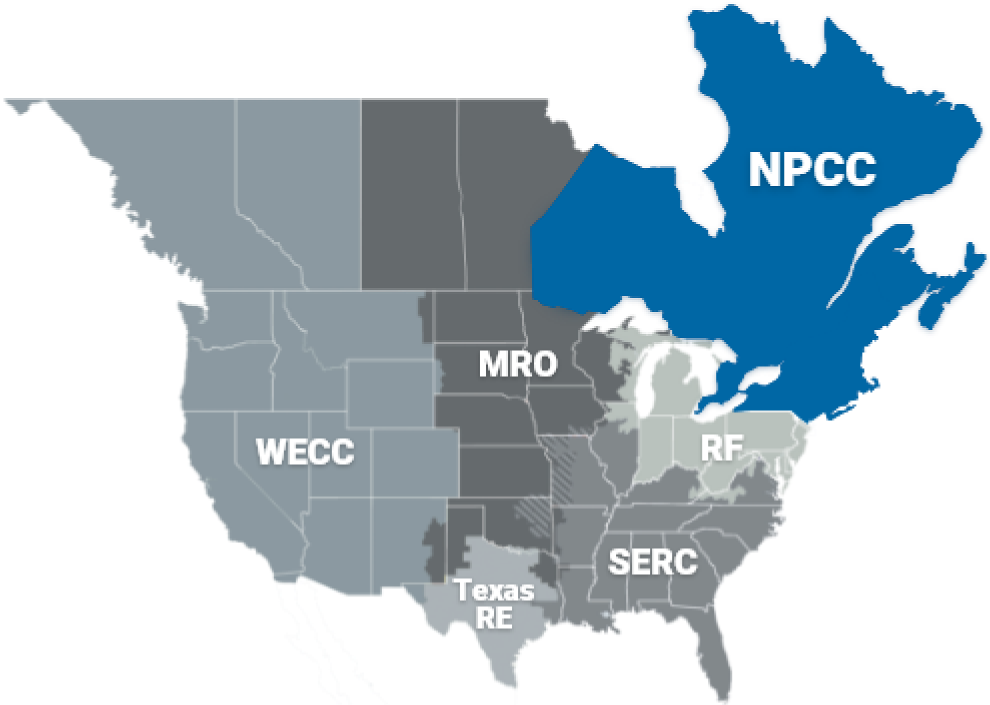
Northeast Power Coordinating Council

Reliability Assessment
For
Summer 2024



FINAL REPORT

Approved by NPCC TFCP/TFCO on April 29, 2024
Revised May 10, 2024

Conducted by the
NPCC CO-12 & CP-8 Working Groups

THE INFORMATION IN THIS REPORT IS PROVIDED BY THE CO-12 OPERATIONS PLANNING WORKING GROUP OF THE NPCC TASK FORCE ON COORDINATION OF OPERATION (TFCO) AND THE CP-8 WORKING GROUP OF THE TASK FORCE ON COORDINATION OF PLANNING. ADDITIONAL INFORMATION PROVIDED BY RELIABILITY COUNCILS ADJACENT TO NPCC.

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The team acknowledges the efforts of Richard Becker, Alexis Gogola, and Shannon Tucker, Mitch Bringolf (formerly of GE) GE Energy Consulting, Cary Oler of the Solar Terrestrial Dispatch, Andreas Klaube (formerly of NPCC), Andrey Oks and Michael Lombardi of the Northeast Power Coordinating Council, Inc., and Patricio Rocha-Garrido, PJM Interconnection, and thank them for their assistance in this analysis.

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1. **Executive Summary**

This report is based on the work of the NPCC CO-12 Operations Planning Working Group and focuses on the assessment of reliability within the NPCC Region for the 2024 Summer Operating Period. Portions of this report were based on work previously completed for the NPCC Reliability Assessment for the 2024 Summer Operating Period. [1]

The NPCC CP-8 Working Group on the Review of Resource and Transmission Adequacy provides a seasonal multi-area probabilistic reliability assessment. Results of this assessment are included later in this report (Chapter 9) and supporting documentation is provided in Appendix VIII.

The results of the studies performed by CO-12 (deterministic) and CP-8 (probabilistic) Working Groups indicate that under Base Case conditions, only New York Area shows a likelihood greater than 0.5 days/period of using their Operating Procedures (activating their demand response programs) designed to mitigate resource shortages during the 2024 summer period for the expected 50/50 peak load forecast (representing the probability weighted average of all seven load levels modeled). The probabilistic analysis indicates the estimated use of the established NPCC Area's operating procedures during the Summer of 2024. In addition, the results indicate a greater cumulative likelihood of New England and New York using more of their Operating Procedures and relying on imports to mitigate resource shortages for the Severe Case Scenario assuming the highest peak load levels. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. However, the resource and transmission assessments in this report are mere snapshots in time and base case studies. Continued vigilance is required to monitor changes to any of the assumptions that can potentially alter the report's findings.

The forecasted coincident peak demand for NPCC occurs during the peak week (week beginning August 11, 2024) [2] is 105,014 MW. The capacity outlook indicates a forecasted Net Margin for that week of 12,382 MW. This equates to a net margin of 11.8% in terms of the 105,014 MW forecasted peak demand. Unless otherwise noted, all forecasted demands are 50/50 net peak forecasts. The minimum forecasted NPCC "Revised Net Margin" (including bottled resources) of 6,046 MW (or 5.9%) is expected to occur during the week beginning June 9, 2024. This is a decrease from last year and can mainly be attributed to decreases in maintenance and projected derate values paired with a decrease in installed capacity.

The Maritimes Area has forecasted a 2024 summer (excluding April, May, and September) peak demand of 3,524 MW for the week beginning July 21, 2024, with a projected net margin of 978 MW (27.8%). The Maritimes expects to have sufficient resources for the duration of the 2024 summer with the smallest net margins of 16.1% and 9.3% for the respective 50/50 and 90/10 cases during the week beginning September 8, 2024.

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[1] The NPCC Assessments can be downloaded from the NPCC website: https://www.npcc.org/library/reports/seasonal-assessment

[2] Load and Capacity Forecast Summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in Appendix I.

The New England Area expects to have sufficient resources to meet the 2024 summer peak demand forecast of 24,553 MW, for the weeks beginning June 2 through week beginning September 15, 2024, with the lowest projected net margin of -525 MW (-2.1%) during the weeks of June 2, 2024 through June 23, 2024. This margin assumes a Net Interchange of 1,194 MW, which is capacity backed. However, ISO-NE typically imports around 3,000 MW [3] during summer peak load conditions. Additionally, 330 MW of resources are currently on emergency outage but are scheduled to be available during the summer operating period. The 2024 summer demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.

The New York Area anticipates adequate resources to meet demand for the 2024 Summer Operating Period. The 2024 summer peak forecast is 31,541 MW and anticipated net margins for the expected summer peak period (June 16 through September 8) are at a minimum of 508 MW (1.6%).

The forecasted 2024 Ontario summer peak demand is 22,753 MW for 50/50 weather (week beginning July 14, 2024) and 24,669 MW for 90/10 weather (week beginning July 21, 2024). Ontario does not anticipate adequacy concerns under 50/50 conditions and expects to be adequate for 90/10 conditions with the availability of imports or other operating control actions.

The Québec Area forecasted summer peak demand (excluding April, May, and September) is 22, 922 MW during the week beginning August 11, 2024, with a forecasted net margin of 7,423 MW (32.4%). No particular resource adequacy problems are forecasted, and the Québec Area expects to be able to provide assistance to other areas, if needed, up to the transfer capability available.

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[3] See https://www.npcc.org/content/docs/public/library/publications/tie-benefits/2024-2028-review-of-interconnection-assistance-reliability-benefits.pdf

2. Introduction

The NPCC Task Force on Coordination of Operation (TFCO) established the CO-12 Operations Planning Working Group to conduct overall assessments of the reliability of the generation and transmission system in the NPCC Region for the Summer Operating Period (defined as the months of May through September) and the Winter Operating Period (defined as the months of December through March). The Working Group may occasionally study other operating periods or specific conditions as requested by the TFCO.

For the 2024 Summer Operating Period, [4] the CO-12 Working Group:

- Examined historical summer operating experiences and assessed their applicability for this period.
- Examined the existing emergency operating procedures available within NPCC and reviewed recent operating procedure additions and revisions.
- Reflected the results of the NPCC CP-8 Working Group's probabilistic assessment [5] of the implementation of operating procedures for the 2024 Summer Operating Period.
- Reported potential sensitivities that may impact resource adequacy on a Reliability Coordinator (RC) Area basis. These sensitivities may include temperature variations, capacity factors of renewables generation resources, in-service delays of new generation, load forecast uncertainties, evolving load response measures, fuel availability, system voltage and generator reactive capability limits.
- Reviewed the capacity margins for 50/50, 90/10 and Above 90/10 system load forecasts, while accounting for assumed resource outages, derates and bottled capacity within the NPCC region.
- Reviewed inter-Area and intra-Area transmission adequacy, including new transmission projects, upgrades or derates and potential transmission problems.
- Reviewed the Operational Readiness of the NPCC region and actions to mitigate potential problems.
- Coordinated data and modeling assumptions with the NPCC CP-8 Working Group and documented the methodology of each Reliability Coordinator Area in its projection of load forecasts.
- Coordinated with other parallel seasonal operational assessments, including the NERC Reliability Assessment Subcommittee [6] (RAS) 2024 Summer Reliability Assessment (NERC SRA).

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[4] For the purpose of this report, the Summer Operating Period evaluation will include operating conditions from week beginning May 5, 2024 through the week beginning September 22, 2024.

[5] The CP-8 WG assessment conclusions are included in this report as Chapter 9 and Appendix IX.

[6] Reliability Assessment Subcommittee (RAS) (nerc.com)

3. Demand Forecasts for Summer 2024

The coincident peak demand of 105,014 MW is expected during the week beginning August 11, 2024. For reference, the all-time NPCC coincident peak demand for summer was 112,384 MW on August 1, 2006. The all-time NPCC coincident peak demand was 112,552 on February 3, 2023. Demand and Capacity forecast summaries for the NPCC Region, Maritimes, New England, New York, Ontario, and Québec are included in Appendix I. The corresponding assumptions used in the probabilistic assessment are described in Appendix VIII.

Ambient weather conditions are the single most important variable impacting the demand forecasts during the summer months. As a result, each Reliability Coordinator is aware that the summer peak demand could occur during any week of the summer period because of these weather variables. Historically, the peak demands and temperatures between New England and New York can have a high degree of correlation due to the relative locations of their respective load centers. Based on the extent and duration of a weather system, there is the potential for the Ontario peak demand to be coincident with New England and New York as well. It should also be noted that the non-coincident peak demand calculation is impacted primarily by the fact that the Maritimes and Québec experience late spring demands influenced by heating loads that occur during the defined Summer Operating Period.

The impact of ambient weather conditions on load forecasts can be demonstrated by various means. The Maritimes and Ontario represent the resulting load forecast uncertainty in their respective Areas as a mathematical function of the base load. ISO New England updates the Load Forecast for the New England Area twice daily, on a seven-day time horizon in each forecast. The Load Forecast models are provided with a weather input of an eight-city weighted average dry bulb temperature, dew point, wind speed, cloud cover and precipitation. Zonal load forecasts are produced for the eight Load Zones across New England using the same weather inputs with different locational weightings. The NYISO uses a weather index that relates air temperature and humidity to the load response and increases the load by a MW factor for each degree above the base value. Hydro-Québec, the Québec system operator, updates Area forecasts on an hourly basis within a 12-day horizon based on information on local weather, wind speed, cloud cover, sunlight incidence and type and intensity of precipitation over nine regions of the Québec Balancing Authority Area.

While most of the peak demands appear to be confined to the operating weeks in late June through August, each Area is aware that reduced margins could occur during any week of the operating period as a result of weather variables and/or higher than normal outage rates.

The method each Reliability Coordinator uses to determine the peak forecast demand and the associated load forecast uncertainty relating to weather variables is described in Appendix IV. Below is a summary of all Reliability Coordinator forecasts. The historical peak demands for each week are indicated by the "Historical Peak Load" markers on the corresponding figures.

Summary of Reliability Coordinator Forecasts

Maritimes

	Summer 2024 Forecasted Peak: week beginning Sept 22, 2024	Summer 2023 Forecasted Peak: week beginning June 4, 2023	Summer 2023 Actual Peak: May 5, 2023 at HE08 EDT	All-time Summer Peak[7]: On May 17, 2007
50/50	3586 MW	3,612 MW	3578 MW	3886 MW
90/10	3810 MW	3,845 MW		
Above 90/10	3924 MW	3,953 MW		

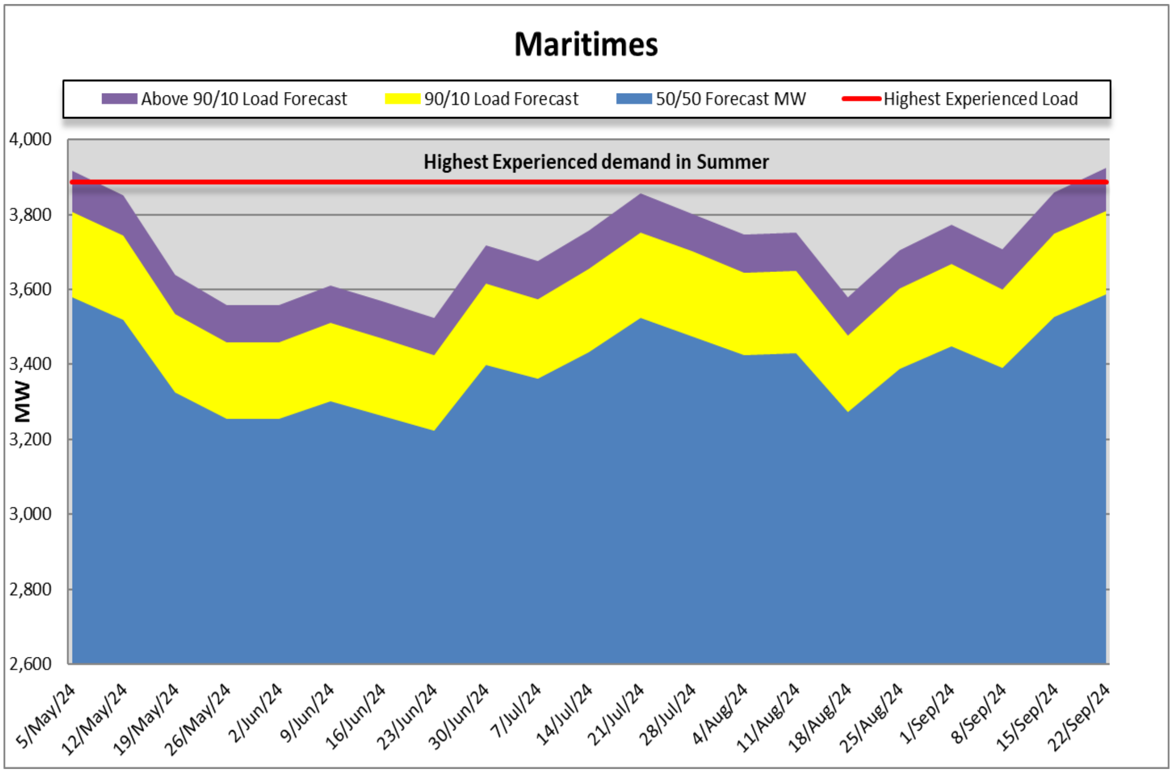

Figure 3-1: Maritimes Summer 2024 Weekly Demand Profile[8]

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[7] Represents the non-coincident value.

[8] The highest-ever experienced load in the Maritimes Area is beyond the expected 90/10 forecast for the summer.

New England

	Summer 2024 Forecasted Peak: week beginning June 2, 2024	Summer 2023 Forecasted Peak [9]: week beginning June 25, 2023,	Summer 2023 Actual Peak: Sept 7, 2023 at HE 18 EDT	All-time Summer Peak[10]: On August 2, 2006
50/50	24,553 MW	24,664 MW	23,521[11] MW	28,130 MW
90/10	26,383 MW	26,479 MW		
Above 90/10	28,064 MW	28,154 MW		

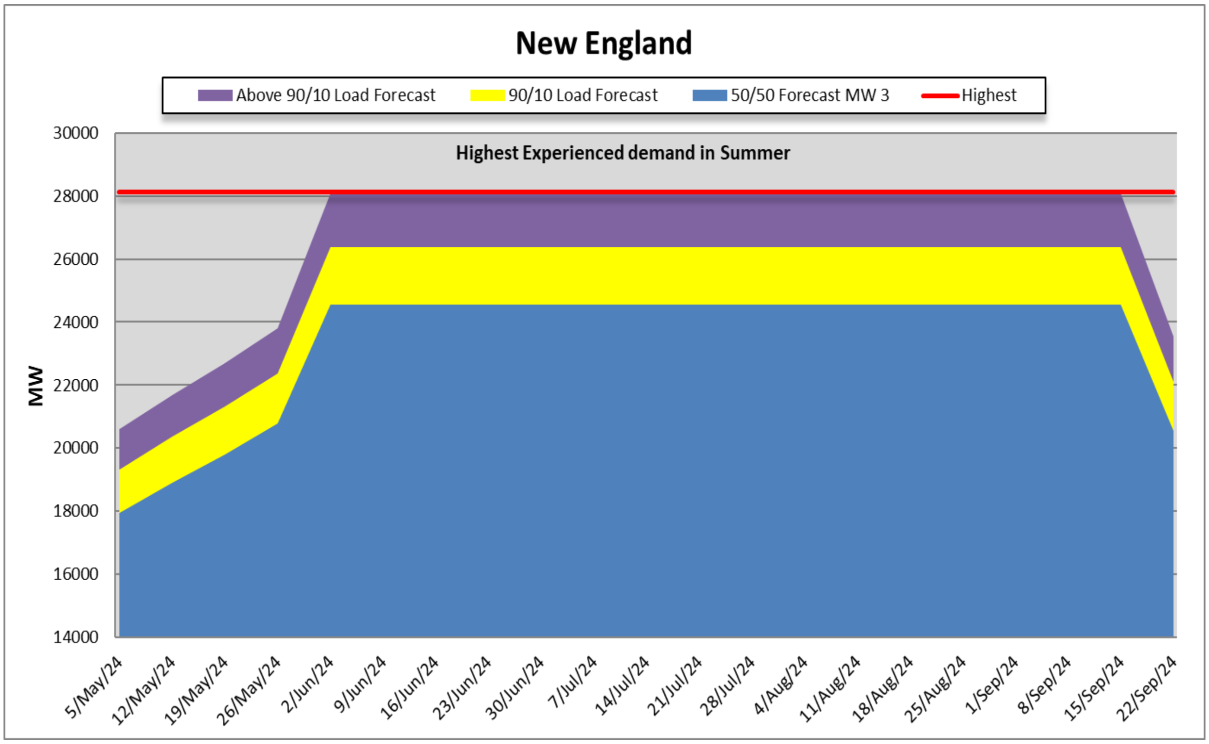

Figure 3-2: New England Summer 2024 Weekly Demand Profile [12]

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[9] The summer Peak Load Exposure (PLE) period covers the months of June through September 15; and was developed to help mitigate the effects of abnormal weather during the scheduling of generator outages and help forecast conservative operable capacity margins.

[10] Represents the non-coincident value.

[11] New England Actual Peak does not account for load served by Settlement Only Generators.

[12] The New England Area Highest Experienced Load observed on August 2, 2006, is approximately equivalent to the above 90/10 forecast for this summer.

New York

	Summer 2024 Forecasted Peak: week beginning July 28, 2024	Summer 2023 Forecasted Peak: week beginning July 31, 2023	Summer 2023 Actual Peak: September 6, 2023 at HE17 EDT	All-time Summer Peak [13]: On July 19, 2013 at HE17 EDT
50/50	31,541 MW	32,049 MW	30,206 MW	33,956 MW
90/10	33,301 MW	33,883 MW		
Above 90/10	34,790 MW	35,382 MW		

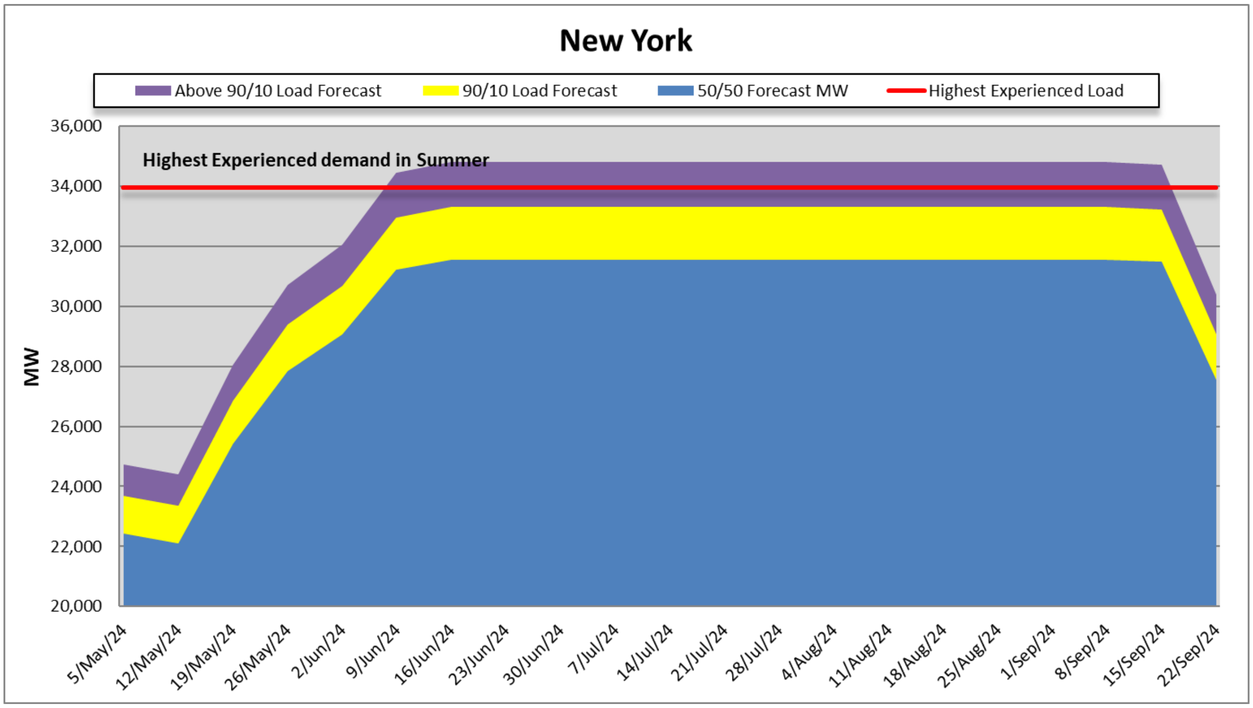

Figure 3-3: New York Summer 2024 Weekly Demand Profile [14]

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[13] Represents the non-coincident value.

[14] The New York Area's expected Above 90/10 load forecast for the summer exceeds the highest-ever experienced demand from July 19, 2013.

