Northeast Power Coordinating Council, Inc.

2025 NPCC Long Range Adequacy Overview (LRAO)

NERC Probabilistic Assessment (ProbA)

RCC Approved Dec. 1, 2025
Conducted by the NPCC CP-8 Working Group

Final Report - Public

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Foreword

The NPCC 2025 Long Range Adequacy Overview was conducted in the second half of the year in 2025 based on the best available information and is consistent with the assumptions used in the NERC 2025 Long Term Reliability Assessment (LTRA).

Executive Summary

Northeast Power Coordinating Council, Inc. (NPCC) highlights in this report the risks and reliability concerns for 2026-2030 based on a probabilistic resource adequacy assessment for Northeastern North America and neighboring Regions.

2025 NPCC Long Range Adequacy Overview

This study evaluated, on a consistent basis, the long-range adequacy of the NPCC and neighboring Regions' plans to meet their annual Loss of Load Expectation (LOLE) planning criteria.[1] The study conducts a multi-area probabilistic reliability assessment for the period from 2026 to 2030, based on the data reported within the 2025 NERC *Long-Term Reliability Assessment*[2] (LTRA). General Electric's (GE) Multi-Area Reliability Simulation (MARS) program[3] was selected by NPCC for this analysis. GE Energy Consulting was retained by the CP-8 Working Group on the Review of Resource and Transmission Adequacy and GE MARS version 5.7.3765 was used for the assessment.

The database, developed by the NPCC CP-8 Working Group for the 2025 NPCC Reliability Assessments, beginning with the 2025 *NPCC Summer Assessment*,[4] served as the foundation for this overview. CP-8 Working Group members reviewed the existing data and then revised it to reflect the conditions expected for the 2026 - 2030 period, consistent with the information reported for the 2025 NERC LTRA.

The assessment illustrates that all Areas meet the annual loss of load expectation (LOLE) criterion of 0.1 days/year under expected resource conditions and expected demand forecasts associated with normal weather except Maritimes which is slightly above the NPCC LOLE criteria of 0.1 days per year in 2026. This is a deviation from the results of the 2024 *Long Range Adequacy Overview*[5] for study year 2026, which can largely be attributed to a change in modeling assumptions for expected wind output during peak hours due to the variability of wind from hour-to-hour in the wind shape used. During the 2026-2030 period, the Maritimes capacity is expected to increase at a higher rate than the expected increase in load. The Maritimes' 2025 *Comprehensive Review of Resource Adequacy*[6] concludes the Maritimes Area not complying with the NPCC resource adequacy criterion in the near term and meeting the criterion in the later years of the study, consistent with NPCC's wide area

[1] See: Directory No. 1- Section 5.2 https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories.
[2] See: Reliability Assessments (nerc.com).
[3] See: Product and Service Offerings | GE Energy Consulting.
[4] See: NPCC Seasonal Assessments.
[5] See: 2024 NPCC Long Range Adequacy Overview.
[6] See: Reliability Services | NPCC.

assessment in the LRAO. The Maritimes is a relatively small area, and the forced outage of a single large unit through probabilistic simulation can result in the use of emergency procedures when margins are at their thinnest.

Additionally, NPCC staff conducted a sensitivity case to evaluate energy sufficiency across the NPCC footprint for study year 2029 satisfying a 2025 Corporate Goal.[7] Using NERC's *Technical Reference Document Considerations for Performing an Energy Reliability Assessment Volumes 1[8] & 2[9]* , the assessment incorporated area specific risks and assumptions, with results compared against the base case and included in Appendix G. While most areas applied the same 50/50 load levels, New York tested a higher demand scenario from the 2025 Gold Book.[10] Although NYISO's results under this assumption were lower due to differing methodologies, overall system trends remained directionally consistent with the base case. The analysis serves to illustrate potential energy sufficiency risks beyond anticipated resources, including factors such as the potential impact of extreme weather events, anticipated performance of aging generators, uncertainties of resource procurement, and greater than expected load forecast uncertainty.

2025 NERC Probabilistic Assessment – NPCC Region

NERC performs a probabilistic assessment as part of its resource adequacy assessment and results are published in the LTRA report. NERC in their LTRA used two approaches to assess future resource and energy risk. In addition to comparing the reserve margin, NERC included probabilistic indices to measure risk of inadequacy in future resource and energy risk. Loss-of-load hours (LOLH) and expected unserved energy (EUE) are used to identify risk levels. For the 2025 LTRA, NERC considers an assessment area at high risk if LOLH exceeds 2.4 hours/year and normalized expected unserved energy (NEUE) exceeds 0.002% for study years.[11] NERC considers an assessment area elevated risk if LOLH is between 0.1 and 2.4 hours/year and NEUE is below 0.002% for study years.

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[7] Assess energy sufficiency across the NPCC footprint by systematically identifying area-specific considerations and risks in alignment with the NERC Technical Reference Document.

[8] See: Considerations for Performing an Energy Reliability Assessment ERATF White Paper.

[9] See: Technical Reference Document: Considerations for Performing an Energy Reliability Assessment Volume 2.

[10] See: 2025-Gold-Book-Public.pdf.

[11] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*. The workshop, "Evolving Planning Criteria for a Sustainable Power Grid," assembled industry thought leaders to build consensus around the need for additional criteria, actionable short- and long-term recommendations, and next steps. Since the traditional resource adequacy models and approaches rooted in a LOLE of 1-day-in-10 years do not adequately account for the essential role to capture risks, regulators and policymakers in many states and market areas have begun considering or developing resource adequacy targets based on other criteria that can better address energy risks and extreme weather-related supply disruption.

The 2025 ProbA identified negligible risk of unserved energy and load loss for the study years 2027 and 2029 for most of NPCC Areas, except Québec and Maritimes, due to resource shortages. NPCC Area Québec was identified at elevated risks based on the capacity shortfall to meeting reference margin for year 2030-31 winter, and a 0.11 LOLH for year 2029-30 winter. NPCC Area Maritimes was identified at elevated risk based on capacity shortfall to meeting reference margin for years 2025-26 winter, 2026-27 winter, and 2027-28 winter, as well as a 0.25 LOLH for year 2027-28 winter.

Introduction

This study evaluated, on a consistent basis, the long-range adequacy of Northeast Power Coordinating Council's (NPCC) and neighboring Regions' plans to meet NPCC Areas Loss of Load Expectation (LOLE) planning criterion through a multi-area probabilistic assessment for the period from 2026 to 2030, based on the reported *NERC 2025 Long-Term Reliability Assessment*[2] (LTRA) data.

Definition of Loss-of-Load Event

NPCC Regional Reliability Reference Directory No. 1 *Design and Operation of the Bulk Power System* Resource Adequacy – Design Criteria states:[12]

Resource Adequacy

R4 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, resource variability, 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.

Area operators may invoke their available operating procedures in any order, depending on the situation faced at the time; for this analysis, the reliability indices were calculated following the sequential order shown in the tables below; the CP-8 Working Group agreed that modeling the actions this way was a reasonable approximation for this analysis.

It should be recognized that changing the assumed order of the operating procedures in the analysis will change the magnitude of the calculated indices of the associated actions of the operating procedures while the magnitude associated with the disconnection of firm load will not be impacted. The metrics calculated in this assessment are consistent with NPCC's Resource Adequacy – Design Criteria, i.e., they are calculated following all possible allowable "load relief from available operating procedures."

[12] See: https://www.npcc.org/program-areas/standards-and-criteria/regional-criteria/directories.

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program[3] was selected by NPCC for its analysis. GE Energy Consulting was retained by the Working Group to conduct the simulations. GE MARS version 5.7.3765 was used for the assessment.

The database developed by the NPCC CP-8 Working Group's NPCC *Reliability Assessment for Summer 2025, April 23, 2025,*[4] was used as the starting point for this Overview. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the 2026-2030 period, consistent with the information reported for the NERC *2025 Long-Term Reliability Assessment.*[2]

This report is organized in the following manner: after a brief Introduction, findings of the *NPCC 2025 Long Range Adequacy Overview* are presented as well as summary of the NERC 2025 Prob A for the NPCC region is presented.

- **Appendix A** shows the Objective and Scope of Work.
- **Appendix B** summarizes the modelling assumptions used in the analysis.
- **Appendix C** describes the modelling software used.
- **Appendix D** provides overview of the NERC ProbA supply and demand for each Area for the risk day.
- **Appendix E** summarizes detail results of each Area reported for 2025 NERC Prob A and comparison to previous ProbA.
- **Appendix F** describes detailed definitions.
- **Appendix G** describes assumptions and observations from the 2025 Corporate Goal RAPA IIB-1 energy sufficiency analysis.
- **Appendix H** illustrates the estimated monthly NPCC Areas and Neighboring Region's LOLE, LOLH, and normalized EUE for the study period for the expected load level.

2025 NPCC Long Range Adequacy Overview Results

Figures 1(a) and **1(b)** show the estimated annual NPCC Area Loss of Load Expectation (LOLE) for the 2026-2030 period. The 50/50 expected load level results were based on the probability-weighted average of all seven load levels simulated.

All NPCC Areas demonstrate meeting the annual LOLE criterion of 0.1 days/year except Maritimes for year 2026.[13] Maritime's 2026 LOLE value is estimated to be slightly above NPCC LOLE criteria of 0.1 days/year. Although demand and resource levels in the Maritimes are similar to study year 2026 in the 2024 *Long Range Adequacy Overview*[5], elevated LOLE is largely a result of modeling assumptions. The current probabilistic model used a narrower wind dataset (2020-2024), which lowers expected wind output during peak hours compared to last year's broader range. Additional planned maintenance outages and reduced support from neighboring regions further contribute to this risk. These results are also driven by the Maritimes' forecast load and corresponding reserve margin expectations. Additionally, the rate of increase of resources is expected to outpace the rate of increase in demand over the 2026-2030 period.

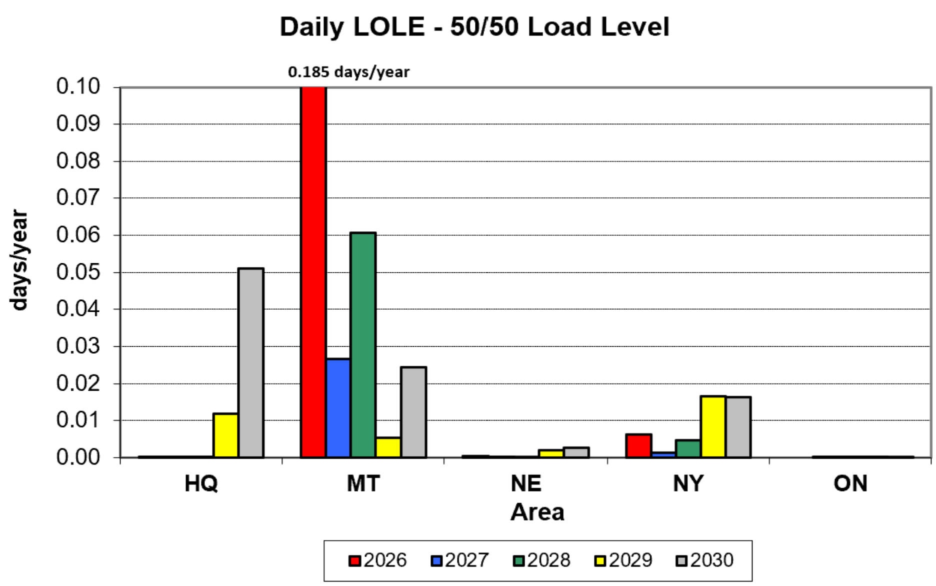

Figure 1(a) - 50/50 expected Load Level Annual NPCC Area LOLE (2026 – 2030)

[13] Maritime's 2026 LOLE value is estimated to be slightly above of 0.185 days/year.

The expected load level results represent the probability-weighted average of all seven load levels simulated.

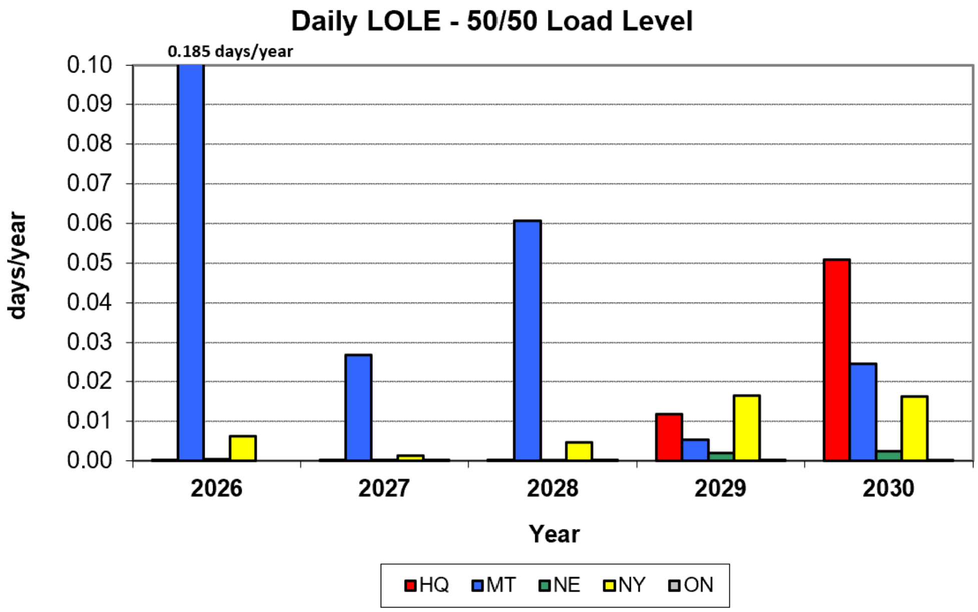

Figure 1(b) – 50/50 expected Load Level Annual NPCC Area LOLE (2026 – 2030)

Figures 1(c) and **1(d)** below show the estimated annual NPCC Areas and Neighboring Region's Loss of Load Expectation (LOLE) for the 2026-2030 period for the 50/50 expected load level.[14] Maritime's 2026 LOLE value is estimated to be slightly above NPCC LOLE criteria of 0.1 days/year. The 2025 NERC LTRA highlights Maritimes and Québec under elevated risk area indicating that the supply of electricity is insufficient and more firm resources are needed in years 2026-2027, and 2027-2028 winter for Maritimes, and years 2029-2030 and 2030-2031 winter for Québec. Maritimes margins and probabilistic results show that these risks decrease throughout the study as new generation gets built, and Québec is increasing demand response program targets to minimize peak demand.

[14] The 50/50 expected load level results were based on the probability-weighted average of all seven load levels simulated.

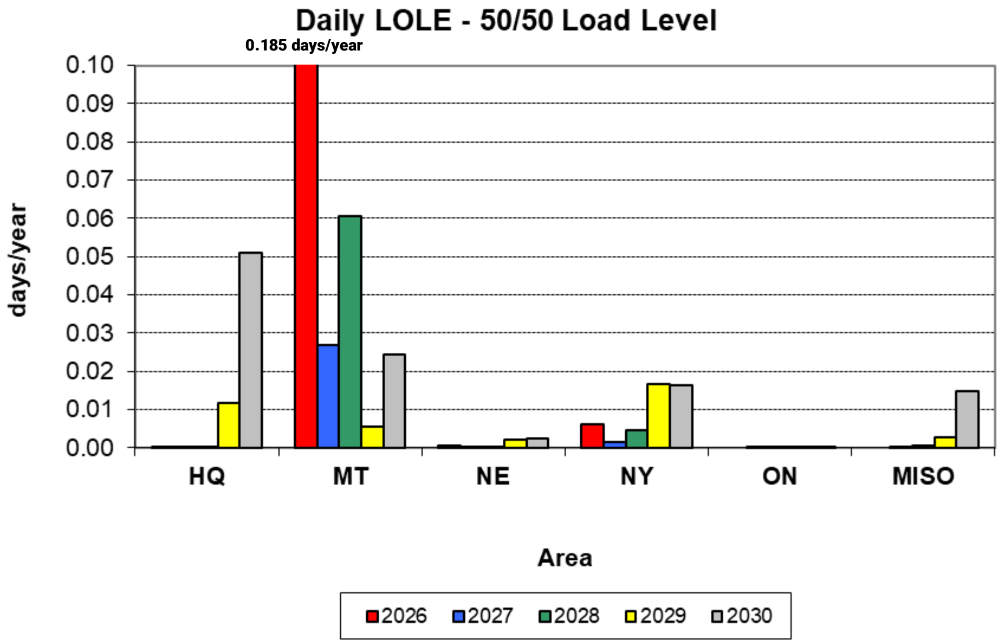

Figure 1(c) - 50/50 expected Load Level Annual NPCC Areas and Neighboring Regions LOLE (2026 – 2030)

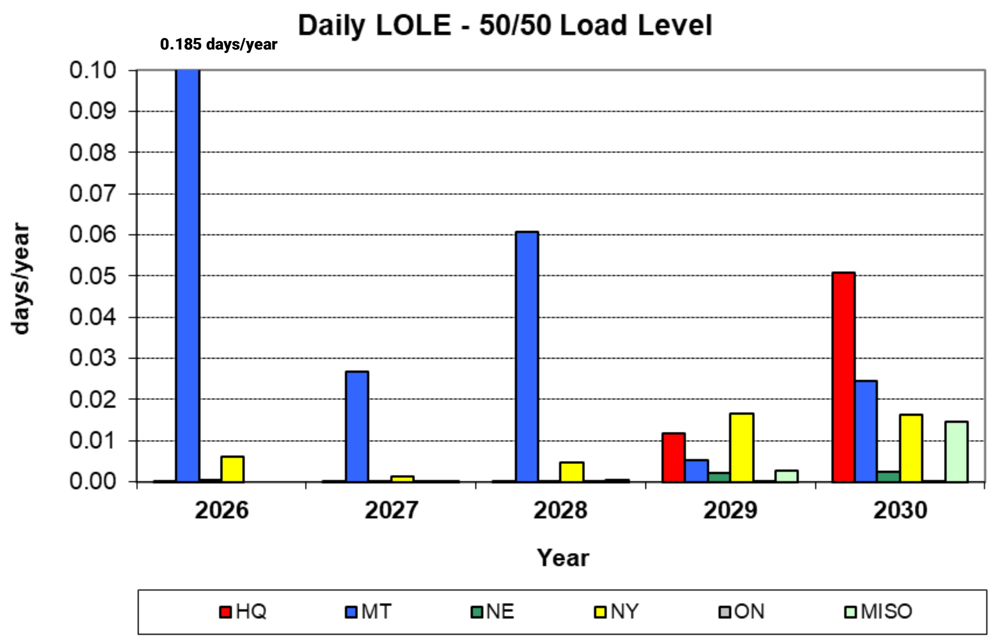

Figure 1: (d) – 50/50 expected Load Level Annual NPCC Areas and Neighboring Region's LOLE (2026 – 2030)

Figures 2(a) and **2(b)** below show the estimated annual NPCC Area Loss of Load Hours (LOLH), estimated the 2026-2030 period for the 50/50 expected load level.

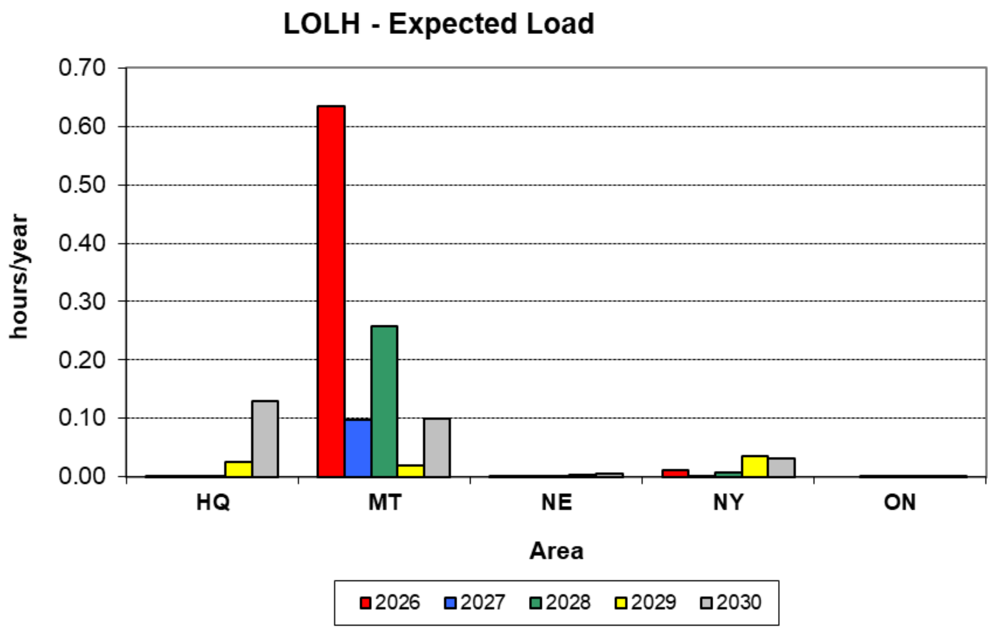

Figure 2(a) - 50/50 expected Load Level Annual NPCC Area LOLH (2026 – 2030)

The expected load level results represent the probability-weighted average of all seven load levels simulated.

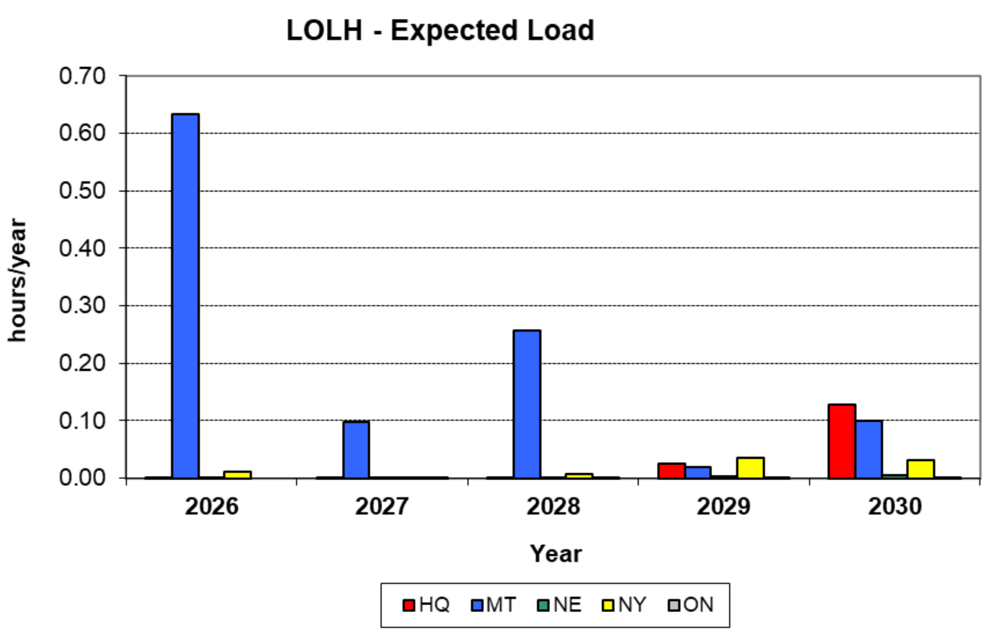

Figure 2(b) - 50/50 expected Load Level Annual NPCC Area LOLH (2026 – 2030)

The 50/50 expected load level results represent the probability-weighted average of all seven load levels simulated.

Figures 2(c) and **2(d)** show the estimated annual Loss of Load Hours (LOLH) for NPCC Areas and neighboring Regions for the 2026-2030 period for the 50/50 expected load level.

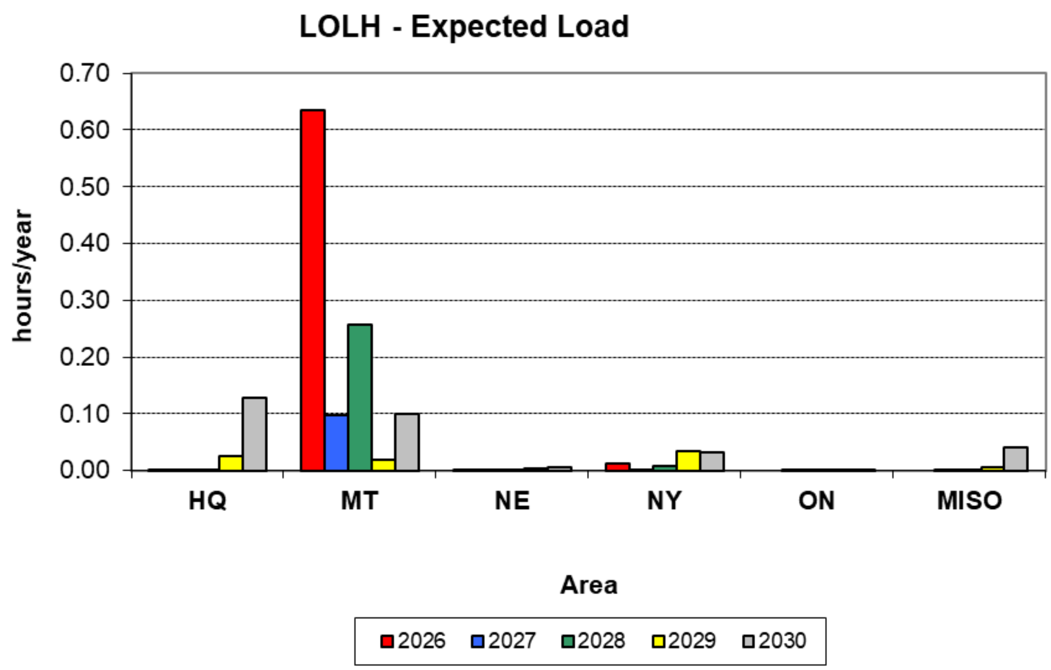

Figure 2(c) – 50/50 expected Load Level Annual LOLH for NPCC Areas and Neighboring Regions (2026 – 2030)

The 50/50 expected load level results represent the probability-weighted average of all seven load levels simulated.

