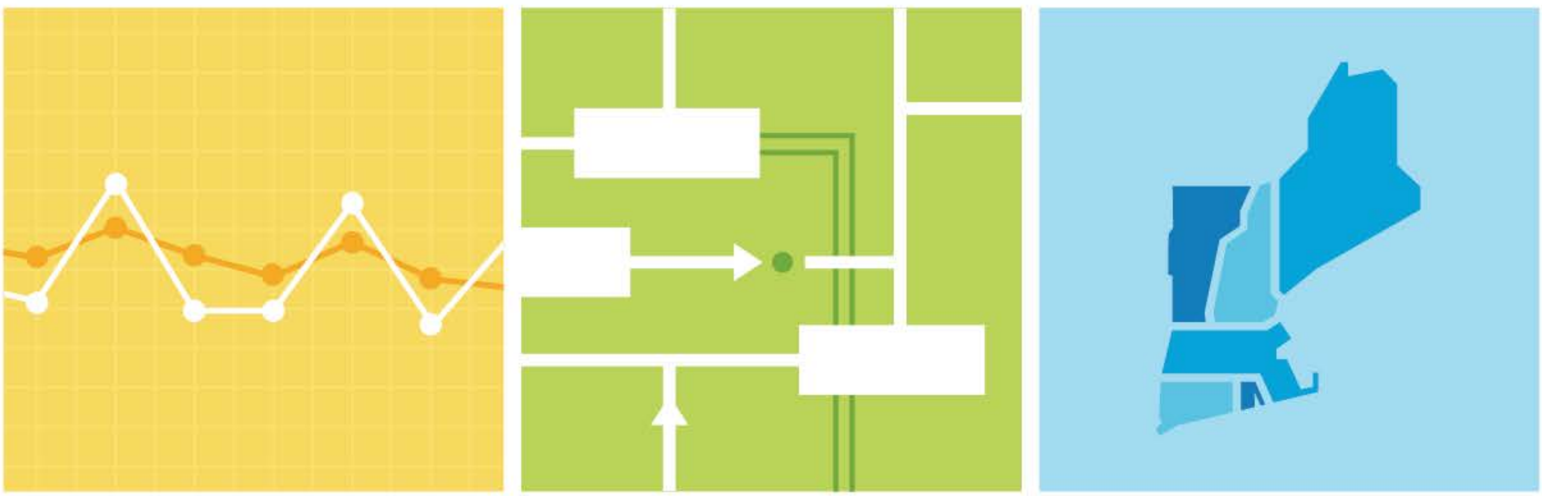

Section 1
Executive Summary

This report is ISO New England's (ISO) 2019 annual assessment (Interim Review) of its 2017 Comprehensive Review of Resource Adequacy, and covers the time period of 2020 through 2022. This Interim Review is conducted to comply with the Reliability Assessment Program (RAP) as established by the Northeast Power Coordinating Council (NPCC). It follows the resource adequacy review guidelines as outlined in the *NPCC Regional Reliability Directory #1 Appendix D, Design and Operation of Bulk Power System*.

To ensure the resource adequacy for the region, ISO New England identifies the amount and locations of resources the system needs and meets these needs in the short term through the Forward Capacity Market (FCM). Forward Capacity Auctions have been conducted to purchase needed resources for the Capacity Commitment Periods (CCP) 2020-2021[1] to 2022-2023. The resources procured by ISO New England through the FCM assume a capacity supply obligation (CSO), and must be available to offer energy and reserve to the New England energy markets. Resources that do not have a CSO can participate in the energy markets to serve New England load and provide reserve on a voluntary basis. For this Interim Review, resource adequacy is assessed under two sets of resource assumptions: 1) using resources' seasonal claimed capabilities; 2) using capacity supply obligations of resources in the Forward Capacity Market.

Table 1-1 and Table 1-2 summarize the Loss of Load Expectation (LOLE) for the study period using two demand forecasts and two sets of capacity resource assumptions.

Table 1-1
New England LOLE using Reference Demand Forecast

Year	2017 Comprehensive Review (Days/Year)	2019 Interim Review (Days/Year)	
	Based on Resources' Seasonal Claimed Capabilities	Based on Resources' Seasonal Claimed Capabilities	Based on Resources' Capacity Supply Obligations
2020	0.030	0.00094	0.00106
2021	0.058	0.00104	0.00563
2022	0.061	0.00189	0.00893

[1] A capacity commitment period of 20xx-yy refers to a period from June 1, 20xx through May 31, 20yy.