Ontario

	Summer 2024 Forecasted Peak: week beginning July 14, 2024	Summer 2023 Forecasted Peak: week beginning July 23, 2023	Summer 2023 Actual Peak: September 5, 2023 at HE16 EDT	All-time Summer Peak [15]: On August 1, 2006
50/50	22,753 MW	22,439 MW	23,713 MW	27,005 MW
90/10	24,550 MW	24,420 MW		
Above 90/10	26,231 MW	27,021 MW		

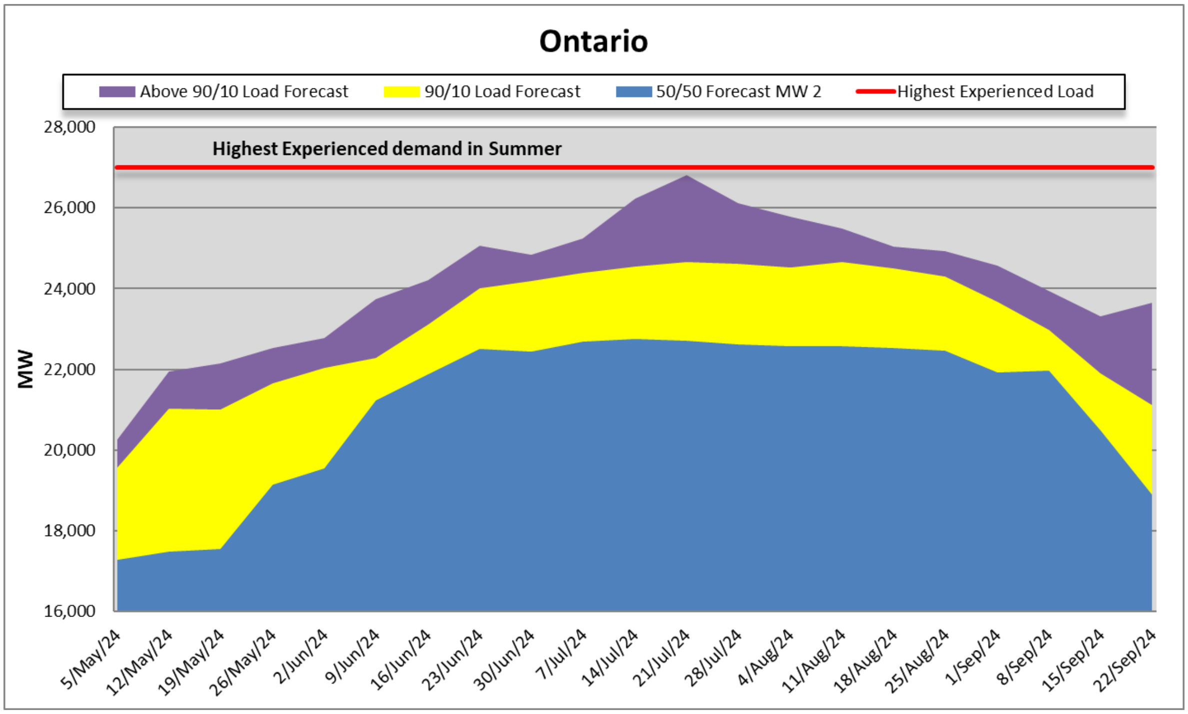

Figure 3-4: Ontario Summer 2024 Weekly Demand Profile [16]

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[15] Represents the non-coincident value.

[16] The highest-ever experienced load in the Ontario Area is beyond the expected 90/10 forecast for the summer.

Québec

	Summer 2024 Forecasted Peak: week beginning August 11, 2024	Summer 2023 Forecasted Peak: week beginning August 13, 2023	Summer 2023 Actual Peak: September 6, 2023 at HE18 [17] EDT	All-time Summer Peak [18]: On September 6, 2023
50/50	22,922 MW	22,859 MW	22,780 MW	22,780 MW
90/10	24,020 MW	23,900 MW		
Above 90/10	24,787 MW	24,459 MW		

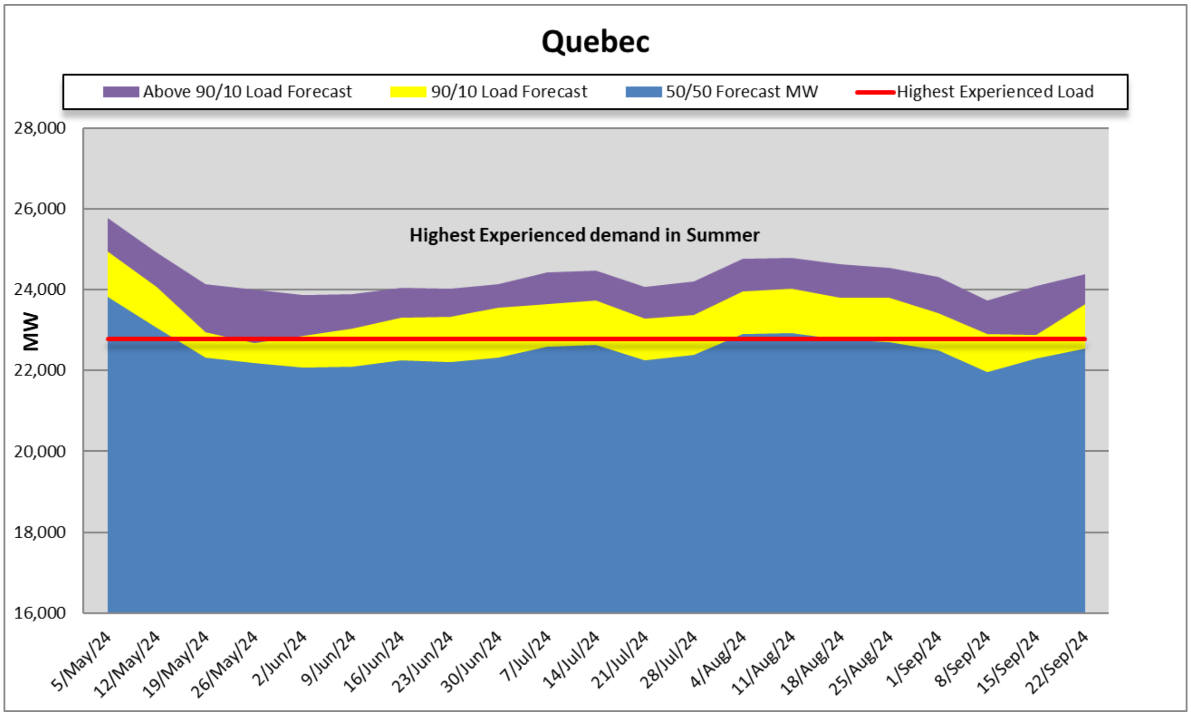

Figure 3-5: Québec Summer 2024 Weekly Demand Profile [19]

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[17] At 17h23 EDT

[18] Represents the non-coincident value.

[19] The Québec Area Highest Experienced Load observed on September 6, 2023, is approximately equivalent to the 50/50 forecast for this summer.

4. Resource Adequacy

NPCC Summary for Summer 2024

The assessment of resource adequacy indicates the week with the highest coincident NPCC demand is the week beginning August 11, 2024 (105,014 MW). Detailed Projected Load and Capacity Forecast Summaries specific to NPCC and each Area are included in Appendix I.

In Appendix I, **Table AP-1** reflects the NPCC (50/50) load and capacity summary for the 2024 Summer Operating Period. **Appendix I**, **Tables AP-2** through **AP-6** contain the 50/50 load forecast and capacity summary for each NPCC Reliability Coordinator.

Each entry within **Table 4-1** below is the aggregate of the corresponding entry for the five NPCC Reliability Coordinators. It summarizes the load and capacities for the peak week beginning August 11, 2024, compared to the summer 2023-forecasted peak week (beginning August 20, 2023).

Table 4-1: Resource Adequacy Comparison of Summer 2024 and 2023 Forecasts

All values in MW	2023 Forecast	2024 Forecast	Difference
Installed Capacity (+)	158,835	158,029	-805
Net Interchange (+)	2,144	1,117	-1027
Dispatchable DSM (+)	2,360	2,859	500
Total Capacity	163,338	162,006	**-1,333**
Demand (-)	105,200	105,014	-186
Interruptible load (+)	360	340	-20
Maintenance/De-rate (-)	31,012	27,705	-3,307
Required Reserve (-)	8,719	8,712	-7
Unplanned Outages (-)	8,719	8,532	-187
Net Margin	10,047	12,382	**2,335**
Bottled Resources (-)	1,837	2,607	770
Revised Net Margin	8,210	9,776	**1,565**

Note: Net Interchange represents purchases and sales with Areas outside of NPCC.

The Revised Net Margin for the 2024 Summer Operating Period has an increase of 1,565 when compared with the previous Summer Operating Period. This can mainly be attributed to decreases in forecasted demand, and anticipated maintenance outages.

Table 4-2 below summarizes the NPCC forecasted load and resource adequacy for the regional, coincident peak week under the 50/50, 90/10 and Above 90/10 forecast scenarios. Reliability Coordinator-specific details, assumptions and methodologies for the forecast analyses are detailed below and in Appendix IV.

The Above 90/10 forecast case represents a low probability, high impact composite scenario for the Region and relies heavily on individual Area risk assumptions. The analysis serves to assess a range of system conditions and resource adequacy outcomes. Individual Area Operational Readiness mitigations are detailed in Section 6.

Table 4-2: Resource Adequacy Comparison of 2024 Summer Forecast Scenarios

All values in MW	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity	158,029	158,029	158,019
Net Interchange	1,117	1,117	1,117
Dispatchable DSM	2,859	2,859	2,837
Total Capacity	**162,006**	**162,006**	**161,973**
Demand	105,014	112,011	117,598
Interruptible load	340	340	344
Maintenance/De-rate	27,705	27,705	33,014
Required Reserve	8,712	8,712	8,712
Unplanned Outages	8,532	8,532	8,916
Net Margin	**12,382**	**5,385**	**-5,923**
Bottled Resources	2,607	2,607	2,339
Revised Net Margin	**9,776**	**2,779**	**-8,262**
Week Beginning	11-Aug-24	11-Aug-24	21-Jul-24
Revised Net Margin %	9.3%	2.5%	-7.0%

A negative Revised Net Margin, as shown in **Table 4-2** for only the Above 90/10 Forecast Scenario, indicates a combination of imports and operating procedures will be necessary to mitigate potential resource shortages. The following sections detail the Summer 2024 capacity analysis for the NPCC Region and each Reliability Coordinator.

Maritimes

The Maritimes Area declared Installed Capacity is scheduled to be operational for the summer period. The net margins calculated include derates for variable generation (wind and hydro flows), ambient temperatures and scheduled out-of-service generation. Imports into the Maritimes Area are not included unless they have been confirmed released capacity from their source. Therefore, unless forced generator outages were to occur, there would not be any further reduction in the net margin. As part of the planning process, dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on-site to enable sustained operation in the event of natural gas supply interruptions. **Table 4-3** conveys the Maritimes anticipated operable capacity margins for the 50/50, 90/10 and Above 90/10 load forecasts of the Summer Operating Period during the Maritimes forecasted peak week (beginning September 22, 2024).

Table 4-3: Maritimes Operable Capacity Forecast (MW)

Summer 2024	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity (+)	7749	7749	7749
Net Interchange (+)	63	63	63
Dispatchable DSM (+)	0	0	0
Total Capacity	7812	7812	7812
Interruptible Load (+)	327	327	327
Known Maintenance & Derates (-)	2720	2720	3104
Operating Reserve Requirement (-)	893	893	893
Unplanned Outages (-)	339	339	339
Peak Load Forecast (-)	3586	3810	3924
Operating Margin	601	377	-121
Operating Margin (%)	16.8%	9.9%	-3.1%

Above 90/10 Forecast Assumptions

Above 90/10 forecast assumptions are based on historical data for ambient temperature thermal de-rates and in the extreme case of wind capacity de-rated by half coupled with an assumed 50% reduction in natural gas fired generation. Above 90/10 load forecast values are estimated using the Long-Term Load Forecast High/Low Sensitivities modelling and the maximum temperatures for each month from the past 20 years. Outages are based on historical operating experience.

New England

To determine New England capacity margins, ISO-NE compares Installed Capacity and Operable Capacity projections, recognizing 50/50 peak demand forecasts and applying its operating experience to adjust the available capacity, as needed. For example, ISO-NE adjusts the available capacity from natural-gas-fired generation during pipeline maintenance and construction. The Installed Capacity is based on the seasonal claimed capability (SCC) of the resources. The SCC is recognized as a generator's maximum output established through seasonal audits and reflected as capacity throughout this report and used in **Table 4-4 and AP-3**. **Table 4-4** breaks down New England's forecasted operable capacity margins for its lowest net margin week, week beginning June 2, 2024.

Table 4-4: New England Operable Capacity Forecast (MW)

Week Beginning June 2, 2024	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity (+)	27,393	27,393	27,393
Net Interchange (+)	1,194	1,194	1,194
Dispatchable DSM (+)	560	560	560
Total Capacity	29,147	29,147	29,147
Peak Demand Forecast (-)	24,553	26,383	28,064
Interruptible Load (+)	0	0	0
Known Maintenance & Derates (-)	14	14	14
Operating Reserve Requirement (-)	2,305	2,305	2,305
Unplanned Outages (-)	2,800	2,800	2,800
Operating Margin	-525	-2,355	-4,036
Operating Margin (%)	-2.1	-8.9	-14.4

New England also compares Installed Capacity and Operable Capacity with 90/10 demand forecasts to further evaluate operable-capacity risks. This broadened approach helps operations identify potential capacity concerns for the upcoming capacity period and prepare for higher demand conditions. The analysis in Table 4-4 above shows the further reduction in operable capacity margin recognizing these factors. The net interchange in these capacity assessments only considers the capacity cleared in capacity markets, which is much lower than actual transmission transfer capabilities. If 90/10 summer forecast conditions materialize, New England would expect to receive higher imports from neighboring Areas, as well as possible implementation of Emergency Operating Procedures (EOPs). These actions are anticipated to provide sufficient energy or load relief to cover the operable capacity deficiency identified in the 50/50 (50th percentile), 90/10 (90th percentile) and Above 90/10 (99th percentile) demand forecasts. The 90/10 forecast has a 10% chance of being exceeded because of weather conditions, expected to occur in the summer in New England at a weighted New England-wide temperature of 94.6°F.

New England forecasts the lowest Net Margin of the 2024 summer period to occur on the week, beginning June 2, 2024. The calculation for the operable-capacity margin considers summer Peak Load Exposure (PLE), which covers operating periods from June 2, 2024 through September 15, 2024. The PLE was developed and implemented to help mitigate the effects of abnormal weather during generator maintenance and outage scheduling and to support conservative forecasts for the operable-capacity margin(s).

Above 90/10 Forecast Assumptions

ISO-NE also compares the Installed Capacity with Operable Capacity for an Above 90/10 load forecast to determine New England's capacity risks for a load associated with the warmest day in the historical dataset used to produce the analysis load data. This extended approach helps identify potential capacity concerns for the upcoming capacity period and prepare for what would be the highest demand conditions for historically observed weather conditions. This analysis, shown in **Table 4-4** for June 2, 2024, shows the further reduction in the operable capacity margin recognizing these factors. Like the 90/10 forecast, if forecasted extreme summer conditions materialize and generators do not achieve their SCC, New England expects to receive higher imports from neighboring areas, as well as implement emergency operating procedures to maintain system reliability.

New York

New York determines its operating margin by comparing the 50/50 seasonal peak forecast with the projected Installed Capacity adjusted for seasonal operating factors. Installed Capacity is based on seasonal Dependable Maximum Net Capability (DMNC), tested seasonally, for all traditional thermal and large hydro generators. Wind generators, Limited Control Run-of-River hydro generators and grid-connected solar units are counted at nameplate for Installed Capacity and seasonal derates are applied. Net Interchange includes the election of Unforced Capacity Deliverability Rights (UDRs), External CRIS Rights, Existing Transmission Capacity for Native Load (ETCNL) elections, estimated First Come First Serve Rights (FCFSR), and grandfathered exports. UDR is capacity provided by controllable transmission projects that provide a transmission interface to the New York Control Area (NYCA). Interruptible Load includes Emergency Demand Response Programs and Special Case Resources. Known maintenance and derates includes generator maintenance outages known at the time of this writing and derates for renewable resources such as wind, hydro, solar and refuse, based on historical performance data. The NPCC Operating Reserve Requirement for New York is one-and-a-half times the largest single generating source contingency in the NYCA. The NYISO procures operating reserve of two times the largest single generating source contingency to ensure compliance with a New York State Reliability Council Rule (2,620 MW reserve). Unplanned Outages are based on expected availability of all generators in the NYCA based on historic availability. Historic availability factors in all forced outages, including those due to weather and availability of fuel. In the 90/10 scenario, the NYISO has 3,275 MW of relief available by means of its Emergency Operating Procedures.

The values in **Table 4-5** are anticipated quantities as of the time of publishing this report. Finalized values are available in the NYISO *Load & Capacity Data "Gold Book"* [20] published annually in late April.

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[20] NYISO Document Library - https://www.nyiso.com/library

Table 4-5: New York Operable Capacity Forecast [21] (MW)

Summer 2024	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity (+)	37,867	37,867	37,867
Net Interchange (+)	1,585	1,585	1,585
Dispatchable DSM (+)	1,281	1,281	1,281
Total Capacity	40,733	40,733	40,733
Interruptible Load (+)	13	13	13
Known Maintenance & Derates (-)	2,453	2,453	2,453
Operating Reserve Requirement (-)	2,620	2,620	2,620
Unplanned Outages (-)	3,271	3,271	3,867
Peak Load Forecast (-)	31,541	33,301	34,790
Operating Margin	861	-899	-2,984
Operating Margin (%)	2.7	-2.7	-8.6

Above 90/10 Forecast Assumptions

The Above 90/10 summer scenario for New York was assumed to occur during a heat wave. Accordingly, a 99/1 load forecast and additional thermal generation derates based on assumed temperatures were applied.

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[21] For the New York and NPCC coincident peak week, beginning August 11, 2024.

Ontario

For the 2024 Summer Operating Period, Ontario shows negative margins under the 90/10 and Above 90/10 scenarios. If these projected negative margins do materialize and cannot be remedied by outage management, the IESO may have to rely on some imports from neighbouring jurisdictions or other operating actions to ensure that Ontario's demand is met.

Table 4-6 conveys the Ontario anticipated operable capacity margins for the 50/50, 90/10 and Above 90/10 load forecasts of the Summer Operating Period during the Ontario forecasted peak week.

Table 4-6: Ontario Operable Capacity Forecast [22] (MW)

Summer 2024	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity (+)	38,253	38,253	38,253
Net Interchange (+)	600	600	600
Dispatchable DSM (+)	996	996	996
Total Capacity	39,849	39,849	39,849
Interruptible Load (+)	0	0	0
Known Maintenance & Derates (-)	11,090	11,388	12,972
Operating Reserve Requirement (-)	1,394	1,394	1,394
Unplanned Outages (-)	1,489	1,049	1,049
Peak Load Forecast (-)	22,753	24,669	26,819
Operating Margin	3,123	890	-2,385
Operating Margin (%)	13.7%	3.6%	-8.9%

The forecast energy production capability of the Ontario generators is calculated on a month-by-month basis. Monthly energy production capabilities for the Ontario generators are provided by market participants or calculated by the IESO. They account for fuel supply limitations, scheduled, and forced outages and de-ratings as well as environmental and regulatory restrictions.

The results in **Table 4-7** indicate that occurrences of unserved energy are not expected over the summer 2024 period. Based on these results it is anticipated that Ontario will be energy adequate for the 50/50 weather scenario for the review period.

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[22] Ontario's peak week for the 50/50 is July 14, 2024. Under the 90/10 and Above 90/10 scenarios, the peak week is July 21, 2024.

Table 4-7: Ontario Energy Production Capability Forecast by Month

Month	Forecast Energy Production Capability (GWh)	Forecast Energy Demand (GWh)
May 2024	15,641	10,661
June 2024	17,341	10,893
July 2024	18,750	12,346
Aug 2024	18,394	12,392
Sept 2024	17,464	10,998

Above 90/10 Forecast Assumptions

The Above 90/10 case was achieved using a probabilistic weather simulation method. The initial dataset of hourly demand forecasts was created by using 31 years of weather history and utilizing a shifting-iterative methodology. This dataset is then sliced for the weekly peaks at the 90/10 and 99/1 levels of probability. The difference between those forecasts is added to the weather scenario weekly peaks to approximate an Above 90/10 peak.

Resources under the respective weather scenarios are de-rated based on ambient sensitivity. The unplanned outages number is probabilistic and calculated with a variability of the weather under extreme scenarios taken into consideration.

Québec

The Québec Area anticipates adequate resources to meet demand for the 2024 summer season. The current 2024 peak forecast is 22,922 MW with a forecasted operating margin of 7,423 MW for the peak week, beginning August 11, 2024. This includes known maintenance and derates of 11,894 MW, including scheduled generator maintenance and wind generator derating. **Table 4-8** shows the factors included in the operating margin calculation.

Table 4-8: Québec Operable Capacity Forecast (MW)

Summer 2024	50/50 Load Forecast	90/10 Load Forecast	Above 90/10 Forecast
Installed Capacity (+)	46,767	46,767	46,767
Net Interchange (+)	-2,325	-2,325	-2,325
Dispatchable DSM (+)	0	0	0
Total Capacity	44,442	44,442	44,442
Interruptible Load (+)	0	0	0
Known Maintenance & Derates (-)	11,398	11,398	11,398
Operating Reserve Requirement (-)	1,500	1,500	1,500
Unplanned Outages (-)	1,200	1,200	1,550
Peak Load Forecast (-)	22,922	24,020	24,787
Operating Margin (MW)	7,423	6,325	5,207
Operating Margin (%)	32.4	26.3	21.0

Above 90/10 Forecast Assumptions

Two standard deviations of the load forecast uncertainty of the 50/50 forecast scenario is used to establish the above 90/10 forecast scenario. This represents a 96/4 forecast scenario. In addition to that, a generation loss of 350 MW is added to the Unplanned Outages, increasing it from 1,200 to 1,550 MW. If Québec real-time peak demands are higher than forecasted, several measures are available to the System Control personnel and are listed in Chapter 6: Operational Readiness.

Québec Area's energy requirements are met for the greatest part by hydro generating stations located on different river systems and scattered over a large territory. The major plants are backed by multi-annual reservoirs (water reserves lasting more than one year). A single year of low water inflow cannot adversely impact the reliability of energy supply. However, a series of a few consecutive dry years may require some operating measures such as the reduction of exports or capacity purchases from neighbouring Areas.

To assess its energy reliability, Hydro-Québec has developed an energy criterion stating that sufficient resources should be available to go through a sequence of two consecutive years of low water inflows totalling 64 TWh, or a sequence of four years totalling 98 TWh, and having a 2% probability of occurrence. The use of operating measures and the hydro reservoirs should be managed accordingly. Reliability assessments based on this criterion are presented three times a year to the Québec Energy Board. Such documents can be found on the Régie de l'Énergie du Québec website. [23]

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[23] https://www.regie-energie.qc.ca/fr

Table 4-9: Summary of Projected Capacity by Reliability Coordinator

Table 4-9 below summarizes projected capacity and margins by Reliability Coordinator area. Appendix I shows these projections for the entire 2024 Summer Operating Period.

