NPCC 2022 New England Interim Review of Resource Adequacy

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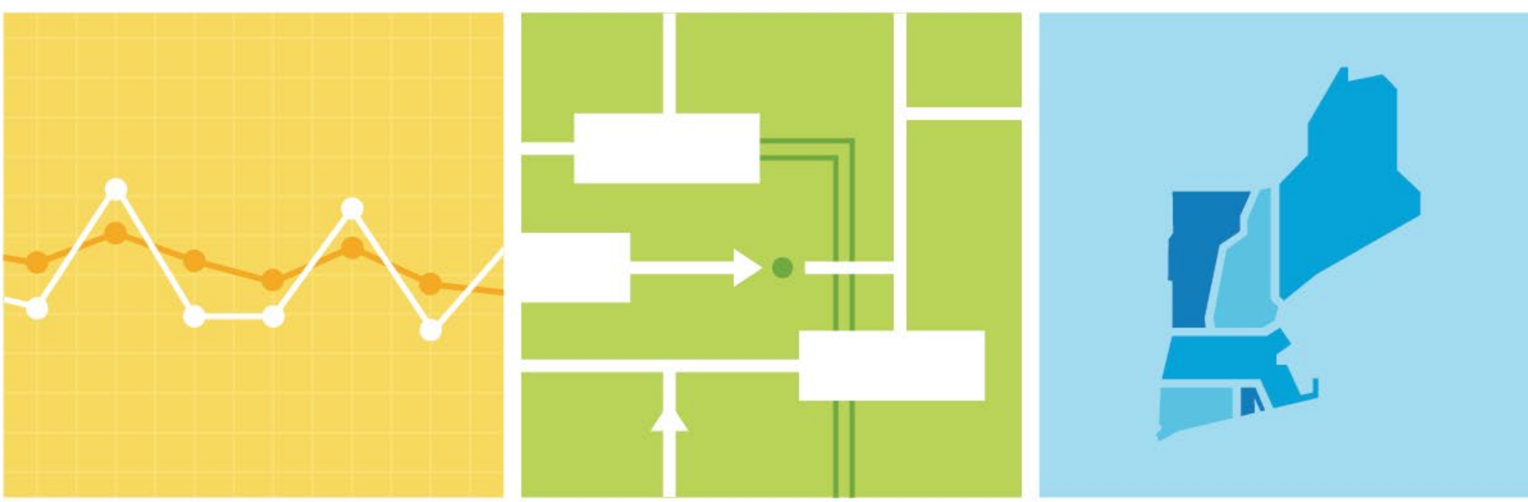

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Section 1 - Executive Summary

This report is ISO New England's (ISO-NE) annual Area Review of Resource Adequacy entitled *NPCC 2022 New England Interim Review of Resource Adequacy* (aka, *Interim Review*) covering the 2023 through 2025 assessment period. This is the second Interim Review associated with the *2020 New England Comprehensive Review of Resource Adequacy*, which covered the 2021 through 2025 assessment period. Results of this *Interim Review* show that New England meets the Northeast Power Coordinating Council's (NPCC) Full Member Resource Adequacy Criteria (Requirements 4 & 4.1 of the *NPCC Regional Reliability Directory #1*, Design and Operation of the Bulk Power System (Directory #1)) of disconnecting firm load customers no more than once in ten years (loss of load expectation (LOLE) of 0.1 days/year) during each year of the assessment period. ISO-NE conducted this *Interim Review* to comply with the Reliability Assessment Program (RAP) as established by the NPCC. This *Interim Review* followed the guidelines outlined in *Appendix D-Guideline for Area Review of Resource Adequacy* of Directory#1.

Results of this *Interim Review* show that ISO-NE has purchased more than the required amounts of capacity resources through its FCM process to meet the NPCC Full Member Resource Adequacy Criteria for 2023 through 2025 (Capacity Commitment Periods (CCPs) 2023-2024 through 2025-2026).