Table 1-2
New England LOLE using High Demand Forecast

Year	2017 Comprehensive Review (Days/Year)	2019 Interim Review (Days/Year)	
	Based on Resources' Seasonal Claimed Capabilities	Based on Resources' Seasonal Claimed Capabilities	Based on Resources' Capacity Supply Obligations
2020	0.043	0.00479	0.00528
2021	0.080	0.00852	0.02614
2022	0.086	0.01675	0.04498

Results of this Interim Review show that New England has adequate existing and planned resources to meet the NPCC Resource Adequacy Design Criteria under both the reference and high demand forecasts for the study period 2020 through 2022. Capacity supply obligations acquired in the Forward Capacity Market auctions for the 2020 through the 2022 years will meet the region's resource adequacy needs.

Section 2
Introduction

This is the second update of New England's 2017 Comprehensive Review of Resource Adequacy, which was approved by NPCC in December 2017. The load and resource assumptions of this Interim Review are based on the "2019-2028 Forecast Report of Capacity, Energy, Loads, and Transmission" (2019 CELT Report)[2]. Resource performance and transmission interface transfer capability assumptions are consistent with the values used by ISO New England in its calculation of the region's Installed Capacity Requirements. ISO New England continues to use the General Electric Multi-Area Reliability Simulation (MARS) model to simulate New England system resource adequacy.

[2] https://www.iso-ne.com/static-assets/documents/2019/04/2019_celt_report.xls

Section 3
Assumptions Changes

3.1 Resources

Table 3-1 compares resource assumptions between the two reviews. As shown, the total resources assumed for the 2019 review is higher than the amount assumed for each of the common years of the reviews. The total amount of resources for 2020 is approximately 930 MW higher, mainly due to more demand resources are expected and additional import resources are procured. For 2021 and 2022, the resource amount is approximately 1,500 MW and 1,025 higher, and it is the result of more demand resources expected, additional capacity imports procured in Forward Capacity Auction, and after accounting for resource retirement, and resource rating changes.

This review also conducts an assessment using only the resources with capacity supply obligations. The amount of capacity supply obligations are based on the values as of October 2019.[3]

Table 3-1
New England Resource Assumptions Comparison (Summer Ratings in MW)

Year	Based on Resources' Summer Claimed Capabilities				Capacity Supply Obligations assumed in 2019 Review
	2017 Review	2019 Review	Difference	Major Reasons for Changes	
2020	35,287	36,219	932	• Increase in demand resources (~450) • Increase in import resources (~360) • Increase in resource ratings (~100)	36,058
2021	34,540	36,057	1,517	• Increase in demand resources (~670) • Increase in capacity imports procured for 2021 in FCA (~1,160) • Increase in resource ratings (~100) • Decrease in resources due retirements (~400)	35,061
2022	34,840	35,865	1,025	• Increase in demand resources (~800) • Increase in capacity imports procured for 2022 in FCA (~1,100) • Increase in resources ratings (~100) • Decrease in resources due to retirements (~1,000)	34,839

3.2 Load

This Interim Review uses the 2019 load forecast. The forecast updates the data for the region's historical annual use of electric energy and peak loads by adding another year of historical data to the model, incorporates the most recent economic and demographic forecasts, and makes

[3] https://www.iso-ne.com/static-assets/documents/2019/10/october-2019-coo-report.pdf

adjustments for resettlement that include meter corrections. In the 2019 load forecast, the ISO incorporated three improvements in the summer gross demand modeling. First, a second weather variable, cooling degree days ("CDD") was incorporated in 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 that took place during the 2018 summer. Second, for monthly peak demand modeling, separate July and August monthly models were developed. Third, the historical weather period used to generate 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 distributions of the loads. The forecast also reflects the impacts of behind-the-meter photovoltaics (PV) load reductions. Demand response programs, which include both active and passive demand resources, are modeled and reported on the resource side. Table 3-2 compares the reference summer peak demand forecasts between the 2017 and the 2019 reviews. This year's summer peak load forecast is lower by approximately 800 MW to 1,000 MW. Table 3-3 compares the high demand forecasts, which also shows a downward trend.