Area	Measure	Week Beginning Sundays	Installed Capacity MW	Net Interchange MW	DDSM MW	Total Capacity MW	Demand Forecast MW	Interrupt. Load MW	Known Maint. / Derat. MW	Required Operating Reserve MW	Unplanned Outages MW	Net Margin MW
NPCC	NPCC Peak Week	August 11, 2024	158,029	1117	2,859	162,006	105,014	340	27,705	8,712	8,532	12,382
Maritimes	Peak Week	September 22, 2024	7,749	63	0	7,812	3586	327	2720	893	339	601.2
	Lowest Net Margin	September 8, 2024	7,749	63	0	7,812	3390	333	2980	893	337	545
	NPCC Peak Week	August 11, 2024	7,749	63	0	7,812	3429	327	2486	893	339	992
New England	Peak Week	August 11, 2024	27,393	1194	560	29,147	24,553	0	63	2,305	2,100	126
	Lowest Net Margin	June 2, 2024	27,393	1,194	560	29,147	24,553	0	14	2,305	2,800	-525
	NPCC Peak Week	August 11, 2024	27,393	1,194	560	29,147	24,553	0	63	2,305	2,100	126
New York	Peak Week	August 11, 2024	37,867	1,585	1,281	40,733	31,541	13	2,453	2,620	3,271	861
	Lowest Net Margin	September 15, 2024	37,867	1,585	1,281	40,733	31,474	13	3,257	2,620	3,206	189
	NPCC Peak Week	August 11, 2024	37,867	1,585	1,281	40,733	31,541	13	2,453	2,620	3,271	861
Ontario	Peak Week	July 14, 2024	38,253	600	996	39,849	22,753	0	11,090	1,394	1,489	3,123
	Lowest Net Margin	June 16, 2024	38,193	600	1,032	39,825	21,880	0	14,379	1,660	1,550	391
	NPCC Peak Week	August 11, 2024	38,253	600	1,018	39,871	22,569	0	11,306	1,394	1,622	2,981
Québec	Peak Week	August 11, 2024	46,767	-2,325	0	44,442	22,922	0	11,398	1,500	1,200	7,423
	Lowest Net Margin	June 16, 2024	46,767	-2,325	0	44,442	22,243	0	13,700	1,500	1,200	5,799
	NPCC Peak Week	August 11, 2024	46,767	-2,325	0	44,442	22,922	0	11,398	1,500	1,200	7,423

Generation Resource Changes

Tables 4-10 - 4-14 list the recent and anticipated generation resource additions, changes, and retirements.

Table 4-10: Maritimes Resource Changes from Summer 2023 through Summer 2024

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	Effective Date
Maritimes	Bayside permanently derated	-15	Natural Gas	Q1 - 2024
	Milltown Generating Station	-3	Hydro	Q3 - 2023
	PEI Solar	40	Solar	Q1-Q3 2024
	PEI BESS	11.5	BESS	Q1-Q3 2024
	Northern Maine	25	Solar	Q1-Q3 2024
	Nova Scotia	-3	Wind	Q2 2023
	Total Additions	**76.5**		
	Total Subtractions	**-21**		
	Net Change	**55.5**		

Table 4-11: New England Resource Changes from Summer 2023 through Summer 2024

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	Effective Date
New England	Berlin Renewable	+11	Storage	Q4 - 2023
	Georges River Energy	+5	Wood/Wood Waste Solids	Q4 - 2023
	142 Blackstone	-4	Storage	Ret. Q4 - 2023
	Altus New Marlborough	-2	Storage	Ret. Q4 - 2023
	Norwich Jet	-18	Distillate Fuel Oil	Ret. Q4 - 2023
	Potter 2	-49	Dual Fuel	Ret. Q1 - 2024
	NERP Bethlehem	-0	Wood/Wood Waste Solids	Ret. Q1 - 2024
	Vergennes 5 & 6	-5	Distillate Fuel Oil	Ret. Q1 - 2024
	Mystic 8 & 9	-1,415	Natural Gas	Ret. Q2 - 2024
	Vineyard Wind	+68 [24]	Offshore Wind	Q1 2024
	Total Additions	**84**		
	Total Reductions	**(1,493)**		
	Net Change	**-1,409**		

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[24] Vineyard Wind's 68 MW of nameplate capacity is not included in ISO-NE's 2024 Installed Capacity.

Table 4-12: New York Resource Changes from Summer 2023 through Summer 2024

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	Effective Date
New York	South Fork Wind	96	Off-shore Wind	Q3
	South Fork Wind II	40	Off-shore Wind	Q3
	East Point Solar	50	Solar	Q1
	High River	90	Solar	Q2
	Riverhead Expansion (Solar)	36	Solar	Q2
	Clear View Solar	20	Solar	Q2
	Dolan Solar	20	Solar	Q2
	CS Hawthorn	20	Solar	Q3
	Hills Solar	20	Solar	Q1
	KCE NY 6	20	Battery	Q1
	Darby Solar	20	Solar	Q1
	Stillwater Solar	20	Solar	Q4 2023
	Total Additions	**+452**		
	Net ICAP Adjustments	**+258**		
	Retirements	**-59**		
	Net Change	**+651**		

Table 4-13: Ontario Resource Changes from Summer 2023 through Summer 2024

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	Effective Date
Ontario	Romney Wind Energy Center	60	Wind	Commercial Operation
	Total Reductions	**-**		
	Total Additions	**60**		
	Net Change	**60**		

Table 4-14: Québec Resource Changes from Summer 2023 through Summer 2024

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	Effective Date
Québec	-	-	-	-
	Total Retirement	**-**		
	Total Addition	**-**		
	Seasonal Adjustments	**-9**		
	Net Change	**-9**		

Maritimes

By the end of the 2024 Summer Operating Period, the Maritimes anticipates a total of 65MW of solar will be added to the system as well as 11.5MW of battery storage. Additionally, a 3 MW hydro generating station was retired as well as a natural gas unit was derated by 15 MW.

The Maritime Link undersea cable, in conjunction with the construction of the Muskrat Falls hydro development in Labrador, presently provides for a 153 MW firm capacity import to Nova Scotia, with an effective load carrying capability (ELCC) of 95%. Due to short-term maintenance outages and the ongoing commissioning work on the HVDC transmission link from Labrador to Newfoundland, a 148 MW coal-fired unit will be retained in Nova Scotia, if needed, to provide firm capacity and maintain an adequate planning reserve margin for reliability.

New England

During the 2024 Summer Operating Period, New England expects 16 MW of nameplate capacity for resource additions. This includes one hydro resource and two CSF (continuous storage facilities) facilities. Mystic 8 and 9, 1,415 MW of natural gas generation, will be retiring at the beginning of the 2024 Summer Operating Period. This accounts for nearly a 5 percent reduction in New England's Installed Capacity compared to the region's 2023 Summer projections. Additionally, 23 MW of distillate fuel oil generators (Norwich Jet & Vergennes 5 & 6) and 49 MW of dual fuel generation (Potter 2) are officially retired and will not be available during Summer 2024.

New York

Through the 2024 Summer Operating Period, 296 MW of solar, 136 MW of offshore wind, and 20 MW of energy storage nameplate capacity are expected in service. It is also expected that 59 MW of mixed generation will be retiring this summer.

In addition, starting with for the 2024/2025 Capability Year, beginning May 1, 2024, the NYISO Installed Capacity Market implemented the new Capacity Accreditation process for all Installed Capacity Suppliers, which aligns Capacity Market compensation with resource marginal contribution toward meeting NYSRC resource adequacy [25].

Ontario

By the end of the 2024 Summer Operating Period, one new wind generator is expected to be included in the capacity. There are no capacity reductions expected. The total Ontario Installed Capacity is expected to be at 38,253 MW by the end of the Period.

Québec

There is little change in the total capacity of hydro generation for the Summer Operating Period of 2024 compared to summer 2023. The Installed Capacity is adjusted by nine (9) MW seasonally, resulting in a total of 46,767MW - a net 9 MW reduction from the last Summer Operating Period.

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[25] See Capacity Accreditation - NYISO for further information.

Fuel Infrastructure by Reliability Coordinator Area

Figures 4-1 and **4-2** depict installed generation resource profiles for each Reliability Coordinator area and for the NPCC Region by fuel supply infrastructure as projected for the NPCC coincident peak week.

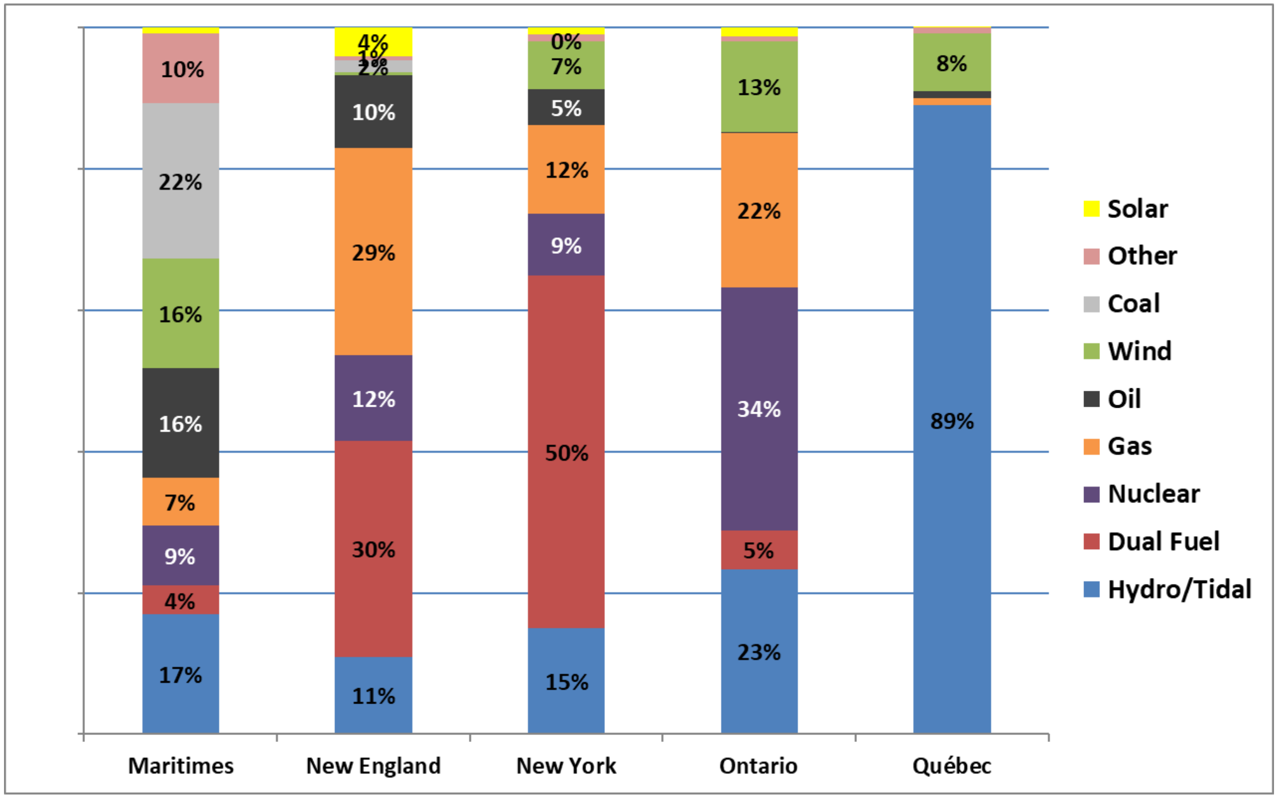

Figure 4-1: Resource Fuel Type by Reliability Coordinator Area

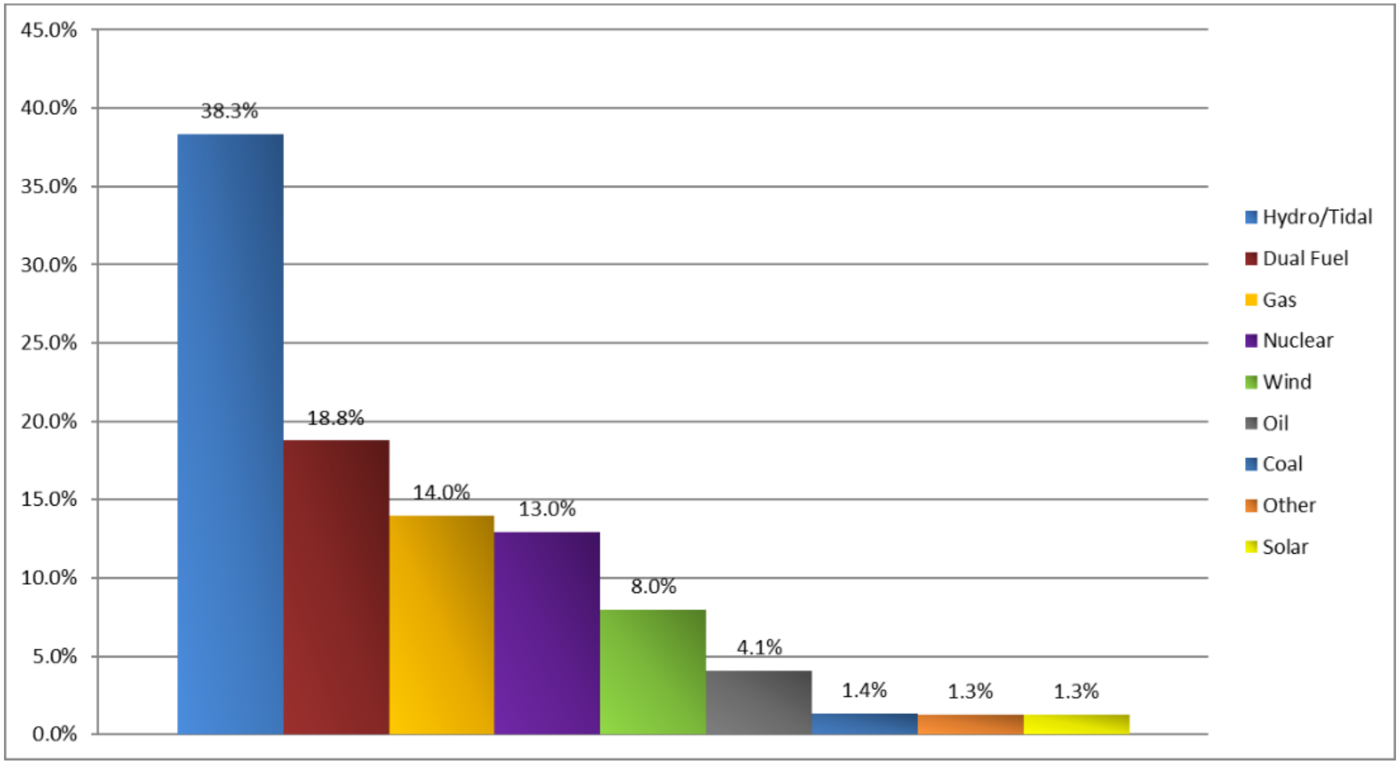

Figure 4-2: Resource Fuel Type for NPCC

Wind and Solar Capacity Analysis by Reliability Coordinator Area

For the upcoming 2024 Summer Operating Period, installed wind and solar capacity accounts for approximately 9.3% of the total NPCC Installed Capacity during the coincident peak load. This breaks down to 8% wind and 1.3% solar. This is a small increase from 8.3% reported in 2023 (7.5% and 0.7% respectively). Reliability Coordinators have distinct methods of accounting for both types of generation. The Reliability Coordinators continue to develop their knowledge regarding the operation of wind and solar generation in terms of capacity forecasting and utilization factor. The corresponding assumptions used in the probabilistic assessment are described in Appendix VIII.

Table 4-15 below illustrates the nameplate wind capacity in NPCC for the 2024 Summer Operating Period. The Maritimes, Ontario, New York and Québec Areas include the entire nameplate capacity in the Installed Capacity section of the Load and Capacity Tables and use a derate value in the Known Maintenance/Constraints section to account for the fact that some of the capacity will not be online at the time of peak. New England (ISO-NE) reduces the nameplate capacity and includes this reduced capacity value directly in the Installed Capacity section of the Load and Capacity Table. Please refer to Appendix II, for information on the derating methodology used by each of the NPCC Reliability Coordinators.

Table 4-15 below also illustrates the nameplate solar capacity in NPCC for the 2024 Summer Operating Period. The IESO and NYISO include the entire nameplate capacity in the Installed Capacity section of the Load and Capacity Tables and use a derate value in the Known Maintenance/Constraints section to account for the fact that some of the capacity will not be online at the time of peak. ISO-NE reduces the nameplate capacity and includes this reduced capacity value directly into the Installed Capacity section of the Load and Capacity Table. Please refer to Appendix II for information on the derating methodology used by each of the NPCC Reliability Coordinators.

Table 4-16 illustrates behind-the-meter solar PV capacity and the amount of impact it has on peak load demand for each area. The IESO, ISO-NE, HQ and NYISO each factor in behind-the-meter solar as a peak load reduction. Methodologies for each area can be found in Appendix IV.

Table 4-15: NPCC Wind and Metered Solar Capacity

Area	Nameplate Wind Capacity (MW)	Wind Capacity After Applied Derating Factor (MW)	Nameplate Offshore Wind Capacity (MW) [26]	Offshore Wind Capacity After Applied Derating Factor (MW)	Nameplate Solar Capacity (MW)	Solar Capacity After Applied Derating Factor (MW)
Maritimes	1209	262	-	-	69	0
New England	1,549	122	100	3	2,988	1,111
New York [27]	2,590	340	136	18	370	53
Ontario	4,883	723	-	-	478	66
Québec	3,820	0	-	-	10	0
Total	**14,051**	**1,447**	**236**	**21**	**3,915**	**1,230**

Table 4-16: Behind-the-Meter Solar PV

Area	Installed Behind-the-Meter Solar PV (MW)	Impact of BTM Solar PV on Peak Load (MW)
Maritimes	121	0
New England	4357	1,097
New York	6,186	1,133
Ontario	2,172	893
Québec	6	0
Total	**12,842**	**3,123**

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[26] Nameplate Offshore Wind capacity is included in the Total Nameplate Wind capacity.

[27] Total nameplate wind capacity in New York is 2,590 MW, however only 340 MW participate in the ICAP market as of this writing. Total nameplate grid connected solar capacity is 370 MW, while only 53 MW participates in the ICAP market.

Maritimes

Wind projected capacity is derated to its demonstrated output for each summer capability period.

In Prince Edward Island the wind facilities that have been in production over a three-year period, a derated monthly average is calculated using metering data from previous years over each seasonal assessment period.

The Northern Maine Independent System Administrator (NMISA) uses a fixed capacity derate of 32 MW for the summer assessment period for their Mars Hill Windfarm.

New Brunswick and Nova Scotia apply a 18% capacity value to installed wind capacity (82% derated).

For Nova Scotia, this amount is based on the effective load carrying capability (ELCC) of wind determined through a Loss of Load Expectation (LOLE) study [28]. The LOLE study considered multiple years of historical load and wind data and simulated the system under a variety of factors.

New England

During the 2024 Summer Operating Period, ISO-NE has over 1,500 MW of wind resources interconnected to the grid and has derated these wind resources by nearly 92% as a result of established summer Claimed Capability Audits (CCAs).

Based on ISO-NE's analysis of PV performance during peak demand conditions, BTM PV [29] is expected to reduce the summer gross peak load by 1,097 MW. The percentage of nameplate, used by ISO-NE to estimate the peak demand reduction is meant to reflect realistic performance of PV during summer peak demand conditions, as well as diminishing PV production as increasing PV penetrations shift the timing of the summer peak later in the day. Therefore, this percentage of nameplate becomes lower as PV penetrations increase. The BTM PV factor continues to affect the load forecasting process, as further discussed in Appendix IV.

New York

For the 2024 Summer Operating Period, the NYISO anticipates 10,146 MW of nameplate renewable resource capacity to be available. This includes 2,590 MW of nameplate wind and 370 MW of nameplate grid-connected solar capacity. As indicated above, 340 MW of nameplate wind and 53 MW of nameplate grid connected solar capacity participate in the New York ICAP (Installed Capacity) market as of this writing. Non-ICAP capacity is not included in the Installed Capacity of **Tables 4-5 and AP-4**. The ICAP nameplate capacity is counted at full value towards the Installed Capacity for New York. The wind and solar capacities are derated by 87% and 86% respectively based on historical performance, and their Capacity Accreditation Factors when determining operating margins.

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[28] Attachment 17 to NS Power's Pre-IRP Deliverables Final Report at: https://irp.nspower.ca/documents/pre-irp-deliverables/

[29] The ISO New England 2024 PV Forecast can be found at Final 2024 Photovoltaic (PV) Forecast

In 2023, 5,122 gigawatt-hours (GWh) of New York's energy was produced by wind and solar resources representing approximately 4.13 % of New York's electric generation. This was higher than the 2022 values of 4,935 GWh and 3.93%, respectively.

Behind-the-meter solar photovoltaic resources are expected to have a significant impact on peak loads in New York. The most current, available assumptions from 2023 estimate that there are 6,186 MW of installed behind-the-meter solar PV which is forecasted to reduce coincident peak load by 1,133 MW. This impact is reflected in New York's 31,541 MW peak load forecast. Additionally, behind-the-meter solar PV energy is expected to be 6,529 GWh in 2023. The actual impact of solar PV varies considerably by hour of day. The hour of the NYCA coincident 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 PV is added to the system, and as electric vehicle charging impacts increase during the evening hours.

Ontario

For Ontario, monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values in percentage of installed capacity are determined from actual historic median wind generator contribution over the last 10 years at the top five contiguous demand hours of the day for each winter and summer season, or shoulder period month. The top five contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months. For the month of July when the peak loading is anticipated to occur, the monthly Wind Capacity Contribution factor is expected to be 14.8%.

Similarly, monthly Solar Capacity Contribution (SCC) values are used to forecast the contribution expected from solar generators. SCC values in percentage of installed capacity are determined by calculating the median contribution during the top five contiguous demand hours of the day for each winter and summer season, or shoulder period month. As actual solar production data becomes available in future, the process of combining historical solar data and the simulated 10-year historical solar data will be incorporated into the SCC methodology, until sufficient actual solar production history has been accumulated, at which point the use of simulated data will be discontinued. For the month of July when the peak loading is anticipated to occur, the SCC factor is 13.8%.

From an adequacy assessment perspective, although the entire installed capacity of the wind and solar generation is included in Ontario's total installed capacity number, the appropriate reduction is applied to the 'Known Maint./Derate/Bottled Cap.' number to ensure the WCC and SCC values are accounted for when assessing net margins.

Embedded (behind-the-meter) generation reduces the need to grid supplied electricity by generating electricity on the distribution system. Since most embedded generation is solar powered, embedded generation is divided into two separate components – solar and non-solar. Non-solar, embedded generation includes generation fuelled by biogas and natural gas, water, and wind. Contract information is used to estimate both the historical and future output of embedded generation. This information is incorporated into the demand forecast model. The growth in embedded generation capacity, a major offset to demand, has plateaued, but continues to be a significant driver of change in the sector.

Ontario currently has visibility on 2,172 MW of embedded solar PV. It should be noted that due to the increasing penetration of embedded solar generation, the grid demand profile has been changing, with summer peaks being pushed later in the day. Consequently, the contribution of grid-connected solar resources at the time of peak Ontario demand has declined.

Québec

In Québec Area, wind generation plants are owned and operated by Independent Power Producers (IPPs). During the summer period, 100% of the wind installed capacity is derated and the current solar generation in the Québec Area is negligible.

Demand Response Programs

Each Reliability Coordinator area utilizes various methods of demand management. Grid modernization, smart grid technologies, and their resulting market initiatives have created a need to treat some demand response programs as supply-side resources, rather than as a load-modifier. The table below summarizes the expected Dispatchable Demand-Side Management (DDSM) Resources and Interruptible Loads available within the NPCC region for the forecasted peak demand week of August 11, 2024. Definitions of the terms are included in Appendix II. The corresponding assumptions used in the probabilistic assessment are described in Appendix VIII. **Table 4-17** summarizes the Active Demand Response Programs across the NPCC region by Area.