While ISO-NE has adequate installed capacity to meet its regional resource adequacy requirements during the assessment period, a previously identified/standing concern is whether there will be sufficient electrical energy available to satisfy electricity demand (while satisfying operating reserves) during an extended cold spell given the existing resource mix and seasonally-constrained fuel delivery infrastructure. To address the energy security concerns, ISO-NE will utilize its "Energy Assessment" process -- the development of a 21-Day Forecast of projected system energy availability during winter seasons. Depending on the severity, projected energy deficiencies can trigger "Energy Alerts," or "Energy Emergencies," which are disseminated to market participants and federal and state regulators. This early notification of potential energy shortages should initiate actions by market participants, as necessary, to firm up their fuel supplies or replenish inventories, in order to enhance supply-side capability.

In addition, ISO-NE has initiated a reliability-based project with the Electric Power Research Institute (EPRI), entitled *Modeling/Assessing Operational Impacts of Extreme Weather Events*, to conduct a probabilistic energy-security study for the New England region under extreme weather events and to develop a framework for ISO-NE 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 bulk power system and to prompt thinking about how best to prepare for such events.

Table 1-1 summarizes New England's 50/50 peak demand net of behind-the-meter photovoltaic (BTM PV) and associated capacity conditions during 2023 through 2025. The table shows the required installed capacity[1] to meet the 0.1 days per year LOLE, the amount of capacity purchased

[1] The "required installed capacity" needed to meet the 0.1 days per year LOLE is the net Installed Capacity Requirement shown in the ICR and Related Values presentation to the NEPOOL Reliability Committee located at: https://www.iso-ne.com/static-assets/documents/2022/10/a07_hqiccs_icr_values_2023_aras.zip.

in the Forward Capacity Market (FCM)[2] to meet the required installed capacity, and the assumed capacity[3] during the assessment period.

Table 1-1 - New England's Capacity Conditions During 2023 through 2025

Year (CCP[4])	50/50 Peak Demand[5] (Net of BTM PV)	Required Installed Capacity (A)		Capacity Purchased in FCM (CSO) (B)			Assumed Capacity (C)		
		Amount (MW)	Resulting LOLE (days/yr)	Amount (MW)	Surplus MW (B-A)	Resulting LOLE[6] (days/yr)	Amount (MW)	Surplus MW (C-A)	Resulting LOLE (days/yr)
2023 (2023-2024)	28,212	31,690	0.1	33,956	2,266	< 0.1	36,398	4,708	< 0.1
2024 (2024-2025)	27,935	31,545	0.1	34,621	3,076	< 0.1	35,986	4,441	< 0.1
2025 (2025-2026)	27,163	30,585	0.1	32,811	2,226	< 0.1	35,460	4,875	< 0.1

[2] The amount of capacity purchased in the FCM is based on total of FCM obligations listed in Section 1.1 (line 2.4) of the *2022-2031 Forecast Report of Capacity, Energy, Loads and Transmission* (*2022 CELT Report*).

[3] The "assumed capacity" is based on generation claimed for capability (line 3.1) plus demand capacity resources' FCM obligations (line 2.2) and net of capacity imports (line 2.3) as documented in Section 1.1 of the 2022 CELT Report.

[4] A CCP entitled "20xx-20yy," refers to the period from June 1, 20xx through May 31, 20yy.

[5] The 50/50 peak demand is the gross peak net of BTM PV and reflects the gross load forecast adjustments as part of the reconstitution methodology relating to passive demand resources (PDR) for calculating the Installed Capacity Requirement values for the Forward Capacity Market Annual Reconfiguration Auctions (ARAs). These adjustments account for the differences in the amount of PDR anticipated to participate in the upcoming Forward Capacity Auction (FCA), which is embedded in the gross load forecast, and the amounts of PDR anticipated to participate in each upcoming ARA, which are associated with prior commitment periods. The amount of PDR adjustments are listed in Appendix A.1 of the 2022 CELT Report.

[6] Resulting LOLE for (B) and (C) are based on non-simulation estimates.

Section 2 - Introduction

This is the second update of *New England's 2020 Comprehensive Review of Resource Adequacy*, which the NPCC Reliability Coordinating Committee (RCC) approved in December 2020.