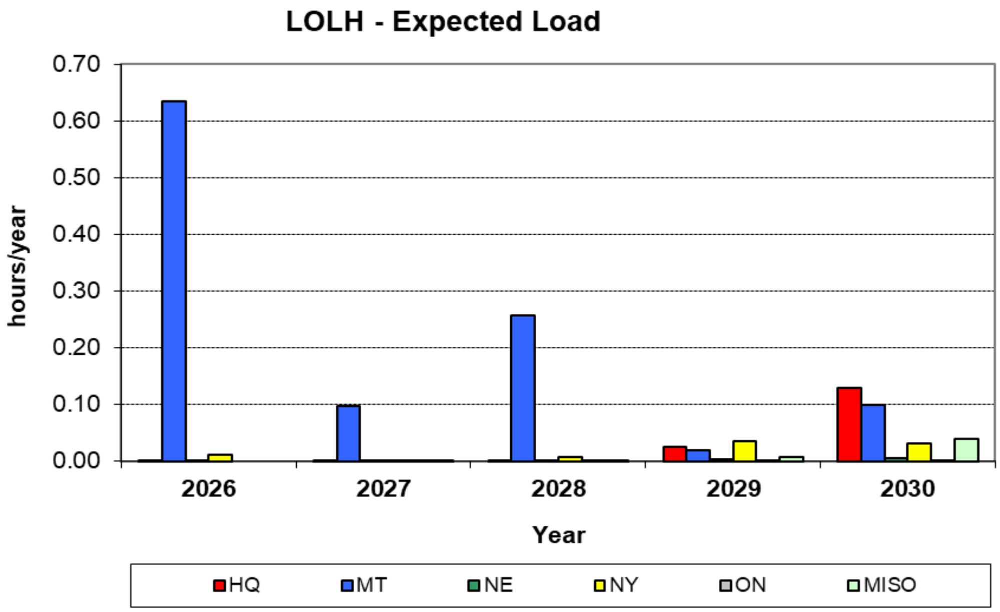

Figure 2(d) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2026 – 2030)

The 50/50 expected load level results represent the probability-weighted average of all seven load levels simulated.

Figures 3(a) and **3(b)** show the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2026-2030 period for the 50/50 expected load level.

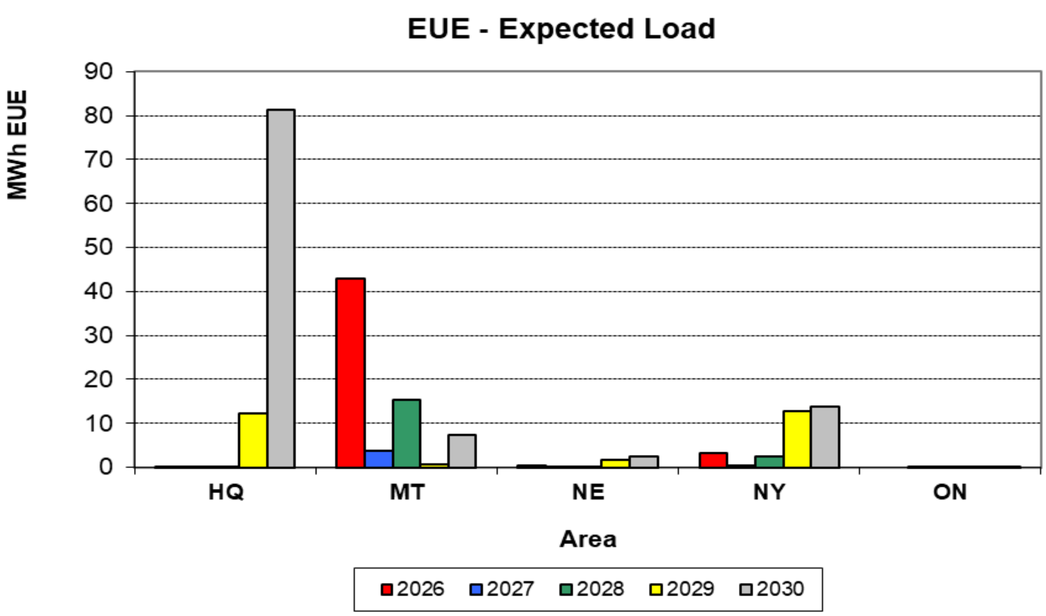

Figure 3(a) - 50/50 expected Load Level Annual NPCC Area EUE (2026 – 2030)

The 50/50 expected load level results represent the probability-weighted average of all seven load levels simulated.

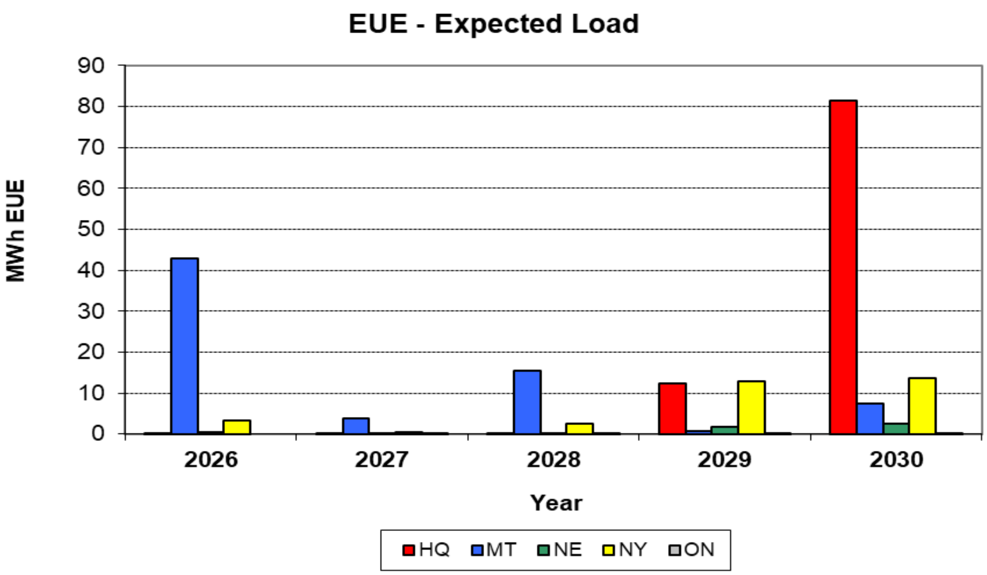

Figure 3(b) – 50/50 expected Load Level Annual NPCC Area EUE (2026 – 2030)

The 50/50 expected load level results represent the probability-weighted average of all seven load levels simulated.

Figures 3(c) and **3(d)** show the estimated annual EUE for NPCC and the neighboring Regions for the 2026-2030 period for the 50/50 expected load level.

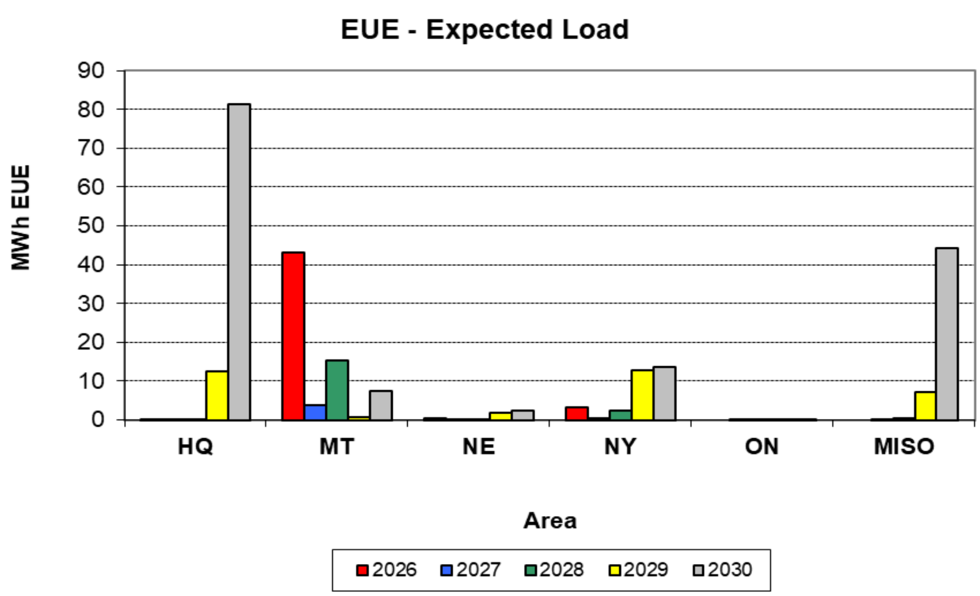

Figure 3(c) - 50/50 expected Load Level Annual EUE for NPCC Areas and Neighboring Regions (2026 – 2030)

The 50/50 expected load level results represent the probability-weighted average of all seven load levels simulated.

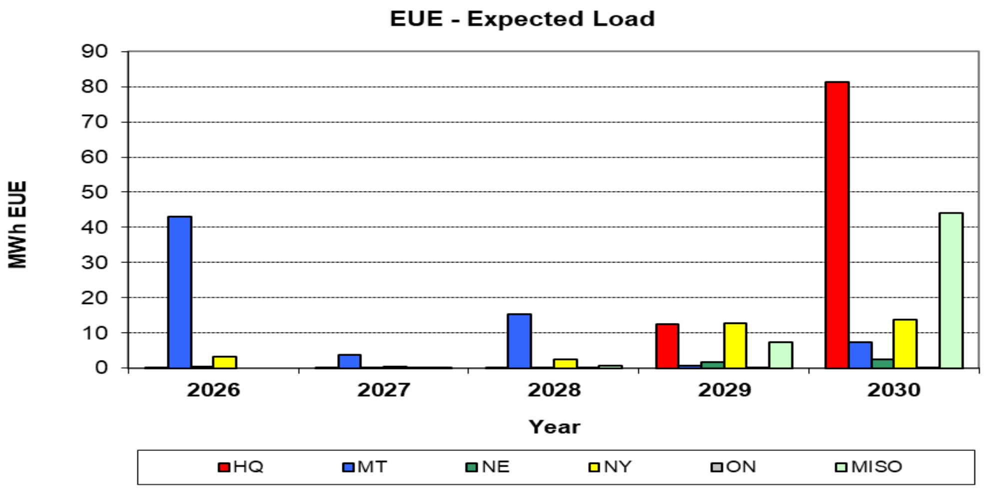

Figure 3(d) - 50/50 expected Load Level Annual EUE for NPCC Areas and Neighboring Regions (2026 – 2030)

The 50/50 expected load level results represent the probability-weighted average of all seven load levels simulated.

Observations

Figures 4(a) and **4(b)** summarize the estimated annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments under Base Case assumptions for the 50/50 expected load level.

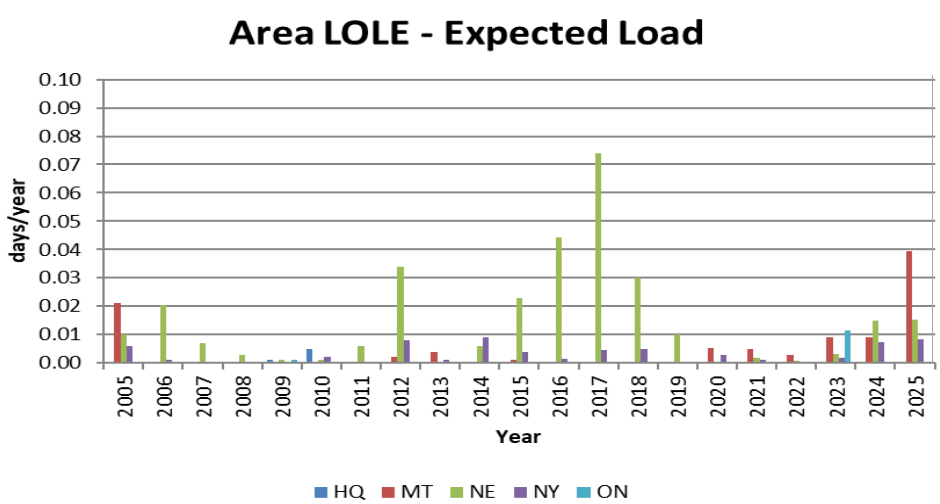

Figure 4(a) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

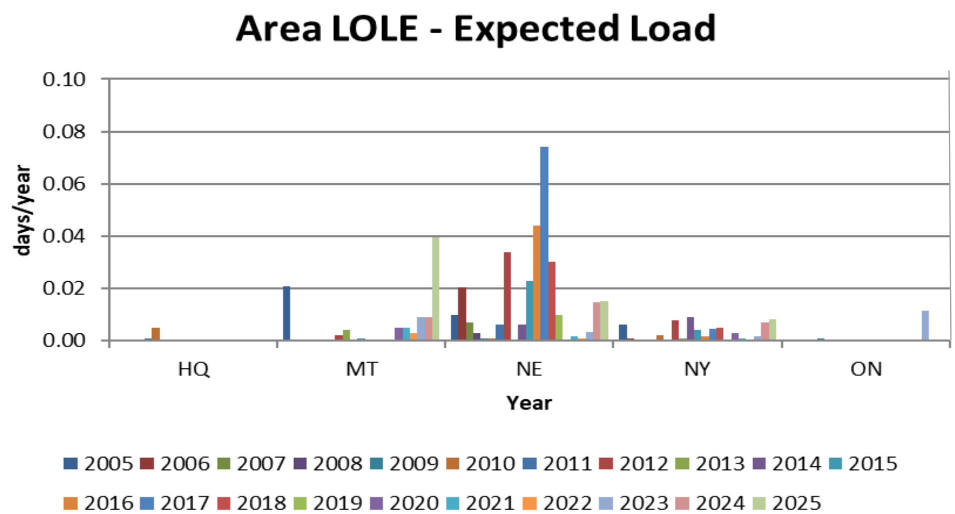

Figure 4(b) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

This retrospective summary illustrates the NPCC Areas have generally demonstrated, on average, an annual LOLE significantly less than 0.1 days/year.

Figures 5(a) and **5(b)** adds the estimated annual NPCC Area Loss of Load Expectation (LOLE) estimated for 2026 – 2030 for the 50/50 expected load level.

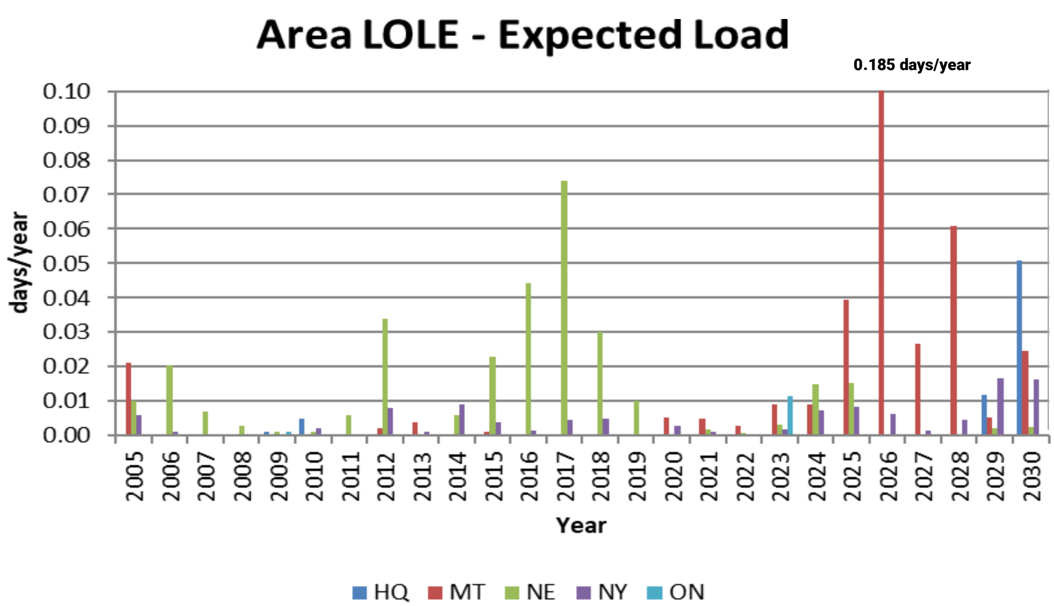

Figure 5(a) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

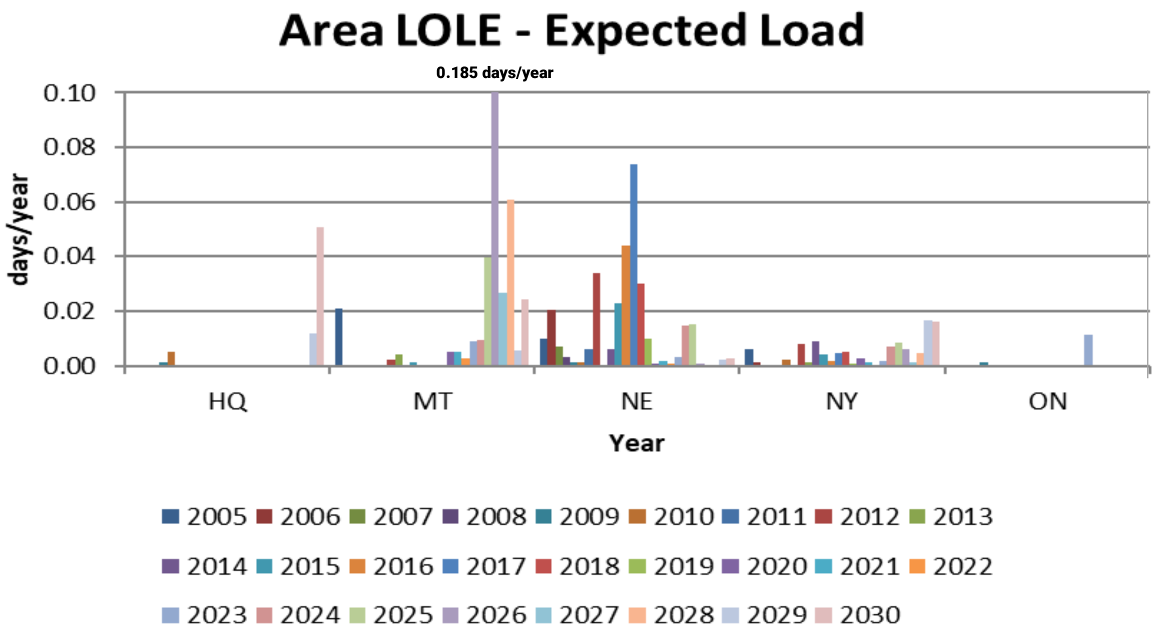

Figure 5(b) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

2025 NERC Probabilistic Assessment – NPCC Region Summary

Per NERC Reliability Assessment Subcommittee (RAS) request, the NPCC region supported the 2025 Probabilistic Assessment, which was based on the NPCC 2025 *Long Range Adequacy Overview* and utilized data from the NERC 2025 *Long-Term Reliability Assessment*[2] (LTRA). The NPCC region provided probability-based simulations which measure potential load loss events by analyzing projected demand and resource availability, highlighting high-risk periods and energy constraints through metrics such as Loss-of-Load Hours (LOLH) and Expected Unserved Energy (EUE) as requested by NERC to describe shortfalls for the NPCC Areas for the years 2027 and 2029.

The primary focus of the 2025 NERC *Probabilistic Assessment* (ProbA) was to analyze the factors behind the annual and monthly Expected Unserved Energy (EUE) and the estimated Loss-of-Load Hours (LOLH). By examining shortfall events through hourly results, the ProbA aimed to offer insights into the size, duration, frequency, clustering, and spacing of these events. The objective was to use quantitative data to support a qualitative analysis, enhancing the understanding of the uncertainty and variability in the drivers of these events.

The estimated Expected Unserved Energy (EUE) and the estimated Loss-of-Load Hours (LOLH) shown in **Table 1(a-e)** are based on the results of NPCC's 2025 *Long-Range Adequacy Overview*, with assumptions consistent with those used for NPCC in the NERC 2025 *Long-Term Reliability Assessment*.[2] The two years reported in this assessment are the years 2027 and 2029.

In **Tables 1(a-e)**, the Forecast Capacity Resources shown equal to the total installed capacity, minus capacity derates, plus net firm transactions. The 2025 ProbA hourly supply and demand risk visualization, which demonstrate a day with the most significant loss of load conditions, are shown in **Appendix D**. The detailed results of LOLH and EUE, including a breakdown of the estimated usage of operating procedures from the 2025 NPCC *Long Range Adequacy Overview* are presented in **Appendix E**. Definitions used in the calculations are shown in **Appendix F**. Detailed monthly results are shown in **Appendix H**.

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast[15] Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2027	157,220	32,280	38,958	0.466	0.002	24.5%
2029	160,370	32,620	39,110	12.478	0.035	23.6%

Table 1(a) - Annual Peak Demand and Capacity Resources – New York

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast[15] Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2027	118,591	24,945	29,999	0.07	0.000	22.9%
2029	120,659	25,347	30,986	1.79	0.004	24.9%

Table 1(b) - Annual Peak Demand and Capacity Resources – New England[16]

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast[15] Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2027	157,541	25,587	27,830	0.001	0.000	20.1%
2029	175,908	26,546	29,130	0.066	0.000	16.5%

Table 1(c) - Annual Peak Demand and Capacity Resources - Ontario[17]

15 Forecast Capacity Resources includes Capacity Expected on Peak + Net Firm Import/Exports - Capacity Adjustments.
16 The Total Internal Demand reported is higher than reported in the NERC LTRA due to the treatment of passive demand response; in order to provide a proper comparison with the NERC LTRA, the data in **Appendix B** was adjusted to report the load demand response the same way as reported in the LTRA.
17 The same resources are used as in the LTRA; the capacity reported for nuclear generation is not reduced for long-term refurbishment outages but instead is captured as a scheduled unavailability in the model.

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast[15] Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2027	203,561	41,901	42,797	0.01	0.000	16.7%
2029	214,718	43,635	43,163	62.99	0.106	13.0%

Table 1(d) - Annual Peak Demand and Capacity Resources – Québec (Winter)

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast[15] Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh)	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2027	29,102	6,157	6,959	15.21	0.247	18.5%
2029	29,404	6,231	7,306	7.31	0.100	23.0

Table 1(e) - Annual Peak Demand and Capacity Resources – Maritimes (winter)

Table 2 (below) shows the percentage difference between the amount of annual energy estimated by the GE MARS program for the study period (2026-2030) and the amount reported in the NERC 2025 *Long Term Reliability Assessment*[2]. This is primarily due to the differences in the NPCC Area assumptions used for their respective energy forecasts. The GE MARS program calculation for the total estimated NPCC annual energy is within approximately 1 to 1.5% of the corresponding sum of the NPCC Areas annual energy forecasts.

Year	2026	2027	2028	2029	2030
Québec					
MARS	198,573	202,106	207,095	212,661	218,795
2025 LTRA	200,038	203,561	208,526	214,718	219,789
MARS - LTRA	-1,465	-1,455	-1,431	-2,057	-994
%(MARS-LTRA)/LTRA	-0.73%	-0.71%	-0.69%	-0.96%	-0.45%
Maritimes					
MARS	30,157	30,191	30,505	30,297	30,578
2025 LTRA	29,186	29,102	29,295	29,404	29,615
MARS - LTRA	971	1,089	1,210	893	963
%(MARS-LTRA)/LTRA	3.33%	3.74%	4.13%	3.04%	3.25%
New England					
MARS	115,886	117,221	119,458	121,498	123,167
2025 LTRA	117,828	118,591	119,559	120,659	122,044
MARS - LTRA	-1,942	-1,370	-101	839	1,123
%(MARS-LTRA)/LTRA	-1.65%	-1.16%	-0.08%	0.70%	0.92%
New York					
MARS	153,659	154,967	156,647	158,749	161,676
2025 LTRA	155,460	157,220	158,700	160,370	163,200
MARS - LTRA	-1,801	-2,253	-2,053	-1,621	-1,524
%(MARS-LTRA)/LTRA	-1.16%	-1.43%	-1.29%	-1.01%	-0.93%
Ontario					
MARS	148,156	153,034	160,679	167,144	172,235
2025 LTRA	150,198	157,541	166,945	175,908	183,152
MARS - LTRA	-2,042	-4,507	-6,266	-8,764	-10,917
%(MARS-LTRA)/LTRA	-1.36%	-2.86%	-3.75%	-4.98%	-5.96%

Year	2026	2027	2028	2029	2030
NPCC					
MARS	646,431	657,519	674,384	690,349	706,451
2025 LTRA	652,710	666,015	683,025	701,059	717,800
MARS - LTRA	-6,279	-8,496	-8,641	-10,710	-11,349
%(MARS-LTRA)/LTRA	-0.96%	-1.28%	-1.27%	-1.53%	-1.58%

Table 2 – Comparison of Energies Modeled (Annual GWh)

Appendix A: Objective and Scope of Work

2025 NPCC GE MARS Multi-Area Probabilistic Planning Database

1. Objective

Using input from each Area, NPCC and its consultant will develop a planning 5-year ahead (2026 – 2030 assessment period) General Electric (GE) Multi-Area Reliability Simulation (MARS) Database, in order to facilitate NPCC Area Resource Adequacy studies and the related NERC Reliability Assessment Subcommittee probabilistic analysis. To the extent possible, a detailed reliability representation for regions bordering NPCC for the defined assessment period will be modeled.