Table 4-17: Summary of Active Demand Response Programs

Area	DDSM Resources (MW)	Interruptible Loads (MW)	Total (MW)
Maritimes	0	327	327
New England	560	0	560
New York	1,281	13	1,294
Ontario	1,018	0	1,018
Québec	0	0	0
Total	**2,960**	**340**	**3,300**

Maritimes

Interruptible loads are forecast on a weekly basis and range between 318 MW and 342 MW. The values can be found in **Table AP-2** and are available for use when corrective actions are required within the Maritimes Area.

New England

ISO-NE Active Demand Capacity Resources (ADCR) can participate in the Forward Capacity Market to fulfill a market participant's capacity supply obligation pursuant to Market Rule 1, Section III.13. There is currently 560 MW of ADCR that is economically dispatchable on peak.

New York

The NYISO has three demand response programs to support system reliability. The NYISO currently projects 1,294 MW of total demand response available for the 2024 Summer Operating Period, consisting of approximately 1,281 MW of Special Case Resources and 13 MW of Emergency Demand Response Program resources.

The Emergency Demand Response Program ("EDRP") provides demand resources an opportunity to earn the greater of $500/MWh or the prevailing locational-based marginal price ("LBMP") for energy consumption curtailments provided when the NYISO calls on the resource. Resources must be enrolled through Curtailment Service Providers (“CSPs”), which serve as the interface between the NYISO and resources, in order to participate in EDRP. There are no obligations for enrolled EDRP resources to curtail their load during an EDRP event.

The Installed Capacity (“ICAP”) Special Case Resource program allows demand resources that meet certification requirements to offer Unforced Capacity (“UCAP”) to Load Serving Entities (“LSEs”). The load reduction capability of Special Case Resources (“SCRs”) may be sold in the ICAP Market just like any other ICAP Resource; however, SCRs participate through Responsible Interface Parties (“RIPs”), which serve as the interface between the NYISO and the resources. RIPs also act as aggregators of SCRs. SCRs that have sold ICAP are obligated to reduce their system load when called upon by the NYISO with two or more hours’ notice, provided the NYISO notifies the Responsible Interface Party a day ahead of the possibility of such a call. In addition, enrolled SCRs are subject to testing each Capability Period to verify their capability to achieve the amount of enrolled load reduction. Failure of an SCR to reduce load during an event or test results in a reduction in the amount of UCAP that can be sold in future periods and could result in penalties assessed to the applicable RIP in accordance with the ICAP/SCR program rules and procedures. Curtailments are called by the NYISO when reserve shortages are anticipated or during other emergency operating conditions. Resources may register for either EDRP or ICAP/SCR but not both. In addition to capacity payments, RIPs are eligible for an energy payment during an event, using the same calculation methodology as EDRP resources. The Targeted Demand Response Program (“TDRP”), introduced in July 2007, is a NYISO reliability program that deploys existing EDRP and SCR resources on a voluntary basis, at the request of a Transmission Owner, in targeted subzones to solve local reliability problems. The TDRP program is currently available in Zone J, New York City.

Ontario

Ontario’s demand response is comprised of the following programs: Dispatchable Loads, demand response capacity procured through the IESO’s capacity auctions, interruptible and residential DR. Demand measures are dispatched like a generation resource and therefore are included in the supply mix.

Load modifiers include energy efficiency (energy-efficiency programs, codes, and standards), price impacts (time of use and Industrial Conservation Initiative or “ICI”) and embedded generation. The load modifiers are incorporated into the demand forecast.

Québec

Demand Response programs are neither required nor available during the Summer Operating Period.

5. Transmission Adequacy

Regional Transmission studies specifically identifying interface transfer capabilities in NPCC are not normally conducted. However, NPCC uses the results developed in each of the NPCC Reliability Coordinator Areas and compiles them for all major interfaces and for significant load areas (Appendix III). Recognizing this, the CO-12 Working Group reviewed the transfer capabilities between the Reliability Coordinator Areas of NPCC under all demand configurations.

The following is a transmission adequacy assessment from the perspective of the ability to support energy transfers for the differing levels: Inter-Region, Inter-Area, and Intra-Area. The corresponding assumptions used in the probabilistic assessment are described in Appendix VIII.

Inter-Regional Transmission Adequacy

Ontario – Manitoba Interconnection

The Ontario – Manitoba interconnection consists of two 230 kV circuits and one 115kV circuit. The transfers on the 230 kV interconnection points are under the control of PARs. Ontario and Manitoba are synchronously connected at 230kV, while the 115kV interconnection is operated normally open.

Ontario – Minnesota Interconnection

The Ontario – Minnesota interconnection consists of a single 115 kV circuit. The interconnection is under the control of a PAR. Ontario and Minnesota are synchronously connected.

Ontario – Michigan Interconnection

The Ontario – Michigan interconnection consists of two 230/345 kV circuits, one 230/115 kV circuit, and one 230 kV circuit. The interconnection is under the control of PARs. Ontario and Michigan are synchronously connected.

New York – PJM Interconnection

The New York – PJM interconnection consists of one PAR controlled 500/345 kV circuit, one uni-directional DC cable into New York, one uni-directional DC/DC controlled 345 kV circuit into New York, two free flowing 345 kV circuits, a VFT controlled 345/230 kV circuit, five PAR controlled 345/230 kV circuits, two free flowing 230 kV circuits, three 115 kV circuits, and a 138/69 kV network serving a PJM load pocket through the New York system.

The Hudson-Farragut and Marion-Farragut PAR controlled 230/345 kV circuits (B3402 & C3403) are expected to remain out of service for the duration of the 2024 Summer Operating Period.

The Warren-Falconer 171, 115 kV tie line will be operated as normally open for the 2024 Summer Operating Period.

Inter-Area Transmission Adequacy

Appendix III provides a summary of the Total Transfer Capabilities (TTC) on the interfaces between NPCC Reliability Coordinator Areas and for some specific load zone areas. They also indicate the corresponding Available Transfer Capabilities (ATC) based on internal limitations or other factors and indicate the rationale behind reductions from the Total Transfer Capability.

Area Transmission Adequacy Assessment

Transmission system assessments are conducted in order to evaluate the resiliency and adequacy of the bulk power transmission system. Within each region, Areas evaluate the ongoing efforts and challenges of effectively managing the reliability of the bulk transmission system and identifying transmission system projects that would address local or system wide improvements. The CO-12 Working Group reviewed the forecasted conditions for the Summer 2024 Operating Period and have provided the following review as well as identified transmission improvements listed in **Table 5-1**.

Table 5-1: NPCC – Recent and Future Transmission Additions

NPCC Sub-Area	Transmission Project	Voltage (kV)	In Service
Maritimes	None	N/A	N/A
New England	211-514 Line Bifurcation (Boston Area Transmission Upgrade)	115	Q2 2024
	3136 Line (Boston Area Transmission Upgrade)	345	Q2 2024
	Keene Rd Reactor (Northern Maine Voltage Stability)	115	Q2 2024
New York	Lovett Station (new)	345	Q2 - 2024
	Knickerbocker Series Compensation Y57	345	Q4 – 2023
	Edic – Princetown 351 & 352	345	Q4 – 2023
	L34 PAR	345	Q4 – 2024
Ontario	Hawthorne TS x Merivale TS: Upgrade conductor (Network Transfer Capability)	230	Q4 – 2023
	A8/9K Tx Ln Refurb	115	Q4 – 2023
Québec	–Line 7110	735	Q4 – 2023

Maritimes

The Maritimes bulk transmission system is projected to be adequate to supply the demand requirements for the Summer Operating Period. Part of the Total Transfer Capability (TTC) calculation with HQ is based on the ability to transfer radial loads onto the HQ system. The radial load value is calculated monthly, and HQ will be notified of the changes (see Appendix III).

New England

The New England transmission system is projected to be sufficient for the 2024 Summer Operating Period. Transmission upgrades continue to be commissioned to address New England's reliability needs. The 211–514-line bifurcation (Woburn to Mystic) will provide thermal support within Boston's 115kV system. The 3136 line (Woburn to Wakefield Junction) will be installed to bolster Boston's 345kV system. As area generation continues to retire, both the 3136 and 211-514XY lines will provide the thermal support necessary to import transfers into the city. The Keene Road reactor will mitigate potential local high voltage exposure during light load conditions. Numerous transmission upgrades continue to be commissioned to address New England's transmission security needs. These transmission improvements have reinforced the overall reliability of the electric power system and reduced congestion, enabling power to flow more easily around the entire region. The improvements support decreased energy costs and increased power system flexibility.

New York

For the 2024 Summer Operating Period, New York does not anticipate any reliability issues for operating the bulk power system.

In Q4 of 2023, the L34 345 kV PAR was replaced, two new lines between Edic and Princetown 345 kV stations were installed (351 and 352), and the new Knickerbocker 345 kV series compensation (Y57) was installed.

Additionally, by the peak load period in 2024 it is expected that the new Lovett 345 kV Station will be in service in the Hudson Valley.

Lastly, the Hudson-Farragut and Marion-Farragut PAR controlled 230/345 kV (B3402 & C3403) circuits are expected be out of service for the 2024 Summer Operating Period.

Ontario

For the Summer 2024 Operating Period, Ontario's transmission system is expected to be adequate. Generally, Ontario is operating within a period of challenging conditions due to a significant number of major generation and transmission projects either currently underway or expected to begin in the near future. The IESO has been actively coordinating and planning outages with market participants to maintain reliability.

Outages affecting neighboring jurisdictions can be found in **Table 5-2**: Area Transmission Outage Assessment. Based on the information provided, Ontario does not foresee any transmission issues for the Summer 2024 season.

Québec

In the Québec Reliability Coordinator Area, most transmission line, transformer and generating unit maintenance is done during the summer period. Internal transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales and additional uncertainty margins. They should not impact inter-area transfer capabilities with neighboring systems. During the 2024 Summer Operating Period, some maintenance outages are scheduled on the interconnections. Maintenance is coordinated with neighboring Reliability Coordinator Areas so as to leave maximum capability to summer peaking areas.

Area Transmission Outage Assessment

The section and **Table 5-2** below outline any known scheduled outages on interfaces between Reliability Coordinators.

Table 5-2: Area Transmission Outage Assessment

Maritimes

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
Quebec	Circuit 1 (Eel River)	2024/09/29	2024/10/08	175 MW Export
				175 MW Import
New England	L3016	2024/05/08	2024/05/13	1000 MW Export
				120 MW Import
New England	L3009	2024/05/14	2024/05/23	1000 MW Export
				100 MW Import

New England

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
New Brunswick	NB-NE NE-NB	2024/04/06 0900	2024/06/14 0900	375 MW Import 150 MW Export
Québec	Highgate Converter	2024/04/25 0600	2024/06/03 1800	225 MW Import 200 MW Export
New York	CSC	2024/04/29 0500	2024/05/04 1800	330 MW Import 330 Export
New York	NE-NY	2024/05/01 0000	2024/05/10 1500	500 MW Export
Québec	NE-HQ	2024/05/20 0600	2024/05/31 1800	200 MW Export
New Brunswick	NB-NE NE-NB	2024/05/20 1200	2024/05/20 1600	750 MW Import 375 MW Export
New Brunswick	NB-NE NE-NB	2024/05/21 0900	2024/05/21 1500	665 MW Import 200 MW Export
New Brunswick	NE-NB	2024/05/30 0630	2024/06/26 1600	200 MW Export
Québec	NE-HQ	2024/06/03 0600	2024/06/04 1800	200 MW Export
Québec	NE-HQ	2024/06/05 0600	2024/06/06 1800	200 MW Export
Québec	NE-HQ	2024/06/18 0600	2024/06/20 1800	200 MW Export

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
Québec	NE-HQ	2024/06/25 0600	2024/06/27 1800	200 MW Export
Québec	NE-HQ	2024/09/03 0600	2024/09/13 1800	200 MW Export
Québec	NE-HQ	2024/09/16 0600	2024/09/18 1800	200 MW Export
Québec	HQ-NE NE-HQ	2024/09/23 0700	2024/10/14 1000	2000 MW Import 1200 MW Export

New York

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
PJM	Hudson-Farragut & Marion-Farragut (B3402 & C3403)	2018/01/15	2024/12/31	150 MW Import
				250 MW Export

Ontario

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
New York	BP76	2024/05/20	2024/05/31	550 MW (Export) / 450 MW (Import)
New York	PA302	2024/05/27	2024/05/31	1050 MW (Export) / 900 MW (Import)
Quebec	B31L	2024/06/09	2024/06/28	400MW (Beau Import)
Michigan	L51D	2024/08/07	2024/08/21	550 MW (Export) / 450 MW (Import)

Québec

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
New England	Derby	2024/06/17	2024/06/20	62 MW
New York	Ma	2024/08/04	2024/08/04	1000 MW
Ontario	LAW	2024/05/27	2024/06/14	62 MW

6. Operational Readiness for Summer 2024

NPCC

NPCC promotes and provides a forum for the active coordination of reliability and operation of the international, interconnected bulk power system within northeastern North America. NPCC Task Forces and Working Groups support continued reliability operations prior to and throughout the Summer Operating Period by reviewing and assessing the performance of the bulk power system.

In addition to conducting pre-seasonal reliability assessments, the NPCC also coordinates periodic and specific operational communications to ensure that potential system changes and outages for operations are properly reviewed. Whenever adverse system operating or weather conditions are expected or encountered, any RC Area or NPCC Staff, may request an Emergency Preparedness Conference Call to discuss issues related to the adequacy and security of the interconnected bulk power supply system with appropriate operations management personnel from the NPCC RC Areas, NPCC staff and neighboring systems. These procedures are frequently tested on a continual basis throughout the year. NPCC also conducts Weekly Conference Calls to review a seven-day outlook for the Region, including largest contingencies, operating margins, and weather, as well as to ensure that future system changes, such as generation and transmission outages that have the potential to affect neighboring Areas are coordinated.

The region also actively monitors all types of weather, including solar storms, as power system reliability can be affected under certain conditions. Both NERC and NPCC have implemented standards [30] and procedures [31] requiring entities to mitigate the potential effects of geomagnetic disturbances.

Lastly, NPCC supports Electric-Gas Operations reliability coordination efforts to promote interdependent sector communications, awareness, and information sharing.

In addition to coordinated regional activities, NPCC Reliability Coordinator-specific readiness activities and real-time procedures are detailed in **Table 6-1** below.

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[30] See: NERC EOP-010-1, Geomagnetic Disturbance Operations

[31] See: NPCC C-15, Procedures for Geomagnetic Disturbances Which Affect Electric Power Systems

Table 6-1 Real-Time Procedures and Expected MW Relief

Actions	Maritimes	New England	New York	Ontario	Quebec
Allow depletion of Operating Reserve	893	~600	2,620 (30 Min) 1,310 (10 Min)	473/945	~750
Curtailment of interruptible load	327		243	1,032	400
Manual Voltage Reduction	N/A	Variable (0 - 375)	9 - 611	1.1%/1.6%	~180
Curtailment of non-essential Market Participant load	N/A		9		
Voluntary curtailment of large LSE customers	N/A	200	15		
Public Appeals	80	300	74	1%	
Additional Actions	N/A	Variable (45 – 2,545) [32]			~1,400
Total Assumption Range	1300	1,145 – 4,020	1,660 – 3,572		1,330
Lowest Net Margin Week **Lowest 90/10 Net Margin MW |** **With Real-Time Procedures Relief**	**Sept 8, 2024** **335 (9.3) |** **1635(45%)**	**June 2, 2024** **-2,355 (-8.9%) |** **-1,210 (-0.5%)**	**Sept 15, 2024** **-1,979 (-6.0%) |** **1,593 (4.6%)**	**Jun 16, 2024** **-1,852 (-8.4%)|** **(N/A)**	**Jun 16, 2024** **3639 (15.1%)|** **(N/A)**

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[32] See: ISO-NE OP4 - Appendix A - Estimates of Additional Generation and Load Reliefs (iso-ne.com)

Maritimes

Voltage Control

The Maritimes Area, in addition to the reactive capability of the generating units, employs a number of capacitors, reactors, synchronous condensers and a Static VAR Compensator (SVC) in order to provide local area voltage control**.**

Operational Procedures

The Maritimes is a winter peaking area and as a result, the possibility of light system loads along with high wind generator outputs could occur. If this scenario were to happen, procedures are in place to mitigate the event. Steps that can be taken to balance supply with demand include reducing dispatchable generation down to minimum operating levels, taking generation units offline that can be restarted in time for the next peak load, and attempt short-term energy sales. If those steps are not adequate to alleviate the over-supply, then individual wind farm generation can be curtailed in blocks until the supply demand imbalance is alleviated.

For changes to internal operating conditions (i.e., transmission and or generator outages), these will be handled with Short Term Operating Procedures (STOP) which would outline any special operating conditions.

New England

Voltage Management and Control

ISO-NE manages and monitors both reactive resources and transmission voltages on the Bulk Power System (BPS). These elements are monitored in dedicated EMS reactive power displays, specific voltage/reactive transmission operating guides and via real-time voltage transfer limit evaluation software. ISO-NE also reviews and coordinates high side Load Power Factor requirements in the region, which accounts for the potential impacts of the distribution load on the BPS transmission performance. ISO-NE also maintains a detailed set of generator voltage set points and appropriate operational bandwidths recognizing the lead/lag capabilities of the individual resources, which are monitored in real time within the EMS. In conjunction with the asset owners, ISO-NE has developed a set of comprehensive normal, long-term, and short-term voltages limits for the BPS transmission system and communicates potential issues or concerns with the Transmission Owners. Based on operational studies and experience, the impact of available dynamic and static reactive resources is accounted for in outage coordination and real-time operations. For the 2024 Summer Operating Period, ISO-NE does not anticipate issues managing light load conditions. In the event the regions reactive devices are not sufficient, ISO-NE will commit the necessary area generation to help control voltage.

In preparation for the summer and winter operating periods, ISO–NE will perform a voltage reduction test & audit with each Transmission Owner (TO) that has control over transmission/distribution facilities to verify voltage reduction capability. It is intended that voltage reductions be fully implemented within ten minutes from the time ordered. However, it is recognized that it may not be practical for some TOs with control over transmission/distribution facilities to meet this requirement. In those circumstances, voltage reduction that can be implemented in thirty minutes is permissible. ISO-NE and the Local Control Centers (LCCs) use this capability to reduce demand to maintain system reliability. ISO New England Operating Procedure No. 13 (OP-13) Standards for Voltage Reduction and Load Shedding Capability [33], establishes standards for the testing of TOs that have control over transmission/distribution facilities voltage reduction and load shedding capability.

Solar Integration (PV)

New England is forecasting a gross 50/50 summer peak of 27,424 MW and a net 50/50 summer peak of 24,553 MW. The net demand forecast considers demand reducers such as 1,775 MW of Energy Efficiency (EE) [34] and 1,097 MW of BTM PV. Historical hourly loads are reconstituted for the impacts of EE and BTM PV to ensure the proper accounting of EE and BTM PV, which are both forecast separately. The 2024 BTM PV forecast reflects recent development trends in the region, as indicated by data provided by region's Distribution Owners, and updated policy information provided by the New England states.[35]

In the day-ahead load-forecast process, BTM PV is explicitly forecasted and included in several demand models. Multiple methods are used to best estimate the impact of BTM PV on net demand. Production data is received daily and used for refinement of the BTM PV forecast models. Efforts to improve BTM PV forecasts in the short-term and real-time process are ongoing and are expected to continue for the foreseeable future.

Behind-the-Meter Photovoltaic (BTM PV)

Since 2014, BTM PV has had great impact on ISO New England's daily demand curves. BTMPV is tied to the distribution system, and therefore, the control room has no visibility of the resources. A large increase of BTMPV installed in New England is contributing to significant volatility on system load during the day. It is becoming common to see mid-afternoon loads dip below overnight lows when the when the sun is shining bright.

Zonal Load Forecasting

In addition to the efforts above, New England continues to produce a zonal load forecast for the eight regional load zones for up to six days in advance through the current operating day. This forecast enhances reliability by considering weather differences across the region, which may distort the normal distribution of load. An example would be when the Boston zone temperature is forecasted to be sixty-five degrees while the Hartford area is forecasting ninety degrees. This zonal forecast when rolled up provides a better New England demand forecast resulting in a better reliability commitment across the region.

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[33] Operating Procedure No. 13 is located on the ISO's website at: ISO-NE OP13 - Standards for Voltage Reduction and Load Shedding Capability

[34] The Energy Efficiency reconstitution methodology for the gross load forecast is described here: Final 2023 Energy Efficiency Forecast

[35] See: Final 2024 Photovoltaic (PV) Forecast

Natural Gas Supply

With natural gas as the predominant fuel source for power generation in New England, the ISO continues to monitor factors impacting the natural gas fuel deliverability for the area. For the 2024 Summer capacity period, the ISO expects limited amounts of natural gas pipeline maintenance and construction to occur for select areas and does not forecast major deliverability issues that would affect the installed capacity.

Operating Procedures

For the 2024 Summer Operating Period, ISO-NE has several operating procedures that can be invoked to help mitigate energy emergencies impacting the power generation sector:

1. ISO-NE's Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP 4) is a procedure that establishes criteria and guidelines for actions during capacity deficiencies resulting from generator and transmission contingencies and prescribe actions to manage Operating Reserve Requirements.[36]
2. ISO-NE's Operating Procedure No. 7 – *Action in an Emergency* (OP 7) is a procedure that establishes criteria to be followed in the event of an operating emergency involving unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels, or any other emergency that ISO-NE deems appropriate in an isolated or widespread area of New England.[37]
3. ISO-NE's Operating Procedure No. 21 - *Operational Surveys, Energy Forecasting & Reporting and Actions During An Energy Emergency* (OP 21) is designed to help mitigate the impacts on bulk power system reliability resulting from the loss of operable capacity due to regional fuel supply deficiencies that can occur anytime during the year [38]. Fuel supply deficiencies are the temporary or prolonged disruption to regional fuel supply chains for coal, natural gas, LNG, and heavy and light fuel oil.

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[36] Operating Procedure No. 4 is located on the ISO's website at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4_rto_final.pdf Operating Procedure No. 4 is located on the ISO's website at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4_rto_final.pdfISO-NE OP4 - Action During a Capacity Deficiency

[37] Operating Procedure No. 7 is located on the ISO's website at: http://www.iso-ne.com/rules_proceds/operating/isone/op7/op7_rto_final.pdf Operating Procedure No. 7 is located on the ISO's website at: http://www.iso-ne.com/rules_proceds/operating/isone/op7/op7_rto_final.pdfISO-NE OP7 - Action in an Emergency

[38] Operating Procedure No. 21 is located on the ISO's website at: http://www.iso-ne.com/rules_proceds/operating/isone/op21/op21_rto_final.pdf Operating Procedure No. 21 is located on the ISO's website at: http://www.iso-ne.com/rules_proceds/operating/isone/op21/op21_rto_final.pdfISO-NE OP21 - Operational Surveys, Energy Forecasting & Reporting and Actions During an Energy Emergency

New York

Operational Readiness

The New York Independent System Operator (NYISO), as the sole Balancing Authority for the New York Control Area (NYCA), anticipates adequate capacity exists to meet the New York State Reliability Council (NYSRC) Installed Reserve Margin (IRM) of 22.0% for 2024.

The actual 2023 peak was 30,206 MW, 1,843 (5.8%) lower than the forecast of 32,049 MW. The current 2024 peak forecast is 31,151 MW. It is lower than the 2023 forecast by 898 MW (2.8%). The forecast based on 90/10 weather conditions, set to the 90th percentile of typical peak-producing weather conditions for 2024 is 33,301 MW. Significant load-reducing impacts occur due to energy efficiency initiatives and the growth of distributed behind-the-meter energy resources, such as solar PV. Much of these impacts are due to New York State's energy policies and programs, including the 2019 Climate Leadership and Community Protection Act ("CLCPA"), the 2020 Accelerated Renewable Energy Growth and Community Benefit Act ("AREA"), the Clean Energy Standard ("CES"), the Clean Energy Fund ("CEF"), the NY-SUN initiative, the energy storage initiative, and other programs developed as part of the Reforming the Energy Vision ("REV") proceedings.