To ensure resource adequacy of New England's bulk power system (BPS), every year ISO-NE identifies the amount of installed capacity needed to meet the LOLE of disconnecting firm customer load due to resource deficiencies, on average, no more than 0.1 days per year over the CELT forecast period. This two-part annual resource adequacy exercise covers nine years into the future using the annually updated bulk power system load and resource forecasts published in the CELT and other relevant assumptions. The first part, covering the first four years, relates to the development of the Installed Capacity Requirement[7] values needed for the Forward Capacity Market auctions (the primary auction and three Annual Reconfiguration Auctions for the years preceding the year of the primary auction). The second part, covering the remaining five years, relates to the development of representative ICR values[8], beyond the FCM period, to inform the regional market participants, regulatory authorities and reliability entities regarding future regional installed resource needs. ISO-NE uses these ICR and representative ICR values to reflect the region's capacity needs for the NPCC annual Area Review of Resource Adequacy. ISO-NE also uses these identified ICR and representative ICR values for the North American Electric Reliability Corporation (NERC) annual Long Term Reliability Assessment (LTRA).

For this year's ICR development effort, ISO-NE used demand and resource data from the ISO-NE 2022 CELT Report, as well as assumptions covering resource performance, transmission interface transfer capability, load and capacity relief assumed obtainable through emergency operating procedures (EOPs), etc. to generate the ICR and representative ICR values. ISO-NE continues to use the General Electric Multi-Area Reliability Simulation (MARS) model to simulate and assess New England's resource adequacy.

As in the past, this year's development of the ISO-NE ICR values for the regional FCM involved an extensive stakeholder process participated in by various New England Power Pool (NEPOOL) committees and New England states' public utility commission staffs. The ICR development process included the review of the simulations' input assumptions, results, and findings, and voting on the ICR values by the NEPOOL Reliability Committee (RC) and Participants Committee (PC). ISO-NE will file the ICR values presented in this *Interim Review* with the Federal Energy Regulatory Commission (FERC) by November 30, 2022.

ISO-NE has conducted Forward Capacity Auctions (FCAs) and purchased capacity resources to meet the regional resource adequacy needs for CCPs 2023-2024 to 2025-2026, which cover this Interim Review assessment period. The procurement of resources by ISO-NE through the FCM/FCA process is done (contractually) through a capacity supply obligation (CSO) awarded to the resources with winning bids. The resources that are awarded the CSO must be available (during the respective CCP) to offer both energy and reserves into the New England day-ahead and real-

[7] The Installed Capacity Requirement is the amount of resources needed by New England to meet the region's resource adequacy criterion of 0.1 days Loss of Load Expectation including load and capacity relief assumed obtainable from implementing EOPs.

[8] https://www.iso-ne.com/static-assets/documents/2022/07/a6_net_installed_capacity_requirements_representative_future_net_icrs_and_operable_capacity_analysis.pdf.

time energy markets. Resources that do not have a CSO can still participate in these energy markets on a voluntary basis.

Section 3 - Assumptions Changes

3.1 Resources

Table 3-1 compares assumptions of capacity resources expressed in terms of their summer claimed capabilities between the 2022 Interim and the 2020 Comprehensive Reviews. As shown in Table 3-1, the annual amount of summer claimed capabilities assumed for this *Interim Review* is higher than the amount assumed for the *Comprehensive Review*. Table 3-1 also lists the major reasons that contributed to the changes.

Table 3-1 – A Comparison of New England's Resource Assumptions

YEAR (CCP)	Comparisons Based on Resources' Summer Claimed Capabilities (MW)			
	2020 Comprehensive Review	***2022 Interim Review***	**Difference (2022 – 2020)**	**Major Reasons for Changes[9]**
2023 (2023-2024)	35,838	36,398	560	• ~ 400 MW increase due to rating updates • ~ 500 MW increase due to generation resource additions • ~ 200 MW decrease due to retirements
2024 (2024-2025)	33,741	35,986	2,245	• ~ 400 MW increase due to rating updates • ~ 1,800 MW increase due to generating resource additions • ~ 1,400 MW increase in capacity imports (procured through FCA) • ~ 200 MW decrease due to retirements
2025 (2025-2026)	34,020	35,460	1,440	• ~ 400 MW increase due to rating updates • ~ 2,000 MW increase due to generating resource additions • ~ 500 MW decrease due to retirements • ~ 200 MW increase in active demand resources • ~ 800 MW decrease in passive demand resources due to new reconstitution methodology • ~ 1,500 MW increase in capacity imports