Table 3-2
New England Reference Summer Peak Demand Forecast Comparison

Year	2017 Comprehensive Review (MW)			2019 Interim Review (MW)			Delta of Net Peak
	Gross Peak Forecast	BTM PV Peak Reduction[4]	Net of BTM PV Peak	Gross Peak Forecast	BTM PV Peak Reduction	Net of BTM PV Peak	
2020	30,036	848	29,188	29,130	777	28,353	-835
2021	30,322	891	29,431	29,341	842	28,499	-932
2022	30,620	929	29,691	29,561	891	28,670	-1,021

Table 3-3
New England High Summer Peak Demand Forecast Comparison

Year	2017 Comprehensive Review (MW)			2019 Interim Review (MW)			Delta of Net Peak
	Gross Peak Forecast	BTM PV Peak Reduction	Net of BTM PV Peak	Gross Peak Forecast	BTM PV Peak Reduction	Net of BTM PV Peak	
2020	30,431	848	29,583	29,940	777	29,163	-420
2021	30,773	891	29,882	30,428	842	29,586	-296
2022	31,115	929	30,186	30,878	891	29,987	-199

3.3 Interface Limits

The same sub-area configuration (bubble transportation model) is used to represent the transmission system in these two reviews. The transfer capabilities for the Boston Import interface and Southeast New England (SENE) Import interface have been updated to account for the delay in the Wakefield Woburn 345 kV Project[5]. This project, which is part of the Greater Boston upgrades, consists of installing a new 345 kV underground cable between Wakefield and Woburn,

[4] These values are the estimated peak load reduction impacts from the BTM PV. Hourly profiles were used in the simulation model.

[5] https://www.iso-ne.com/static-assets/documents/2019/03/a7_fca_14_transmission_transfer_capabilities_and_capacity_zone_development.pdf

approximately 8.5 miles long, and a 160 MVAR shunt reactor in addition to termination facilities at both Wakefield and Woburn. The project is now expected to be service by June 2021.

3.4 Unit Availability

Table 3-5 compares the weighted average EFORd assumptions used in the 2017 Comprehensive Review and this Interim Review. Overall, the system weighted average EFORd for generating capacity assumed in this review has improved as compared to the 2017 review assumptions. The change is the result of the update of the rolling 5-year average of generator- submitted Generation Availability Data System (GADS) data.

Table 3-4
New England Change In EFORd Assumptions – Weighted Averages

Unit Type	2017 Comprehensive Review EFORd (%)	2019 Interim Review EFORd (%)[6]
Fossil	19.3	14.4
Combined Cycle	3.9	3.7
Diesel	9.3	7.9
Combustion Turbine	10.4	10.6
Nuclear	1.9	1.2
Hydro	3.5	2.0
Others	10.0	11.6
System	7.3	**5.9**

3.5 Energy Security

The electric power system in New England is undergoing a major transition. The owners of traditional power plants – nuclear, coal, and oil-fired – are permanently retiring many of these stations due to economic and environmental pressures. The majority of the region's electricity, both currently and for the foreseeable future, is likely to come from newer, more efficient natural gas-fired generation and an array of renewable energy technologies, such as solar and wind powered generation. However, both renewable and natural gas-fired generation technologies rely on the "just-in-time" delivery of their "input" fuel/energy sources. Solar- and wind-based power inherently vary with the weather. Less obviously and of greater concern is the just-in-time, non-firm delivery of natural gas from several interstate gas pipelines into the region. During cold winter conditions, these gas pipelines run at full capacity with the firm gas supplies of the regional gas local distribution companies (gas LDC's); subsequently, they are unable to satisfy the additional non-firm demands from the electric power sector.

From the electric power sector's perspective, 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 hydroelectric resources) and natural gas-fired generators (with operational limitations on their energy production during the winter) are replacing

[6] https://www.iso-ne.com/static-assets/documents/2018/08/a3_pspc_prpsd_icr_values_08302018.pdf

traditional nuclear, coal, and oil-fired resources. With its existing fuel infrastructure, New England has faced challenging operating conditions, particularly during extreme cold weather conditions. Given the shift in the current resource mix, these challenges are beginning to extend beyond the winter season. During extreme cold periods, historical electricity needs have been met through a combination of generators using natural gas from gas pipelines and liquefied natural gas (LNG) storage facilities, and an ever-declining mix of nuclear, coal, and oil-fired generation. Although new, incremental natural gas-fired generation is being added to the fuel mix, the regional natural gas pipelines continue to have limited fuel deliverability during winter, for any power generators without firm gas transportation contracts. Additionally, LNG deliveries to New England, which are influenced by global economics and maritime transportation logistics, can also be uncertain without such contracts. Environmental permitting for new, dual-fuel capability (typically, natural gas and fuel oil) is more difficult under "ever-tightening" state and federal air emissions regulations. Even when these units are granted dual-fuel permits, their run times for burning fuel oil are usually restricted to limit both their annual and ozone season (May 1st – September 30th) air emissions.