Based on 2023 assumptions, the peak load forecast was reduced by 806 MW for energy efficiency impacts, 1,133 MW for behind-the-meter PV impacts, 367 MW for other distributed generation impacts, and 351 MW for behind-the-meter energy storage. Projected electric vehicle usage increased the peak load forecast by 176 MW.

The NYISO maintains Joint Operating Agreements with each of its adjacent Reliability Coordinators that include provisions for the procurement or supply, of emergency energy, and provisions for wheeling emergency energy from remote areas, if required. Prior to the operating month, the NYISO identifies to neighboring control areas the capacity-backed transactions that are expected to be both imported into and exported from NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved. During the 2024 Summer Operating Period, New York expects to have 1,585 MW of net import capacity available based on current external purchases and sales.

The NYISO anticipates sufficient resources, including demand response, to meet peak demand without the need to resort to emergency operations. The Emergency Demand Response Program (EDRP) and ICAP/Special Case Resource program (ICAP/SCR) designs promote participation, and the expectation is for full participation. Further control actions are outlined in NYISO policies and procedures. There is no limitation as to the number of times a DR resource can be called upon to provide response. SCRs are required to respond when notice has been provided in accordance with NYISO's procedures; response from EDRP is voluntary for all events.

Voltage Control

The NYISO does not foresee any voltage issues for the upcoming summer season. Generators are compensated for reactive capability and are required to maintain Automatic Voltage Regulators (AVRs) in service at all times for said compensation. Generators must adjust their VAr output when called upon to provide voltage support. The NYCA also has two SVCs at Fraser and Leeds as well as a Convertible Static

Compensator (STATCOM) at Marcy that can provide either dynamic or static VAr support as needed. Furthermore, switched shunt capacitors and reactors are installed at key locations throughout the bulk power system to be utilized for voltage control.

Environmental Impacts

As a distinct effort in parallel with the clean energy mandates and emission reduction requirements contained in the Climate Leadership and Community Protection Act (CLCPA), signed into law in July 2019, the New York State Department of Environmental Conservation (NYSDEC) also finalized regulations in 2019 to implement stricter ozone season NOX emissions rate limits to reduce ozone-forming pollutants associated with New York State-based simple cycle combustion turbine generation. These new compliance obligations, referred to as the "Peaker rule," impacted a total of 3,300 megawatts. Emission rate reduction requirements initially phased-in on May 1, 2023 and will be fully implemented in May 2025. The NYISO has accounted for the unavailability of generators affected by the DEC Peaker Rule based on compliance plans submitted to the DEC by the affected generators. Of the 3,300 MW, approximately 1,000 MW retired or limited their operations before the 2023 compliance date of May 1, 2023.) Another 600 MW of Peaker's would become unavailable beginning May 1, 2025, except for those that have been designated as necessary to be temporarily retained to maintain electric system reliability until permanent solutions are deployed. The DEC regulations include a provision to allow an affected generator to continue to operate for up to two years, with a possible further two-year extension, after the compliance deadline if the generator is designated by the NYISO or by the local transmission owner as needed to resolve a reliability need until a permanent solution is in place. Consistent with the DEC's regulations and detailed in the Short-Term Reliability Process report, the NYISO has designated the Gowanus 2 & 3 and Narrows 1 & 2 generators to temporarily continue operation beyond May 2025 until permanent solutions are in place, for an initial period of up to two years (May 1, 2027). Remaining Peaker units have stated either that they comply with the emission limits as currently operated, or proposed equipment upgrades to achieve the more stringent emissions limits. The availability of these generators, which function as quick start reserves, may reduce the need to run more generators at lower dispatch levels while ensuring reliable operations. These generators may also be called upon to fully respond to NYISO dispatch signals, which could occur during long duration hot weather events or following the loss of significant generation or transmission assets in NYC.

Energy Storage

Energy storage units are split between transmission system, distribution system, and customer-sited storage. Customer-sited units are considered behind-the-meter, while transmission system and distribution system units are assumed to be part of the wholesale market. Both wholesale and behind-the-meter energy storage units will have relatively small positive net annual electricity consumption due to battery charging and discharging cycles. Only behind-the-meter energy storage units will reduce peak loads when injecting into the grid and only a portion of installed units are expected to be injecting during the NYCA summer and winter peak hours. Wholesale market energy storage does not reduce peak load because it is assumed to be dispatched as generation. Based on 2023 projections, total energy storage nameplate capacity is projected to be 882 MW including both wholesale and behind-the-meter capacity by the end of 2024.

Ontario

Supply/Demand Balance

Ontario is currently showing negative margins for a number of weeks under the 90/10 scenarios. This means some reliance on imports from our neighbours can be expected during these weather conditions.

With the foreseeable future projected to be under tighter supply conditions, surplus baseload generation will be much less of a concern than it has been in recent years.

Embedded solar and wind generation will continue to reduce demand on the transmission system, in particular during summer peaks. The summer peaks will also be subject to lower demands due to the Industrial Conservation Initiative (ICI [39]).

Outage Management

Outage coordination will be very important the next several years given the significant amount of capital upgrades, such as refurbishment outages and station rebuilds, which are happening the same time as routine maintenance. It will be one of the first tools to be utilized to minimize risks to meeting demand. Market Participants have been strongly encouraged to review ahead and coordinate plans with the IESO to ensure their outages can be appropriately scheduled.

Seasonal Readiness

Ontario will continue to use existing programs such as unit readiness to prepare for this summer. Testing generation may identify concerns to be remedied and may provide updated information in development of the operating plan.

Québec

Equipment Maintenance

Most transmission line, transformer and generating unit maintenance is done during the summer period. The maintenance outages are being planned so that all exports can be maintained.

Voltage Control

Québec is a winter peaking area, therefore during summer periods, reactive capability of generators is not a problem. Hydro-Québec does not expect to encounter any kind of low voltage problem during the summer. On the contrary, controlling over-voltages on the 735 kV network during off-peak hours is the concern. This is accomplished mainly with the use of shunt reactors. Typically, about 15,000 MVar of 735 kV shunt reactors is connected at any given time during the summer, with seven (7) to ten (10) 735 kV lines being out of service for maintenance. Most shunt capacitors, at all voltage levels, are disconnected during the summer.

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[39] For more information on the ICI, see: Industrial Conservation Initiative Backgrounder and FAQs

Thermal limits

On a few occasions during the last summers, several 735 kV lines in the southern part of the system became heavily loaded, due to the hot temperatures in southern Québec. Because summers are generally getting warmer, the air conditioning load is increasing year after year and transfers to summer peaking systems are increasing. Studies have been performed and thermal limits continue to be optimized to ensure that no line becomes overloaded following a contingency in hot temperature periods.

Forest fire

During last summer, Quebec faced its most severe forest fire season in modern history, surpassing the previous record set in 1923. The wildfires began on May 28, 2023, with transmission lines starting to trip on May 31st on the Churchill Falls – Arnaud transmission corridor and from June 1, 2023, on James Bay transmission corridors. Throughout June and July of 2023, several 735kV lines tripped.

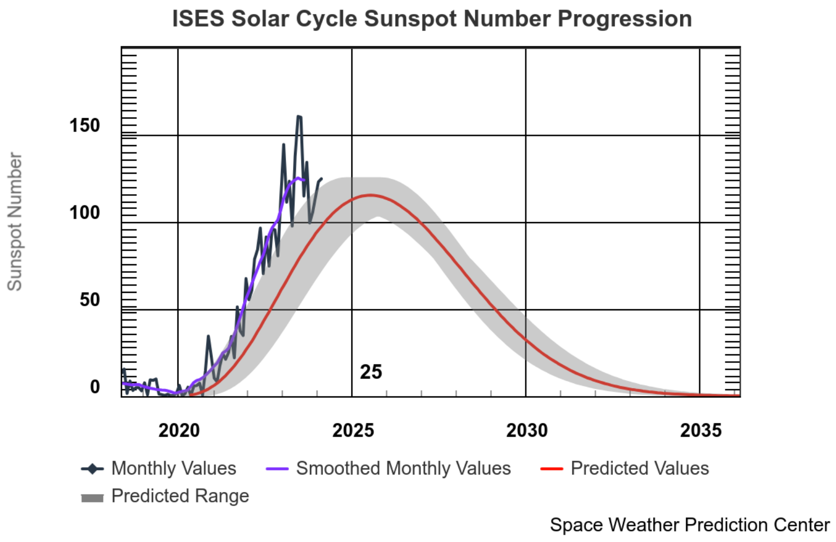
To address the situation, only essential planned outages were permitted from June 1st to July 19th, with many ongoing planned outages cancelled. Additionally, control measures were implemented to uphold reliability, and extra margin on resource adequacy assessment was applied to mitigate the impact of line tripping. Daily optimization of system configuration, preparation of contingency plans, and implementation of control measures were conducted to ensure reliability in response to the evolving fires.

Hydro-Quebec already has some operating procedures to follow during wildfires. These procedures were improved from the experience gained during last summer.

Summer 2024 Solar Terrestrial Dispatch [40] Spring/Summer GIC [41] Activity Update

Solar activity continues to progress faster than originally predicted toward a maximum of sunspot activity.

The original predicted maximum by the ISES [42] and the SWPC [43] is depicted below.



The inaccuracy of the original prediction forced solar and space weather forecasters to re-evaluate their methods of depicting the solar cycle. Earlier this year, the Space Weather Prediction Center came up with a numerical method of re-adjusting the timing of the solar cycle so that it better agrees with observations. It effectively "tunes" the prediction to hopefully better represent reality. [44]

The need for this adjustment illustrates how we still don't have a firm handle on how the solar cycle is driven. More research is needed.

The plot below shows this adjusted solar cycle prediction, together with the expected upper (dashed red) and lower (dashed green) limits of expected solar activity. The green dots represent observed sunspot numbers. The dark blue dots represent the predicted values from this numerical technique.

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[40] Solar Terrestrial Dispatch: spacew.com

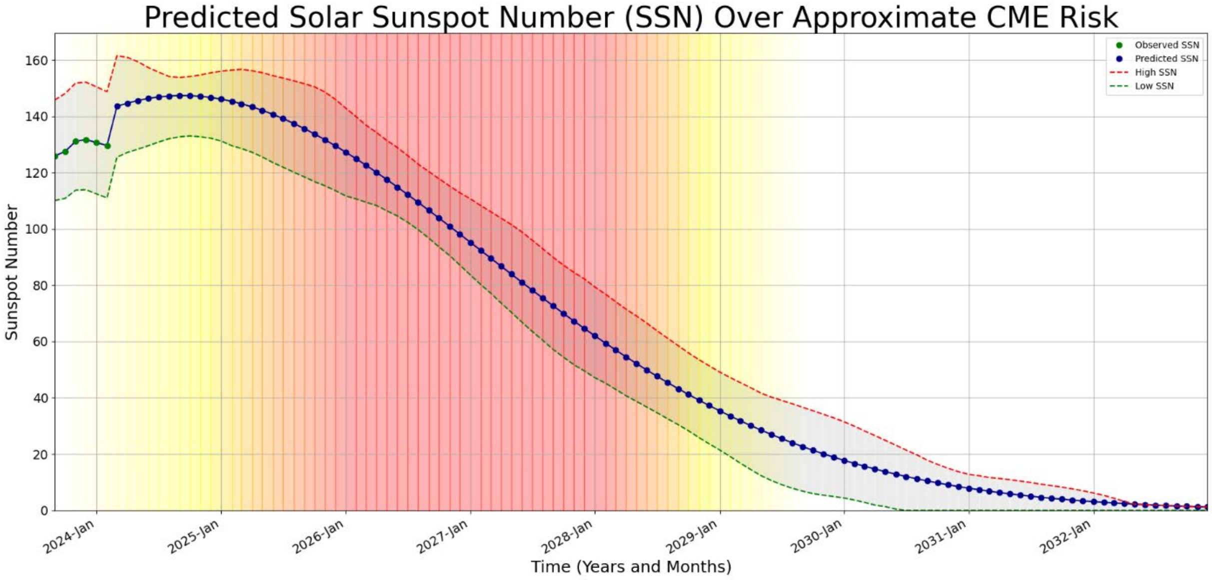
[41] Geomagnetically Induced Current

[42] International Space Environmental Services

[43] Space Weather Prediction Center: swpc.noaa.gov

[44] Details on its validation can be found here:

https://testbed.swpc.noaa.gov/sites/default/files/2024-01/solar_cycle_experimental_prediction_validation.pdf



The yellow to red shading is an approximation of the risk period for significant earthward-directed coronal mass ejection (CME) and geomagnetic activity. The red zone is roughly the time-period when geomagnetic activity reaches a peak during the solar cycle and when complex sunspot formation is more common near the solar equator, which enhances the risk for earthward directed coronal mass ejections.

As can be seen from this revised prediction, the peak in sunspot numbers is now expected to occur over the next year to a year and a half (before the summer of 2025). Geomagnetic activity will then start increasing over the following two years toward its natural cycle peak, corresponding to the red region. The probabilities for GICs will therefore be higher in two years than they are now. However, remember that strong coronal mass ejections that could produce significant GIC activity are possible at any time.

Over the next six months, through the summer and into the fall of 2024, there will be periods of minor to major geomagnetic storming that support minor to perhaps moderate GIC activity. And there is a small, but increasing chance that we could observe a geomagnetic storm large enough to produce moderate to strong GICs.

Operators are encouraged to rely heavily on the daily updated predictions. Note that over the last 6 months, there have been a few coronal mass ejections that were not earthward directed that could have traversed the distance from the Sun to the Earth in less than 24 hours, had they been earthward directed. These events can occur without warning from complex sunspot groups. Reliance on short-term daily predictions is therefore strongly encouraged over the next several years until the frequency of these types of coronal mass ejections decreases.

7. Post-Seasonal Assessment and Historical Review

Summer 2023 Post-Seasonal Assessment

The sections below describe each Reliability Coordinator Area's Summer 2023 operational experiences. The NPCC coincident peak was 100,408 MW and occurred on September 6, 2023, at HE18 EDT.

Additional details from Summer 2023 can be found in **Appendix VIII - CP-8 2024 Summer Multi-Area Probabilistic Reliability Assessment**, Section 5, "Historical Review".

Maritimes

The Maritimes demand during the NPCC coincident peak was 3,156 MW. Maritimes actual peak was 3,578 MW on May 5, 2023, at HE08 EDT.

New England

The New England demand during the 2023 NPCC coincident peak was 21,966 MW. The New England peak demand value of 23,521 MW [45] was observed on September 7, 2023, HE19 EDT. Peak loads were generally in line with forecasts given the weather conditions on the peak day.

On July 7, 2023, ISO-NE declared M/LCC 2, Abnormal Conditions Alert, for capacity deficiency and later enacted steps 1 & 2 of OP4, Action During a Capacity Deficiency. M/LCC 2 was declared on three additional occasions during the 2023 Summer Operating Period: August 21 (capacity deficiency), September 6 (capacity deficiency) and September 15-17 (severe weather).

New York

The peak demand of 30,206 MW occurred on September 6, 2023, HE 17 EDT; at the same time as the NPCC coincident peak demand. There were no fuel supply, transmission, or reactive capability issues.

Ontario

The Ontario demand during the 2023 NPCC coincident peak was 22,300 MW. The actual peak demand was 23,713 MW on September 5, 2023, at HE 16 EDT. This was higher than the originally forecasted 22,439 MW. There were no significant operational issues observed during the 2023 Summer Operating Period.

Québec

The Québec Area actual internal peak demand for summer 2023 and all-time summer peak demand occurred on September 6, 2023, at HE18 EDT and was 22,780 MW. This was at the same time as the NPCC coincident peak demand. Higher than usual temperature is the main contributor to the last year's historical peak occurrence. Although Québec had its historical summer peak last year, it is important to emphasize the fact that Hydro-Québec's system is designed for a winter peaking load of almost two times the historical summer peaking load.

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[45] New England Actual Peak does not account for load served by Settlement Only Generators.

During last summer, Quebec faced its most severe forest fire season in modern history, surpassing the previous record set in 1923. The wildfires began on May 28, 2023, with transmission lines starting to trip on May 31st on the Churchill Falls – Arnaud transmission corridor and from June 1, 2023, on James Bay transmission corridors. Throughout June and July of 2023, several 735kV lines tripped.

Historical Summer Demand Review

Table 7-1 below summarizes historical non-coincident summer peaks for each NPCC Reliability Coordinator Areas over the last ten years along with the forecast 50/50 non-coincident peak demand for summer 2024.

Table 7-1: Ten Year Historical and Forecast Summer Peak Demands (MW)

Summer	Maritimes	New England	New York	Ontario	Québec	NPCC Coincident Demand	NPCC Coincident Date
2007	3,886	26,145	32,169	25,737	21,411	108,018	August 2, 2007
2008	3,675	26,111	32,432	24,195	21,488	106,295	June 9, 2008
2009	3,566	25,100	30,843	24,380	21,141	102,903	August 17, 2009
2010	3,497	27,102	33,452	25,075	22,092	109,924	July 6, 2010
2011	3,725	27,707	33,865	23,342	21,356	109,754	July 21, 2011
2012	3,403	25,880	32,439	24,636	21,938	106,247	July 17, 2012
2013	3,299	27,379	33,956	24,927	21,702	109,278	July 17, 2013
2014	3,721	24,443	29,782	21,363	21,165	96,068	July 1, 2014
2015	3,688	24,398	31,138	22,516	20,766	100,883	July 29, 2015
2016	3,391	25,466	32,076	23,213	20,724	103,350	August 11, 2016
2017	3,118	23,708	29,699	21,786	21,118	96,911	June 12, 2017
2018	3,243	25,808	31,861	23,240	21,448	103,231	August 28, 2018
2019	3,236	24,004	30,397	21,791	20,493	98,578	July 4, 2019
2020	3,346	24,736	30,660	24,446	21,850	102,722	July 27, 2020
2021	3,443	25,801	30,919	22,986	22,480	103,461	August 26, 2021
2022	3,435	24,330	30,505	22,607	22,480	100,427	August 08, 2022
2023	3,389	23,521	30,206	23,713	22,780	100,408	September 06, 2023
2024 Forecasted	3,586	24,553	31,541	22,753	22,922	105,014	August 11, 2024

Table 7-2 below presents the all-time summer peak demand for each NPCC Area with the corresponding date and time.

Table 7-2 : All-Time Summer Peak Demand by Area

Reliability Coordinator Area	Load (MW)	Date and time
Maritimes	3,886	May 17, 2007, HE 08 EST
New England	28,130	August 2, 2006, HE19 EST
New York	33,956	July 19, 2013, HE19 EST
Ontario	27,005	August 1, 2006, HE16 EST
Québec	22,780	September 06, 2023, HE18 EST

8. 2024 Reliability Assessments of Adjacent Regions

For a comprehensive review of the ReliabilityFirst Corporation Seasonal Resource and Demand, and Transmission Assessment, please go to:

https://www.rfirst.org/news/

For reviews of the other NERC Regions, please see:

http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

9. CP-8 2024 Summer Multi-Area Probabilistic Reliability Assessment Executive Summary

This assessment was prepared by the CP-8 Working Group to estimate the use of the available NPCC Area Operating Procedures to mitigate resource shortages from May through September 2024 period. Please refer to Appendix VIII (**Tables 9 and 10**) for a description of the Base Case and Severe Case Assumptions.

Base Case Scenario Summary

50/50 Peak Load Level

Under the Base Case Scenario and 50/50 peak load level, only the New York Area shows a likelihood greater than 0.5 days/period of using their Operating Procedures such as activating their demand response programs designed to mitigate resource shortages during the 2024 summer period.

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

Highest Peak Load Levels

Under the Base Case Scenario and higher peak load level assumptions, the New England Area shows a likelihood of using their Operating Procedures reducing 30-min reserve requirements to mitigate resource shortages.

The New York Area shows a cumulative likelihood of activating their demand response programs, reducing their 30-min reserve, initiating voltage reductions, and reducing 10-min reserve, and initiating public appeals to mitigate shortages for the 2024 summer period for the Base Case Scenario assuming the highest peak load levels.

The highest peak load level results were based exclusively on only the two highest load levels of the seven load levels modeled, having approximately a combined seven percent chance of occurring.

Severe Case Scenario Summary

50/50 Peak Load Level

The New York Area shows a cumulative likelihood of activation of their demand response programs and reducing 30-min reserve (0.5 days/period) during the 2024 summer period for the Severe Case Scenario assuming the 50/50 peak load level.

The New England Area shows a likelihood of using their Operating Procedures reducing 30-min reserve requirements to mitigate resource shortages.

The 50/50 peak load level results were based on the probability-weighted average of all the seven load levels simulated. The probabilistic results indicate that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during the Summer of 2024.

Highest Peak Load Levels

The New England, New York, and Ontario, Areas show greater cumulative likelihoods of using more of their Operating Procedures designed to mitigate resource shortages during the 2024 summer period for the Severe Case Scenario assuming the highest peak load levels.

The highest peak load level results were based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring.

Québec

The Québec Area is not expected to require use of their operating procedures designed to mitigate resource shortages during the Summer of 2024. The Québec Area is winter peaking and has a large reserve margin for the summer period; as a result, Québec did not demonstrate any measurable amounts of cumulative LOLE**,** [46] LOLH [47] or EUE [48] risks over the summer May – September period for all the scenarios modeled.

LOLH and EUE can provide insight on system reliability because of their ability to measure loss of load duration and magnitude. EUE is helpful in quantifying the reliability risk impacts of weather or other natural events.

Ontario

The severe case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.03 days/period), with associated cumulative LOLH (0.06 hours/period) and EUE (30 MWh/period) with the highest risk occurring in Aug, correlated to the availability of their external imports at the time of Ontario's peak load. Negligible cumulative LOLE, LOLH and EUE risks were estimated over the May to September summer period for the other scenarios modeled.

New England

The severe case, highest peak load level conditions resulted in a small estimated cumulative LOLE risk (0.69 days/period), with associated LOLH (2.8 hours/period) and EUE (1,604 MWh/period) with the highest risk occurring in July and August. Negligible cumulative LOLE (<0.022 days/period), LOLH (<0.08hours/period) and EUE (<17 MWh/period) risks were estimated over the summer May to September period for the other scenarios modeled.

New York

The severe case, highest peak load level conditions resulted in an estimated cumulative LOLE risk (1.2 days/period), with associated LOLH (4.3 hours/period) and EUE (3,424 MWh/period) with the highest risk highest risk occurring in July and August. Negligible cumulative LOLE (<0.023 days/period), LOLH (<0.0.07 hours/period) and EUE (39 MWh/period) risks were estimated over the summer May to September period for the other scenarios modeled.

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[46] LOLE: The number of events in which system load is not served in a given time period.

[47] LOLH: The expected number of hours in a given time period (often one year) when a system's hourly demand is projected to exceed the generating capacity.