3.2 Demand

This *Interim Review* uses the *2022 CELT Report's* demand forecast as noted earlier. The demand forecast is updated annually by adding another year of data to the region's historical model of annual use of electric energy and peak loads, incorporating the most recent economic and demographic forecasts, and by making adjustments for re-settlement that include revenue-quality meter corrections. For calculating the required installed capacity, the gross load forecast reflects adjustments to account for the differences in the amount of PDR anticipated to participate in the

[9] Please note that the Mystic Units 8 & 9 are scheduled to retire on June 1, 2024 within the modeling of both the *Comprehensive* and *Interim Reviews*. Therefore, their retirement impacts are not highlighted in the table.

upcoming FCA, which is embedded in the gross load forecast, and the amounts of PDR anticipated to participate in each upcoming ARA, which are associated with prior commitment periods.

Table 3-2 shows the difference in the 50/50 summer peak demand forecast assumed in the two reviews. As shown, the *Interim Review's* 50/50 net peak demand forecast was <u>lower</u> than the *Comprehensive Review's* peak demand forecast, ranging from approximately 870 MW to 995 MW during the 2023 through the 2025 review period.

Table 3-2 – A Comparison of New England's Reference (50/50) Summer Peak Demand Forecasts

YEAR (CCP)	***2020 Comprehensive Review (MW)***			***2022 Interim Review (MW)***			Delta of Net Peak Forecasts (2022-2020)
	50/50 Gross Peak Demand	BTM PV Peak Reduction[10]	50/50 Net Peak Demand	50/50 Gross Peak Demand	BTM PV Peak Reduction	50/50[11] Net Peak Demand	
2023 (2023-2024)	29,977	894	29,083	29,147	935	28,212	-871
2024 (2024-2025)	30,241	938	29,303	28,896	961	27,935	-961
2025 (2025-2026)	30,504	970	29,534	28,157	994	27,163	-994

Note: Values shown may not sum correctly due to rounding.

3.3 Transmission Interface Transfer Limits

With the exception of Boston Import and Southeast New England Import transfer limits, which increased by 100 MW starting in 2024, the assumptions relating to the transmission interface limits remained the same between the *Comprehensive Review* and the *Interim Review*.

Please note that ISO-NE relied on resource adequacy simulations to perform the ICR calculations to demonstrate its compliance with the NPCC resource adequacy criterion. The ICR calculation methodology only models the internal transmission interfaces that are associated with possible export- or import-constrained load zones to determine local resource needs to meet the system LOLE. Since the publication of the *Comprehensive Review*, the system demand forecast has decreased while the capacity has increased and the transmission system stayed approximately unchanged. Since the transmission interfaces would be modeled the same way within this *Interim Review* as in *the Comprehensive Review*, ISO-NE expects the same reliability results for the 2023 through 2025 review period. Therefore, ISO-NE did not simulate the transfer capability between the 13 sub-areas as was done in the *Comprehensive Review*.

[10] These values are the estimated peak-load-reduction impacts from the BTM PV. ISO-NE used hourly profiles in the simulation model.

[11] The 50/50 peak demand is the gross peak net of BTM PV and reflects the gross load forecast adjustments as part of the reconstitution methodology relating to passive demand resources (PDR) for calculating the Installed Capacity Requirement values for the Forward Capacity Market Annual Reconfiguration Auctions (ARAs). These adjustments account for the differences in the amount of PDR anticipated to participate in the upcoming Forward Capacity Auction (FCA), which is embedded in the gross load forecast, and the amounts of PDR anticipated to participate in each upcoming ARA, which are associated with prior commitment periods. The amount of PDR adjustments are listed in Appendix A.1 of the 2022 CELT Report.

3.4 Unit Availability

Table 3-3 compares the resource availability (by technology type) weighted average EFORd assumptions used in the *Comprehensive Review* and this *Interim Review*. The ISO's 2022 update of the rolling 5-year average of Generation Availability Data System (GADS) data resulted in the BPS weighted average EFORd for the overall system (generating capacity) remaining almost the same as compared with the 2020 assumptions. With the exception of nuclear technology, the EFORd assumptions for all the other unit types/technologies changed.