The resultant GE MARS model will reflect NPCC Area(s) and neighboring regional proposed plans and the applicable demand forecast(s) to meet their respective resource adequacy planning criteria, including the potential impacts of Area(s) recommended clean energy initiatives.

2. Scope

The CP-8 Working Group's GE MARS database will be used to develop a planning model suitable for the years 2026 – 2030, consistent with the NPCC Area and neighboring regional data reported in the 2025 NERC *Long-Term Reliability Assessment*[2] (LTRA), recognizing:

- uncertainty in forecasted demand,
- scheduled outages of transmission,
- forced and scheduled outages of generation facilities, including fuel supply disruptions,
- the impacts of sub-Area transmission constraints,
- the impacts of proposed retirements and resource additions,
- the impacts of proposed load response programs; and,
- as appropriate, the reliability impacts that the existing and anticipated market rules may have on the assumptions, including the input data.

3. Schedule

Completion of the 2025 NPCC Long-Range Adequacy Overview Database follows finalization of the reported 2025 NERC *Long-Term Reliability Assessment*[2] data, expected by July 30, 2025.

2025 NPCC Long Range Adequacy Overview (LRAO)

1. Objective

Utilize the GE MARS program and the 2025 NPCC *Long Range Adequacy Overview* (LRAO), incorporating the 2025 NPCC GE MARS Planning Database, to estimate the annual Loss of Load Hours and Expected Unserved Energy for NPCC Areas. Ensure alignment with expected reliability metrics supporting the NERC Reliability and Security Technical Committee's 2025 and ERO Enterprise probabilistic analysis requirements, as well as the NERC 2025 *Long-Term Reliability Assessment*[2] probabilistic analysis requirements for the years 2026–2030.

2. Scope

Review the NPCC 2024 NERC *Probabilistic Assessment* (ProbA) Base Case results (for the years 2026 and 2028) and assess the validity in relation to the NPCC 2025 *Long-Range Adequacy Overview* results, reviewing underlying assumptions, methodology, and data inputs used in the 2024 ProbA to assess its validity in forecasting reliability risks and resource adequacy in the 2025 NERC *Long-Term Reliability Assessment*[2] (LTRA). In addition to the base case scenario for the 2025 LRAO NPCC will consider including a severe case scenario analysis per Area's specific consideration based on the NPCC Corporate Goal recommendations into the 2025 NPCC LRAO.

3. Schedule

A report summarizing the assumptions and consolidating the results of the NPCC 2025 LRAO reliability metrics, along with providing illustrative loss-of-load datasets to support the requested input for the 2025 NERC ProbA—specific to the NPCC Region assessment—will be developed. This report is expected to be approved by the NPCC Task Force on Coordination of Planning at their November meeting and by the Reliability Coordinating Committee (RCC) no later than December 2025.

Appendix B: Modeling Assumptions and Areas' Studies Summaries

Modeling Assumptions

The assumptions used in the NPCC 2025 *Long Range Adequacy Overview* are consistent with the data reported in NERC 2025 *Long-Term Reliability Assessment*[2] and have as an input the following recently completed Area studies:

Area Studies Summary

New York

The New York assumptions used in this overview are consistent with the date reported in the 2025 *Load and Capacity Report* ("Gold Book")[10] the 2025 *Reliability Planning Processes including* the *Short-Term Assessments of Reliability* (STAR)[18], and the comprehensive Reliability Plan (CRP)[19] The current cycle of the NYISO's Reliability Planning Process, in conjunction with the Short-Term Reliability Process, plans for the 10-year horizon out to 2034. The key generation additions and removals, net imports, as well as the large loads assumptions are in **Table 3** below.

Year (1)	Additions (2)	Removals (3)	Summer Peak			Winter Peak		
			Net Imports	Baseline Coincident Peak	Large Loads Demand (4)	Net Imports	Baseline Coincident Peak	Large Loads Demand (4)
2026	225	828	3,094	31,990	1,023	735	24,920	1,095
2027	3,120	928	3,094	32,280	1,329	735	25,330	1,347
2028	4,424	928	3,094	32,410	1,500	735	25,850	1,567
2029	4,424	928	3,094	32,620	1,718	735	26,410	1,822
2030	4,424	928	3,094	32,910	2,005	735	27,080	2,106

Notes:
1. For Winter Peak, represents the winter beginning with the listed year (e.g. Winter 2027 is Winter 2027-28).
2. Represents running total of MW based on the Nameplate Rating for the first summer peak period following the addition.
3. Represents running total of MW based on the Summer Capability (DMNC) for the first summer peak period following the removal.
4. Large loads are included in the Baseline Coincident Peak load forecasts.

Table 3 - New York Load and Generation Additions

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[18] 2024 Q3 STAR Report, *available at* https://www.nyiso.com/documents/20142/16004172/2024-Q3-STAR-Report-final.pdf; 2023 Q2 STAR Report, *available at* https://www.nyiso.com/documents/20142/16004172/2023-Q2-STAR-Report-Final.pdf.
[19] NYISO's Reliability Planning Process Reports (RNA. CRP): https://www.nyiso.com/library#reports.

NYISO, in collaboration with its stakeholders, develops multiple demand forecast scenarios for the New York Control Area (NYCA) that are published in the most recent Gold Book.[10] All forecasts account for drivers, such as economic growth, energy efficiency, behind-the-meter load-reducing resources (e.g. solar, distributed generators), large loads, and electrification. The incremental impacts of additional policy-driven energy efficiency, and distributed generation are deducted from the forecast, and the incremental impacts of electric vehicle usage, building electrification, and large loads are added to the forecast. The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts. In developing seasonal peak forecasts, NYISO aggregates hourly load shapes (8,760 hours per year) for base load, load-modifying technologies, and end-uses on a zonal basis. For the MARS model, the NYISO models BTM solar as 5 years of hourly shapes.

The resource additions are primarily wind and solar and include two offshore wind projects—Sunrise Wind (estimated commercial operation date is 2027) and Empire Wind 1 (estimated commercial operation date is 2027)—consisting of 1,740 MW (nameplate).

The 2025 reliability planning model representation of the NYCA contains recent resource retirements and anticipated generation status change due to environmental policy.

The NYCA has several major transmission projects that have been placed in service or are currently under development. Such major transmission projects are largely related to achieving New York State's policy objectives. The 2025 RPP models include the AC Transmission projects—both of which entered service in 2024. Other transmission projects that are currently under development or construction, but not yet complete, include:

- Champlain Hudson Power Express (CHPE) (estimated in-service is 2026),
- Northern New York Priority Transmission Project (estimated in-service is 2025),
- Brooklyn Clean Energy Hub (estimated in-service is 2028),
- Eastern Queens Clean Energy Hub (estimated in-service is 2028), and
- Propel Alternate Solution 5 (estimated in-service is May 2030).

In addition to the modeling assumptions for the New York Area discussed above, starting with the 2024 RNA, the reliability planning models reflected several changes highlighted below (additional details in Appendix A of this report):

- Modified assumptions to account for winter uncertainties:
    - Dynamic LFU: on the demand side, increasing winter peak load forecast uncertainty (throughout the study years) was modeled to account for the impacts of heating electrification, EV charging, and large loads; and

- Winter gas unavailability: on the resources side, assumed the risk of gas unavailability mainly related with gas-only plants.

- New data sources: using 5 years of hourly MW model-based data developed by DNV-GL for land-based and offshore wind, and front-of-the- meter solar.
- Further limiting external reliance: the top 5 (changed from 3 starting 2024 RNA as an additional method to further limit reliance) summer and winter peak load days of an external Control Area are modeled as coincident with the NYCA top five peak load days.
- SCR model: modeled as duration-limited resources with units being constrained to be called once in a day when a loss of load event occurs.
- Large loads: certain proposed large loads were assumed flexible and will decrease demand on peak days, as shown in the Gold Book[10] Table I-14. This was modeled in MARS as an EOP step before the SCR step.

Additionally, starting with the 2025 reliability planning models, the NYISO assumed:

- 10 years of cable outage data (rather than five years of data), and
- Reduced the Québec to Chateaugay emergency assistance import limit in winter to zero for a more conservative assumption.

The 2024 RNA contains assumptions for the growing uncertainty in forecasted demand for winter to account for electrification and the flexibility of approximately 1,200 MW of cryptocurrency mining and hydrogen producing large loads during peak conditions. The 2024 RNA found that the planned New York grid will meet the statewide resource adequacy criterion throughout the ten-year horizon for the base case assumptions. Although a violation is not identified, the loss of load expectation approaches the 0.1 event-days per year criterion in study in 2034, indicating that no surplus power would remain in ten years without further resource development.

The RNA and the draft 2025-2034 *Comprehensive Reliability Plan* (CRP)[20] (targets completion November 2025) perform variations of assumptions to gauge plausible, which inform potential solutions and assess risks to the bulk electric grid. The scenarios fall primarily into two groups.

- Scenarios that result in additional margin to avoid potential resource adequacy and transmission security violations include added new resources to systems; differences

[20] October 16, 2025 Draft 2025-2034 Comprehensive Reliability Plan "CRP": https://www.nyiso.com/documents/20142/54426374/11b_Draft_2025-2034-Comprehensive-Reliability-Plan_OC.pdf.

in the assumptions for firm gas during winter; and effects in demand response programs.

- Scenarios to inform system risks that can result in significant statewide resource adequacy deficiencies include differences in the assumptions for large load flexibility; the effect of a higher demand forecast; the unavailability CHPE; and additional retirement of New York's fossil fuel-fired capacity.

The 2024 RNA,[21] CRP, and the 2025 Q3 STAR[22] findings are impacted by significant uncertainties associated with future demand growth and changing supply mix that will be continuously reviewed through NYISO's quarterly short-term assessments and biennial long-term assessments.

While the NYCA LOLE is below its 0.1 event-days/year for the 5-year study period, the 2025 Q3 STAR identified transmission security reliability needs (additional details in the report from the link above).

Also, below is an excerpt from October 16, 2025, draft CRP report:

> While this 2025–2034 *Comprehensive Reliability Plan* (CRP)[20], under current applicable reliability criteria and procedures, identifies no actionable Reliability Needs, this outcome should not be mistaken for long-term system adequacy. The margin for error is extremely narrow, and most plausible futures point to significant reliability shortfalls within the next ten years. Depending on demand growth and retirement patterns, the system may need several thousand megawatts of new dispatchable generation over that timeframe.
>
> The grid is at an inflection point, driven by the convergence of three structural trends: the aging of the existing generation fleet, the rapid growth of large loads, and the increasing difficulty of developing new dispatchable resources.
>
> The CRP shows that key factors that affect the New York transmission system, either by itself or combined with others, will have consequential impacts to reliability that current planning methods do not fully capture. Today's approach assumes a single expected future, but the analysis shows that this is no longer sufficient. NYISO must evolve its methodology so that Reliability Needs are identified earlier and more accurately under a broader range of conditions, enabling timely solutions that the NYISO needs to be able to plan for through the identification of solutions.

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[21] See: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf.

[22] 2025 Q3 STAR final Report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf.

NYISO recommends adopting scenario planning concepts into formal procedures for determining actionable Reliability Needs.

New England

The New England assumptions used in this overview are consistent with the data reported in the *NERC 2025 LTRA*[2] the *2025-2034 Forecast Report of Capacity, Energy, Loads and Transmission* (2025 CELT)[23] data and the NPCC 2025 *New England Interim Review of Resource Adequacy*.[24]

ISO-New England (ISO-NE) develops an independent demand forecast for its Balancing Authority (BA) Area by using historical hourly demand data from individual member utilities. This data is used to develop the regional hourly peak demand and energy forecasts. ISO-NE then develops a forecast of both state and system hourly peak and energy demands. The regional peak and state demand forecasts are considered coincident. This peak demand forecast is the gross peak demand forecast, which is then decreased to a net peak demand forecast by subtracting the impacts resulting from conservation/energy efficiency (EE) measures and behind-the-meter photovoltaics (BTM PV). ISO-NE is a summer-peaking, electrical bulk power system (BPS). ISO-NE's 50/50 reference demand forecast is based on the reference economic forecast, which reflects the economic conditions that are expected to occur within New England.

Over the assessment period 2026 through 2030, the 50/50 New England net summer peak demand (gross peak demand minus behind-the-meter photovoltaic (BTM PV) resources) is expected to increase from 24,877 MW for the summer of 2026 to 25,557 MW by the summer of 2030. The 680 MW increase in net peak demand represents a 2.73% growth during the 5-year period.

The annual New England net energy for load[25] is expected to increase from 117,829 GWh in 2025 to 122,044 GWh by 2030. The 4,215 GWh increase in net energy for load represents 3.58% in energy growth during the same 5-year study period.

In 2020, ISO-NE included its first electrification forecast within its load forecast. The new electrification forecast reflects the added electricity demand associated with heat pumps (within the residential and commercial space heating sector) and electric vehicles (EVs) (within the transportation sector). Heat pumps are projected to add only a minimal amount of demand to the New England summer peak loads, amounting to 25 MW in 2029, since they are primarily designed for winter operation. ISO-NE's future EV summer demand is forecast

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[23] See: 2025_celt_report.xlsx.
[24] See: *NPCC 2025 New England Interim Review of Resource Adequacy*.
[25] New England annual net energy for load accounted for load reduction from BTM PV and energy efficiency.

to be 66 MW on peak with 224 GWh of energy in 2025, and 244 MW on peak and 2,499 GWh of energy in 2029.

On June 1, 2018, ISO-New England integrated price-responsive Demand Response (DR) into the energy and reserve markets. In 2026, approximately 623 MW of DR participates in these markets and is dispatchable (i.e., treated like generators). Regional DR will decrease to 544 MW by 2030, and this value is assumed constant/available through the remainder of the assessment period.

Resource additions from July 2024 through June 2025 consisted mainly of approximately 183 MW of wind, 192 MW of battery resources, and 362 MW nameplate of solar capacity. Total Tier 1 nameplate capacity additions by mid-2026 amount to approximately 1,800 MW. Those additions consist of primarily PV, wind, and battery resources, amounting to 270 MW, 1,005 MW, and 470 MW, respectively. Tier 2 nameplate capacity additions scheduled for operation by 2026 include 118 MW of solar generation, a 258 MW hybrid solar and battery project, 674 MW of battery storage projects, and 827 MW of offshore wind.

Existing certain capacity for 2025 totals 27,351 MW. New England currently (summer 2025) has 160 MW (1,615 MW nameplate) of wind generation and 1,736 MW (4,716 MW nameplate) of BTM PV. As of October 17, 2025, approximately 6,000 MW (nameplate) of wind generation projects have requested generation interconnection studies. The BTM PV peak load reduction values are calculated as a percentage of AC nameplate. The percentages include the effect of diminishing PV production at the time of the system peak as increasing PV penetrations shift the timing of the summer peaks to later in the day.

No resource retirements (>25 MW) are anticipated through June 2026.

New England is interconnected with the three Balancing Areas (BAs) of Québec, the Maritimes, and New York. ISO-NE considers the transmission transfer capability between these BAs to ensure that their limits are accounted for in regional resource adequacy assessments. ISO-NE's Forward Capacity Market (FCM) methodology limits the purchase of import capacity based on these interconnection transfer limits. ISO-NE's capacity net imports are assumed to range from 567 MW in 2026, decreasing to 465 MW in 2027 and 84 MW in 2028 through 2030. An additional 1,090 MW are expected imports in 2026 through 2030.

The region has constructed several major reliability-based transmission projects within the past few years to strengthen the regional BPS. While a few major projects are nearing completion, few significant projects remain under construction. The table below (**Table 4**) highlights these transmission projects.[26]

	PPA	TCA	Construction
Southeast MA/RI Reliability (SEMA/RI)	Approved 5/2017, 4/2018	Submitted	2018 - 2027
Greater Boston – North, South, Central and Western Suburbs	Approved 4/2015, 5/2015, 6/2016, 7/2019, 10/2020	Submitted	2010 - 2025
New Hampshire (NH) 2029 Solutions	Approved 1/2022, 6/2022	7/16/2024	2023 - 2025
Upper Maine (UME) 2029 Solutions	Approved 2/2022 (Versant Power) Approved 5/2022, 8/2023 (Avangrid)	Submitted (Versant power) Not Submitted (Avangrid)	2024 - 2028
Boston 2033 Solutions	Not Approved	Not Submitted	2026 - 2028

Table 4: New England Transmission Projects

Ontario

The Ontario assumptions used in this study are consistent with the data reported in the NERC 2025 *Long-Term Reliability Assessment*.[2]

Demand is driven by newly announced industrial EV production and supply chain projects and project pipelines; strong interest from new commercial artificial intelligence service-providing data centers; incremental decarbonization/electrification projects across the economy; and higher population growth and household formation. In the near term, significant electricity demand growth is forecasted in industrial mineral extraction and processing, primary metals (by way of steel production electrification), and chemical production (by way of battery materials processing and hydrogen production) sub-sectors.

The IESO identifies reliability needs through our planning studies, which then determine the set of planned actions to address needs, using the mechanisms in the Resource Adequacy Framework (RAF), and regional and bulk transmission system plans. The increase in supply observed in the 2025 LRAO is primarily due to assumption of resources operating until end of technical life, while they were previously assumed to be unavailable beyond their contract

[26] As taken from ISO-NE's Final RSP Project List – Planning Advisory Committee (PAC) Presentation, dated June 20, 2025. Located on the ISO-NE web site at: https://www.iso-ne.com/static-assets/documents/100013/final_project_list_presentation_june_2025.pdf.

expiry in the 2024 LRAO. The RAF provides the IESO with the ability to reacquire existing resources that are reaching end of contract. It is important to differentiate between a resource that comes off-contract and a resource that has (or is expected to) reached end of life or officially retire. Existing resources in Ontario can be re-contracted, and this is evidenced by the successful results of procurements such as the Medium Term-2 procurements. A contract expiry or unsuccessful participation in the Medium-Term procurement does not indicate or imply that a resource would cease operations. These resources can still participate in the Capacity Auction or as a merchant generator. Further, this methodology aligns Ontario with methodologies performed by other regions.

The IESO continues to actively procure existing and new resources to meet longer-term needs, using the mechanisms in the Resource Adequacy Framework.

The IESO calculates the reserve margin requirement on an annual basis and publishes this in the Annual Planning Outlook (APO). The requirement is calculated for each year for net demand at the time of the annual demand peak to provide a LOLE that is at or below 0.1 days per year. The Resource Adequacy Framework translates planning and operational information, such as the forecasts outlined in the APO and bulk and regional plans, into a series of procurement and market activities designed to meet the needs identified.

The 2023 Capacity Sharing Agreement between the IESO and Hydro-Québec permits for the swap of 600 MW of capacity over a period of up to seven years, starting in winter 2024/2025. Under the agreement, the IESO will provide 600 MW to Hydro-Québec in the winter, and Hydro-Québec will provide 600 MW to the IESO in the summer. The IESO may choose to bank any amount of the 600 MW of summer capacity provided in a given year, to be used in a later summer during the agreement (up to the limit of the main intertie with Québec), allowing capacity to be saved until it is required.

Transmission projects that are expected to come into service within the outlook period are included in the IESO's system plans, as these projects are sufficiently far along in their planning and development to be considered committed projects for the purpose of long-term system planning. The description and status of planned bulk transmission projects are provided in detail in the Annual Planning Outlook[27] published by the IESO.

Québec

The Québec Area assumptions used in this study are consistent with the data reported in the NERC 2025 *Long-Term Reliability Assessment.*[2]

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[27] See: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/2025/2025-Annual-Planning-Outlook.pdf.

Demand requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by applying load factors to each end-use and/or sector sale. The sum of these monthly end-use sector peak demands is the total monthly peak demand. EE and conservation programs are integrated in the demand forecasts.

The Québec Area has various types of DR resources specifically designed for peak shaving during winter operating periods. The first type of DR resource is the interruptible load program that is mainly designed for large industrial customers; it has an impact of 2598 MW on winter 2025-2026 peak demand. The area is also expanding its existing interruptible load program for commercial buildings which will grow from 930 MW in 2025-2026 to 953 MW in 2029-2030. Dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 608 MW for winter 2025-2026, increasing to 1,047 MW for winter 2029-2030.

Additionally, data centers focusing on blockchain applications are required to decrease their electricity usage during peak hours as requested by Hydro-Québec. Their projected contribution is approximately 290 MW for winter 2025-2026, with this level expected to remain steady throughout the study period. A new rate structure for greenhouse growers and other businesses also involves demand reduction during peak periods, with an anticipated contribution of 262 MW for winter 2025-2026. Furthermore, a voltage reduction scheme enables a peak demand reduction of 250 MW. Energy efficiency and conservation programs are incorporated into the assessment area's demand forecasts.

Four wind projects with a total installed capacity of 4,000 MW are expected to be commissioned during the assessment period. The first project, Apuiat (204 MW), is expected to be commissioned for winter 2025-2026. The second project is the 2021 call for tenders for a total of 1,144 MW divided into 6 wind farms and is expected to be commissioned starting in winter 2026-2027. The third project is Des Neiges (1,200 MW) and is divided into three phases. The first phase (400 MW) is expected to be operational in the winter of 2026-27. The second and third phases, with the same capacity (400 MW each), are expected to be in service for the 2027-28 and 2028-29 winters, respectively. The fourth project is the 2023 call for tenders for a total of 1,550 MW divided into 8 wind farms, which are expected to be operational in the winters of 2027-28, 2028-29 and 2029-30 depending on the location.

Also, a 600 MW of firm import capacity from Ontario will be added to the resources. For this purpose, the governments of Québec and Ontario have already signed a Memorandum of Understanding (MOU).[28] This agreement will allow Hydro-Québec to import 600 MW of firm

[28] See: The Governments of Ontario and Québec Support New Electricity Trade Agreement | Ontario Newsroom.

capacity during the winter periods from 2025-2026 to 2030-2031 except for the winter 2026-2027 and to export 600 MW of firm capacity to Ontario during summer peak period.

Appalaches-Maine Interconnection (NECEC)

This project to increase transfer capability between Québec and Maine by 1,200 MW has resumed construction. The project will be connected to the New England Clean Energy Connect project (NECEC) in Maine. It involves the construction of a ±320-kV DC transmission line about 100 km (62 miles) long from Des Appalaches 735/230-kV substation to the Canada – U.S.A. border. From the international border crossing, the DC transmission line will be extended 145 miles to a substation in Lewiston, ME, where the power will be converted from DC to AC. The project in Québec also includes the construction of an AC to DC converter at Des Appalaches substation and triggers the need of thermally upgrading two 735 kV lines in the south of the system. The project is expected to be in service in December 2025.

Hertel-New York Interconnection (CHPE)

This project to increase transfer capability between Québec and New York by 1,250 MW is currently under construction. It involves the construction of a ±400-kV DC underground transmission line about 60 km (37 miles) long from Hertel 735/315-kV substation just south of Montréal to the Canada – U.S.A. border. The project will connect to the Champlain Hudson Power Express project (CHPE) in New York State. From the international border crossing, the DC transmission line will be extended 339 miles to a substation in Astoria, NY, where the power will be converted from DC to AC. The project in Québec also includes the construction of an AC to DC converter at Hertel substation. The project is expected to be in service in May 2026.

Maritimes

The Maritimes Area is a winter peaking area with separate markets and regulators in New Brunswick (NB), Nova Scotia, Prince Edward Island (PEI), and Northern Maine. NB Power is the Reliability Coordinator for the Maritimes Area with its system operator functions performed by its Transmission and System Operator division under a regulator approved Standards of Conduct.

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes Area. The peak Area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of New Brunswick and Nova Scotia which are historically highly coincidental. Demand for the Maritimes Area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period. The Maritimes Area peak loads are expected to increase by 8.6% during summer and by 10.0% during winter seasons over the

10-year assessment period. The Maritimes Area annual energy forecasts are expected to increase by a total of 6.6% during the 10-year assessment period.

Plans to develop up to 100 MW by 2030/2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway. During the 10-year LTRA assessment period in the Maritimes Area, annual amounts for summer peak demand reductions associated with Energy Efficiency and Conservation programs rise from 21 MW to 147 MW while the annual amounts for winter peak demand reductions rise from 177 MW to 652 MW.[29]

The Distributed Energy Resources (DER) installed capacity in NS is approximately 245 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar.

LTRA wind capacity for New Brunswick, Nova Scotia and Prince Edward Island is de-rated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding Northern Maine which uses seasonal capacity factors. In NS, an ELCC of 18% is applied to existing installed wind on the system; incremental new wind assumes a declining marginal ELCC from 10% to 6% depending on the cumulative installed wind capacity. Behind The Meter (BTM) solar is assumed to have an ELCC of 0% during winter period. The Maritimes Area has shown embedded BTM solar PV projections of 197 MW in summer 2025 rising to 1,230 MW by summer 2035. These projects include distributed small-scale solar (mainly rooftops) that fall under the net metering program and serve as a reduction in load mainly in the residential class. There is no capacity contribution from solar generation due to the timing of area's system peak which occurs either before sunrise or after sunset in the winter period.