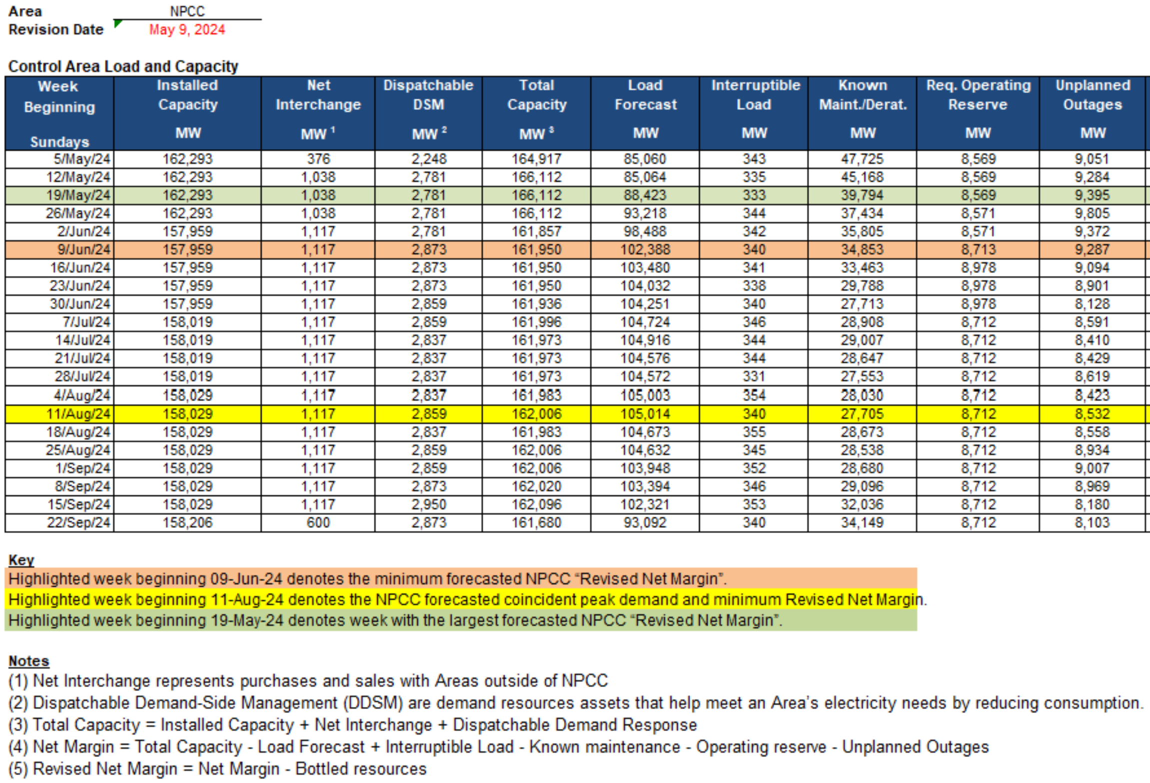
[48] EUE: The expected amount of energy (MWh) that will not be served in a given year (or period)

Maritimes Area

The Maritimes Area is winter peaking. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer May – September period for all the scenarios modeled.

Appendix I – Summer 2024 Expected Load and Capacity Forecasts

Table AP-1 - NPCC Summary



Area NPCC
Revision Date May 9, 2024

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW [1]	Dispatchable DSM MW [2]	Total Capacity MW [3]	Load Forecast MW	Interruptible Load MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Total Outages MW	Net Margin MW [4]	Net Margin %	Revised Net Margin MW [5]	Revised Net Margin %
5/May/24	162,293	376	2,248	164,917	85,060	343	47,725	8,569	9,051	56,776	14,856	**17.5%**	14,856	**17.5%**
12/May/24	162,293	1,038	2,781	166,112	85,064	335	45,168	8,569	9,284	54,452	18,362	**21.6%**	17,816	**20.9%**
19/May/24	162,293	1,038	2,781	166,112	88,423	333	39,794	8,569	9,395	49,189	20,265	**22.9%**	18,791	**21.3%**
26/May/24	162,293	1,038	2,781	166,112	93,218	344	37,434	8,571	9,805	47,239	17,428	**18.7%**	15,225	**16.3%**
2/Jun/24	157,959	1,117	2,781	161,857	98,488	342	35,805	8,571	9,372	45,177	9,963	**10.1%**	8,598	**8.7%**
9/Jun/24	157,959	1,117	2,873	161,950	102,388	340	34,853	8,713	9,287	44,140	7,050	**6.9%**	6,046	**5.9%**
16/Jun/24	157,959	1,117	2,873	161,950	103,480	341	33,463	8,978	9,094	42,557	7,276	**7.0%**	6,190	**6.0%**
23/Jun/24	157,959	1,117	2,873	161,950	104,032	338	29,788	8,978	8,901	38,689	10,589	**10.2%**	6,976	**6.7%**
30/Jun/24	157,959	1,117	2,859	161,936	104,251	340	27,713	8,978	8,128	35,841	13,205	**12.7%**	10,070	**9.7%**
7/Jul/24	158,019	1,117	2,859	161,996	104,724	346	28,908	8,712	8,591	37,499	11,406	**10.9%**	9,638	**9.2%**
14/Jul/24	158,019	1,117	2,837	161,973	104,916	344	29,007	8,712	8,410	37,417	11,271	**10.7%**	9,931	**9.5%**
21/Jul/24	158,019	1,117	2,837	161,973	104,576	344	28,647	8,712	8,429	37,076	11,953	**11.4%**	9,615	**9.2%**
28/Jul/24	158,019	1,117	2,837	161,973	104,572	331	27,553	8,712	8,619	36,172	12,848	**12.3%**	9,944	**9.5%**
4/Aug/24	158,029	1,117	2,837	161,983	105,003	354	28,030	8,712	8,423	36,453	12,170	**11.6%**	9,835	**9.4%**
11/Aug/24	158,029	1,117	2,859	162,006	105,014	340	27,705	8,712	8,532	36,237	12,382	**11.8%**	9,776	**9.3%**
18/Aug/24	158,029	1,117	2,837	161,983	104,673	355	28,673	8,712	8,558	37,231	11,722	**11.2%**	9,318	**8.9%**
25/Aug/24	158,029	1,117	2,859	162,006	104,632	345	28,538	8,712	8,934	37,472	11,534	**11.0%**	8,836	**8.4%**
1/Sep/24	158,029	1,117	2,859	162,006	103,948	352	28,680	8,712	9,007	37,687	12,011	**11.6%**	9,145	**8.8%**
8/Sep/24	158,029	1,117	2,873	162,020	103,394	346	29,096	8,712	8,969	38,066	12,194	**11.8%**	8,812	**8.5%**
15/Sep/24	158,029	1,117	2,950	162,096	102,321	353	32,036	8,712	8,180	40,216	11,200	**10.9%**	9,358	**9.1%**
22/Sep/24	158,206	600	2,873	161,680	93,092	340	34,149	8,712	8,103	42,252	17,964	**19.3%**	16,408	**17.6%**

Key

Highlighted week beginning 09-Jun-24 denotes the minimum forecasted NPCC "Revised Net Margin".

Highlighted week beginning 11-Aug-24 denotes the NPCC forecasted coincident peak demand and minimum Revised Net Margin.

Highlighted week beginning 19-May-24 denotes week with the largest forecasted NPCC "Revised Net Margin".

Notes

(1) Net Interchange represents purchases and sales with Areas outside of NPCC
(2) Dispatchable Demand-Side Management (DDSM) are demand resources assets that help meet an Area's electricity needs by reducing consumption.
(3) Total Capacity = Installed Capacity + Net Interchange + Dispatchable Demand Response
(4) Net Margin = Total Capacity - Load Forecast + Interruptible Load - Known maintenance - Operating reserve - Unplanned Outages
(5) Revised Net Margin = Net Margin - Bottled resources

Table AP-2 – Maritimes

Area	Maritimes
Revision Date	March 24, 2024

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW	Highest Experienced Load	Interruptible Load MW	Known Maint./Derat. MW ^{1}	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
5/May/24	7,739	81	0	7,820	3,578	3,886	330	3,087	486	339	661	**18.5%**
12/May/24	7,739	81	0	7,820	3,518	3,886	322	3,111	486	339	688	**19.6%**
19/May/24	7,739	81	0	7,820	3,326	3,886	320	3,178	486	339	812	**24.4%**
26/May/24	7,739	81	0	7,820	3,254	3,886	331	3,476	486	339	596	**18.3%**
2/Jun/24	7,739	63	0	7,802	3,254	3,886	329	3,400	486	339	653	**20.1%**
9/Jun/24	7,739	63	0	7,802	3,301	3,886	327	3,141	628	339	721	**21.8%**
16/Jun/24	7,739	63	0	7,802	3,263	3,886	328	2,533	893	339	1,103	**33.8%**
23/Jun/24	7,739	63	0	7,802	3,223	3,886	325	2,487	893	339	1,186	**36.8%**
30/Jun/24	7,739	63	0	7,802	3,398	3,886	327	2,468	893	339	1,032	**30.4%**
7/Jul/24	7,739	63	0	7,802	3,361	3,886	333	2,544	893	339	998	**29.7%**
14/Jul/24	7,739	63	0	7,802	3,433	3,886	331	2,399	893	339	1,069	**31.1%**
21/Jul/24	**7,739**	**63**	**0**	**7,802**	**3,524**	**3,886**	**331**	**2,399**	**893**	**339**	**978**	**27.8%**
28/Jul/24	7,739	63	0	7,802	3,475	3,886	318	2,424	893	339	990	**28.5%**
4/Aug/24	7,749	63	0	7,812	3,424	3,886	341	2,461	893	339	1,036	**30.3%**
11/Aug/24	7,749	63	0	7,812	3,429	3,886	327	2,486	893	339	992	**28.9%**
18/Aug/24	7,749	63	0	7,812	3,272	3,886	342	2,499	893	339	1,151	**35.2%**
25/Aug/24	7,749	63	0	7,812	3,387	3,886	332	2,509	893	337	1,017	**30.0%**
1/Sep/24	7,749	63	0	7,812	3,449	3,886	339	2,577	893	337	895	**26.0%**
8/Sep/24	7,749	63	0	7,812	3,390	3,886	333	2,980	893	337	545	**16.1%**
15/Sep/24	7,749	63	0	7,812	3,527	3,886	340	2,810	893	339	583	**16.5%**
22/Sep/24	7,749	63	0	7,812	3,586	3,886	327	2,720	893	339	601	**16.8%**

Key

Highlighted week beginning 11-Aug-24 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 19-May-24 denotes week with the largest forecasted NPCC "Revised Net Margin".

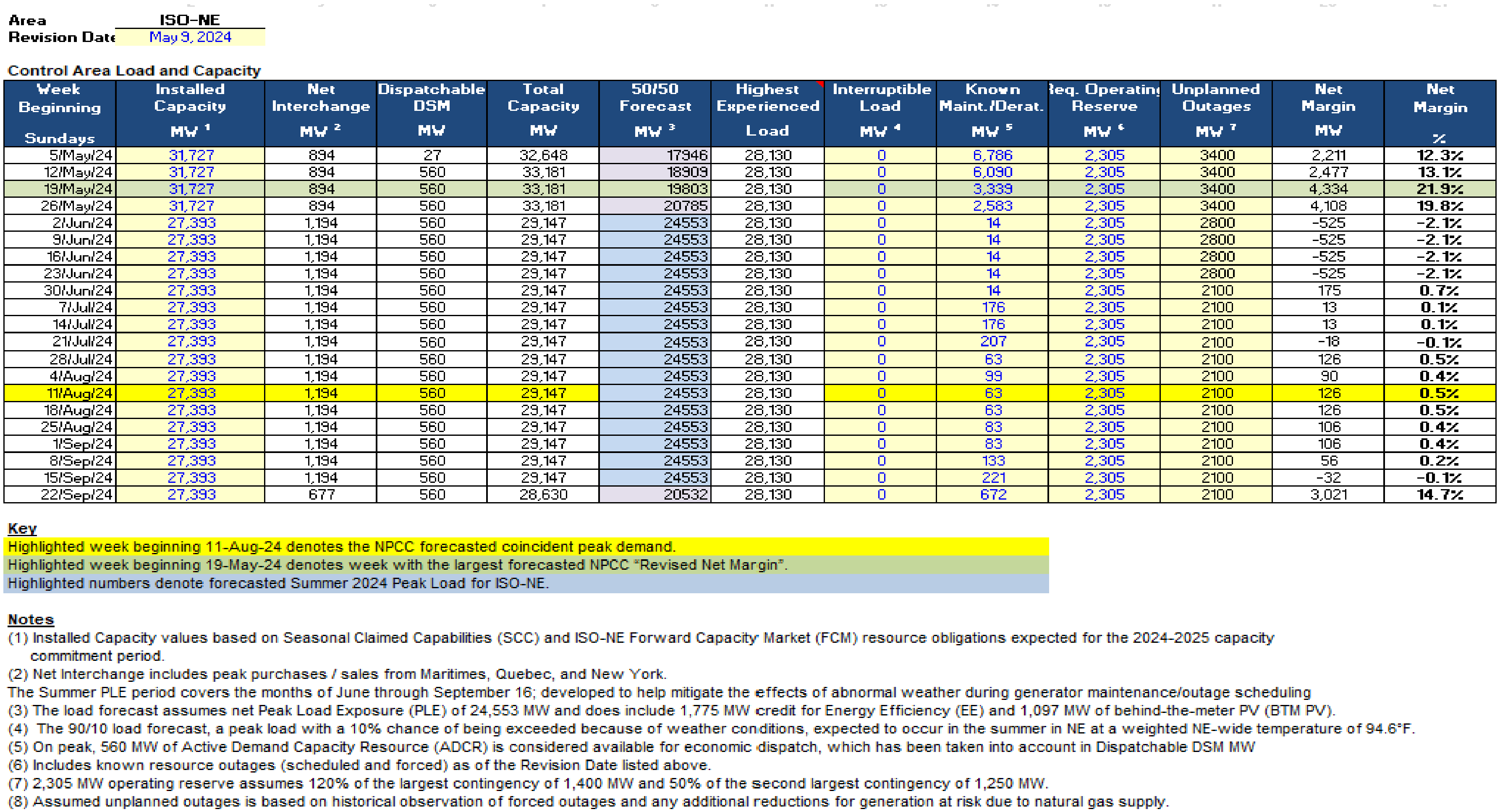
Highlighted number denotes forecasted Summer 2024 Peak Load for Maritimes.

Notes

(1) Known Maint./Derate include wind.

(2) Week beginning 22-Sep-24 denotes the forecasted Maritimes Summer 2024 Peak Week.

Table AP-3 – New England



Area ISO-NE
Revision Dat May 9, 2024

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW [1]	Net Interchange MW [2]	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW [3]	Highest Experienced Load	Interruptible Load MW [4]	Known Maint./Derat. MW [5]	eq. Operatin Reserve MW [6]	Unplanned Outages MW [7]	Net Margin MW	Net Margin %
5/May/24	31,727	894	27	32,648	17946	28,130	0	6,786	2,305	3400	2,211	**12.3%**
12/May/24	31,727	894	560	33,181	18909	28,130	0	6,090	2,305	3400	2,477	**13.1%**
19/May/24	31,727	894	560	33,181	19803	28,130	0	3,339	2,305	3400	4,334	**21.9%**
26/May/24	31,727	894	560	33,181	20785	28,130	0	2,583	2,305	3400	4,108	**19.8%**
2/Jun/24	27,393	1,194	560	29,147	24553	28,130	0	14	2,305	2800	-525	**-2.1%**
9/Jun/24	27,393	1,194	560	29,147	24553	28,130	0	14	2,305	2800	-525	**-2.1%**
16/Jun/24	27,393	1,194	560	29,147	24553	28,130	0	14	2,305	2800	-525	**-2.1%**
23/Jun/24	27,393	1,194	560	29,147	24553	28,130	0	14	2,305	2800	-525	**-2.1%**
30/Jun/24	27,393	1,194	560	29,147	24553	28,130	0	14	2,305	2100	175	**0.7%**
7/Jul/24	27,393	1,194	560	29,147	24553	28,130	0	176	2,305	2100	13	**0.1%**
14/Jul/24	27,393	1,194	560	29,147	24553	28,130	0	176	2,305	2100	13	**0.1%**
21/Jul/24	27,393	1,194	560	29,147	24553	28,130	0	207	2,305	2100	-18	**-0.1%**
28/Jul/24	27,393	1,194	560	29,147	24553	28,130	0	63	2,305	2100	126	**0.5%**
4/Aug/24	27,393	1,194	560	29,147	24553	28,130	0	99	2,305	2100	90	**0.4%**
11/Aug/24	27,393	1,194	560	29,147	24553	28,130	0	63	2,305	2100	126	**0.5%**
18/Aug/24	27,393	1,194	560	29,147	24553	28,130	0	63	2,305	2100	126	**0.5%**
25/Aug/24	27,393	1,194	560	29,147	24553	28,130	0	83	2,305	2100	106	**0.4%**
1/Sep/24	27,393	1,194	560	29,147	24553	28,130	0	83	2,305	2100	106	**0.4%**
8/Sep/24	27,393	1,194	560	29,147	24553	28,130	0	133	2,305	2100	56	**0.2%**
15/Sep/24	27,393	1,194	560	29,147	24553	28,130	0	221	2,305	2100	-32	**-0.1%**
22/Sep/24	27,393	677	560	28,630	20532	28,130	0	672	2,305	2100	3,021	**14.7%**

Key

Highlighted week beginning 11-Aug-24 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 19-May-24 denotes week with the largest forecasted NPCC "Revised Net Margin".

Highlighted numbers denote forecasted Summer 2024 Peak Load for ISO-NE.

Notes

(1) Installed Capacity values based on Seasonal Claimed Capabilities (SCC) and ISO-NE Forward Capacity Market (FCM) resource obligations expected for the 2024-2025 capacity commitment period.

(2) Net Interchange includes peak purchases / sales from Maritimes, Quebec, and New York.

The Summer PLE period covers the months of June through September 16; developed to help mitigate the effects of abnormal weather during generator maintenance/outage scheduling

(3) The load forecast assumes net Peak Load Exposure (PLE) of 24,553 MW and does include 1,775 MW credit for Energy Efficiency (EE) and 1,097 MW of behind-the-meter PV (BTM PV).

(4) The 90/10 load forecast, a peak load with a 10% chance of being exceeded because of weather conditions, expected to occur in the summer in NE at a weighted NE-wide temperature of 94.6°F.

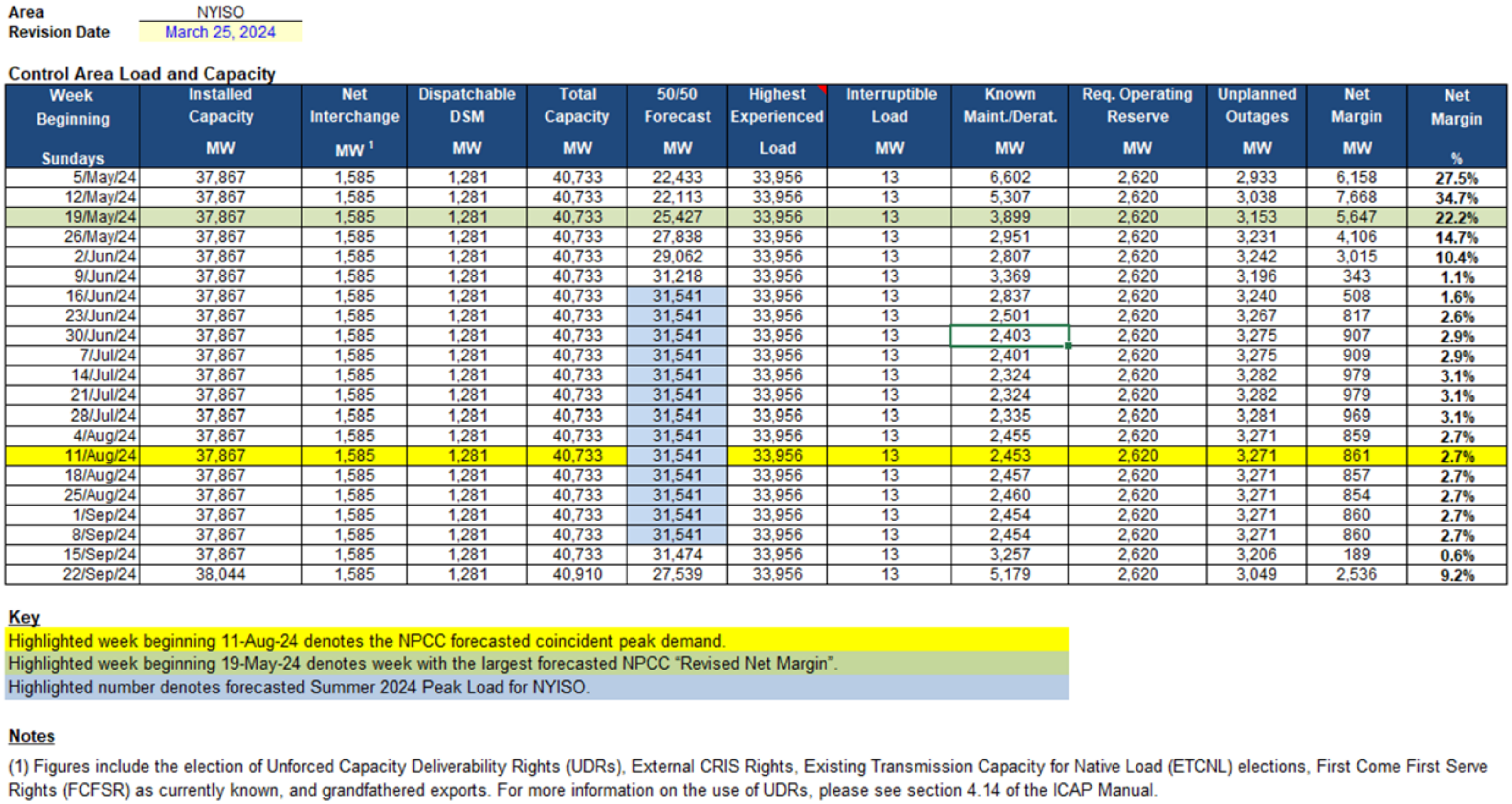
(5) On peak, 560 MW of Active Demand Capacity Resource (ADCR) is considered available for economic dispatch, which has been taken into account in Dispatchable DSM MW

(6) Includes known resource outages (scheduled and forced) as of the Revision Date listed above.

(7) 2,305 MW operating reserve assumes 120% of the largest contingency of 1,400 MW and 50% of the second largest contingency of 1,250 MW.

(8) Assumed unplanned outages is based on historical observation of forced outages and any additional reductions for generation at risk due to natural gas supply.