Table 3-3 – A Comparison of the Changes in New England's Generator EFORd Assumptions (Weighted Averages)

Unit Type/Technology	***2020*** ***Comprehensive Review*** **EFORd (%)**[12]	***2022*** ***Interim Review*** **EFORd (%)**[13]	**Delta (2020-2022) EFORd (%)**
Fossil	15.4	18.3	2.9
Combined Cycle	4.1	3.9	-0.2
Diesel	8.3	12.3	4.0
Combustion Turbine	10.2	8.5	-1.7
Nuclear	1.2	1.2	0.0
Hydro	2.1	2.8	0.7
Others	13.1	12.8	-0.3
System	**6.4**	**6.5**	0.1

3.5 Environmental Regulations and Initiatives

There are no changes in environmental regulations or initiatives during the review period that will affect the New England BPS reliability.

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

New England has witnessed significant growth in the development of solar photovoltaic resources over the past few years, and anticipates continued growth of these resources. Most recently, there has been an abundance of Distributed Energy Resources (DERs) interconnecting to the electric distribution systems. Many of these DERs are solar PV or a combination of solar PV and battery (storage) facilities. On September 17, 2020, *FERC Order No. 2222* required removing barriers to entry for DER aggregations in the wholesale electric markets.[14]

[12] https://www.iso-ne.com/static-assets/documents/2020/08/a2_.fca_15_icr_and_related_values_r1.pptx.

[13] https://www.iso-ne.com/static-assets/documents/2022/08/a02_proposed_icr_related_values_for_fca17.pptx.

[14] FERC Order 2222 describes DERs as: "Any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, EE, thermal storage, and electric vehicles and their supply equipment." The ISO does not currently have participation models to allow DERs to participate in the markets using heterogeneous aggregations of DER asset types. ISO-NE is also addressing a number of directives in the Order, including the size and location requirements, metering and telemetry requirements, registration requirements, and coordination among the ISOs, distribution utilities, DER Aggregators and retail regulatory entities.

In addition to future market enhancements, ISO-NE has recently adopted a number of planning and operational practices to ensure the reliable integration of new inverter-based resources (IBRs), including the use of advanced simulation models. These new models more accurately simulate IBR performance during post-contingency recovery and confirm the appropriate voltage and frequency ride-through of both VERs and DERs.

ISO-NE actively participates in developing industry standards, including *IEEE 1547—Standard for the Interconnection of Distributed Resources with Electric Power Systems,* which ensures that increased amounts of VERs and DERs can be reliably and economically interconnected to the distribution system. Looking to the future, ISO-NE has begun a multi-year project (2021-2023) referred to as the *Inverter-Based Resource Integration and Modeling Assessment.* The purpose of this project is to evaluate and adopt advanced, innovative analysis techniques that capture the unique performance and characteristics of IBRs, which is critical to transmission studies beyond the 10-year planning horizon.

The continued development of VERs and DERs may ultimately require a potentially significant bulk transmission (and distribution-level) buildout to interconnect these resources in a successively reliable manner. ISO-NE is currently leading or supporting a number of Transmission Planning study efforts to examine the continued evolution of the BPS.

3.7 Transmission Tie-Line Benefits

ISO-NE considered the interconnection benefits from neighboring Control Areas in both NPCC reliability reviews. Since the *Comprehensive Review*, ISO-NE has conducted additional tie benefit studies to identify the amount of tie reliability assistance New England can rely on from its neighbors for inclusion in resource adequacy studies. Table 3-4 summarizes the tie benefit assumptions for the 2020 and 2022 NPCC resource adequacy reviews.

Table 3-4 – A Comparison of New England's Tie Benefits from Neighboring Areas (MW)

YEAR (CCP)	*2020 Comprehensive Review*	*2022 Interim Review*
2023 (2023-2024)	1,940	1,980[15]
2024 (2024-2025)	1,735	1,735[16]
2025 (2025-2026)	1,735	1,830[17]

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

[15] https://www.iso-ne.com/static-assets/documents/2022/09/a03_review_of_2023_2024_ara_3_tie_benefits_study_results.pptx.

[16] https://www.iso-ne.com/static-assets/documents/2020/08/a02_pspc_2020_08_14_.results_tie_benefits.pptx.

[17] https://www.iso-ne.com/static-assets/documents/2021/07/a02_pspc_2021_07_27_fca_tie_benefits.pptx.

Section 4 – Addressing Energy Security

A previously identified/standing concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional seasonally-constrained fuel delivery infrastructure.