An anticipated replacement PPA contract, a long-term firm energy contract from neighboring jurisdiction and opportunities to buy in day ahead and real time markets, will be utilized to maintain the overall resource adequacy.

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[29] Current and projected energy efficiency effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

During the 10-year period, Tier 2 resources for the Maritimes includes 2,237 MW of wind, 600 MW of natural gas combustion turbines, 250 MW of energy storage, and 100 MW of solar projects.

Load Representation

The loads for each Area were modeled on an hourly, chronological basis. The MARS program modified the input hourly loads through time to meet each Area's specified annual or monthly peaks and energies.

Load Shape

For the past several years, the Working Group has been using different load shapes as the selection of the summer and winter load shape assumptions are reevaluated on a periodic basis to determine if the load shape used in the Multi-Area Probabilistic Reliability Assessment is the most conservative for the region. The Working Group considered the 2021 load shape to be representative of a reasonable expected coincidence of Area loads for the summer assessments. Likewise, the winter 2013 – 2014 load shape has been used for many years for winter assessments and was compared to the winter 2024 – 2025 load shape. A review of the results for both load shape assumptions indicated only slight differences in the result, and the Working Group agreed that the weather patterns associated with the 2013/14 load shape are representative of weather conditions that stress the system, appropriate for use in future winter assessments.[30]

The selection of these load shapes was based on a review of the weather characteristics and corresponding loads and is summarized as follows:

- a 2021 load shape representative of a summer weather pattern with a typical expectation of hot days; and,
- a 2013-14 load shape representative of a winter weather pattern that includes a consecutive period of cold days.

For a study such like the LRAO that focuses on the entire year rather than a single season, the Working Group agreed to develop a composite load shape from the historical hourly loads for 2021, 2013, and 2014. January through March of the composite shape was based on the data for January through March of 2014. The months of April through September were based on those months for 2021, and October through December was based on the 2013 data.

[30] See: 2022/2023 Winter Load Shape Analysis The 2022/2023 Winter Load Shape Analysis is currently available on the NPCC website. The **2024/2025 Winter Load Shape Analysis** will also be published at Reliability Services | NPCC.

Before the composite load model was developed by combining the various pieces, the hourly loads for 2013 and 2014 were adjusted by the ratios of their annual energy to the annual energy for 2021. This adjustment removed the load growth that had occurred from 2021, from the 2013 and 2014 loads, to create a more consistent load shape throughout the year.

The resulting load shape was then adjusted through the study period to match each Area's monthly or annual peak and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast. It is important to note that the most conservative load shape for the probabilistic assessment may not be the season when the most severe weather was observed.

Load Forecast Uncertainty

Load forecast uncertainty was also modeled. The effects on reliability of uncertainties within the load forecast, due to weather and economic conditions, were captured through the load forecast uncertainty model in the GE MARS program. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled - three loads lower and three loads higher than the median peak) and calculates weighted-average values based on input probabilities of occurrence.

While the per unit variations in Area and sub-Area load can vary on a monthly and annual basis, **Table 5(a)** shows the values assumed for January 2026, corresponding to the assumed occurrence of the NPCC winter peak load (assuming the composite load shape) and **Table 5(b)** shows the values assumed for August 2026, corresponding to the NPCC summer peak load. **Tables 5(a) and 5(b)** also show the probability of occurrence assumed for each of the seven load levels modeled.

In computing the reliability indices, all the areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty affect all of the areas at the same time. The amount of the effect can vary according to the variations in the load levels.

For this study, the reliability indices were calculated for the expected load conditions, derived from computing the reliability at each of the seven load bin levels modeled, and computing a weighted-average expected value based on the specified probabilities of occurrence.

Area	Per-Unit Variation in Load						
Bin	Bin 1	Bin 2	Bin 3	Bin 4	Bin 5	Bin 6	Bin 7
HQ	1.116	1.081	1.033	0.984	0.932	0.877	0.846
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.123	1.045	0.996	0.939	0.912	0.684	0.389
NY	1.105	1.067	1.032	1.000	0.970	0.940	0.912
ON	1.070	1.050	1.026	1.000	0.971	0.937	0.901
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Table 5(a) - Per Unit load multipliers Assumed (Month of January 2026)

Area	Per-Unit Variation in Load						
Bin	Bin 1	Bin 2	Bin 3	Bin 4	Bin 5	Bin 6	Bin 7
HQ	1.104	1.078	1.042	1.006	0.973	0.943	0.928
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.080	1.036	1.008	0.976	0.902	0.623	0.582
NY	1.120	1.081	1.037	0.990	0.940	0.888	0.833
ON	1.165	1.115	1.058	1.000	0.938	0.876	0.821
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Table 5(b) - Per Unit load multipliers Assumed (Month of August 2026)

Demand Response

New England: Active demand resources participate in the New England Forward Capacity Market (FCM) and are represented as supply-side resources in this study. For the active demand resources, the study assumes the actual amount procured under the FCM. Active demand capacity resources participate in the ISO New England capacity market and are offered into the energy market daily and dispatched according to price. These demand resources are discounted in the assessment to account for performance based on the observed availability factors of demand response programs in the past.

New York: Special Case Resources and Emergency Demand Response Programs The Installed Capacity (ICAP) Special Case Resource (SCR) program allows demand resources that meet certification requirements to offer Unforced Capacity ("UCAP") to Load Serving Entities. SCRs are modeled as one of the Emergency Operating Procedure (EOP) step in MARS. Starting with the 2024 reliability models, SCRs are modeled as duration-limited resources. SCRs are assumed to be available to be called once in a day when a loss of load event occurs for a duration between 5 and 7 hours (defined by zone), which is determined based on historical SCR performance in the applicable zone. Hourly response rates are used.

The contribution by the SCRs varies monthly by applicable zone. These monthly values are also derived from historical performance of the SCRs.

The Emergency Demand Response Program (EDRP) resources are not modeled at this time as the program enrollment was less than 2 MW.

Ontario: Ontario's demand-side resources are comprised of Demand Response resources procured through auction and dispatchable loads. These resources can be dispatched in the same way that generators are. In June 2023, in response to a Ministerial directive, the IESO launched a residential demand response program known as Peak Perks, targeting residential sector air conditioners. Peak Perks has grown from up to 90MW to up to 152 MW (in 2026) of peak system demand and is expected to continue growing at a 0.8% compound growth rate until 2050. As part of the recently approved 2025–2036 Electricity Demand Side Management (eDSM) Framework, the IESO has expanded Peak Perks to include small business customers and increased the peak savings targets for the program.

Maritimes: Demand Response in the Maritimes Area is currently comprised of contracted interruptible loads.

Québec: In Québec, Demand Response (DR) programs are specifically designed for peak-load reduction during winter operating periods. Some DR is expected to remain available for the summer period. DR consists of interruptible demand programs mainly for large industrial customers. DR programs are usually used in situations where either the load is expected to reach elevated levels or when resources are expected to be insufficient to meet peak load demand. Interruptible load program specifications differ among programs and participating customers. They usually allow for one or two calls for reduction per day and between 20 to 120 hours load interruption per winter period. Interruptible load programs are planned with participating industrial customers with whom contracts are signed. Before the peak period, generally during the fall season, all customers are regularly contacted to reaffirm their commitment to provide capacity when called, during peak periods. DR programs are modeled as resources with their constraints and limitations in the resource adequacy model in GE MARS.

Generation

Generator Unit Availability

Details regarding each NPCC Area's assumptions for generator unit availability are described in the respective Area's most recent NPCC *Seasonal Multi-Area Probabilistic Assessment.*[31]

[31] See: NPCC Seasonal Multi-Area Probabilistic Assessment.

Capacity and Load Summary

Figures 6 through **10** summarize area capacity and load assumed in this Overview at the time of area peak for the period 2026 to 2030. Area peak load is shown against the initial area generating capacity (includes demand resources modeled as resources), adjusted for purchases, retirements, and additions. New England generating capacity also includes active Demand Response, based on the Capacity Supply Obligations obtained through ISO-NE's Forward Capacity Market.

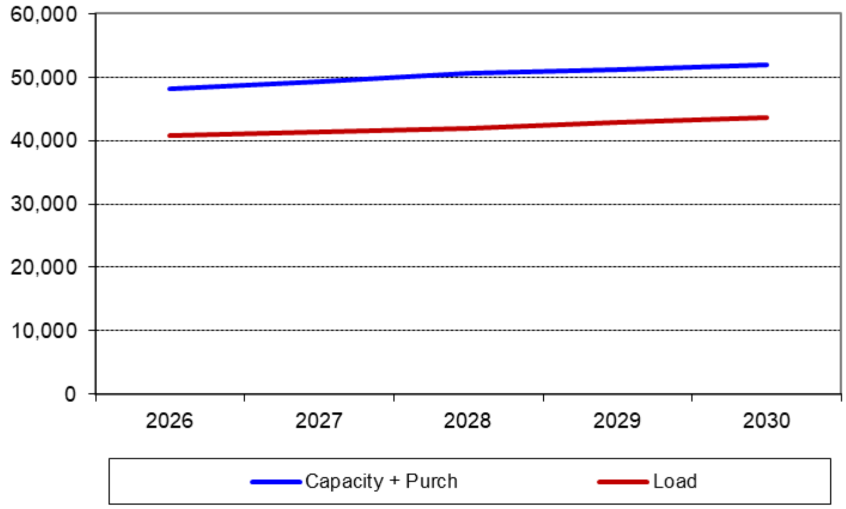

Figure 6 – Québec Winter Capacity and Load – MW

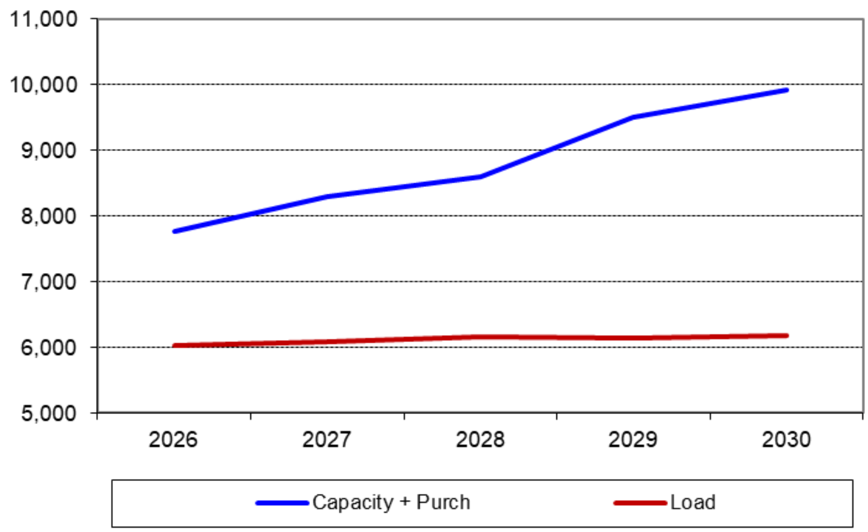

Figure 7 – Maritimes Winter Capacity and Load – MW

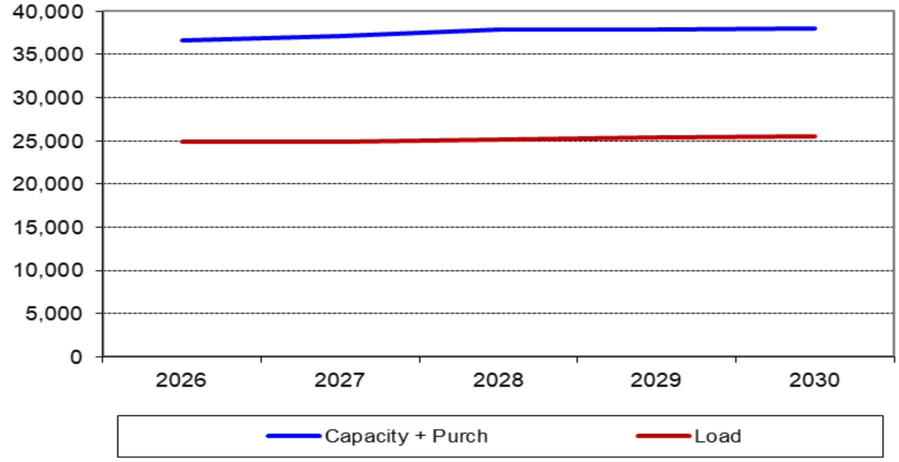

Figure 8 – New England Summer Capacity and Load – MW

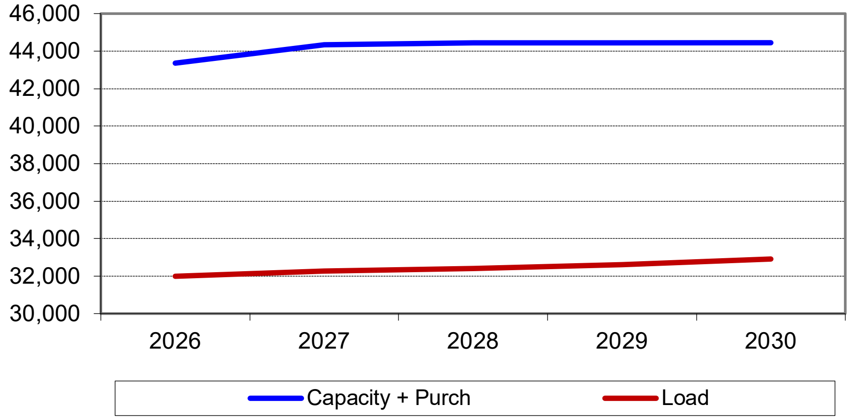

Figure 9– New York Summer Capacity and Load – MW

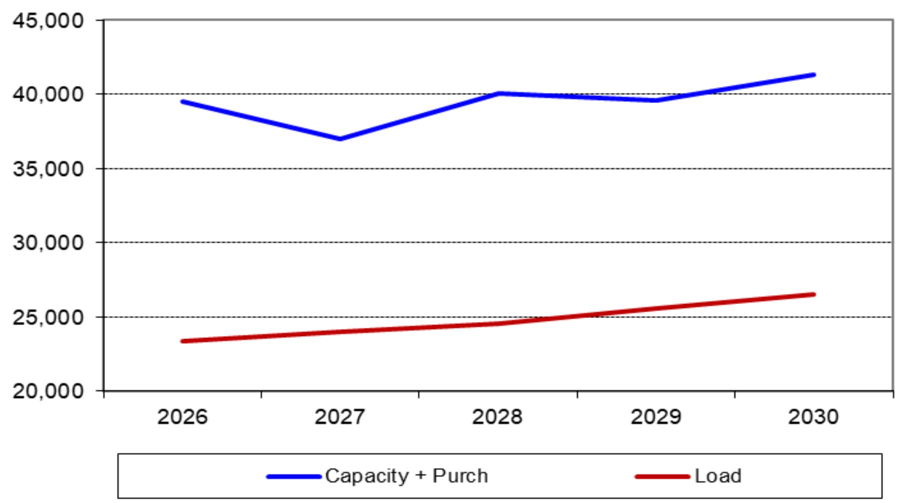

Figure 10 – Ontario Summer Capacity and Load – MW

Resource Modeling

Generator Unit Availability

Details regarding each NPCC Area's assumptions for generator unit availability are described in the respective Area's most recent NPCC *Comprehensive Review of Resource Adequacy*.[32]

New England: This probabilistic assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period. Unit availability modeled reflects the projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based upon the approved maintenance schedules. Individual generating unit forced outage assumptions were based on the unit's historical data and North American Reliability Corporation (NERC) average data for the same class of unit.

New York: Generating unit forced and partial outages are modeled by inputting a multistate outage model that represents an equivalent demand forced outage rate (EFORd) for each unit represented. Outage data used to determine the EFORd is received by the NYISO from generator owners based on outage data reporting requirements established by the NYISO. Capacity unavailability is modeled by considering the average forced and partial outages for each generating unit that have occurred over the most recent five-year time period.

Ontario: The assumptions for Ontario are consistent with the anticipated resource case in the NERC 2025 *Long-Term Reliability Assessment*.[2]

Québec: The planned outages for the winter period are reflected in this assessment. The number of planned outages is consistent with five-year historical values.

Maritimes: Individual generating unit maintenance assumptions are based on approved maintenance schedules for the study period.

Hydro

New England: New England uses the Seasonal Claimed Capability as established through the Claimed Capability Audit to represent the hydro resources. The Seasonal Claimed Capability for intermittent hydro resources is based on their median net real power output during Reliability Hours (Hours ending 14:00 – 18:00).

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[32] See: https://www.npcc.org/reliability-services?category=Resource%20Adequacy.

New York: Large hydro units are modeled as thermal units with a corresponding multi-state representation that represents an equivalent forced outage rate on demand (EFORd). For run of river units, New York provides 8,760 hours of historical unit profiles for each year of the most recent five-year calendar period for each facility based on production data. Run of river unit seasonality is captured by using GE-MARS functionality to randomly select an annual shape for each run of river unit in each draw. Each shape is equally weighted.

Ontario: Hydroelectric resources are modelled in the MARS Program as capacity-limited and energy-limited resources. Minimum capacity, maximum capacity, and monthly energy values are determined on an aggregated basis for each zone based on historical data since market opening (2002).

Québec: For hydro resources, maximum capacity is set equal to the power that each plant can generate at its maximum rating during two full hours, while expected on-peak capacity is set equal to maximum capacity minus scheduled maintenance outages and restrictions.

Maritimes: Hydro in the Maritimes is predominantly run of the river, but enough storage is available for full rated capability during daily peak load periods.

Thermal

New England: The seasonal claimed capability as established through claimed capability audits, is used to rate the sustainable maximum capacity of non-intermittent thermal resources. The Seasonal Claimed Capability for intermittent thermal resources is based on their historical median net real power output during ISO-New England defined seasonal reliability hours.

New York: Installed capacity values for thermal units are based on the minimum of seasonal Dependable Maximum Net Capability (DMNC) test results and the capacity resource interconnection service (CRIS) MW values from the 2025 NYISO's Gold Book. Generator availability is derived from the most recent calendar five-year period forced outage data. Units are modeled in the MARS Program using a multi-state representation that represents an equivalent forced outage rate on demand (EFORd). Planned and scheduled maintenance outages are modeled based upon schedules received by the New York ISO and adjusted for historical maintenance.

Ontario: The capacity values and planned outage schedules for thermal units are based on information submitted by market participants. The available capacity states and state transition rates for each existing thermal unit are derived based on analysis of a rolling five-year history of actual forced outage data. For existing units with insufficient historical data, and for new units, capacity states and state transition rate data of existing units with similar size and technical characteristics are applied.

Québec: For thermal units, Maximum Capacity is defined as the net output a unit can sustain over a two-consecutive hour period.

Maritimes: Combustion turbine capacity for the Maritimes Area is winter DMNC. During summer, these values are de-rated accordingly.

Solar

New England: Hourly output profiles are used to model solar resources. The total Network Resource Capability (NRC) of solar resources is calculated by aggregating them by zone and modeling their hourly output profiles for five historical years (2020–2024) based on their simulated output over the previous five years. With every sample draw, GE MARS chooses at random one of the five profiles.

New York: New York provides 8,760 hours of model-based solar profiles for each year of the past available five-year calendar period for each front of the meter solar plant. Solar seasonality is captured by using GE-MARS functionality to randomly select an annual solar shape for each solar unit in each draw. Each solar shape is equally weighted. Both behind the meter and front of the meter solar is modeled using this method. The BTM solar shapes are developed based on sampled inverter data.

Ontario: Solar generation is aggregated by IESO zone. In the Monte Carlo analysis, in each iteration the model randomly shuffles the order of the days within each month for solar production. Solar generation uses hourly output profiles for five historical years (2020-2024) based on their simulated output over the previous five years. Solar generators are matched to the closest simulated site and technology type (ground-mount or rooftop), and then output is scaled relative to installed capacity.

Québec: Behind-the-meter generation (solar and wind) is estimated at approximately 45 MW of installed capacity for the 2025-26 winter. Contributions of BTM generation are negligible during the winter peak-period (~1 MW) and don’t affect the load monitored from a network perspective. Front-of-the-meter PV installed capacity is expected to be 9.5 MW by the end of this year. The impact of this resource at peak time period is not significant.

Maritimes: At this time, solar capacity in the Maritimes is behind the meter and netted against load forecasts. It does not currently count as capacity, as the Maritimes experiences a Winter peak in either the early morning or evening when solar generation is minimal or not present.

Wind

New England: Hourly output profiles are used to model wind resources. The total Network Resource Capability of wind resources is calculated by aggregating them by zone and modeling their hourly output profiles for five historical years (2020–2024) based on their simulated output over the previous five years. In GE MARS, every sample draw corresponds to a randomly selected profile.

New York: New York provides 8,760 hours of model-based wind profiles for each year of the past available five-year calendar period for each wind plant based on production data. Wind seasonality is captured by using the-MARS functionality to randomly select an annual wind shape for each wind unit in each draw. Each wind shape is equally weighted.

Ontario: Wind generation is aggregated by IESO zone and hourly output profiles for five historical years (2020-2024) based on their simulated output over the previous five years hourly profiles used. The MARS model randomly selects a different yearly simulated profile during each iteration. Wind generators are matched to the closest simulated site, and then output is scaled relative to installed capacity.

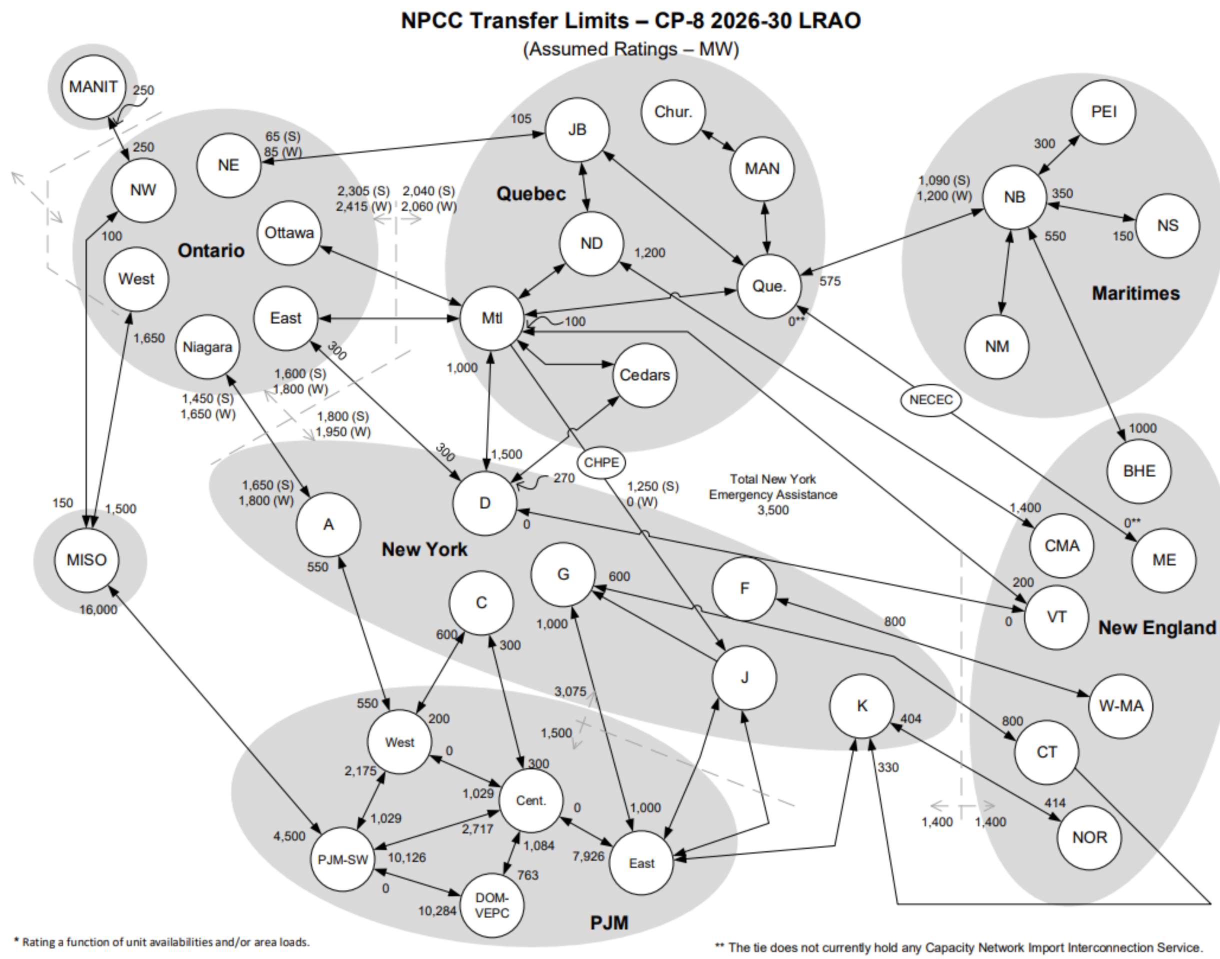
Québec: Wind generation is modeled using five years of hourly historical data (2020-2024), adjusted to meet the planned installed capacity.