Table AP-4 – New York



Area NYISO
Revision Date March 25, 2024

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW[1]	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW	Highest Experienced Load	Interruptible Load MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
5/May/24	37,867	1,585	1,281	40,733	22,433	33,956	13	6,602	2,620	2,933	6,158	**27.5%**
12/May/24	37,867	1,585	1,281	40,733	22,113	33,956	13	5,307	2,620	3,038	7,668	**34.7%**
19/May/24	37,867	1,585	1,281	40,733	25,427	33,956	13	3,899	2,620	3,153	5,647	**22.2%**
26/May/24	37,867	1,585	1,281	40,733	27,838	33,956	13	2,951	2,620	3,231	4,106	**14.7%**
2/Jun/24	37,867	1,585	1,281	40,733	29,062	33,956	13	2,807	2,620	3,242	3,015	**10.4%**
9/Jun/24	37,867	1,585	1,281	40,733	31,218	33,956	13	3,369	2,620	3,196	343	**1.1%**
16/Jun/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,837	2,620	3,240	508	**1.6%**
23/Jun/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,501	2,620	3,267	817	**2.6%**
30/Jun/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,403	2,620	3,275	907	**2.9%**
7/Jul/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,401	2,620	3,275	909	**2.9%**
14/Jul/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,324	2,620	3,282	979	**3.1%**
21/Jul/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,324	2,620	3,282	979	**3.1%**
28/Jul/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,335	2,620	3,281	969	**3.1%**
4/Aug/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,455	2,620	3,271	859	**2.7%**
11/Aug/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,453	2,620	3,271	861	**2.7%**
18/Aug/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,457	2,620	3,271	857	**2.7%**
25/Aug/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,460	2,620	3,271	854	**2.7%**
1/Sep/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,454	2,620	3,271	860	**2.7%**
8/Sep/24	37,867	1,585	1,281	40,733	31,541	33,956	13	2,454	2,620	3,271	860	**2.7%**
15/Sep/24	37,867	1,585	1,281	40,733	31,474	33,956	13	3,257	2,620	3,206	189	**0.6%**
22/Sep/24	38,044	1,585	1,281	40,910	27,539	33,956	13	5,179	2,620	3,049	2,536	**9.2%**

Key

Highlighted week beginning 11-Aug-24 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 19-May-24 denotes week with the largest forecasted NPCC "Revised Net Margin".
Highlighted number denotes forecasted Summer 2024 Peak Load for NYISO.

Notes

(1) Figures include the election of Unforced Capacity Deliverability Rights (UDRs), External CRIS Rights, Existing Transmission Capacity for Native Load (ETCNL) elections, First Come First Serve Rights (FCFSR) as currently known, and grandfathered exports. For more information on the use of UDRs, please see section 4.14 of the ICAP Manual.

Table AP-5 – Ontario

Area Ontario
Revision Date March 24, 2024

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW[1]	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	50/50 Forecast MW[2]	Highest Experienced Load	Interruptible Load MW	Known Maint./ Derat./Bottled Cap. MW[3]	Req. Operating Reserve MW	Unplanned Outages MW[4]	Net Margin MW	Net Margin %
5/May/24	38,193	-62	940	39,071	17,274	27,005		16,992	1,658	1,179	1,968	**11.4%**
12/May/24	38,193	600	940	39,733	17,475	27,005		17,318	1,658	1,307	1,975	**11.3%**
19/May/24	38,193	600	940	39,733	17,543	27,005		16,237	1,658	1,303	2,992	**17.1%**
26/May/24	38,193	600	940	39,733	19,149	27,005		15,882	1,660	1,635	1,407	**7.3%**
2/Jun/24	38,193	600	940	39,733	19,554	27,005		16,089	1,660	1,791	639	**3.3%**
9/Jun/24	38,193	600	1,032	39,825	21,217	27,005		14,505	1,660	1,752	691	**3.3%**
16/Jun/24	38,193	600	1,032	39,825	21,880	27,005		14,379	1,660	1,515	391	**1.8%**
23/Jun/24	38,193	600	1,032	39,825	22,502	27,005		13,500	1,660	1,295	868	**3.9%**
30/Jun/24	38,193	600	1,018	39,811	22,449	27,005		11,316	1,660	1,214	3,172	**14.1%**
7/Jul/24	38,253	600	1,018	39,871	22,685	27,005		11,214	1,394	1,677	2,901	**12.8%**
14/Jul/24	38,253	600	996	39,849	22,753	27,005		11,090	1,394	1,489	3,123	**13.7%**
21/Jul/24	38,253	600	996	39,849	22,699	27,005		11,388	1,394	1,508	2,860	**12.6%**
28/Jul/24	38,253	600	996	39,849	22,625	27,005		11,088	1,394	1,699	3,043	**13.5%**
4/Aug/24	38,253	600	996	39,849	22,582	27,005		11,290	1,394	1,513	3,070	**13.6%**
11/Aug/24	38,253	600	1,018	39,871	22,569	27,005		11,306	1,394	1,622	2,981	**13.2%**
18/Aug/24	38,253	600	996	39,849	22,539	27,005		11,749	1,394	1,648	2,519	**11.2%**
25/Aug/24	38,253	600	1,018	39,871	22,462	27,005		11,929	1,394	2,026	2,060	**9.2%**
1/Sep/24	38,253	600	1,018	39,871	21,915	27,005		11,996	1,394	2,099	2,467	**11.3%**
8/Sep/24	38,253	600	1,032	39,885	21,957	27,005		11,939	1,394	2,061	2,535	**11.5%**
15/Sep/24	38,253	600	1,109	39,962	20,481	27,005		12,950	1,394	1,335	3,802	**18.6%**
22/Sep/24	38,253	600	1,032	39,885	18,884	27,005		12,759	1,394	1,415	5,433	**28.8%**

Key

Highlighted week beginning 11-Aug-24 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 19-May-24 denotes week with the largest forecasted NPCC “Revised Net Margin”.

Highlighted number denotes forecasted Summer 2024 Peak Load for Ontario.

Notes

(1) "Installed Capacity" includes all generation registered in the IESO-administered market.
(2) "Load Forecast" represents the normal weather case, weekly 60-minute peaks.
(3) "Known Maint./Derat./Bottled Cap." includes planned outages, deratings, historic hydroelectric reductions and variable generation reductions.
(4) "Unplanned Outages" is based on the average amount of generation in forced outage for the assessment period.
(5) Week beginning 14-Jul-24 denotes the Ontario Peak Week

Table AP-6 – Québec

Area Québec

Revision Date February 11, 2024

Control Area Load and Capacity

Week Beginning Sundays	2 Installed Capacity MW [1]	5 Net Interchange MW [2]	6 Dispatchable DSM MW	7 Total Capacity MW	8 50/50 Forecast MW	11 Highest Experienced Load	13 Interruptible Load MW	14 Known Maint./Derat. MW [3]	16 Req. Operating Reserve MW	17 Unplanned Outages MW	19 Net Margin MW	20 Net Margin %
5/May/24	46,767	-2,122	0	44,645	23,829	22,780	0	14,258	1,500	1,200	3,858	**16.2%**
12/May/24	46,767	-2,122	0	44,645	23,049	22,780	0	13,342	1,500	1,200	5,554	**24.1%**
19/May/24	46,767	-2,122	0	44,645	22,323	22,780	0	13,141	1,500	1,200	6,481	**29.0%**
26/May/24	46,767	-2,122	0	44,645	22,192	22,780	0	12,542	1,500	1,200	7,211	**32.5%**
2/Jun/24	46,767	-2,325	0	44,442	22,066	22,780	0	13,495	1,500	1,200	6,181	**28.0%**
9/Jun/24	46,767	-2,325	0	44,442	22,099	22,780	0	13,824	1,500	1,200	5,819	**26.3%**
16/Jun/24	46,767	-2,325	0	44,442	22,243	22,780	0	13,700	1,500	1,200	5,799	**26.1%**
23/Jun/24	46,767	-2,325	0	44,442	22,213	22,780	0	11,286	1,500	1,200	8,243	**37.1%**
30/Jun/24	46,767	-2,325	0	44,442	22,310	22,780	0	11,512	1,500	1,200	7,920	**35.5%**
7/Jul/24	46,767	-2,325	0	44,442	22,584	22,780	0	12,574	1,500	1,200	6,584	**29.2%**
14/Jul/24	46,767	-2,325	0	44,442	22,636	22,780	0	13,018	1,500	1,200	6,088	**26.9%**
21/Jul/24	46,767	-2,325	0	44,442	22,259	22,780	0	12,329	1,500	1,200	7,155	**32.1%**
28/Jul/24	46,767	-2,325	0	44,442	22,378	22,780	0	11,643	1,500	1,200	7,720	**34.5%**
4/Aug/24	46,767	-2,325	0	44,442	22,902	22,780	0	11,725	1,500	1,200	7,115	**31.1%**
11/Aug/24	46,767	-2,325	0	44,442	22,922	22,780	0	11,398	1,500	1,200	7,423	**32.4%**
18/Aug/24	46,767	-2,325	0	44,442	22,768	22,780	0	11,905	1,500	1,200	7,068	**31.0%**
25/Aug/24	46,767	-2,325	0	44,442	22,689	22,780	0	11,557	1,500	1,200	7,496	**33.0%**
1/Sep/24	46,767	-2,325	0	44,442	22,490	22,780	0	11,570	1,500	1,200	7,682	**34.2%**
8/Sep/24	46,767	-2,325	0	44,442	21,954	22,780	0	11,591	1,500	1,200	8,198	**37.3%**
15/Sep/24	46,767	-2,325	0	44,442	22,286	22,780	0	12,798	1,500	1,200	6,658	**29.9%**
22/Sep/24	46,767	-2,325	0	44,442	22,551	22,780	0	12,818	1,500	1,200	6,373	**28.3%**

Key

Highlighted week beginning 11-Aug-24 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 19-May-24 denotes week with the largest forecasted NPCC “Revised Net Margin”.

Highlighted number denotes forecasted Summer 2024 Peak Load for Québec area.

Notes

(1) Includes Independant Power Producers (IPPs) and available capacity of Churchill Falls at the Newfoundland - Québec border.

(2) Includes firm sale of 145 MW to Cornwall and transmission losses due to firm sales.

(3) Includes 100% of Wind capacity derating.

(4) Numbers published in this report may not exactly correspond to the values available on other Hydro-Québec public information sources because assumptions specific to the current report are applied.

Appendix II – Load and Capacity Tables definitions

This appendix defines the terms used in the Load and Capacity tables of Appendix I. Individual Balancing Authority Area particularities are presented when necessary.

Installed Capacity

This is the generation capacity installed within a Reliability Coordinator area. This should correspond to nameplate and/or test data and may include temperature derating according to the Operating Period. It may also include wind and solar generation derating.

Individual Reliability Coordinator area particularities

Maritimes

This number is the maximum net rating for each generation facility (net of unit station service) and does not account for reductions associated with ambient temperature derating and intermittent output (e.g., hydro and/or wind).

New England

Installed capacity is based on generator Seasonal Claimed Capabilities (SCC) and generation anticipated to be commercial for the identified capacity period. Totals also account for the operable capacity values of renewable resources.

New York

This number includes all generation resources that participate in the NYISO Installed Capacity (ICAP) market.

Ontario

This number includes all generation registered with the IESO.

Québec

Most of the Installed Capacity in the Québec Area is owned and operated by Hydro-Québec. The remaining capacity is provided by Churchill Falls and by private producers (hydro, wind, biomass, and natural gas cogeneration).

Net Interchange

Net Interchange is the total of Net Imports – Net Exports for NPCC and each Balancing Authority Area.

Dispatchable Demand-Side Management

Dispatchable Demand-Side Management (DDSM) are demand resources assets that help meet an Area's electricity needs by reducing consumption. This is the portion of the Demand Response Programs that is accounted as capacity instead of load modifier.

Total Capacity

Total Capacity = Installed Capacity +/- Net Interchange + Dispatchable Demand-Side Management.

Demand Forecast

This is the total internal demand forecast for each Reliability Coordinator area as per its Demand Forecast Methodology (Appendix IV)

Interruptible Loads

Loads that are interruptible under the terms specified in a contract and are not dispatchable.

Known Maintenance/Constraints

This is the reduction in Capacity caused by forecasted generator maintenance outages and by any additional forecasted transmission or by other constraints causing internal bottling within the Reliability Coordinator area. Some Reliability Coordinator areas may include wind generation derating.

Individual Reliability Coordinator area particularities

Maritimes

This includes scheduled generator maintenance and ambient temperature derates. It also includes wind, solar, and hydro generation derating.

New England

Known maintenance includes all known outages as reported on the ISO-NE Annual Maintenance Schedule.

New York

This includes scheduled generator maintenance and includes all wind and other renewable generation derating.

Ontario

This includes planned generator outages, deratings, bottling, historic hydroelectric reduction, and variable generation reductions.

Québec

This includes scheduled generator maintenance and hydraulic as well as mechanical restrictions. It also includes wind generation derating. It may include – usually in summer – transmission constraints on the TransÉnergie system.

Required Operating Reserve

This is the minimum operating reserve on the system for each Reliability Coordinator area.

NPCC Glossary of Terms

Operating reserve: This is the sum of ten-minute and thirty-minute reserve (fully available in 10 minutes and in 30 minutes).

Individual Reliability Coordinator area particularities

Maritimes

The required operating reserve consists of 100% of the first largest contingency plus 50% of the second largest contingency.

New England

The required operating reserve consists of 120% of the first largest contingency plus 50% of the second largest contingency.

New York

The required operating reserve consists of 200% of the single largest generator contingency.

Ontario

The required operating reserve consists of 100% of the first largest contingency plus 50% of the second largest contingency.

Québec

The required operating reserve consists of 100% of the largest first contingency + 50% of the largest second contingency, including 1,000 MW of hydro synchronous reserve distributed all over the system to be used as stability and frequency support reserve.

Unplanned Outages

This is the forecasted reduction in Installed Capacity by each Reliability Coordinator area based on historical conditions used to consider a certain probability that some capacity may be on forced outage.

Individual Reliability Coordinator area particularities

Maritimes

Monthly unplanned outage values have been calculated based on historical unplanned outage data.

New England

Monthly unplanned outage values have been calculated based on historical unplanned outage data and will include values for at-risk natural gas capacity.

New York

Seasonal generator unplanned outage values are calculated based on historical generator availability data and include the loss of largest generator source contingency value.

Ontario

This value is a historical observation of the capacity that is on forced outage at any given time.

Québec

This value includes a provision for frequency regulation in the Québec Balancing Authority Area, for unplanned outages and for heavy loads as determined by the system controller.

Net Margin

Net margin = Total capacity – Load forecast + Interruptible load – Known maintenance/Constraints – Required operating reserve – Unplanned outages

Individual Reliability Coordinator area particularities

New York

New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin. The Installed Reserve Margin requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). New York also maintains locational reserve requirements regions, including New York City (Load Zone J), Long Island (Load Zone K) and the G-J Locality (Load Zones G, H, I and J are located in Southeast New York). Load serving entities in those regions must procure a certain amount of their capacity from generators within those regions.

Bottled Resources

Bottled resources = Québec Net margin + Maritimes Net margin – available transfer capacity between Québec/Maritimes and the rest of NPCC.

Though this is primarily impactive in the summer capacity period, it is determined for both the summer and winter capacity analysis. The Bottled Resources calculation considers the fact that the margin available in Maritimes and Québec exceeds the transfer capability to the rest of NPCC.

Revised net margin (NPCC Summary only)

Revised net margin = Net margin – Bottled resources

This is used in the NPCC assessment and follows from the Bottled Resources calculation.

Appendix III – Summary of Total Transfer Capability under Forecasted Summer Conditions

The following table represents the forecasted transfer capabilities between Reliability Coordinator areas represented as Total Transfer Capabilities (TTC). It is recognized that the forecasted and actual transfer capability may differ depending on system conditions and configurations such as real-time voltage profiles, generation dispatch or operating conditions and may also account for Transmission Reliability Margin (TRM). Readers are encouraged to review information on the Available Transfer Capability (ATC) and Total Transfer Capability (TTC) between Reliability Coordinator Areas. These capabilities may not correspond to exact ATC values posted on the Open Access Same-Time Information Transmission System (OASIS) or the Reliability Coordinator's website since the existing transmission service commitments are not considered. Area specific websites are listed below.

- **Maritimes**

  https://tso.nbpower.com/public/en/access.aspx

  http://oasis.nspower.ca/en/home/oasis/default.aspx

- **New England**

  https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/ttc-tables

- **New York**

  http://mis.nyiso.com/public/

- **Ontario**
  - http://reports.ieso.ca/public/TxLimitsAllInService0to34Days/
  - http://reports.ieso.ca/public/TxLimitsOutage0to2Days/
  - http://reports.ieso.ca/public/TxLimitsOutage3to34Days/

- **Québec**

  http://www.hydroquebec.com/transenergie/en/oasis.html

Transfers from Maritimes to

Interconnection Point	TTC at Interconnection Points (MW)	ATC under Specified Conditions (MW)	Rationale
Québec			
Eel River (NB)/Matapédia (QC) Edmundston (NB)/Madawaska (QC)	348 390	348 390	Eel River HVDC (capable of 350 MW) reduced by 2 MW due to losses. When Eel River converter losses and line losses to the Québec border are considered, Eel River to Matapédia transfer is 348 MW. Madawaska HVDC derated due to temperature. (350 MW @ 35 °C / 95 °F) plus available radial load transfers.
Total	**738**	**738**	
New England			
Keswick (3001 line), Point Lepreau (390/3016 line)	1,000	1,000	For resource adequacy studies, NE assumes that it can import 1,000 MW of capacity to meet New England loads with 50 MW of margin for real-time balancing control margin.
Total	**1,000**	**1,000**	

Transfers from New England to

Interconnection Point	TTC (MW)	ATC (MW)	Comments
Maritimes			
Keswick (3001 line), Point Lepreau (390/3016 line)	550	550	Transfer capability depends on operating conditions in northern Maine and the Maritimes area. If key generation or capacitor banks are not operational, the transfer limits from New England to New Brunswick will decrease. At present, the NBP-SO has limited the transfer to 200 MW but will increase it to 550 MW on request from the NBP-SO under emergency operating conditions for up to 30 minutes. This limitation is due to system security/stability within New Brunswick.
Total	**550**	**550**	
New York			
Northern AC Ties (393, 398, E205W, PV20, K7, K6 and 690 lines)	1,200	1,200	ISO-NE to NYISO interface capability is limited to 1,200 MW respecting facility thermal LTE ratings.
NNC Cable (601, 602 and 603 cables)	200	200	The NNC is an interconnection between Norwalk Harbor, Connecticut and Northport, New York. The flow on the NNC Interface is controlled by the Phase Angle Regulating transformer at Northport, adjusting the flows across the cables listed. ISO New England and New York ISO Operations staff evaluates the seasonal TTC across the NNC Interface on a periodic basis or when there are significant changes to the transmission system that warrant an evaluation. A key objective while determining the TTC is to not have a negative impact on the prevalent TTC across the Northern NE-NY AC Ties Interface
LI / Connecticut (CSC)	330	330	The transfer capability of the Cross Sound Cable (CSC) is 346 MW. However, losses reduce the amount of MWs that can actually be delivered across the cable. When 346 MW is injected into the cable, 330 MW is received at the point of withdrawal.
Total	**1,730**	**1,730**	
Québec			
Phase II HVDC link (451 and 452 lines)	1,200	1,200	Export capability of the facility is 1,200 MW.
Highgate (VT) – Bedford (BDF) Line 1429	170	100	Capability of the tie is 225 MW but at times, conditions in Vermont limit the capability to 100 MW or less. The DOE permit is 170 MW.
Derby (VT) – Stanstead (STS) Line 1400	0	0	Though there is no capability scheduled to export to Québec through this interconnection path, exports may be able to be provided, dependent upon New England system load levels and generation dispatch. ISO-NE planning assumptions are based on a path limit of 0 MW.
Total	**1,370**	**1,300**	The New England to Québec transfer limit at peak load is assumed to be 0 MW. It should be noted that this limit is dependent on New England generation and could be increased up to approximately 350 MW depending on New England dispatch. If energy was needed in Québec and the generation could be secured in the Real-Time market, this action could be taken to increase the transfer limit.

Transfers from New York to

Interconnection Point	TTC (MW)	ATC (MW)	Rationale for Transfer Capability
New England			
Northern AC Ties (393, 398, E205W, PV20, K7, K6 and 690 lines)	**1,600**	**1,400**	New York applies a 200 MW Transmission Reliability Margin (TRM).
LI / Connecticut Northport-Norwalk Harbor Cable	200	200	
LI / Connecticut Cross-Sound Cable	330	330	Cross Sound Cable power injection is up to 346 MW; losses reduce power at the point of withdrawal to 330 MW.
Total	**2,130**	**1,930**	
Ontario			
Lines PA301, PA302, BP76, PA27, L33P, L34P	**1,650**	**1,350**	New York applies a 300 MW Transmission Reliability Margin (TRM). Thermal limits on the QFW interface may restrict exports to lesser values when the generation in the Niagara area is considered.
PJM			
PJM AC Ties	1,200	900	New York applies a 300 MW Transmission Reliability Margin (TRM).
NYC/PJM Linden VFT	315	315	
LI/PJM Neptune Cable	0	0	The Neptune DC cable is uni-directional into New York.
NYC/PJM HTP DC/DC Tie	0	0	The HTP DC/DC tie is uni-directional into New York.
Total	**1,515**	**1,215**	
Québec			
Chateauguay (QC)/Massena (NY)	1,000	1000	
Cedars / Québec	100	100	
Total	**1,100**	**1,100**	

Transfers from Ontario to

Interconnection Point	TTC (MW)	ATC (MW)	Rationale for Transfer Capability
New York			
Lines PA301, PA302, BP76, PA27, L33P, L34P	1,950	1,750	The TRM is 200 MW.
Total	**1,950**	**1,750**	
MISO Michigan			
Lines L4D, L51D, J5D, B3N	1,650	1,450	The TRM is 200MW.
Total	**1,650**	**1,450**	
Québec			
NE / RPD – KPW Lines D4Z, H4Z	95	85	The 95 MW reflects an agreement through the TE-IESO Interconnection Committee. The TRM is 10 MW.
Ottawa / BRY – PGN Lines P33C, X2Y, Q4C	120	120	There is no capacity to export to Québec through Lines P33C and X2Y.
Ottawa / Brookfield Lines D5A, H9A	200	190	Only one of H9A or D5A can be in service at any time. The TRM is 10 MW.
East / Beau Lines B5D, B31L	470	470	Capacity from Saunders that can be synchronized to the Hydro-Québec system.
HAW / OUTA Lines A41T, A42T	1,250	1,230	The TRM is 20 MW.
Total	**2,135**	**2,095**	
MISO Manitoba, Minnesota			
NW / MAN Lines K21W, K22W	225	200	The TRM is 25 MW.
NW / MIN Line F3M	150	140	The TRM is 10 MW.
Total	**375**	**340**	

Transfers from Québec to[1]

Interconnection Point	TTC (MW)	ATC (MW)	Rationale for Transfer Capability
Maritimes			
Matapédia (QC)/Eel River (NB) Madawaska (QC)/Edmundston (NB)	348 + radial loads 390 + radial loads	348 + radial loads 390 + radial loads	Eel River HVDC (capable of 350 MW) reduced by 2 MW due to losses. When Eel River converter losses and line losses to the Québec border are considered, Matapédia to Eel River transfer is 348 MW. Madawaska HVDC derated due to temperature. (350 MW @ 35 °C / 95 °F) plus available radial load transfers.
Total	**738 + radial loads**	**738 + radial loads**	Radial load transfer amount is dependent on local loading and is updated monthly and reviewed annually.
New England			
NIC / CMA HVDC link	2,000	2,000	Capability of the facility is 2,000 MW. At certain times, flows over this tie can be limited to 1,200MW in order to respect operating agreements regarding largest single loss of source.
Bedford (BDF) – Highgate (VT) Line 1429	225	225	Capacity of the Highgate HVDC facility is 225 MW
Stanstead (STS) – Derby (VT) Line 1400	50	50	Normally only 35 MW of load in New England is connected.
Total	**2,275**	**2,275**	
New York			
Chateauguay (QC)/Massena (NY)	1,800	1,800	The maximum capacity in this path is 1,800 MW. This capacity is limited by the maximum allowable short-circuit current of the Châteauguay facilities. It may also be limited by the maximum import capacity of the New York grid, which ranges from 1,500 to 1,800 MW.
Les Cèdres (QC)/Dennison (NY)	190	190	Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 190 MW and 160 MW respectively (during the summer). However, the TTC of both points of delivery combined is 325 MW, the maximum capacity of Les Cèdres substation.
Total	**1,990**	**1,990**	Québec to New York transfer capability may reach 1,990 MW on an hour-ahead basis and depending on operating conditions in New York and in Québec.