To address this concern, ISO-NE implemented its "Energy Assessment" process, the development of a 21-Day Forecast of projected system energy availability. Forecasts of weather, transmission topology, generation capability (including intermittent renewable resources), fuel inventories, known generator outages, pipeline maintenance, and projected imports/exports all factor into a 21-day simulation of New England's energy production capability. Depending on the severity, projected energy deficiencies can trigger "Energy Alerts," or "Energy Emergencies," which are disseminated to market participants and federal and state regulators. This early notification of potential energy shortages should initiate actions by market participants, as necessary, to firm up their fuel supplies or replenish inventories, in order to enhance supply-side capability.

In addition, ISO-NE has initiated a reliability-based project with the Electric Power Research Institute (EPRI), entitled *Modeling/Assessing Operational Impacts of Extreme Weather Events,* to conduct a probabilistic energy-security study for the New England region under extreme weather events and to develop a framework for ISO-NE to assess operational energy-security risks associated with such 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 bulk power system and to prompt thinking about how best to prepare for such events.

Section 5 – Results and Findings

Table 5-1 summarizes New England's expected system conditions for the 2023 through 2025 study period for the two resource adequacy reviews. As shown, the *Interim Review* has higher assumed capacity while lower peak demand during the study period. These conditions mean that if we would calculate the system LOLE using as-is conditions, the *Interim Review* would produce LOLE values lower than the *Comprehensive Review* results.

Table 5-1 also shows that the amount of capacity purchased in ISO-NE's FCA is more than the amount needed to meet the 0.1 days/year LOLE for 2023 (CCP 2023-2024) through 2025 (CCP 2025-2026).

Table 5-1 – A Comparison of New England's Expected Capacity Conditions (MW)

	2020 Comprehensive Review			***2022 Interim Review***			
YEAR (CCP)	**Assumed Capacity**	**50/50 Peak Demand (Net of BTM PV)**	**LOLE (days/year)**	**Assumed Capacity**	**50/50[18] Peak Demand (Net of BTM PV)**	**Capacity Needed to meet 0.1 days/year LOLE**	**Capacity Purchased to meet 0.1 days/year LOLE**
2023 (2023-2024)	35,838	29,083	0.005	36,398	28,212	31,690	33,956
2024 (2024-2025)	33,741	29,303	0.100	35,986	27,935	31,545	34,621
2025 (2025-2026)	34,020	29,534	0.098	35,460	27,163	30,585	32,811

[18] The 50/50 peak demand is the gross peak net of BTM PV and reflects the gross load forecast adjustments as part of the reconstitution methodology relating to passive demand resources (PDR) for calculating the Installed Capacity Requirement values for the Forward Capacity Market Annual Reconfiguration Auctions (ARAs). These adjustments account for the differences in the amount of PDR anticipated to participate in the upcoming Forward Capacity Auction (FCA), which is embedded in the gross load forecast, and the amounts of PDR anticipated to participate in each upcoming ARA, which are associated with prior commitment periods. The amount of PDR adjustments are listed in Appendix A.1 of the 2022 CELT Report.

Section 6 – Conclusions

Results of this *2022 Interim Review* show that ISO-NE has already purchased adequate amounts of capacity to meet the NPCC Resource Adequacy Design Criteria for years 2023 through 2025.

To address energy security concerns, ISO-NE implemented its "Energy Assessment" process, the development of a 21-Day Forecast of projected system energy availability. Depending on the severity, projected energy deficiencies can trigger "Energy Alerts," or "Energy Emergencies," which are disseminated to market participants and federal and state regulators. This early notification of potential energy shortages should initiate actions by market participants, as necessary, to firm up their fuel supplies or replenish inventories, in order to enhance supply-side capability.

In addition, ISO-NE has initiated a reliability-based project with the Electric Power Research Institute (EPRI)[19], entitled *Modeling/Assessing Operational Impacts of Extreme Weather Events*, to conduct a probabilistic energy-security study for the New England region under extreme weather events and to develop a framework for ISO-NE 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 bulk power system and to prompt thinking about how best to prepare for such events.

[19] For details and status of this project please see ISO-NE presentations at: https://www.iso-ne.com/committees/key-projects/operational-impacts-of-extreme-weather-events