Maritimes: The Maritimes Area provides an hourly historical wind profile for each of its four sub-areas based on actual wind shapes for the five historical years (2020-2024) based on their simulated output. The wind in any particular hour is a probabilistic amount determined by selecting a random wind and load shape from the historic years. Each sub-area's actual MW wind output was normalized by the total installed capacity in the sub-area during that calendar year. These profiles, when multiplied by current sub-area total installed wind capacities, yield an annual wind forecast for each sub-area. The sum of these four sub-area forecasts is the Maritimes Area's hourly wind forecast.

Transmission Representation

Transfer Limits

Figure 11 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the period 2026 to 2030.



Note: With the Variable Frequency Transformer operational at Langlois (Cedars), Hydro-Québec can import up to 100 MW from New York.

Figure 11 - Assumed Transfer Limits

Transfer limits between and within some areas are indicated in **Figure 12(a) through Figure 12(e)** with seasonal ratings (S- summer, W- winter) where appropriate. The acronyms and notes used in **Figure 12(a) – Figure 12(e)** are defined as follows:

Chur	Churchill Falls
NOR	Norwalk – Stamford
NM	Northern Maine
MANIT	Manitoba
BHE	Bangor Hydro Electric
NB	New Brunswick
ND	Nicolet-Des Cantons
Mtl	Montréal
PEI	Prince Edward Island
BJ	Bay James

C MA	Central MA
CT	Connecticut
W MA	Western MA
NS	Nova Scotia
Dom-VEPC	Dominion Virginia Power
MAN	Manicouagan
NBM	Millbank
NW	Northwest (Ontario)
NE	Northeast (Ontario)
VT	Vermont
MT	Maritimes Area
MISO	Mid-Continent Independent
Que	Québec Centre System Operator

Details regarding the development of the transmission representation for New York shown in **Figures 12(a)**, and **12(b)** are consistent with the 2024 RNA.

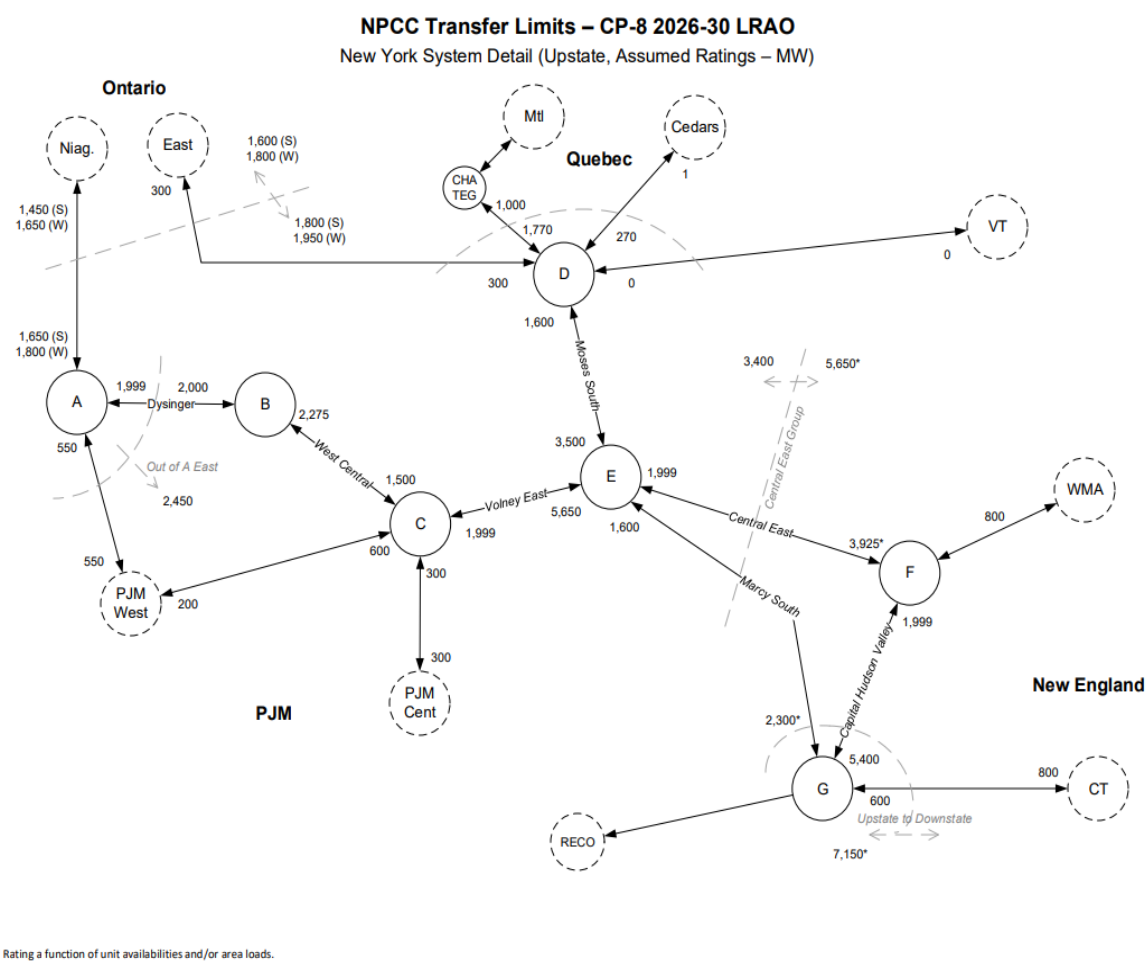


Figure 12(a) - Assumed Northern New York Transmission Limits

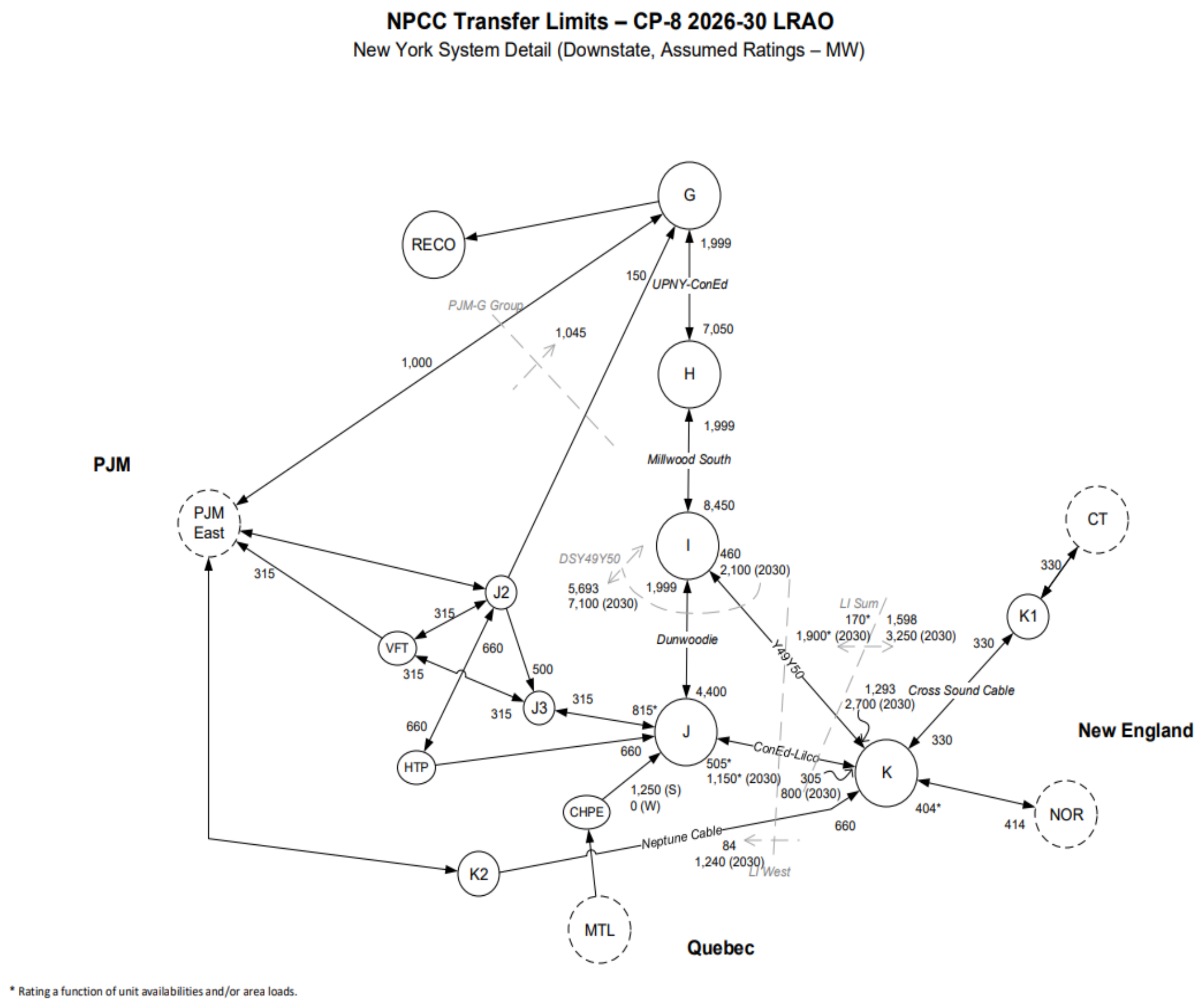


Figure 12(b) - Assumed Southern New York Transmission Limits

Details regarding the development of the transmission representation for New England shown in **Figure 12(c)** can be found in the latest New England Regional System Plan.[33] The Regional System Plan is ISO New England's (ISO) planning efforts to identify the region's electricity needs and actions for meeting these needs in order to maintain reliable and economic operation of New England's bulk power system over a ten-year horizon.

[33] The New England Regional System plans can be found at: http://www.iso-ne.com/trans/rsp/index.html.

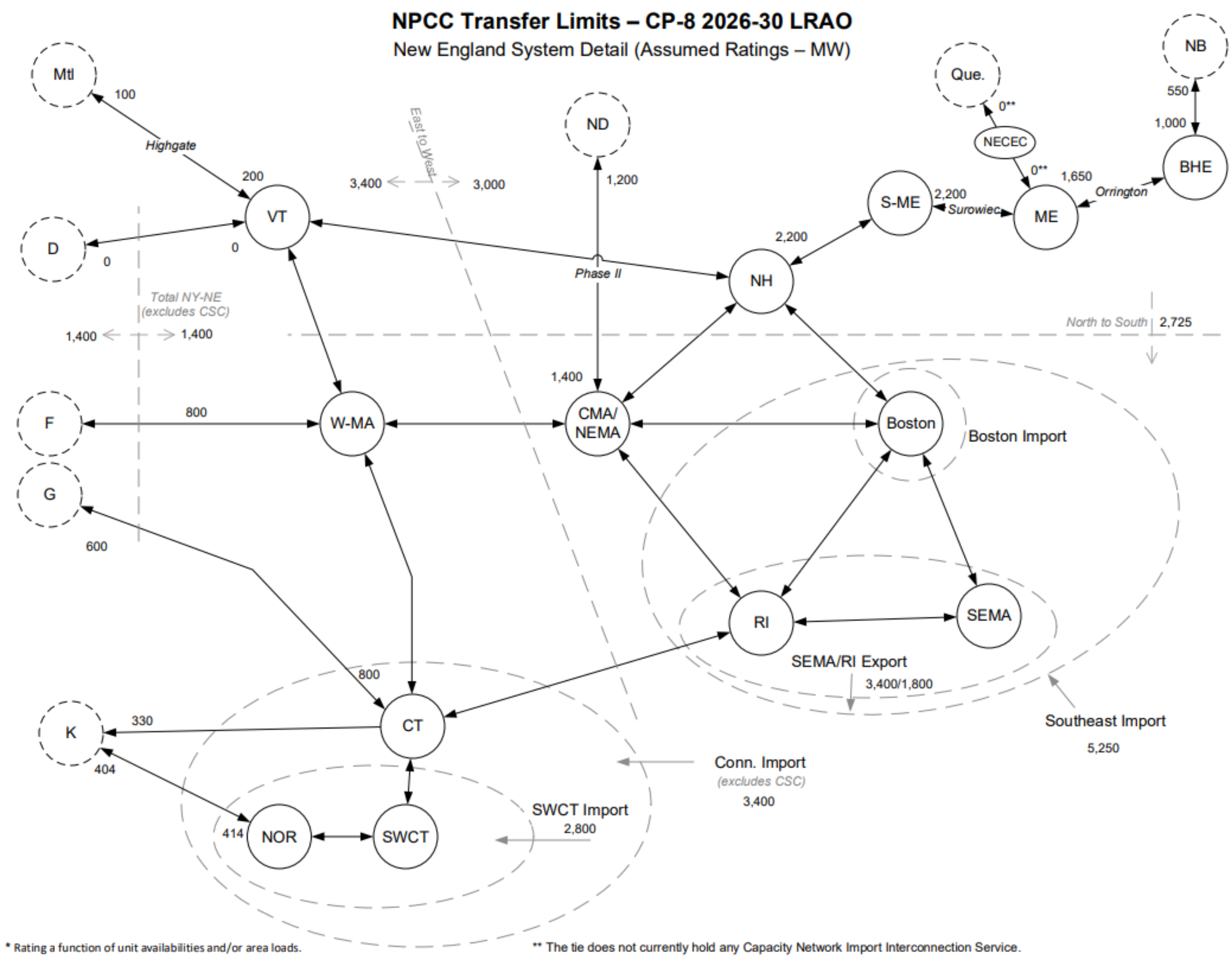


Figure 12(c) - New England Transmission Limits

Details regarding the transmission representation for Ontario shown in **Figure 12(d)** can be found in the *Transfer Capability Assessment Methodology* document.[34]

[34] See: https://ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook.

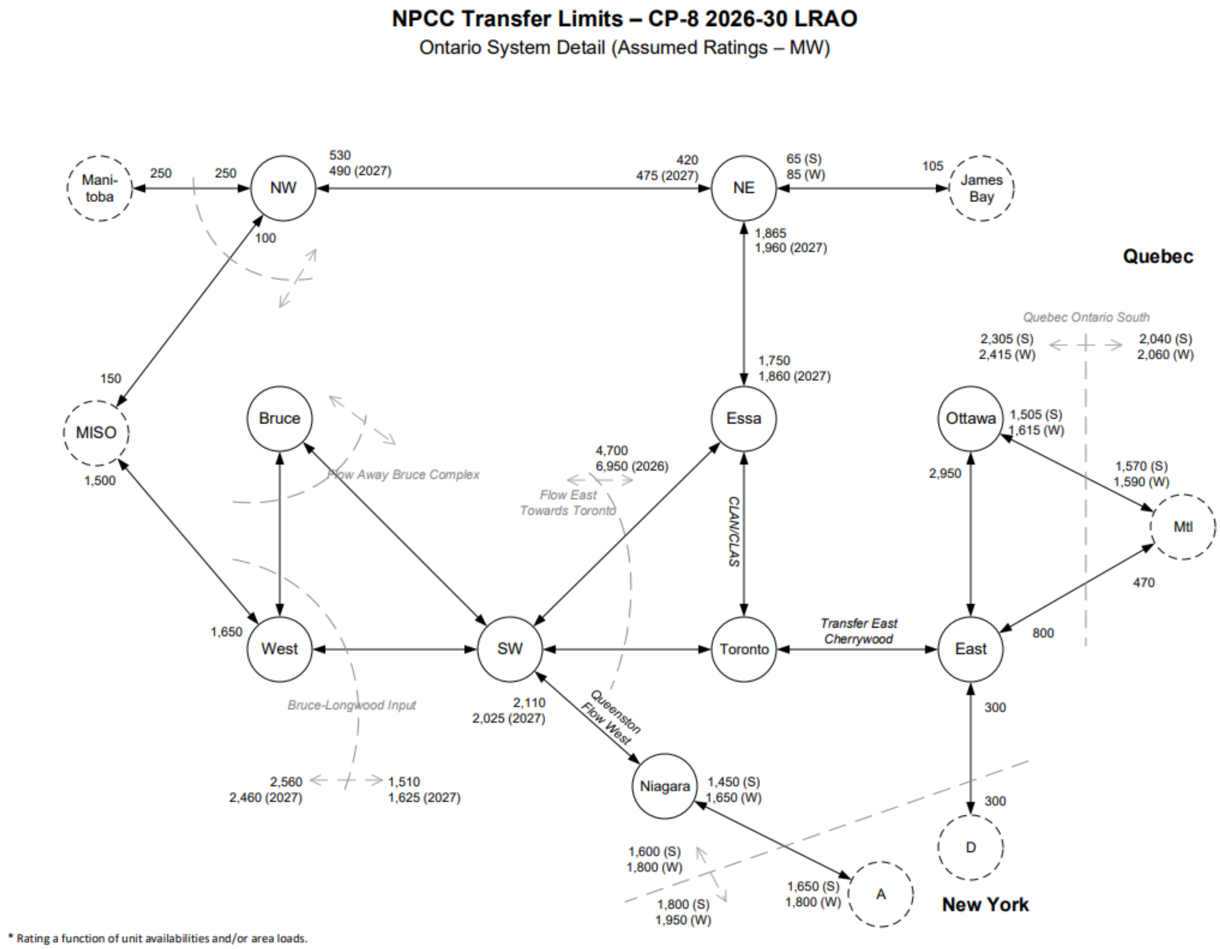


Figure 12(d) - Ontario Transmission Limits

The modeling of Quebec shown in **Figure 12(e)** is consistent with the latest NPCC Québec Balancing Authority Area Review of Resource Adequacy.[35]

[35] See: https://www.npcc.org/reliability-services?category=Resource%20Adequacy.

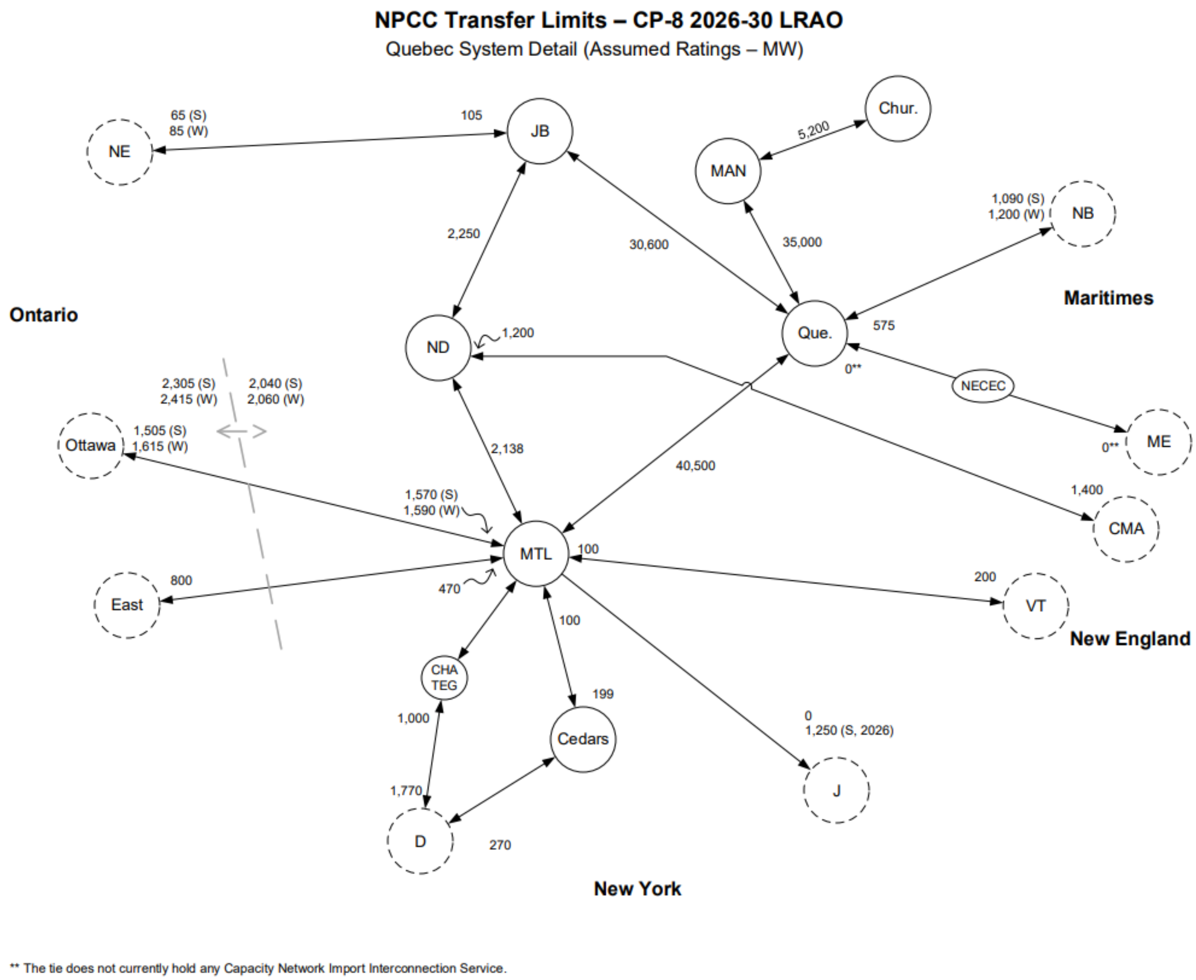


Figure 12(e) - Québec Transmission Limits

The modeling of the PJM-RTO is shown in **Figure 11**. The PJM-RTO was divided into five distinct areas: Eastern Mid-Atlantic, Central Mid-Atlantic, Western Mid-Atlantic, PJM West, and PJM South. This represents a slight departure from modeling practices prior to 2014 in which PJM West and PJM South were combined into one region (PJM Rest). This modeling change was justified on grounds that the PJM South area (Dominion Virginia Power) is a member of SERC while practically all the PJM West area is a member of RFC. Furthermore, PJM West and PJM South are two separate areas in the PJM Capacity Market framework (PJM's Reliability Pricing Model).

Operating Procedures to Mitigate Resource Shortages

Each area takes predefined steps as their reserve levels approach critical levels. These steps consist of load control and generation supplements that can be implemented by System Operators before firm load has to be disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand,

and/or implementing voltage reductions. Other measures could include calling on generation available under abnormal or emergency conditions, and/or reducing operating reserves. **Table 6** summarizes the load relief assumptions modeled for each NPCC area.

Actions	HQ (Jan)	MT (Jan)	NE (Jun)	NY (Jun)	ON (Jul)
1. Curtail Load	-	-	-	-	-
Appeals	-	-	-	-	1% of load
RT-DR/SCR/EDRP	-	-	-	0.01[36]	-
SCR Load /Man. Volt. Red.	-	-	-	0.23% of load	-
2. No 30-min Reserves	500	233	625	655	473
3. Voltage Reduction	250	-	252	1.3% of load	0% of load
Interruptible Loads	-	259	-	261	2,046
4. No 10-min Reserves	750	505	-	-	945
General Public Appeals	-	-	-	74	-
5. 5% Voltage Reduction	-	-	-	-	1.85% of load
No 10-min Reserves	-	-	800	910	-

Table 6 - NPCC Operating Procedures to Mitigate Resource Shortages
Peak Month 2026 Load Relief Assumptions – MW

The need for an area to begin these operating procedures is modeled in the GE MARS program by evaluating the daily probabilistic expectation at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The Working Group recognizes that Areas may invoke these actions in any order, depending on the situation faced at the time; however, it was agreed that modeling the actions as in the order indicated in **Table 6** was a reasonable approximation for this analysis.

[36] Derated value shown accounts for assumed availability.

Assistance Priority

All Areas may receive assistance on a shared basis in proportion to their deficiency. In this analysis, each step was initiated simultaneously in all Areas and sub-Areas.

Modeling of Neighboring Regions

The modeling of the PJM-RTO is shown in **Figure 11**(above). The PJM-RTO was divided into five distinct areas: Eastern Mid-Atlantic, Central Mid-Atlantic, Western Mid-Atlantic, PJM West, and PJM South. This represents a slight departure from modeling practices prior to 2014 in which PJM West and PJM South were modeled as one region (PJM Rest). This modeling change was justified on grounds that the PJM South area (Dominion Virginia Power) is a member of SERC while practically all the PJM West area is a member of RFC. Furthermore, PJM West and PJM South are now two separate areas in the PJM Capacity Market framework (PJM's Reliability Pricing Model).

A detailed representation of the neighboring region of MISO (Midcontinent Independent System Operator) was also assumed. The demand and capacity assumptions for PJM and the MISO for 2025 are summarized in **Table 7** and **Figure 13**.

	PJM	**MISO**
Peak Load (MW)	157,993	90,817
Peak Month	July	July
Assumed Capacity (MW)	184,951	102,915
Purchase/Sale (MW)	-1,808	978
Reserve (%)	21.0	20.7
Operating Reserves (MW)	3,655	3,906
Curtailable Load (MW)	7,955	5,728
No 30-min Reserves (MW)	1,218	2,670
Voltage Reduction (MW)	2,201	2,200
No 10-min Reserves (MW)	2,437	1,236
Appeals (MW)	400	400
Load Forecast Uncertainty	+/- 15.0%, 10.0%, 5.0%	+/- 11.1%, 7.3%, 3.7%

Table 7 – PJM and MISO 2026 Assumptions[37]

[37] Load and capacity assumptions for RFC-Other and MRO-US based on NERC's Electricity, Supply and Demand Database (ES&D) available at: https://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx.