Giving heightened priority to the regional fuel/energy security issue, in 2018 the Federal Energy Regulatory Commission (FERC) directed ISO New England to submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns." That directive arose amidst a contentious regulatory process involving shorter-term, out-of-market actions to bolster the region's (winter) inventoried fuel supplies and by delaying the retirement of the Mystic Generating Station, located in Everett, Massachusetts. This station is fueled solely by vaporized LNG from the Distrigas LNG Import Terminal located on the Mystic River, also located in Everett, MA.

In response to the FERC directive and to address regional fuel/energy security issues, ISO New England and its stakeholders are working to develop a new, three-part market-based approach: a multi-day ahead market, new ancillary services, and seasonal forward procurement. These changes are all scheduled for implementation in the 2024-2025 time-frame.

To address near-term operational energy-security risks in winter, sparked by limited availability of fuel for gas-fired generators and presented by retirement bids, the ISO incorporated a fuel-security reliability review and cost-allocation methodology into the Forward Capacity Market for retaining and compensating generators needed for fuel security. This is not a market-based solution but rather a reliability review to establish a need for a particular resource. This interim step will address regional winter energy security for capacity commitment periods 2022-2023, 2023-2024, and 2024-2025 while the ISO and its stakeholders develop a longer-term, market-based approach.

3.6 Environmental Regulations and Initiatives

Existing and pending federal, regional, and state environmental regulations may require generators to consider adding air pollution control devices; modifying or reducing water use and wastewater discharges; and, in some cases, limiting operations. The actual compliance timelines and costs will depend on the timing and substance of the final regulations and site-specific circumstances of the electric generating facilities. 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 targets for the amount of electric energy load-serving entities (LSEs) provide by renewable resources; individual state targets for 2020 range from requiring LSEs to provide 10% to 59% of the energy they procure from renewable resources, which has driven new proposals for renewable energy. Some of the states also have issued requests for proposals for renewables development. The increased use of various types and amounts of renewable resources may require operational modifications or retrofits, resulting in additional environmental compliance costs. Additionally, the units are likely to experience higher operations and maintenance costs.

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

3.7 Integration of Variable Energy Resources, Demand Response, and Storage

ISO New England has implemented improvements to forecasting techniques that account for wind, PV, and demand response. The ISO incorporates VER forecasting into ISO processes, scheduling, and dispatch services. Wind generators participating in the wholesale markets can download individual unit forecasts of their expected output, which can help market participants build a strategy for bidding in the Day-Ahead Energy Market. The operational forecasts provide better situational awareness and result in more reliable and economical operation of the system. As the amount of wind and PV grows, operational forecasts of variable energy resources take on increasing importance. The ISO is also working to improve its longer-term forecasts of PV and demand response resources used for planning.

Limited transmission infrastructure in northern and western Maine poses the primary obstacle to interconnecting new onshore wind resources. A number of generators currently connected leave this part of the transmission system at its performance limit with little to no remaining margin. Each interconnection request for new resources involves lengthy and complex study work to identify the significant transmission infrastructure, and individual projects are not able or willing on an individual basis to make the scale of system upgrade investments warranted. The ISO's developed a set of clustering revisions to the interconnection procedures for reducing the time for performing system impact studies in Maine and elsewhere on the New England transmission system, should similar conditions arise. It also conducted a strategic infrastructure study—the Maine Resource Integration Study to identify the transmission upgrades necessary for interconnecting proposed resources in Maine.

New England has witnessed significant growth in the development of solar photovoltaic resources over the past few years, and continued growth of PV is anticipated. Existing amounts of PV have caused noticeable effects on system operation and, as they grow, are anticipated to have a greater effect on the system's need for regulation, ramping, reserves, and voltage support. The ISO has engaged in a number of actions to examine and prepare for the effects of large-scale PV development in the region.