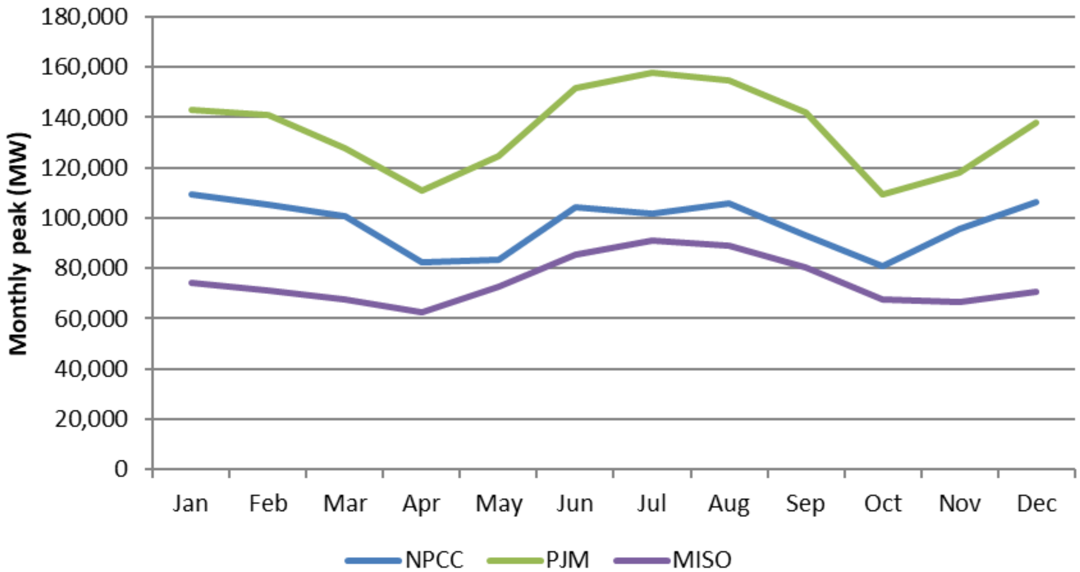


Figure 13 - 2026 Projected Monthly Expected Peak Loads for NPCC, PJM, and MISO MW Composite Load Shape

MISO

The Mid-Continent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets in all or parts of 15 states in the US. Beginning with the 2015 NPCC *Long Range Adequacy Overview*, (LRAO)[38] the MISO region (minus the recently integrated Entergy region) was included in this analysis replacing the RFC-OTH and MRO-US regions. In previous versions of the LRAO, RFC-OTH and MRO-US were included to represent specific areas of MISO, however due to difficulties in gathering load and capacity data for these two regions (since most of the reporting is done at the MISO level), it was decided to start including the entirety of the northern MISO region within the model.

The MISO was modeled in this study due to the strong transmission ties of the region with the rest of the study system.

[38] See: 2015 Long Range Adequacy Overview Report.

PJM-RTO

Load Model

The load model used for the PJM-RTO in this study is consistent with the PJM Planning division's technical methods. The hourly load shape is based on observed 2021 calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report.[39] Load Forecast Uncertainty was modeled consistent with recent PJM planning models[40] considering seven load levels, each with an associated probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones, the period years that the model is based on, sampling size, and how many years in the future for which the load forecast is being derived. Load Forecast Uncertainty is modeled to account for two primary sources of variability: (i) weather uncertainty, represented through the simulation of 31 distinct weather (1993-2024) days and 13 weather rotations, and (ii) load forecast error, incorporated by adjusting the hourly loads within each scenario using factors sampled from a normal distribution with a mean of 0 and a standard deviation equal to the in-sample error of the PJM Load Forecast (currently 1.2%, based on the difference between fitted and actual values).

Expected Resources

All generators that have been demonstrated to be deliverable were modeled as PJM capacity resources in the PJM-RTO study area. Existing generation resources, planned additions, modifications, and retirements are per the EIA-411 data submission and the PJM planning process. Load Management (LM) is modeled as an Emergency Operating Procedure. The total available MW as LM is per results from the PJM's capacity market.

Expected Transmission Projects

The transfer values shown in the study are reflective of peak emergency conditions. PJM is a summer peaking area. The studies performed to determine these transfer values are in line with the Regional Transmission Planning Process employed at PJM, of which the Transmission Expansion Advisory Committee (TEAC) reviews these activities and assumptions. All activities of the TEAC can be found at: www.pjm.com. All transmission projects are treated aggregate, with the appropriate timing and transfer values changing within the model, consistent with PJM's regional Transmission Expansion Plan.[41]

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39 See: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.
40 See: https://www.pjm.com/-/media/planning/res-adeq/2023-pjm-reserve-requirement-study.ashx.
41 See: https://www.pjm.com/planning.aspx.

Summary of Modeled Capacity and Load in Details

	Quebec	Maritimes	New England	New York	Ontario	PJM	MISO
2026	Jan	Jan	Jun	Jun	Jul	Jul	Jul
Capacity (MW) *	48,480	7,893	36,366	40,188	39,247	184,951	102,915
Net Purchase/Sale (MW)	-245	-122	276	3,171	300	-1,808	978
Load (MW)	40,848	6,033	24,876	31,990	23,403	157,993	90,817
Nameplate Demand Response (MW)	0	259	0	0	2,046	7,955	5,728
Active Demand Response (MW)	0	0	584	0	0	0	0
Reserves (%)	18.1	33.1	47.3	35.5	77.7	21.0	20.7
Maintenance - Peak Week (MW)	**	140	0	0	1,679	0	0
Wind Output at Time of Area Peak (MW) ***	1,312	413	936	521	1,304	3,959	2,610
Wind Nameplate Capacity (MW)	3,646	1,264	1,754	3,475	4,817	3,959	2,610
Solar capacity in MARS (MW)	0	81	6,021	1,766	2,835	9,269	1,687
BTM Solar - On peak (MW)	-	-	-	1,516	-	-	-
BTM Solar (MW)	-	-	1,759	8,486	-	-	-

* Wind capacity included at nameplate rating; demand response not included in capacity
** Capacity for Quebec reflects scheduled maintenance and restrictions
*** This value reflects the expected values during peak, although the modeling varies across areas: Québec, New England, PJM, and MISO model wind units as equivalent thermal units; the Maritimes and New York use historical hourly profiles[42]

Table 8(a) – At Time of Area's Annual Peak, Based on Composite Load Shape for 2026

[42] The values shown represent the average wind generation in the top ten load hours, and does not represent the effective load carrying capability of the wind units or the firm capacity value.

	Quebec	Maritimes	New England	New York	Ontario	PJM	MISO
2027	Jan	Jan	Jun	Jun	Jul	Jul	Jul
Capacity (MW) *	49,312	8,473	36,919	40,907	36,502	184,222	102,915
Net Purchase/Sale (MW)	0	-177	216	3,435	470	-1,808	978
Load (MW)	41,405	6,078	24,945	32,280	24,023	165,832	91,253
Nameplate Demand Response (MW)	0	269	0	0	1,998	8,069	5,771
Active Demand Response (MW)	0	0	540	0	0	0	0
Reserves (%)	19.1	40.9	48.9	37.4	62.2	14.9	20.2
Maintenance - Peak Week (MW)	**	0	0	0	2,281	0	0
Wind Output at Time of Area Peak (MW)***	1,576	527	1,179	724	1,304	3,959	2,610
Wind Nameplate Capacity (MW)	4,378	1,795	1,735	4,830	4,817	3,959	2,610
Solar capacity in MARS (MW)	0	98	6,263	1,094	2,835	9,269	1,687
BTM Solar - On peak (MW)	-	-	-	1,548	-	-	-
BTM Solar (MW)	-	-	1,809	9,302	-	-	-

* Wind capacity included at nameplate rating; demand response not included in capacity
** Capacity for Quebec reflects scheduled maintenance and restrictions
*** This value reflects the expected values during peak, although the modeling varies across areas: Québec, New England, PJM, and MISO model wind units as equivalent thermal units; the Maritimes and New York use historical hourly profiles[42]

Table 8(b) – At Time of Area's Annual Peak, Based on Composite Load Shape for 2027

	Quebec	Maritimes	New England	New York	Ontario	PJM	MISO
2028	Jan	Jan	Jun	Jun	Jul	Jul	Jul
Capacity (MW) *	49,992	8,663	38,001	40,998	39,399	184,222	102,915
Net Purchase/Sale (MW)	600	-70	-165	3,435	700	-1,808	978
Load (MW)	41,901	6,155	25,124	32,410	24,544	171,512	91,677
Nameplate Demand Response (MW)	0	283	0	0	2,090	8,176	5,781
Active Demand Response (MW)	0	0	540	0	0	0	0
Reserves (%)	20.7	44.2	50.6	37.1	71.9	11.1	19.6
Maintenance - Peak Week (MW)	**	0	0	0	940	0	0
Wind Output at Time of Area Peak (MW)***	1,773	543	1,179	724	1,272	3,959	2,610
Wind Nameplate Capacity (MW)	4,925	1,907	1,735	4,830	4,817	3,959	2,610
Solar capacity in MARS (MW)	0	116	6,331	1,185	2,835	9,269	1,687
BTM Solar - On peak (MW)	-	-	-	1,546	-	-	-
BTM Solar (MW)	-	-	1,869	9,987	-	-	-

* Wind capacity included at nameplate rating; demand response not included in capacity
** Capacity for Quebec reflects scheduled maintenance and restrictions
*** This value reflects the expected values during peak, although the modeling varies across areas: Québec, New England, PJM, and MISO model wind units as equivalent thermal units; the Maritimes and New York use historical hourly profiles[42]

Table 8(c) – At Time of Area's Annual Peak, Based on Composite Load Shape for 2028

	Quebec	Maritimes	New England	New York	Ontario	PJM	MISO
2029	Jan	Jan	Jun	Jun	Jul	Jul	Jul
Capacity (MW) *	50,580	9,511	38,080	41,008	38,881	181,605	102,915
Net Purchase/Sale (MW)	600	0	-165	3,435	700	-1,808	978
Load (MW)	42,833	6,144	25,347	32,620	25,587	177,411	92,247
Nameplate Demand Response (MW)	0	286	0	0	286	8,266	5,717
Active Demand Response (MW)	0	0	540	0	0	0	0
Reserves (%)	19.5	59.5	49.6	36.2	55.8	6.0	18.8
Maintenance - Peak Week (MW)	**	0	0	0	585	0	0
Wind Output at Time of Area Peak (MW)***	1,897	709	970	724	1,176	3,959	2,610
Wind Nameplate Capacity (MW)	5,271	2,391	1,757	4,830	4,817	3,959	2,610
Solar capacity in MARS (MW)	0	141	6,388	1,185	2,835	9,269	1,687
BTM Solar - On peak (MW)	-	-	-	1,521	-	-	-
BTM Solar (MW)	-	-	1,915	10,555	-	-	-

* Wind capacity included at nameplate rating; demand response not included in capacity
** Capacity for Quebec reflects scheduled maintenance and restrictions
*** This value reflects the expected values during peak, although the modeling varies across areas: Québec, New England, PJM, and MISO model wind units as equivalent thermal units; the Maritimes and New York use historical hourly profiles[42]

Table 8(d) – At Time of Area's Annual Peak, Based on Composite Load Shape for 2029

	Quebec	Maritimes	New England	New York	Ontario	PJM	MISO
2030	Jan	Jan	Jun	Jun	Jul	Jul	Jul
Capacity (MW) *	51,305	9,925	38,145	41,012	40,125	181,605	102,915
Net Purchase/Sale (MW)	600	0	-165	3,435	1,230	-830	0
Load (MW)	43,635	6,181	25,557	32,910	26,546	184,836	92,821
Nameplate Demand Response (MW)	0	286	0	0	286	8,338	5,717
Active Demand Response (MW)	0	0	540	0	0	0	0
Reserves (%)	19.0	65.2	48.6	35.1	56.9	2.3	17.0
Maintenance - Peak Week (MW)	**	0	0	0	1,566	0	0
Wind Output at Time of Area Peak (MW)***	2,128	1,033	1,344	407	1,187	3,959	2,610
Wind Nameplate Capacity (MW)	5,910	3,018	1,728	2,710	4,817	3,959	2,610
Solar capacity in MARS (MW)	0	166	6,482	1,185	2,835	9,269	1,687
BTM Solar - On peak (MW)	-	-	-	1,500	-	-	-
BTM Solar (MW)	-	-	1,938	11,021	-	-	-

* Wind capacity included at nameplate rating; demand response not included in capacity
** Capacity for Quebec reflects scheduled maintenance and restrictions
*** This value reflects the expected values during peak, although the modeling varies across areas: Québec, New England, PJM, and MISO model wind units as equivalent thermal units; the Maritimes and New York use historical hourly profiles[42]

Table 8(e) – At Time of Area's Annual Peak, Based on Composite Load Shape for 2030

Appendix C: Software Model Description

Multi-Area Reliability Simulation Program Description

General Electric's Multi-Area Reliability Simulation (MARS) program[43] allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

Modeling Technique

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method allows for many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies that govern system operation.

Reliability Indices

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily Loss of Load Expectation (LOLE - days/year);
- Hourly LOLE (hours/year);
- Loss of Energy Expectation (LOEE -MWh/year);
- Frequency of outage (outages/year);
- Duration of outage (hours/outage); and,
- Need for initiating Operating Procedures (days/year or days/period).

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all the reliability indices. These values can be calculated both with and without load forecast uncertainty.

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[43] See: https://www.geenergyconsulting.com/practice-area/software-products/mars.

The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates expected values of Loss of Load Expectation (LOLE) and can estimate each Area's expected exposure to their Emergency Operating Procedures. Scenario analysis is used to study the impacts of extreme weather conditions, variations in expected unit in-service dates, overruns in planned scheduled maintenance, or transmission limitations.

Resource Allocation Among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. For each hour, the total available capacity in the area is subtracted from the load. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area's margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls. The second method was used in this assessment. The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

Generation

MARS has the capability to model the following different types of resources:

- Thermal;
- Energy-limited;
- Cogeneration;
- Energy-storage; and,
- Hourly-based generation

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or as a unit with a specified capacity and available monthly energy (Type 2/3 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Hourly-based profile units are modeled as load modifiers. Charging and discharging of energy storage units is determined during the Monte Carlo solutions.

For each unit modeled, the installation and retirement dates and planned maintenance requirements are specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to level reserves on an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs. User specified maintenance was used in the assessment.

Thermal Units

In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as governed by the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

$$\text{TR (A to B)} = \frac{\text{Number of Transitions from A to B}}{\text{Total Time in State A}}$$

If detailed transition rate data for the units is not available, MARS can approximate the transition rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units

Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar where the capacity may be available, but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed monthly. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Type 3 (as-needed) energy limited units are dispatched on an as-needed bases during the Monte Carlo simulation and their generation profile usually changes from one replication to another. With this approach, the Type 3 energy-limited units are used only if the thermal capacity is not sufficient to serve the load. If there is sufficient thermal capacity in a given hour, the energy of the Type 3 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration

MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed monthly. Two types of cogenerations are modeled in the program, the difference being whether the system provides back-up generation when the unit is unable to meet its native load demand.

Energy Storage

Energy-storage units are modeled by providing their nameplate capacity and the amount of energy that they can store. GE MARS dispatches the stored energy when it can reduce negative margins in the system. When the system has a surplus of capacity, energy storage units are allowed to charge energy, as long as they do not cause loss-of-load events or use of emergency operating procedures.

Hourly-based Modifiers

Hourly-based modifiers (e.g., wind or solar) are modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week or a full 8,760 set of hourly values which is subtracted from the hourly loads for the unit's area.

Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. The transfer limits are specified for each direction of the interface and can be changed on a monthly basis. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, using state transition rates.

Contracts

Contracts are used to model firm scheduled interchanges of capacity between areas in the system. In addition, the program schedules any excess capacity in an area in a given hour to provide emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether the sending area has sufficient resources on an isolated basis, but they will be curtailed because of interface transfer limits. Curtailable contracts will be only to the extent that the exporting Area has the necessary resources on its own or can obtain them as emergency assistance from other areas. Firm contracts and emergency assistance were modeled in this assessment.

Appendix D: Supply and Demand on Risk Day for NPCC region

Figures 14 (a-b) through **Figure 18 (a-b)** represents the risk day for the two study years for the NPCC region provided for the 2025 NERC ProbA.

New York[44]

New York – Supply and Demand on Risk Day – 06/29/2027

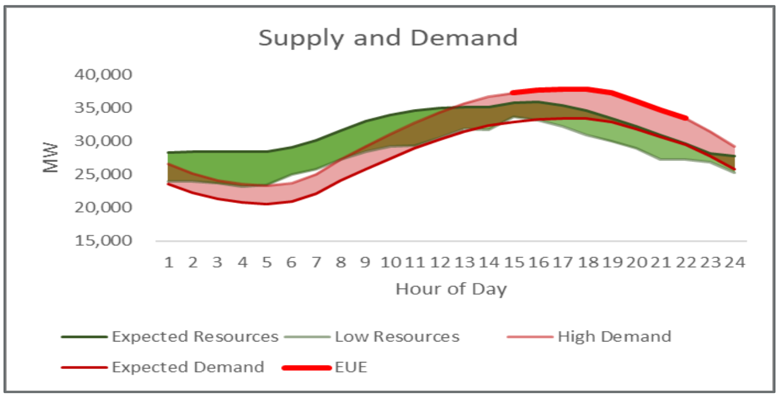

Figure 14(a) - 2027 New York Supply and Demand on Risk Day

Highlights

- In 2027, New York is expected to observe summer peaking demand conditions in the early to late afternoon.
- The morning and evening ramp conditions could lead to additional strain on the system if resources fail to meet expectations.
- Although the expected available resource contribution is sufficient to meet the anticipated demand, there is a risk due to the variability in the demand forecast, with an additional risk stemming from the variability in resource contribution.
- Higher than expected demand corresponding with unavailability of resources is expected to be the leading cause of potential unserved energy.

[44] The NYISO's 2025 Gold Book contains the official NY forecast and insights. The 2025 GB states: "The hour of the actual NYCA peak varies annually. Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak will likely shift into the evening as additional BTM solar is added to the system, and as EV charging impacts increase during the evening hours."

New York - Supply and Demand on Risk Day – 07/04/2029

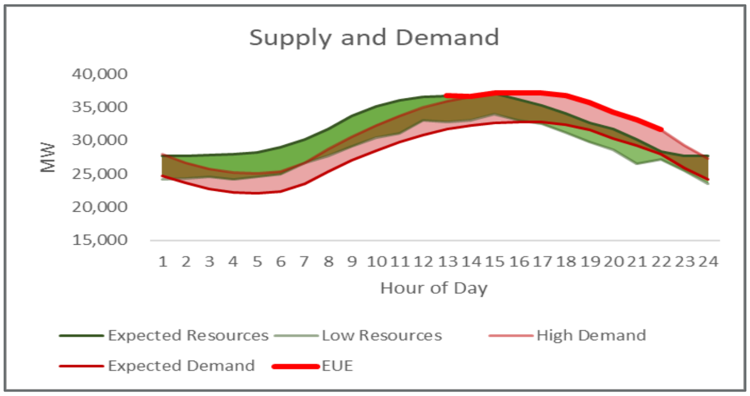

Figure 14(b) - 2029 New York Supply and Demand on Risk Day

Highlights

- In 2029, New York is expected available resources to have same drivers as was explained for the risk day in 2027.

New England

New England – Supply and Demand on Risk Day – 06/30/2027

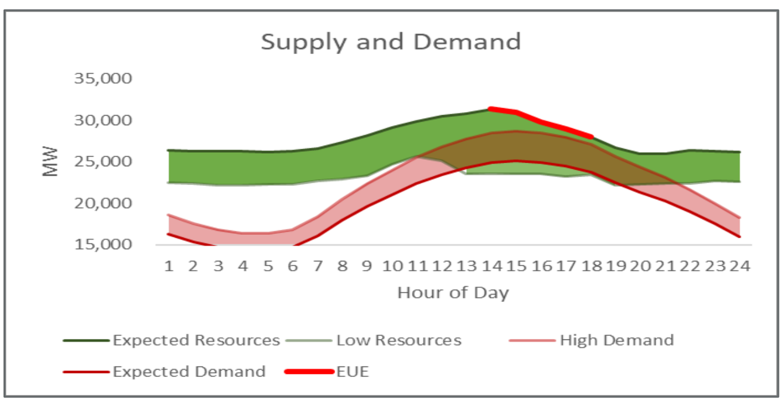

Figure 15(a) – 2027 New England Supply and Demand on Risk Day

Highlights

- In 2027, New England is expected to observe summer peaking demand conditions in the early to late afternoon.
- The evening ramp conditions could lead to additional strain on the system if resources fail to meet expectations.

- Although the expected available resource contribution is sufficient to meet the anticipated demand, there is a risk due to the variability in the demand forecast, with an additional risk stemming from the variability in resource contribution.
- Higher than expected demand corresponding with unavailability of resources is expected to be the leading cause of potential unserved energy.

New England - Supply and Demand on Risk Day – 07/03/2029

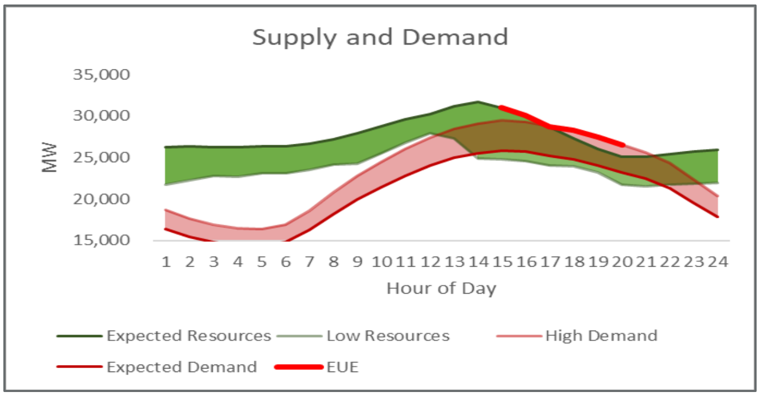

Figure 15(b) - 2029 New England Supply and Demand on Risk Day

Highlights

- The risk day in 2029 has the same drivers as was explained for the risk day in 2027.

Ontario

Ontario - Supply and Demand on Risk Day – 08/28/2027

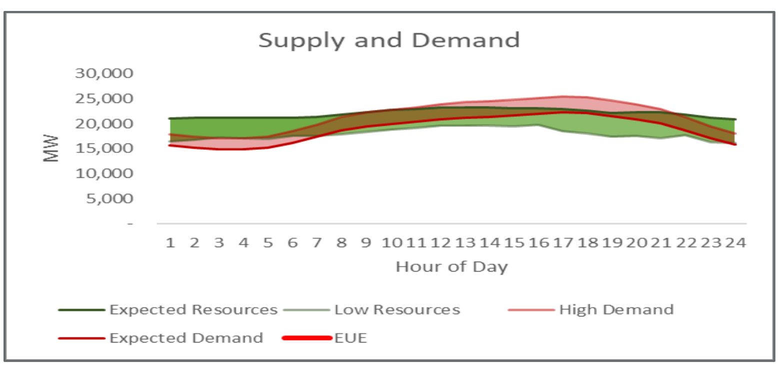

Figure 16(a) – 2027 Ontario Supply and Demand on Risk Day

Highlights

- In 2027, Ontario is expected to observe summer peaking demand conditions in the early to late afternoon hours.

- The evening ramp conditions could lead to additional strain on the system if resources fail to meet expectations.
- Higher than expected demand corresponding with unavailability of resources is expected to be the leading cause of potential unserved energy.

Ontario - Supply and Demand on Risk Day – 04/24/2029

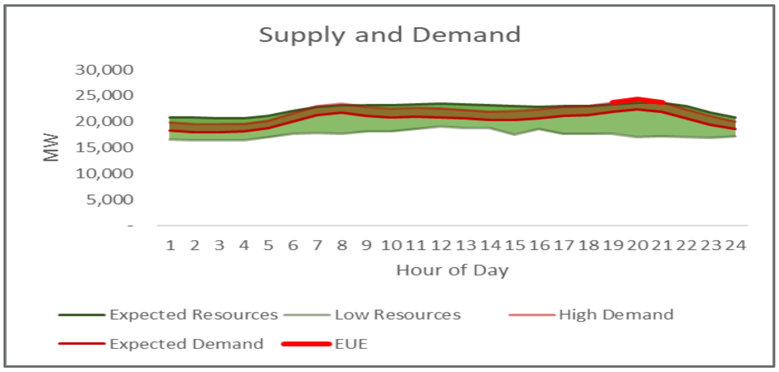

Figure 16(b) - 2029 Ontario Supply and Demand on Risk Day

Highlights

- In 2029, Ontario's risk day is shown to be during spring conditions, due to variable generation and maintenance.
- Planning for maintenance outages during lower load conditions can mitigate this risk.

Québec

Québec - Supply and Demand on Risk Day – 01/1/2028

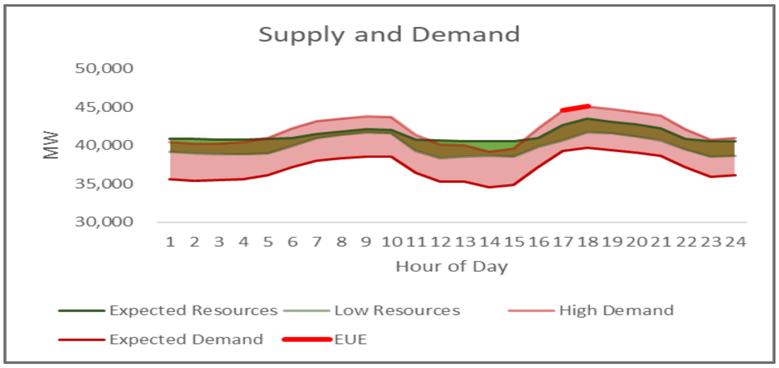

Figure 17(a) - 2027-28 Québec Supply and Demand on Risk Day

Highlights

- In the 2027-28 risk day, the highest risk is shown in the morning and evening hours, due to the possibility for higher-than-expected demand being greater than both expected resource contributions.
- Although the expected resource contribution is sufficient to meet the anticipated demand, there is a risk due to the variability in the demand forecast, with an additional risk stemming from the variability in resource contribution.
- Higher than expected demand corresponding with unavailability of resources is expected to be the leading cause of potential unserved energy.

Québec- Supply and Demand on Risk Day – 01/04/2030

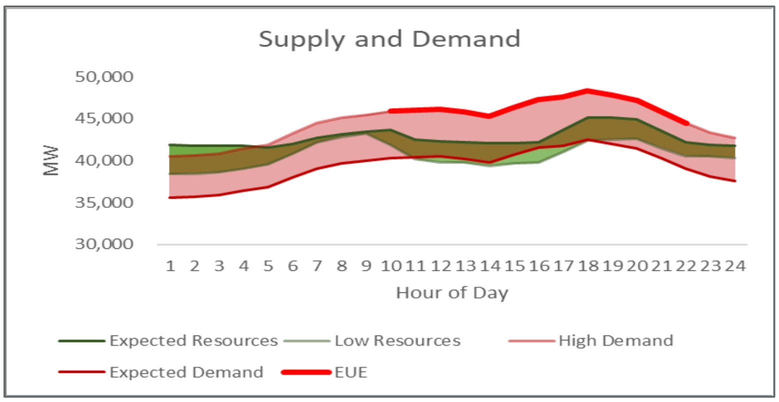

Figure 17(b) - 2029-30 Québec Supply and Demand on Risk Day

Highlights

- The risk day for 2029-30 has the same drivers as for 2027, though the expected load may remain high during midday in addition to morning and evening peaks.

Maritimes

Maritimes - Supply and Demand on Risk Day – 02/18/2028

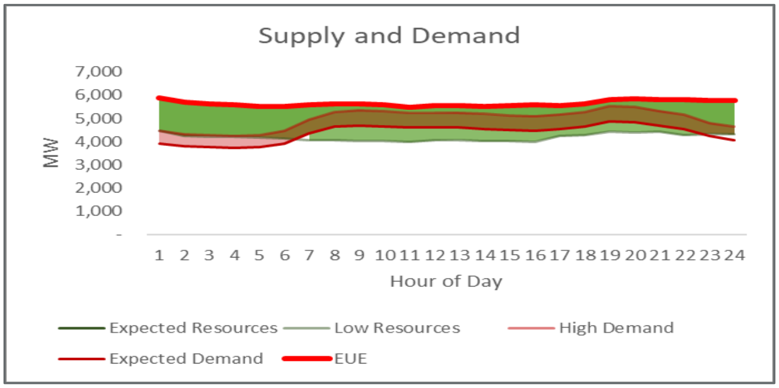

Figure 18(a) - 2027-28 Maritime Supply and Demand on Risk Day

Highlights

- In 2027-28, the Maritime is expected to observe morning peak demand conditions
- The morning ramp conditions could lead to additional strain on the system if resources fail to meet expectations.
- Although the expected resource contribution is sufficient to meet the anticipated demand, there is a risk due to the variability in the demand forecast, and the variability in resource contribution.
- Higher than expected demand corresponding with unavailability of resources is expected to be the leading cause of potential unserved energy.

Maritimes- Supply and Demand on Risk Day – 01/04/2030

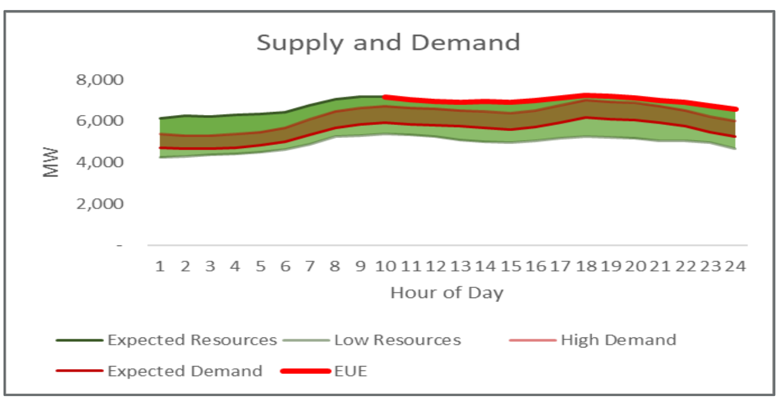

Figure 18(b) - 2029-30 Maritime Supply and Demand on Risk Day

Highlights

- In 2029-30, Maritime risk day has the same drivers as described for the risk day in 2027-28.

Appendix E: NERC Probabilistic Assessment Supporting Documentation

Base Case Results

	50/50 expected Load				
	HQ	MT	NE	NY	ON
Outside assistance	32.3	920	0.213	0.791	13.5
Activation of DR/SCR	2.1	0.000	0.000	0.622	0.173
Reduce 30-min Reserve	0.232	38.2	0.015	0.265	0.064
Interrupt. Loads/Voltage Reduction	0.007	18.7	0.003	0.042	0.003
Reduce 10-min Reserve	0.003	1.211	0.001	0.014	0.000
Appeals	0.000	0.097	0.001	0.010	0.000
Disconnect Load	0.000	0.097	0.000	0.002	0.000

Table 9(a) – Base Case Results for 2027 – LOLH (hours/year)

	50/50 expected Load				
	HQ	MT	NE	NY	ON
Outside assistance	214.3	8,323	1.2	3.5	64.2
Activation of DR/SCR	8.020	-	-	1.944	0.630
Reduce 30-min Reserve	0.176	91.1	0.065	0.652	0.188
Interrupt. Loads/Voltage Reduction	0.012	39.3	0.013	0.118	0.011
Reduce 10-min Reserve	0.005	2.120	0.005	0.030	0.000
Appeals	0.000	0.129	0.005	0.023	0.000
Disconnect Load	0.000	0.129	0.001	0.003	0.000

Table 9(b) – Base Case Results for 2027 – EUE (MWh of EUE per Million MWh of Annual Load Energy)

	50/50 expected Load				
	HQ	MT	NE	NY	ON
Outside assistance	43,317	251,283	136.9	531	9,821
Activation of DR/SCR	1,621	0.0	0.0	301.3	96.4
Reduce 30-min Reserve	35.5	2,747	7.6	101.0	28.7
Interrupt. Loads/Voltage Reduction	2.4	1,187	1.5	18.2	1.7
Reduce 10-min Reserve	1.0	64.0	0.6	4.6	0.0
Appeals	0.0	3.9	0.6	3.5	0.0
Disconnect Load	0.0	3.9	0.1	0.5	0.0

Table 9(c) – Base Case Results for 2027 – EUE (MWh of Unserved Energy)

	50/50 expected Load				
	HQ	**MT**	**NE**	**NY**	**ON**
Outside assistance	44.3	272.4	0.961	4.2	45.6
Activation of DR/SCR	8.043	0.000	0.000	3.2	1.4
Reduce 30-min Reserve	0.979	6.001	0.136	1.531	0.637
Interrupt. Loads/Voltage Reduction	0.158	1.901	0.051	0.405	0.003
Reduce 10-min Reserve	0.103	0.164	0.024	0.150	0.000
Appeals	0.027	0.019	0.020	0.121	0.000
Disconnect Load	0.026	0.019	0.004	0.035	0.000

Table 10(a) – Base Case Results for 2029 – LOLH (hours/year)

	50/50 expected Load				
	HQ	**MT**	**NE**	**NY**	**ON**
Outside assistance	312.5	2,011	6.4	22.0	207.6
Activation of DR/SCR	42.9	-	-	12.2	4.154
Reduce 30-min Reserve	1.704	20.9	0.881	5.3	1.948
Interrupt. Loads/Voltage Reduction	0.478	4.328	0.290	1.389	0.011
Reduce 10-min Reserve	0.292	0.297	0.131	0.449	0.002
Appeals	0.061	0.021	0.111	0.364	0.000
Disconnect Load	0.058	0.020	0.015	0.080	0.000

Table 10(b) – Base Case Results for 2029 – EUE (MWh of EUE per Million MWh of Annual Load Energy)

	50/50 expected Load				
	HQ	**MT**	**NE**	**NY**	**ON**
Outside assistance	66,447	60,929	771.0	3,493	34,700
Activation of DR/SCR	9,114	0.0	0.0	1,934	694.4
Reduce 30-min Reserve	362.3	632.2	107.0	835.7	325.6
Interrupt. Loads/Voltage Reduction	101.6	131.1	35.3	220.5	1.8
Reduce 10-min Reserve	62.2	9.0	15.9	71.3	0.3
Appeals	13.0	0.6	13.5	57.9	0.1
Disconnect Load	12.4	0.6	1.8	12.7	0.1

Table 10(c) – Base Case Results for 2029 – EUE (MWh of Unserved Energy)

Comparison with the 2024 Assessment

Starting in 2025, NERC has changed from conducting the ProbA biennially to annually. Therefore, there is no 2023 ProbA to compare to the 2025 ProbA's study year 2027 results. This comparison will instead compare the 2024 ProbA's study year 2026 results to the 2025 ProbA's study year 2027 results.

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh - ppm[45])	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2026*	152,990	31,900	37,649	0.012	0.011	21.4%
2027	157,220	32,280	38,957	0.003	0.002	24.5%
** 2026 results as reported in the 2024 ProbA (Applies to Tables 11(a) through 11(e))*						

Table 11(a) - New York 2024 assessment comparison for the years 2026 and 2027

The previous study, NERC 2024 *Long-Term Reliability Assessment*[46] estimated an annual LOLH = 0.011 hours/year and a corresponding EUE equal to 0.012 MWh - ppm for the year 2026. The Forecast 50/50 Peak Demand and Capacity Resources for 2027 are higher than reported for 2026 in the previous study, with a higher estimated Forecast Planning Margin. A decrease is estimated in LOLH and EUE between the two assessments, largely due to capacity increasing faster than load.

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh - ppm[45])	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2026*	120,106	24,702	29,952	0.660	0.331	21.3%
2027	118,591	24,945	29,999	0.001	0.000	22.9%

Table 11(b) - New England 2024 assessment comparison for the years 2026 and 2027

The previous study, NERC 2024 *Long-Term Reliability Assessment*[46] estimated an annual LOLH = 0.331 hours/year and a corresponding EUE equal to 0.660 (MWH - ppm) for the year 2026. The 2027 Load and Capacity numbers are similar to 2026 Forecasted values, though the probabilistic metrices are lower, due to differences in uncertainty with both load and resources.

[45] MWh of EUE per Million MWh of Annual Load Energy.
[46] See: NERC 2024 Long-Term Reliability Assessment.

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh - ppm[45])	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2026*	153,518	23,860	26,133	0.000	0.000	19.1%
2027	157,541	24,023	26,394	0.000	0.000	19.8%

Table 11(c) - Ontario 2024 assessment comparison for the years 2026 and 2027

The previous study, *NERC 2024 Long-Term Reliability Assessment*[46] estimated minimal risk of load loss in 2026, and all numbers and margins are roughly equal in the 2027 study.

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh - ppm[45])	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2026*	204,225	41,497	41,258	0.040	0.014	12.2%
2027	203,561	41,901	42,797	0.000	0.000	15.2%

Table 11(d) - Québec 2024 assessment comparison for the years 2026 and 2027

The previous study, *NERC 2024 Long-Term Reliability Assessment*[46] estimated an annual LOLH = 0.014 hours/year and a corresponding EUE equal to 0 MWh - ppm for the year 2026. The Forecast 50/50 Peak Demand for 2027 is slightly higher to that reported in the previous study; outpaced by an increase in the Forecast Capacity Resources and Forecast Planning Reserve Margin, resulting in slightly decreased LOLH and EUE for 2027.

Year	Net Energy for Load (GWh)	Forecast 50/50 Peak Demand (MW)	Forecast Capacity Resources (MW)	Expected Unsupplied Energy (EUE) (MWh - ppm[45])	Loss of Load Hours (LOLH) (hours/yr.)	Forecast Planning Reserve Margin (%)
2026*	29,265	6,056	6,985	0.172	0.087	20.8%
2027	29,102	6,157	6,959	0.523	0.247	16.9%

Table 11(e) - Maritimes 2024 assessment comparison for the years 2026 and 2027

The previous study, *NERC 2024 Long-Term Reliability Assessment*[46] estimated an annual LOLH = 0.087 hours/year and a corresponding EUE equal to 0.172 MWh - ppm for the year 2026. The 50/50 peak demand forecast for 2027 has increased significantly compared to the previous. As a result, the estimated LOLH and EUE increased in the current study.

Appendix F: Definitions

Net Energy for Load (GWh)	Energy Modeled (Input)
Total Internal Demand (MW)	Peak Load (Input)
Demand-Side Management – Available	Sum of DCLM, Interruptible Load, CPP, Load as Cap (from Form A) (Not probabilistic data)
Net Internal Demand (MW)	Peak Load - Demand-Side Management – Available
Capacity Expected on Peak	Sum of capacity by type modeled in probabilistic (Input)
Net Firm Import/Exports	Input
Forecast Capacity Resources (MW)	Capacity Expected on Peak + Net Firm Import/Exports - Capacity Adjustments
Weighted average forced outage	Input based on weighted EFOR by Area
Operable Capacity Resources	Sum of capacity expected on peak * weighted average forced outage rate by type
Forecast Operable Capacity Resources (MW)	Operable Capacity Resources + Net Firm Import/Exports - Capacity Adjustments
Expected Unsupplied Energy (EUE) (MWh)	Result (Input)
Loss of Load Hours (LOLH) (hours/year)	Result (Input)
Forecast Planning Reserve Margin (%)	Forecast Capacity Resources/Net Internal Demand – 1
Forecast Operable Reserve Margin (%)	Forecast Operable Capacity Resources / Net Internal Demand – 1

Appendix G: 2025 Corporate Goal

In accordance with the 2025 Corporate Goal recommendations, a Sensitivity Case was conducted to assess energy sufficiency within the NPCC footprint. This energy assessment identified considerations/risk by area within the NPCC footprint, considering the guidance provided within the NERC *Technical Reference Document*: *Considerations for Performing an Energy Reliability Assessment Volume* 1[47] *and* 2[48]. This assessment was conducted for Study Year 2029. The assumptions were created from the identified considerations/risk by area and are detailed in **Table 12**.

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47 See: Considerations for Performing an Energy Reliability Assessment ERATF White Paper.
48 See: Technical Reference Document: Considerations for Performing an Energy Reliability Assessment Volume 2.

	Identified Consideration/Risk	Sensitivity Case Assumptions for Study Year 2029
Maritimes	Aging generation fleet	Assumes increased DAFOR (derating-adjusted forced outage rate) for coal units nearing retirement • Based on historical performance data indicating higher outage rates as units approach end-of-life
New England	Variable energy resources (wind/solar) production assumptions	Applies an 80% reduction to all intermittent energy resources • Duration: 7 consecutive days • Based on analysis of a 1-in-100-year extreme weather event scenario
New York	Projected changes in actual demand magnitude and profile (load growth)	Utilizes Higher Demand Scenario load levels from the 2025 Gold Book,[10] reflecting: • Accelerated economic growth beyond baseline projections • Increased electric vehicle (EV) adoption • Higher rates of building electrification • Additional load growth from large-scale energy consumers
Ontario	Gas resources are only available until the end of their current contract	Assumes gas resources with expiring contracts will not be renewed • These resources are fully derated and excluded from reliable capacity calculations
Québec	Inter-annual hydro availability	Applies a flat 300 MW derate to capacity assumptions • Based on drought conditions observed during the 2023–2024 period and their impact on resource availability

Table 12 - Sensitivity Case Assumptions for NPCC Areas for Study Year 2029

The sensitivity case results, compared against the base case provided in **Tables 13–15**, applied the same 50/50 load levels across all NPCC areas except New York, which tested a higher demand scenario from the 2025 Gold Book.[10] While NYISO's higher load results appeared lower due to differing assumptions and methodology, overall system trends remained directionally consistent with the base case.

Table 13 below shows the estimated 50/50 load level annual NPCC Area Loss of Load Expectation (LOLE) for the year 2029 comparison of the sensitivity case. The expected load level results represent the probability-weighted average of all seven load levels simulated

	Maritimes	New England	New York	Ontario	Québec
Base Case	0.005	0.002	0.017	-	0.012
Sensitivity Case	0.007	0.007	0.104	0.007	0.024

Table 13 - Sensitivity and Base Case LOLE (Event Days/Year) Comparison for NPCC Areas for Study Year 2029

Table 14 below shows the estimated 50/50 load level annual NPCC Area Loss of Load Hours (LOLH) for the year 2029 comparison of the sensitivity case.

	Maritimes	New England	New York	Ontario	Québec
Base Case	0.019	0.004	0.035	-	0.026
Sensitivity Case	0.026	0.013	0.235	0.019	0.054

Table 14 - Sensitivity and Base Case LOLH (Event Hours/Year) Comparison for NPCC Areas for Study Year 2029

Table 15 below shows the estimated 50/50 load level annual NPCC Area Expected Unserved Energy (EUE) for the year 2029 comparison of the sensitivity case.

	Maritimes	New England	New York	Ontario	Québec
Base Case	0.620	1.795	12.742	0.050	12.383
Sensitivity Case	1.032	6.791	147.429	11.434	28.371

Table 15 - Sensitivity and Base Case EUE (MWh/Year) Comparison for NPCC Areas for Study Year 2029

Appendix H: Monthly LOLE, LOLH, and EUE Metrics

Figures 19(a), **19(b)**, **19(c)**, **19(d)**, and **19(e)** show the estimated monthly Area Loss of Load Expectation (LOLE), monthly Area Loss of Load Hours (LOLH), and monthly Expected Unserved Energy (EUE) for all NPCC areas for the 2026-2030 period for the 50/50 expected load level. **Figure 19(f)** shows the estimated monthly Area Loss of Load Expectation (LOLE), monthly Area Loss of Load Hours (LOLH), and monthly Expected Unserved Energy (EUE) for Neighboring Region's for the 2026-2030 period for the 50/50 expected load level.

	Base Case - Composite Load Shape																	
	Daily LOLE - 50/50 Expected Load Level						LOLH - 50/50 Expected Load Level						EUE - 50/50 Expected Load Level					
	Quebec						Quebec						Quebec					
	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.
2026-Jan	0.746	0.625	0.004	0.002	0.000	0.000	2.248	1.927	0.009	0.003	0.000	0.000	1,742.1	57.7	2.1	0.8	0.0	0.0
2026-Feb	0.080	0.067	-	-	-	-	0.137	0.110	-	-	-	-	66.5	0.8	-	-	-	-
2026-Mar	0.000	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.1	0.0	-	-	-	-
2026-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Dec	0.006	0.000	-	-	-	-	0.018	0.000	-	-	-	-	8.9	0.0	-	-	-	-
2027-Jan	0.593	0.053	0.004	0.002	0.000	0.000	1.828	0.223	0.007	0.003	0.000	0.000	1,452.0	35.5	2.4	1.0	0.0	0.0
2027-Feb	0.092	0.000	-	-	-	-	0.205	0.000	-	-	-	-	147.6	0.0	-	-	-	-
2027-Mar	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.1	-	-	-	-	-
2027-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Dec	0.012	0.003	-	-	-	-	0.037	0.008	-	-	-	-	21.3	0.1	-	-	-	-
2028-Jan	0.916	0.046	0.003	0.002	0.000	0.000	2.650	0.087	0.003	0.002	0.000	0.000	2,445.0	12.1	1.3	0.6	0.0	0.0
2028-Feb	0.177	0.002	0.000	-	-	-	0.433	0.003	0.000	-	-	-	315.4	0.3	0.0	-	-	-
2028-Mar	0.002	-	-	-	-	-	0.002	-	-	-	-	-	0.6	-	-	-	-	-
2028-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Nov	0.002	0.001	-	-	-	-	0.003	0.001	-	-	-	-	0.2	0.0	-	-	-	-
2028-Dec	0.063	0.003	0.000	0.000	-	-	0.251	0.007	0.000	0.000	-	-	205.8	1.1	0.0	0.0	-	-
2029-Jan	1.722	0.222	0.053	0.039	0.011	0.010	6.663	0.828	0.141	0.092	0.023	0.022	7,892.9	313.0	89.8	54.0	10.5	10.0
2029-Feb	0.241	0.005	0.000	-	-	-	0.578	0.016	0.000	-	-	-	361.6	3.1	0.0	-	-	-
2029-Mar	0.015	0.000	-	-	-	-	0.026	0.001	-	-	-	-	10.2	0.1	-	-	-	-
2029-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Aug	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Nov	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2029-Dec	0.165	0.036	0.003	0.002	0.001	0.001	0.777	0.135	0.016	0.011	0.004	0.004	849.6	46.2	11.8	8.2	2.5	2.4
2030-Jan	2.446	0.399	0.110	0.086	0.044	0.043	11.027	1.874	0.395	0.289	0.105	0.102	14,189.0	852.2	328.4	220.1	63.3	60.6
2030-Feb	0.402	0.029	0.001	0.000	0.000	0.000	0.952	0.089	0.001	0.000	0.000	0.000	644.0	17.2	0.4	0.2	0.0	0.0
2030-Mar	0.026	0.003	0.000	-	-	-	0.055	0.009	0.000	-	-	-	24.1	1.4	0.0	-	-	-
2030-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Jun	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2030-Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Aug	0.002	0.001	-	-	-	-	0.003	0.001	-	-	-	-	0.0	0.0	-	-	-	-
2030-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Nov	0.001	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.3	0.0	-	-	-	-
2030-Dec	0.299	0.071	0.017	0.014	0.008	0.008	1.572	0.353	0.070	0.051	0.028	0.027	1,973.6	184.9	68.3	51.5	21.6	20.7

Figure 19(a) - Estimated Monthly LOLE, LOLH, and EUE for NPCC Area Québec (2026 – 2030)