At present, the ISO's demand forecast method considers demand history as an input, which captures the growth and production non-PV Distributed Energy Resources (DERs). To date, the region has not experienced the large-scale growth of other types of DERs, which would present challenges similar to PV. The ISO continues to monitor this situation and actively examines its processes for improving its demand forecasts. This includes applications of modern analysis techniques, such as the latest methods of big data analysis and artificial intelligence.

With more behind-the-meter technologies and time-varying retail rates, demand could become more price responsive and less predictable. The ISO's work with regional stakeholders will help position the region to best integrate rapidly growing DER resources in a way that maintains reliability and allows the states to realize the public policy benefits they have identified as the basis for their DER programs. The ISO continuously works to improve its demand forecast methods to account for additional variations in the net demand.

Distribution owners are reviewing and improving processes and methodologies for integrating DERs. These activities address using cluster analyses for non-FERC-jurisdictional resources, providing information on the hosting capacity of distribution circuits, and making better use of smart inverters. Distribution owners are also modernizing distribution system equipment to better accommodate the large-scale development of DERs.

3.8 Others

The interconnection benefits from neighboring Areas are considered in both assessments. Since the 2017 Comprehensive Review, ISO New England has conducted additional tie benefit studies to identify the amount of tie reliability assistance New England can rely on from its neighbors for resource adequacy studies. Table 3-5 summarizes the tie benefit assumptions for the 2017 and 2019 reviews.

Table 3-5
New England Assumed Tie Benefits from Neighboring Areas (MW)

Year	2017 Comprehensive Review	2019 Interim Review
2020	1,950	1,939[7]
2021	2,020	2,020
2022	2,020	2,000[8]

Other assumptions for these two reviews are consistent with each other.

[7] https://www.iso-ne.com/static-assets/documents/2019/08/2019_08_29_a04_tie_benefits_analysis.pptx

[8] https://www.iso-ne.com/static-assets/documents/2018/07/a41_pspc_propsd_tiebenfits_fca13_07262018.pdf

Section 4
Results

Tables 4-1 and 4-2 summarize the New England system LOLE results for the scenarios investigated within this Interim Review and those from the 2017 Comprehensive Review. They show that New England has adequate existing and planned resources to meet the NPCC Resource Adequacy Design Criteria under all scenarios for the study period 2020 through 2022.

Table 4-1
New England LOLE using Reference Demand Forecast

Year	2017 Comprehensive Review (Days/Year)	2019 Interim Review (Days/Year)	
	Based on Resources' Seasonal Claimed Capabilities	Based on Resources' Seasonal Claimed Capabilities	Based on Resources' Capacity Supply Obligations
2020	0.030	0.00094	0.00106
2021	0.058	0.00104	0.00563
2022	0.061	0.00189	0.00893

Table 4-2
New England LOLE using High Demand Forecast

Year	2017 Comprehensive Review (Days/Year)	2019 Interim Review (Days/Year)	
	Based on Resources' Seasonal Claimed Capabilities	Based on Resources' Seasonal Claimed Capabilities	Based on Resources' Capacity Supply Obligations
2020	0.043	0.00479	0.00528
2021	0.080	0.00852	0.02614
2022	0.086	0.01675	0.04498

Section 5
Conclusions

Results of this Interim Review show that the New England region has adequate existing and planned resources to meet the NPCC Resource Adequacy Design Criteria under both the reference demand forecast and high demand forecast for the study period 2020 through 2022. ISO New England has procured an adequate amount of resources to meet system reliability through the Forward Capacity Market.

To address energy security concerns, ISO New England and its stakeholders are working to develop a new, three-part market-based solution: a multi-day ahead market, new ancillary services, and seasonal forward procurement. They are all scheduled for implementation in the 2024-2025 time-frame. To address near-term operational energy-security risks in winter, sparked by limited availability of fuel for gas-fired generators and presented by retirement bids, the ISO incorporated a fuel-security reliability review and cost-allocation methodology into the Forward Capacity Market for retaining and compensating generators needed for fuel security. This interim step will address regional winter energy security for capacity commitment periods 2022-2023, 2023-2024, and 2024-2025 while the ISO and its stakeholders develop a longer-term, market-based approach.