	Base Case - Composite Load Shape																	
	Daily LOLE - 50/50 Expected Load Level						LOLH - 50/50 Expected Load Level						EUE - 50/50 Expected Load Level					
	Maritimes						Maritimes						Maritimes					
	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.
2026-Jan	-	3.006	1.954	0.575	0.092	0.092	-	15.954	9.379	2.099	0.313	0.313	-	1,767.9	898.8	182.5	22.9	22.9
2026-Feb	-	4.449	3.119	0.782	0.090	0.090	-	27.713	16.498	2.841	0.314	0.314	-	2,537.5	1,440.1	217.4	20.0	20.0
2026-Mar	-	0.262	0.138	0.012	0.001	0.001	-	1.227	0.550	0.029	0.001	0.001	-	70.9	31.6	1.0	0.0	0.0
2026-Apr	-	0.010	0.003	0.000	-	-	-	0.032	0.009	0.000	-	-	-	1.2	0.3	0.0	-	-
2026-May	-	0.002	0.000	-	-	-	-	0.006	0.001	-	-	-	-	0.2	0.0	-	-	-
2026-Jun	-	0.080	0.051	0.001	-	-	-	0.550	0.258	0.002	-	-	-	33.1	13.8	0.1	-	-
2026-Jul	-	0.024	0.013	0.001	0.000	0.000	-	0.164	0.083	0.004	0.000	0.000	-	12.2	6.3	0.2	0.0	0.0
2026-Aug	-	0.061	0.032	0.000	-	-	-	0.321	0.124	0.000	-	-	-	15.9	5.4	0.0	-	-
2026-Sep	-	0.004	0.001	-	-	-	-	0.018	0.005	-	-	-	-	0.7	0.2	-	-	-
2026-Oct	-	0.154	0.099	0.001	-	-	-	0.989	0.435	0.004	-	-	-	55.4	21.4	0.1	-	-
2026-Nov	-	0.075	0.047	0.001	-	-	-	0.377	0.186	0.002	-	-	-	24.7	11.2	0.1	-	-
2026-Dec	-	0.126	0.063	0.016	0.003	0.003	-	0.437	0.197	0.037	0.005	0.005	-	20.2	8.6	1.0	0.1	0.1
2027-Jan	-	1.084	0.476	0.096	0.012	0.012	-	4.845	1.956	0.317	0.045	0.045	-	469.8	135.3	17.8	1.6	1.6
2027-Feb	-	2.051	1.257	0.166	0.010	0.010	-	11.816	6.193	0.629	0.040	0.040	-	905.5	446.4	37.9	2.1	2.1
2027-Mar	-	0.122	0.057	0.012	0.001	0.001	-	0.415	0.169	0.032	0.002	0.002	-	11.9	4.4	0.4	0.0	0.0
2027-Apr	-	0.002	0.001	-	-	-	-	0.004	0.001	-	-	-	-	0.2	0.0	-	-	-
2027-May	-	0.014	0.006	-	-	-	-	0.049	0.015	-	-	-	-	2.0	0.5	-	-	-
2027-Jun	-	0.029	0.020	0.000	-	-	-	0.179	0.090	0.001	-	-	-	11.6	5.1	0.0	-	-
2027-Jul	-	0.031	0.021	0.000	-	-	-	0.195	0.086	0.000	-	-	-	11.0	4.2	0.0	-	-
2027-Aug	-	0.317	0.206	0.003	0.000	0.000	-	1.882	0.887	0.008	0.000	0.000	-	114.7	47.7	0.2	0.0	0.0
2027-Sep	-	0.009	0.003	-	-	-	-	0.034	0.009	-	-	-	-	1.2	0.3	-	-	-
2027-Oct	-	2.644	1.743	0.043	0.001	0.001	-	18.193	8.957	0.175	0.003	0.003	-	1,191.1	530.8	6.9	0.1	0.1
2027-Nov	-	0.050	0.034	0.001	0.000	0.000	-	0.197	0.106	0.002	0.000	0.000	-	13.9	6.5	0.0	0.0	0.0
2027-Dec	-	0.142	0.071	0.022	0.003	0.003	-	0.411	0.187	0.048	0.007	0.007	-	14.7	6.0	0.8	0.1	0.1
2028-Jan	-	2.451	1.457	0.235	0.025	0.025	-	13.539	6.872	0.792	0.078	0.078	-	1,235.0	484.6	42.9	3.3	3.3
2028-Feb	-	2.824	1.972	0.302	0.031	0.031	-	17.588	10.409	1.261	0.157	0.157	-	1,583.9	846.9	92.3	11.7	11.7
2028-Mar	-	0.174	0.091	0.025	0.004	0.004	-	0.689	0.318	0.089	0.020	0.020	-	21.9	9.5	1.6	0.4	0.4
2028-Apr	-	0.002	0.001	0.000	0.000	0.000	-	0.006	0.002	0.001	0.000	0.000	-	0.1	0.0	0.0	0.0	0.0
2028-May	-	0.002	0.001	-	-	-	-	0.010	0.002	-	-	-	-	0.3	0.1	-	-	-
2028-Jun	-	0.000	0.000	-	-	-	-	0.001	0.001	-	-	-	-	0.1	0.0	-	-	-
2028-Jul	-	0.001	0.000	-	-	-	-	0.002	0.001	-	-	-	-	0.1	0.0	-	-	-
2028-Aug	-	0.162	0.128	0.005	0.000	0.000	-	0.975	0.549	0.019	0.000	0.000	-	73.1	35.3	0.7	0.0	0.0
2028-Sep	-	0.002	0.001	-	-	-	-	0.005	0.002	-	-	-	-	0.3	0.1	-	-	-
2028-Oct	-	0.036	0.029	0.000	-	-	-	0.181	0.095	0.000	-	-	-	11.9	5.1	0.0	-	-
2028-Nov	-	0.200	0.145	0.007	0.000	0.000	-	0.897	0.540	0.015	0.000	0.000	-	73.8	38.6	0.5	0.0	0.0
2028-Dec	-	0.147	0.082	0.011	0.001	0.001	-	0.567	0.272	0.026	0.002	0.002	-	38.0	16.6	0.9	0.0	0.0
2029-Jan	-	0.738	0.098	0.030	0.004	0.004	-	2.929	0.301	0.084	0.015	0.015	-	381.4	22.3	4.7	0.4	0.4
2029-Feb	-	0.217	0.083	0.008	0.001	0.001	-	0.830	0.330	0.030	0.003	0.003	-	76.4	23.9	2.0	0.2	0.2
2029-Mar	-	0.002	0.000	-	-	-	-	0.003	0.000	-	-	-	-	0.2	0.0	-	-	-
2029-Apr	-	0.000	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.0	0.0	-	-	-
2029-May	-	0.001	0.001	0.000	-	-	-	0.008	0.005	0.000	-	-	-	0.6	0.3	0.0	-	-
2029-Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Jul	-	0.000	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.0	0.0	-	-	-
2029-Aug	-	0.032	0.024	0.000	-	-	-	0.155	0.079	0.001	-	-	-	10.2	4.3	0.0	-	-
2029-Sep	-	0.001	0.000	-	-	-	-	0.002	0.001	-	-	-	-	0.1	0.0	-	-	-
2029-Oct	-	0.290	0.224	0.010	0.000	0.000	-	1.634	0.967	0.028	0.000	0.000	-	128.6	64.7	0.9	0.0	0.0
2029-Nov	-	0.007	0.004	0.000	0.000	0.000	-	0.022	0.011	0.001	0.000	0.000	-	1.6	0.9	0.0	0.0	0.0
2029-Dec	-	0.096	0.057	0.009	0.000	0.000	-	0.417	0.206	0.020	0.001	0.001	-	33.0	14.8	1.2	0.1	0.1
2030-Jan	-	1.461	0.589	0.103	0.011	0.011	-	7.367	2.383	0.306	0.036	0.036	-	1,026.7	219.9	30.7	3.2	3.2
2030-Feb	-	1.426	1.038	0.171	0.013	0.013	-	7.947	4.813	0.605	0.062	0.062	-	782.7	415.5	42.7	4.1	4.1
2030-Mar	-	0.021	0.011	0.000	0.000	0.000	-	0.090	0.050	0.001	0.000	0.000	-	7.3	3.1	0.1	0.0	0.0
2030-Apr	-	0.000	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.0	0.0	-	-	-
2030-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Jul	-	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-
2030-Aug	-	0.000	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.1	0.0	-	-	-
2030-Sep	-	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-
2030-Oct	-	0.001	0.001	0.000	-	-	-	0.004	0.002	0.000	-	-	-	0.2	0.1	0.0	-	-
2030-Nov	-	0.003	0.002	0.000	-	-	-	0.007	0.004	0.000	-	-	-	0.5	0.2	0.0	-	-
2030-Dec	-	0.081	0.040	0.006	0.001	0.001	-	0.323	0.135	0.015	0.002	0.002	-	29.0	10.7	1.1	0.1	0.1

Figure 19(b) - Estimated Monthly LOLE, LOLH, and EUE for NPCC Area Maritimes (2026 – 2030)

	Base Case - Composite Load Shape																	
	Daily LOLE - 50/50 Expected Load Level						LOLH - 50/50 Expected Load Level						EUE - 50/50 Expected Load Level					
	New England						New England						New England					
	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.
2026-Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Jun	-	0.002	0.001	0.001	0.001	0.000	-	0.010	0.004	0.002	0.002	0.001	-	6.6	2.4	1.6	1.6	0.3
2026-Jul	-	0.010	0.003	0.001	0.001	0.000	-	0.027	0.007	0.003	0.003	0.000	-	16.1	4.1	1.8	1.6	0.1
2026-Aug	-	0.003	0.000	0.000	0.000	0.000	-	0.005	0.001	0.000	0.000	0.000	-	2.2	0.3	0.0	0.0	0.0
2026-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Jun	-	0.003	0.001	0.000	0.000	0.000	-	0.007	0.002	0.001	0.001	0.000	-	3.6	1.0	0.5	0.5	0.1
2027-Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Aug	-	0.004	0.001	0.000	0.000	0.000	-	0.008	0.001	0.000	0.000	0.000	-	4.0	0.5	0.1	0.0	0.0
2027-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Jun	-	0.011	0.004	0.001	0.001	0.000	-	0.024	0.008	0.003	0.003	0.000	-	16.5	4.6	1.7	1.5	0.1
2028-Jul	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Aug	-	0.009	0.003	0.001	0.001	0.000	-	0.017	0.006	0.002	0.002	0.000	-	11.9	3.3	1.2	1.0	0.1
2028-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Jun	-	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-
2029-Jul	-	0.035	0.014	0.007	0.006	0.001	-	0.081	0.031	0.015	0.012	0.002	-	65.7	21.9	10.1	8.4	1.3
2029-Aug	-	0.028	0.011	0.006	0.005	0.001	-	0.056	0.020	0.009	0.008	0.001	-	41.4	13.3	5.8	5.0	0.5
2029-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Jan	-	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-
2030-Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Jun	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Jul	-	0.050	0.022	0.010	0.008	0.002	-	0.117	0.049	0.023	0.019	0.004	-	90.7	31.3	14.4	12.6	2.1
2030-Aug	-	0.017	0.006	0.003	0.003	0.000	-	0.034	0.012	0.005	0.005	0.001	-	24.0	7.2	3.3	3.0	0.4
2030-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 19(c) - Estimated Monthly LOLE, LOLH, and EUE for NPCC Area New England (2026 – 2030)

	Base Case - Composite Load Shape																	
	Daily LOLE - 50/50 Expected Load Level						LOLH - 50/50 Expected Load Level						EUE - 50/50 Expected Load Level					
	New York						New York						New York					
	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.
2026-Jan	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2026-Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Jun	0.079	0.032	0.010	0.005	0.004	0.001	0.194	0.077	0.022	0.010	0.008	0.002	140.1	42.4	12.5	4.2	3.5	0.8
2026-Jul	0.176	0.089	0.030	0.011	0.008	0.003	0.540	0.246	0.071	0.024	0.018	0.006	370.7	158.8	42.0	12.6	9.6	2.0
2026-Aug	0.141	0.081	0.014	0.006	0.004	0.002	0.339	0.190	0.029	0.012	0.008	0.004	160.2	61.1	9.9	2.9	2.1	0.5
2026-Sep	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2026-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Dec	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2027-Jan	0.001	0.000	0.000	0.000	0.000	-	0.002	0.000	0.000	0.000	0.000	-	0.5	0.0	0.0	0.0	0.0	-
2027-Feb	0.000	0.000	0.000	-	-	-	0.000	0.000	0.000	-	-	-	0.1	0.0	0.0	-	-	-
2027-Mar	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2027-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Jun	0.071	0.034	0.008	0.003	0.003	0.001	0.173	0.080	0.016	0.006	0.005	0.001	109.6	34.3	8.1	2.5	2.1	0.3
2027-Jul	0.067	0.029	0.005	0.001	0.001	0.000	0.135	0.053	0.007	0.001	0.001	0.000	45.2	17.7	2.6	0.5	0.3	0.0
2027-Aug	0.125	0.057	0.009	0.003	0.002	0.001	0.311	0.132	0.019	0.006	0.004	0.001	145.6	48.9	7.5	1.6	1.1	0.2
2027-Sep	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2027-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Dec	0.000	0.000	0.000	0.000	0.000	-	0.001	0.000	0.000	0.000	0.000	-	0.3	0.0	0.0	0.0	0.0	-
2028-Jan	0.010	0.002	0.000	0.000	0.000	0.000	0.018	0.003	0.001	0.000	0.000	0.000	8.5	1.4	0.2	0.1	0.1	0.0
2028-Feb	0.001	0.000	0.000	0.000	0.000	-	0.001	0.000	0.000	0.000	0.000	-	0.4	0.1	0.0	0.0	0.0	-
2028-Mar	0.000	0.000	0.000	-	-	-	0.000	0.000	0.000	-	-	-	0.1	0.0	0.0	-	-	-
2028-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Jun	0.178	0.078	0.029	0.010	0.008	0.002	0.510	0.209	0.066	0.020	0.015	0.003	317.6	130.2	36.2	9.6	7.3	1.3
2028-Jul	0.097	0.049	0.007	0.002	0.001	0.000	0.189	0.093	0.011	0.003	0.002	0.000	56.0	25.1	3.5	0.7	0.4	0.0
2028-Aug	0.361	0.162	0.042	0.014	0.010	0.002	0.886	0.390	0.088	0.026	0.018	0.004	446.2	184.5	39.4	9.7	7.1	1.1
2028-Sep	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2028-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Dec	0.013	0.003	0.001	0.000	0.000	0.000	0.019	0.004	0.002	0.001	0.001	0.000	9.0	1.7	0.8	0.2	0.2	0.0
2029-Jan	0.148	0.038	0.008	0.002	0.002	0.000	0.281	0.069	0.013	0.003	0.003	0.000	195.4	45.5	6.1	1.3	1.2	0.1
2029-Feb	0.011	0.002	0.001	0.000	0.000	0.000	0.013	0.003	0.001	0.000	0.000	0.000	6.0	1.0	0.3	0.0	0.0	0.0
2029-Mar	0.001	0.000	0.000	0.000	0.000	-	0.001	0.000	0.000	0.000	0.000	-	0.3	0.0	0.0	0.0	0.0	-
2029-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Jun	0.008	0.003	0.000	0.000	0.000	0.000	0.014	0.005	0.000	0.000	0.000	0.000	3.0	1.0	0.1	0.0	0.0	0.0
2029-Jul	0.511	0.307	0.091	0.039	0.033	0.010	1.473	0.780	0.217	0.090	0.074	0.022	947.1	442.4	126.6	44.8	36.9	8.5
2029-Aug	0.553	0.279	0.082	0.027	0.021	0.006	1.360	0.667	0.173	0.056	0.044	0.013	761.0	342.1	86.8	25.0	19.6	4.1
2029-Sep	0.001	0.000	0.000	0.000	0.000	-	0.002	0.001	0.000	0.000	0.000	-	0.5	0.2	0.0	0.0	0.0	-
2029-Oct	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2029-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Dec	0.020	0.004	0.001	0.000	0.000	0.000	0.034	0.007	0.001	0.000	0.000	0.000	20.3	3.5	0.5	0.1	0.1	0.0
2030-Jan	0.127	0.030	0.002	0.000	0.000	0.000	0.225	0.052	0.003	0.001	0.000	0.000	110.5	25.1	1.3	0.2	0.1	0.0
2030-Feb	0.008	0.003	0.000	0.000	0.000	0.000	0.008	0.003	0.000	0.000	0.000	0.000	6.3	1.4	0.2	0.1	0.0	0.0
2030-Mar	0.005	0.001	0.000	0.000	0.000	-	0.006	0.002	0.000	0.000	0.000	-	4.3	0.9	0.1	0.0	0.0	-
2030-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-May	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2030-Jun	0.006	0.001	0.000	0.000	0.000	-	0.010	0.002	0.000	0.000	0.000	-	2.9	0.7	0.1	0.0	0.0	-
2030-Jul	0.602	0.334	0.124	0.055	0.044	0.012	1.815	0.926	0.311	0.120	0.097	0.024	1,350.9	616.4	190.9	64.9	53.9	10.5
2030-Aug	0.586	0.293	0.100	0.033	0.026	0.005	1.451	0.699	0.210	0.065	0.051	0.008	907.1	411.0	108.3	30.2	23.6	3.2
2030-Sep	0.002	0.000	0.000	-	-	-	0.002	0.000	0.000	-	-	-	0.8	0.1	0.0	-	-	-
2030-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Nov	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2030-Dec	0.033	0.005	0.000	0.000	0.000	-	0.063	0.010	0.000	0.000	0.000	-	28.0	3.8	0.1	0.0	0.0	-

Figure 19(d) - Estimated Monthly LOLE, LOLH, and EUE for NPCC Area New York (2026 – 2030)

Base Case - Composite Load Shape																		
	Daily LOLE - 50/50 Expected Load Level						LOLH - 50/50 Expected Load Level						EUE - 50/50 Expected Load Level					
	Ontario						Ontario						Ontario					
	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.
2026-Jan	0.002	0.001	-	-	-	-	0.003	0.001	-	-	-	-	0.4	0.1	-	-	-	-
2026-Feb	0.000	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.1	0.0	-	-	-	-
2026-Mar	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2026-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-May	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2026-Jun	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.1	0.1	-	-	-	-
2026-Jul	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2026-Aug	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.1	-	-	-	-	-
2026-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Dec	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2027-Jan	0.003	0.001	-	-	-	-	0.004	0.001	-	-	-	-	0.6	0.2	-	-	-	-
2027-Feb	0.012	0.005	0.000	0.000	-	-	0.025	0.009	0.000	0.000	-	-	5.7	2.5	0.0	0.0	-	-
2027-Mar	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2027-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-May	0.001	0.000	0.000	-	-	-	0.002	0.001	0.000	-	-	-	1.0	0.6	0.0	-	-	-
2027-Jun	0.001	0.000	0.000	-	-	-	0.001	0.000	0.000	-	-	-	0.4	0.1	0.0	-	-	-
2027-Jul	0.020	0.004	0.000	-	-	-	0.049	0.009	0.000	-	-	-	29.2	3.0	0.0	-	-	-
2027-Aug	0.030	0.013	0.001	0.000	0.000	0.000	0.088	0.042	0.003	0.000	0.000	0.000	58.8	21.9	1.6	0.0	0.0	0.0
2027-Sep	0.000	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.2	0.0	-	-	-	-
2027-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Nov	0.001	0.001	-	-	-	-	0.001	0.001	-	-	-	-	0.5	0.2	-	-	-	-
2027-Dec	0.000	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.1	0.0	-	-	-	-
2028-Jan	0.011	0.003	0.000	-	-	-	0.018	0.004	0.000	-	-	-	3.1	1.0	0.0	-	-	-
2028-Feb	0.005	0.002	-	-	-	-	0.010	0.003	-	-	-	-	2.1	0.8	-	-	-	-
2028-Mar	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2028-Apr	0.000	0.000	-	-	-	-	0.001	0.000	-	-	-	-	0.1	0.1	-	-	-	-
2028-May	0.002	0.001	-	-	-	-	0.004	0.002	-	-	-	-	1.4	0.6	-	-	-	-
2028-Jun	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2028-Jul	0.003	0.000	-	-	-	-	0.006	0.000	-	-	-	-	2.5	0.0	-	-	-	-
2028-Aug	0.006	0.001	-	-	-	-	0.014	0.002	-	-	-	-	8.7	0.9	-	-	-	-
2028-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Nov	0.190	0.143	0.001	0.000	0.000	0.000	0.467	0.340	0.004	0.001	0.000	0.000	280.2	197.2	3.1	0.6	0.2	0.1
2028-Dec	0.075	0.047	0.000	0.000	-	-	0.163	0.099	0.000	0.000	-	-	80.1	47.0	0.1	0.0	-	-
2029-Jan	0.229	0.099	0.000	0.000	-	-	0.442	0.180	0.000	0.000	-	-	145.8	62.1	0.0	0.0	-	-
2029-Feb	0.158	0.098	0.000	0.000	0.000	0.000	0.372	0.229	0.001	0.000	0.000	0.000	189.2	122.3	0.4	0.1	0.0	0.0
2029-Mar	0.020	0.012	0.000	-	-	-	0.036	0.022	0.000	-	-	-	17.3	10.7	0.0	-	-	-
2029-Apr	0.031	0.024	0.001	0.000	0.000	0.000	0.115	0.090	0.001	0.000	0.000	0.000	80.2	60.3	0.9	0.2	0.1	0.0
2029-May	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2029-Jun	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.1	0.1	-	-	-	-
2029-Jul	0.063	0.013	0.000	0.000	-	-	0.159	0.032	0.000	0.000	-	-	98.6	19.6	0.1	0.0	-	-
2029-Aug	0.070	0.025	0.000	0.000	-	-	0.204	0.074	0.001	0.000	-	-	154.5	46.9	0.4	0.0	-	-
2029-Sep	0.004	0.003	-	-	-	-	0.009	0.005	-	-	-	-	3.9	2.2	-	-	-	-
2029-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Nov	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2029-Dec	0.009	0.003	0.000	0.000	0.000	-	0.017	0.005	0.000	0.000	0.000	-	4.8	1.5	0.0	0.0	0.0	-
2030-Jan	0.583	0.358	0.001	0.000	0.000	0.000	1.299	0.725	0.001	0.000	0.000	0.000	579.8	322.2	0.5	0.0	0.0	0.0
2030-Feb	0.340	0.237	0.002	0.000	0.000	0.000	0.895	0.614	0.004	0.001	0.000	0.000	567.1	394.7	2.7	0.3	0.0	0.0
2030-Mar	0.042	0.028	0.000	0.000	0.000	-	0.085	0.055	0.001	0.000	0.000	-	44.5	25.8	0.1	0.0	0.0	-
2030-Apr	0.002	0.001	0.000	-	-	-	0.005	0.003	0.000	-	-	-	2.8	2.0	0.0	-	-	-
2030-May	0.000	0.000	-	-	-	-	0.000	0.000	-	-	-	-	0.0	0.0	-	-	-	-
2030-Jun	0.001	-	-	-	-	-	0.001	-	-	-	-	-	0.8	-	-	-	-	-
2030-Jul	0.029	0.009	0.000	-	-	-	0.069	0.019	0.000	-	-	-	37.9	9.1	0.0	-	-	-
2030-Aug	0.046	0.007	0.000	-	-	-	0.132	0.015	0.000	-	-	-	99.5	8.5	0.0	-	-	-
2030-Sep	0.001	0.001	-	-	-	-	0.003	0.001	-	-	-	-	1.1	0.6	-	-	-	-
2030-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Nov	0.009	0.006	0.000	0.000	-	-	0.018	0.012	0.000	0.000	-	-	10.1	6.6	0.1	0.0	-	-
2030-Dec	0.152	0.086	0.002	0.001	0.000	0.000	0.371	0.203	0.003	0.001	0.000	0.000	194.2	102.5	0.8	0.1	0.1	0.0

Figure 19(e) - Estimated Monthly LOLE, LOLH, and EUE for NPCC Area Ontario (2026 – 2030)

	Base Case - Composite Load Shape																	
	Daily LOLE - 50/50 Expected Load Level						LOLH - 50/50 Expected Load Level						EUE - 50/50 Expected Load Level					
	MISO						MISO						MISO					
	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.	Cur.Ld	30-min	VR	10-min	Appeal	Disc.
2026-Jan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Jun	0.008	0.000	-	-	-	-	0.030	0.000	-	-	-	-	51.0	0.0	-	-	-	-
2026-Jul	0.068	0.000	0.000	-	-	-	0.209	0.001	0.000	-	-	-	504.9	0.8	0.0	-	-	-
2026-Aug	0.000	-	-	-	-	-	0.001	-	-	-	-	-	0.6	-	-	-	-	-
2026-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2026-Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Jan	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2027-Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Jun	0.010	-	-	-	-	-	0.036	-	-	-	-	-	62.9	-	-	-	-	-
2027-Jul	0.320	0.012	0.003	0.000	0.000	0.000	1.178	0.034	0.007	0.001	0.000	0.000	3,162.1	68.8	9.7	0.6	0.0	0.0
2027-Aug	0.003	-	-	-	-	-	0.006	-	-	-	-	-	3.3	-	-	-	-	-
2027-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2027-Dec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Jan	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.1	-	-	-	-	-
2028-Feb	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Jun	0.031	0.000	-	-	-	-	0.111	0.000	-	-	-	-	215.5	0.2	-	-	-	-
2028-Jul	0.866	0.049	0.012	0.003	0.001	0.000	3.233	0.140	0.034	0.007	0.001	0.001	8,448.2	272.2	52.0	7.2	1.0	0.6
2028-Aug	0.010	-	-	-	-	-	0.024	-	-	-	-	-	19.9	-	-	-	-	-
2028-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2028-Dec	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2029-Jan	0.001	-	-	-	-	-	0.001	-	-	-	-	-	0.7	-	-	-	-	-
2029-Feb	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2029-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Jun	0.075	0.004	0.000	0.000	-	-	0.280	0.010	0.001	0.000	-	-	618.6	12.6	0.9	0.0	-	-
2029-Jul	2.272	0.196	0.050	0.012	0.004	0.003	9.553	0.620	0.149	0.031	0.010	0.007	23,889.8	1,154.0	215.0	36.0	10.7	7.3
2029-Aug	0.524	0.017	0.001	0.000	0.000	0.000	2.089	0.044	0.003	0.000	0.000	0.000	4,306.6	46.5	2.7	0.1	0.0	0.0
2029-Sep	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Oct	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2029-Dec	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.2	-	-	-	-	-
2030-Jan	0.002	-	-	-	-	-	0.003	-	-	-	-	-	1.9	-	-	-	-	-
2030-Feb	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2030-Mar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Apr	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Jun	0.252	0.017	0.003	0.001	0.000	0.000	0.964	0.052	0.010	0.002	0.000	0.000	2,053.3	82.7	12.1	1.5	0.4	0.3
2030-Jul	4.887	0.670	0.191	0.050	0.019	0.015	24.066	2.431	0.621	0.145	0.054	0.040	68,506.4	4,664.6	937.0	181.5	62.5	43.7
2030-Aug	0.735	0.056	0.007	0.001	0.000	0.000	3.018	0.167	0.019	0.002	0.000	0.000	7,976.9	214.4	18.1	1.2	0.2	0.1
2030-Sep	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.0	-	-	-	-	-
2030-Oct	0.000	-	-	-	-	-	0.000	-	-	-	-	-	0.2	-	-	-	-	-
2030-Nov	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2030-Dec	0.003	-	-	-	-	-	0.006	-	-	-	-	-	4.0	-	-	-	-	-

Figure 19(f) - Estimated Monthly LOLE, LOLH, and EUE for NPCC's Neighboring Region MISO (2026 – 2030)

NPCC is dedicated to the continued reliability of the Bulk Power System in Northeastern North America.

NPCC

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