Interconnection Point	TTC (MW)	ATC (MW)	Rationale for Transfer Capability
Ontario			
Les Cèdres (QC)/Cornwall (Ont.)	160	160	Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 190 MW and 160 MW respectively (during the summer). However, the TTC of both points of delivery combined is 325 MW, the maximum capacity of Les Cèdres substation.
Beauharnois (QC)/St-Lawrence (Ont.)	800	800	
Brookfield/Ottawa (Ont.)	200	200	Only one of H9A or D5A can be in services at any time. The transfer capability reflects usage of D5A. The 200 MW reflects the maximum transfer available from Brookfield to Ontario. D5A's transfer limit is 200 MW during the summer period.
Rapide-des-Iles (QC)/Dymond (Ont.)	55	55	This represents Line D4Z capacity in summer. There is no capacity to export to Ontario through Line H4Z.
Bryson-Paugan (QC)/Ottawa (Ont.)	335	335	Capability of line P33C is 270 MW and the X2Y capability is 65 MW (at 30 °C / 86 °F). There is no capacity to export to Ontario through Line Q4C.
Outaouais (Qc)/Hawthorne (Ont.)	1,250	1,250	HVDC back-to-back facility at Outaouais.
Total	**2,800**	**2,800**	

Note 1: These capabilities may not exactly correspond to other numbers posted in Hydro-Québec's Annual Reports or on TransÉnergie's website. Such numbers – usually corresponding to winter ratings – are maximum import/export capabilities available at any one time of the year. The present assessment focuses on summer conditions and these limits recognize transmission or generation constraints in both Québec and its neighbors for the 2024 Summer Operating Period.

Transfers from Regions External to NPCC

Interconnection Point	TTC (MW)	ATC (MW)	Rationale for Transfer Capability
MISO (Michigan) / ONT Lines L4D, L51D, J5D, B3N	1,550	1,350	Represents a worst-case scenario for the implementation of Policy on operation.
Total	1,550	1,350	Simultaneous Transfers between Michigan and Ontario may be impacted by loop flows and assumes phase shifting capability of Ontario-Michigan interface is not available.
MISO (Manitoba-Minnesota) / ONT			
NW / MAN Lines K21W, K22W	293	268	The TRM is 25 MW.
NW / MIN Line F3M	100	80	The TRM is 20 MW.
Total	**393**	**348**	
PJM / New York			
AC Ties	2,100	1,800	The TRM is 300 MW
PJM/NYC Linden VFT	315	315	
PJM/Neptune Neptune Cable	660	660	
PJM/NYC HTP DC/DC Tie	660	660	
Total	**3,735**	**3,435**	

Appendix IV – Demand Forecast Methodology

Reliability Coordinator Area Methodologies

Maritimes

The Maritimes Area demand is the mathematical sum of the forecasted weekly peak demands of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Administrator). As such, it does not take the effect of load coincidence within the week into account. If the total Maritimes Area demand included a coincidence factor, the forecast demand would be approximately 1% to 3% lower.

For New Brunswick, the demand forecast is based on an End-use Model (sum of forecasted loads by use e.g., water heating, space heating, lighting etc.) for residential loads and an Econometric Model for general service and industrial loads, correlating forecasted economic growth and historical loads. Each of these models is weather adjusted using a 30-year historical average.

For Nova Scotia, the load forecast is based on a 10-year weather average measured at the major load center, along with analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources.

For Prince Edward Island, the demand forecast uses average long-term weather for the peak period (typically December) and a time-based regression model to determine the forecasted annual peak. The remaining months are prorated on the previous year.

The Northern Maine Independent System Administrator performs a trend analysis on historic data in order to develop an estimate of future loads.

To determine load forecast uncertainty (LFU) an analysis of the historical load forecasts of the Maritimes Area utilities has shown that the standard deviation of the load forecast errors is approximately 4.6% based upon the four-year lead time required to add new resources. To incorporate LFU, two additional load models were created from the base load forecast by increasing it by 5.0 and 9.0% (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models. The Maritimes uses 5% as the 90/10 Load Forecast Margin.

Above 90/10 load forecast values are estimated using the Long-Term Load Forecast High/Low Sensitivities modelling and the minimum temperatures for each month from the past 20 years.

New England

ISO New England's long-term energy model is an annual model of ISO-NE Area total energy, using real income, the real price of electricity, economics, and weather variables as drivers. Income is a proxy for all economic activity.

ISO New England's long-term load forecast is a 10-year projection of gross and net load for each of the six states and the New England region. Monthly models for gross energy and gross demand are developed for the New England region and each of the six New England states. Monthly gross energy models are typically estimated utilizing the last 27 years of monthly energy consumption and weather, along with a variety of economic drivers. Monthly gross energy forecasts result from applying the estimated models to normal monthly weather, based on 30 years of historical weather. Monthly gross peak demand models are estimated utilizing a 15-year rolling window of historical daily peak loads combined with a variety of weather constructs, trend and calendar variables, and monthly energy consumption. Monthly gross peak demand forecasts are then generated by applying the estimated models to weekly weather distributions, based on 30 years of historical weather. "50/50" and "90/10" gross peak demand forecasts result from extracting the 95th and 99th percentiles of the distribution, respectively.

Net energy and demand forecasts [49], result from subtracting ISO-NE's energy-efficiency (EE) forecast and solar photovoltaic (PV) forecast. Both net and gross forecasts include the expected impacts of electrification as detailed by ISO-NE's transportation and heating electrification forecasts.

The reference summer peak demand forecast, or "50/50", which has a 50% chance of being exceeded, is associated with a WTHI (3-day weighted temperature-humidity index) of approximately 79.8 and CDD (cooling degree days, base 65°F) of 16.7. The 90/10 summer peak demand forecast, or "90/10", which has a 10% chance of being exceeded, is associated with a WTHI of 81.5 and CDD of 20 [50].

From a short-term load forecast perspective, New England has deployed the Metrix Zonal load forecast, which produces a zonal load forecast for the eight regional load zones for up to six days in advance through the current operating day. This forecast enhances reliability on a zonal level by considering conflicting weather patterns. An example would be when the Boston zone is forecasted to be sixty-five degrees while the Hartford area is forecasting ninety degrees. This zonal forecast ensures an accurate reliability commitment on a regional level. The eight zones are then summed for a total New England load. This adds an additional New England load forecast to the Artificial Neural Network models (ANN) and the Similar Day Analysis (SimDays). Accuracy for this zonal forecast has been an improvement since the summer of 2013.

New York

The NYISO conducts load forecasting for the NYCA and for localities within the NYCA. The NYISO employs a two-stage process to develop load forecasts for each of the eleven zones within the NYCA. In the first stage, zonal load forecasts are based upon econometric projections. These forecasts assume a conventional portfolio of appliances and electrical technologies. The forecasts also assume that future improvements in energy efficiency measures will be similar to those of the recent past and that spending levels on energy efficiency programs will be similar to recent history. In the second stage, the NYISO adjusts the econometric forecasts to explicitly reflect a projection of the energy savings resulting from statewide energy efficiency programs, impacts of new building codes and appliance efficiency standards and a projection of energy usage due to electric vehicles. The baseline forecasts include the load-reducing impacts of energy efficiency programs, building codes, and appliance efficiency standards solar PV and

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[49] Additional information describing ISO New England's load forecasting may be found at https://www.iso-ne.com/system-planning/system-plans-studies/celt

[50] Further information describing ISO New England's load forecasting methodologies is available at http://www.iso-ne.com/system-planning/system-forecasting/load-forecast

distributed energy generation. The actual impact of solar PV varies considerably by hour of day. The hour of the NYCA peak varies yearly. The forecast of solar PV-related reductions in summer peak assumes that the NYCA peak occurs from 4 p.m. to 5 p.m. EDT in late July. The forecast of solar PV-related reductions in winter peak is zero because the sun sets before the assumed peak hour of 6 p.m. EST.

In addition to the baseline forecast, the NYISO also produces high and low forecasts for each zone that represent 90/10 weather conditions. The forecast is developed by the NYISO using a Temperature-Humidity Index ("THI"), which is representative of normal weather during peak demand conditions. The weather assumptions for most regions of the state are set at the 50th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak. For Orange & Rockland and for Consolidated Edison, the weather assumptions are set at the 67th percentile of the historic series of prevailing weather conditions at the time of the system coincident peak.

Individual utilities include the peak demand impact of demand side management programs in their forecasts. Each investor-owned utility, the New York State Energy Research and Development Authority ("NYSERDA"), the New York Power Authority ("NYPA"), and the Long Island Power Authority ("LIPA"), maintain a database of installed measures from which estimates of impacts can be determined. The impact evaluation methodologies and measurement and verification standards are specified by the state's evaluation advisory committee known as "E^{2}", in which the NYISO participates, and that provides input to the New York Department of Public Service staff reporting to the New York Public Service Commission.

There are two higher-than-expected scenarios forecast for the NYCA. One is a forecast without the impacts of energy efficiency programs or behind-the-meter solar photovoltaic generation. The second is a forecast based on 90/10 weather conditions, set to the 90th percentile of typical peak-producing weather conditions.

Ontario

The Ontario Demand is the sum of coincident loads plus the losses on the IESO-controlled grid. Ontario Demand is calculated by taking the sum of injections by registered generators, plus the imports into Ontario, minus the exports from Ontario. Ontario Demand does not include loads that are supplied by non-registered generation. The IESO forecasting system uses multivariate econometric equations to estimate the relationships between electricity demand and several drivers. These drivers include weather effects, economic data, calendar variables, conservation, and embedded generation. Using regression techniques, the model estimates the relationship between these factors and energy and peak demand. Calibration routines within the system ensure the integrity of the forecast with respect to energy and peak demand, including zone and system wide projections. The IESO produces a forecast of hourly demand by zone. From this forecast the following information is available:

- hourly peak demand
- hourly minimum demand
- hourly coincident and non-coincident peak demand by zone
- energy demand by zone

These forecasts are generated based on a set of weather and economic assumptions. The IESO uses a number of different weather scenarios to forecast demand. The appropriate weather scenarios are determined by the purpose and underlying assumptions of the analysis. The base case demand forecast uses a median economic forecast and monthly normalized weather. Multiple economic scenarios are only used in longer term assessments. A quantity of price-responsive demand is also forecast based on market participant information and actual market experience.

A consensus of four major, publicly available provincial forecasts is used to generate the economic drivers used in the model. In addition, forecast data from a service provider is purchased to enable further analysis and insight. Population projections, Labouré market drivers and industrial indicators are utilized to generate the forecast of demand.

The impact of conservation measures is decremented from the demand forecast, which includes demand reductions due to energy efficiency, fuel switching and conservation behavior (including the impact smart meters).

In Ontario, demand management programs include Demand Response programs and the dispatchable loads program. Historical data is used to determine the quantity of reliably available capacity, which is treated as a resource to be dispatched.

Embedded generation leads to a reduction in “on-grid” demand on the grid, which is decremented from the demand forecast.

Ontario uses 31 years of history to calculate a weather factor to represent the MW impact on demand if the weather conditions (temperature, wind speed, cloud cover and humidity) are observed in the forecast horizon. Weather is sorted on a monthly basis, and for the 90/10 weather scenario, Ontario uses the maximum value from the sorted history.

For determining wind and solar derating factors, Ontario uses seasonal contribution factors based upon median historical hourly production values.

Québec

Hydro-Québec’s peak demand and energy-sales forecasting is the responsibility of Hydro-Québec.

The energy-sales forecast combines the forecasting results of four different sectors: residential, commercial, small and medium-size industrial, and large industrial. The type of model used for forecasting energy-sales differs for each sector and is based on end-use and/or econometric models. Specifically, they consider weather variables, econometric forecasts, demographics, energy efficiency and different information about large customers. The forecast is normalized to account for weather conditions based on an historical trend weather analysis. The total energy requirements are obtained by adding transmission and distribution losses to the forecasts.

The monthly peak demand model is a regression between historical peak and end-use and/or sector sale. The peak demand forecast is obtained by applying the regression model to the forecasted end-use and/or sector sale.

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a 47 years of temperature data (1971-2017), adjusted by

0.3 °C (0.5 °F) per decade starting in 1971 to account for climate change. In addition, each year of historical climatic data is shifted up and down by 3 days to capture 90/10 weather conditions that could have occurred during either a weekend or a weekday. This approach produces a set of 329 different demand scenarios. The base case scenario is the average of the peak hour for all 329 scenarios. Load uncertainty pertains to economic and demographic uncertainties, and to specific risks associated with large customers.

Overall Uncertainty (OU) is defined as the independent combination of climatic and load uncertainties. The OU, expressed as a percentage of standard deviation over total demand, is lower during the summer than during the winter. For instance, during the summer, the uncertainty associated with peak weather conditions is about 450 MW and is equivalent to one standard deviation. Conversely, the uncertainty increases to 1,450 MW during the winter.

Hydro-Québec – the Québec system operator – then determines the Québec Balancing Authority Area forecasts using Hydro-Québec forecasts (HQ internal demand) and accounting for agreements with different private systems within the Balancing Authority Area. The forecasts are updated on an hourly basis, within a 12-day horizon according to information on local weather, wind speed, cloud cover, sunlight incidence and type and intensity of precipitation over nine regions of the Québec Balancing Authority Area. Forecasts on a minute basis are also produced within a two-day horizon. Hydro-Québec has a team of meteorologists who feed the demand forecasting model with accurate climatic observations and precise weather forecasts. Short term changes in industrial loads and agreements with different private systems within the Balancing Authority Area are also considered on a short-term basis.

Appendix V - NPCC Operational Criteria, and Procedures

NPCC Directories Pertinent to Operations

NPCC Regional Reliability Reference Directory #1 – Design and Operation of the Bulk Power System

Description: This directory provides a "design-based approach" to ensure the **bulk power system** is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design **contingencies.** Includes Appendices F and G "Procedure for Operational Planning Coordination" and "Procedure for Inter Reliability Coordinator Area Voltage Control," respectively.

NPCC Regional Reliability Reference Directory #2 - Emergency Operations

Description: Objectives, principles and requirements are presented to assist the NPCC **Reliability Coordinator areas** in formulating plans and procedures to be followed in an **emergency** or during conditions which could lead to an **emergency**.

NPCC Regional Reliability Reference Directory #5 – Reserve

Description: This directory provides objectives, principles, and requirements to enable each NPCC Reliability Coordinator Area to provide reserve and simultaneous activation of reserve.

NPCC Regional Reliability Reference Directory #6 – "Reserve Sharing Groups"

Description: This directory provides the framework for Regional Reserve Sharing Groups within NPCC. It establishes the requirements for any Reserve Sharing Groups involving NPCC Balancing Authorities.

NPCC Regional Reliability Reference Directory #8 - System Restoration

Description: This directory provides objectives, principles, and requirements to enable each NPCC Reliability Coordinator Area to perform power system restoration following a major event or total blackout.

NPCC Regional Reliability Reference Criteria A-10 Classification of Bulk Power System Elements

Description: This *Classification of Bulk Power System Elements* (Document A-10) provides the methodology for the identification of those elements of the interconnected NPCC Region to which NPCC **bulk power system** criteria are applicable. Each **Reliability Coordinator Area** has an existing list of **bulk power system** elements. The methodology in this document is used to classify elements of the **bulk power system** and has been applied in classifying elements in each **Reliability Coordinator Area** as bulk power system or non-bulk power system.

NPCC Procedures Pertinent to Operations

C-01 NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures

Description: This document details the procedures for the NPCC Emergency Preparedness Conference Calls, which establish communications among the Operations Managers of the Reliability Coordinator (RC) Areas which discuss issues related to the adequacy and security of the interconnected bulk power supply system in NPCC.

C-15 Procedures for Solar Magnetic Disturbances on Electrical Power Systems

Description: This procedural document clarifies the reporting channels and information available to the operator during solar alerts and suggests measures that may be taken to mitigate the impact of a solar magnetic disturbance.

C-43 NPCC Operational Review for the Integration of New Facilities

Description: The document provides the procedure to be followed in conducting operations reviews of new facilities being added to the power system. This procedure is intended to apply to new facilities that, if removed from service, may have a significant, direct, or indirect impact on another Reliability Coordinator area's inter-Area or intra-Area transfer capabilities. The cause of such impact might include stability, voltage, and/or thermal considerations.

Appendix VI - Websites

Hydro-Québec

http://www.hydroquebec.com/en/

Independent Electricity System Operator

http://www.ieso.ca/

ISO- New England

http://www.iso-ne.com

Maritimes

Maritimes Electric Company Ltd.

http://www.maritimeelectric.com

New Brunswick Power Corporation

http://www.nbpower.com

New Brunswick Transmission and System Operator

http://tso.nbpower.com/public/

Nova Scotia Power Inc.

http://www.nspower.ca/

Northern Maine Independent System Administrator

http://www.nmisa.com

Midwest Reliability Organization

http://www.midwestreliability.org

New York ISO

http://www.nyiso.com/

Northeast Power Coordinating Council, Inc.

http://www.npcc.org/

North American Electric Reliability Corporation

http://www.nerc.com

ReliabilityFirst Corporation

http://www.rfirst.org

Appendix VII - References

For historical NPCC Reliability Assessments, please visit:
Seasonal Assessment (npcc.org)

Appendix VIII - CP-8 2024 Multi-Area Probabilistic Reliability Assessment - Supporting Documentation

NPCC, Inc.

Northeast Power Coordinating Council, Inc.

Multi-Area Probabilistic Reliability Assessment

For

Summer 2024

Final Report

Approved by NPCC TFCP/TFCO on April 29, 2024

Revised May 10, 2024

Conducted by the

NPCC CP-8 Working Group

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Table of Contents

1. EXECUTIVE SUMMARY

This report, which was prepared by the CP-8 Working Group, estimates the use of the available NPCC Area Operating Procedures to mitigate resource shortages from May through September 2024 period. General Electric's (GE) Multi-Area Reliability Simulation (MARS) program was used for the analysis. GE Energy was retained by NPCC to conduct the probabilistic simulations.

The assumptions used in this probabilistic study are consistent with the NPCC CO-12 Working Group's development of the NPCC *Reliability Assessment for Summer 2024*, April 2024[51], and are summarized in **Table 1.**

Table 1: Assumed Load and Base Case Capacity for Summer 2024

Area	50/50 Peak[52] (MW)	Higher Peak [53] (MW)	Available Capacity[54] (MW)	Peak Month
Québec (QC)	22,910	25,803	35,250	August
Maritimes Area (MT)	3,558	3,885	7,424	May
New England (NE)	24,553	27,234	28,820	July
New York (NY)	31,766	34,303	36,919	July
Ontario (ON)	25,104	27,629	33,819	August

The study modeled the load forecast as a probability distribution having seven levels. Shown in **Table 1** are the values associated with the 50/50 peak load level (based on each Area's projection of mean demand) and a higher peak load level associated with the second highest peak load level of the seven levels simulated in this assessment (see section 3.1.2). The 50/50 peak load level shown has a 50 percent chance of occurring. The higher peak load level shown has a six percent chance of occurring. While the higher peak load level, as defined for this study, may be different for NPCC Areas in their own studies, the Working Group finds this higher peak load level appropriate for providing an assessment of a range of conditions within NPCC. Details of information provided by each Area for their respective peak load level forecasts are presented in Section 3.1 of this report.

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[51] See: https://www.npcc.org/library/reports/seasonal-assessment

[52] The 50/50 peak load forecast represents each Area's projection of mean peak demand over the study period based on historical data analysis. New England's peak value is based on the 2024 CELT forecast that takes into account the impacts from behind-the-meter PV load reduction, and passive demand resources (energy efficiency). Ontario provided the hourly demand forecast based on the actual 2021 weather. The New York ISO peak value includes the impacts of Behind-the-Meter: Net Generation resources.

[53] The higher peak load forecast is determined at two standard deviations higher than the mean peak, which assumes to have a 6.06 percent probability of occurrence.

[54] Available Capacity represents Area's effective capacity at the time of the peak; it takes into account firm imports and exports, and reductions due to deratings. New England capacity includes active demand capacity resources and net capacity imports. New York capacity includes SCR resources and imports.

For the probabilistic load forecast levels described above, two different system conditions were considered: a Base Case Scenario and a Severe Case Scenario. Details regarding the Scenario assumptions are described in Section 3.7 of the report.

Table 2 shows the estimated use of Operating Procedures designed to mitigate resource shortages under the Base Case Scenario assumptions for the 50/50 peak load and the higher peak load levels during the May – September 2024 period.

The 50/50 peak load results were based on the probability-weighted average of all seven load levels simulated. The highest load level results were based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring. Occurrences greater than 0.5 days/period (other than External Assistance calls) are highlighted.[55]

Table 2: Expected Use of the Operating Procedures under the Base Case Scenario (days/period)

	QC	MT	NE	NY	ON	QC	MT	NE	NY	ON
	50/50 Load Level					Highest Load Levels				
External Assistance Calls	-	1.175	0.095	0.760	0.825	-	3.726	1.405	6.662	5.872
Activation of DR/SCR	-	-	-	0.565	0.007	-	-	-	6.163	0.095
Reduce 30-min Reserve	-	0.020	0.034	0.300	0.004	-	0.135	0.515	3.322	0.053
Initiate Interruptible Loads/Voltage Reduction [56]	-	0.007	0.030	0.128	0.002	-	0.047	0.447	1.794	0.024
Reduce 10-min Reserve [57]	-	-	0.023	0.064	-	-	0.001	0.348	0.912	0.004
Appeals	-	-	0.023	0.057	-	-	-	0.346	0.829	-
Disconnect Load	-	-	0.022	0.023	-	-	-	0.329	0.332	-

Under the Base Case Scenario and 50/50 peak load level, no Area shows a likelihood greater than 0.5 days/period of using their Operating Procedures such as (reducing 30-min reserve requirements and initiating Interruptible Loads) designed to mitigate resource shortages.

Under the higher peak load level assumptions, the New England Area shows a likelihood of using their Operating Procedures (reducing 30-min reserve requirements, and possibly initiating interruptible loads to mitigate resource shortages.

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[55] Rounded to the nearest whole occurrence, likelihoods of less than 0.5 days/period are not considered significant in this assessment.

[56] Initiate Interruptible Loads for the Maritimes Area (implemented only for the Area), Voltage Reduction for all the other Areas.

[57] New York initiates Appeals prior to reducing 10-min Reserve.

The New York Area also shows likelihoods of using their Operating Procedures (activating demand response programs, reducing 30-min reserve requirements, initiating interruptible loads, and reducing 10-min reserve) to mitigate resource shortages.

Table 3 shows the estimated increased use of Operating Procedures under the Severe Case Scenario assumptions for the 50/50 peak load level and the highest peak load levels for the May - September 2024 period. Occurrences greater than 0.5 days/period (other than External Assistance calls) are highlighted. [54]

Table 3: Expected Use of the Operating Procedures under Severe Case Scenario (days/period)

	QC	MT	NE	NY	ON	QC	MT	NE	NY	ON
	50/50 Load Level					Highest Load Levels				
External Assistance Calls	-	2.728	0.290	1.467	1.950	-	6.548	4.226	9.584	11.295
Activation of DR/SCR	-	-	-	1.226	0.252	-	-	-	9.069	3.403
Reduce 30-min Reserve	-	0.058	0.197	0.681	0.111	-	0.328	2.887	6.674	1.488
Initiate Interruptible Loads/Voltage Reduction [58]	-	0.019	0.102	0.337	0.057	-	0.139	1.528	4.471	0.796
Reduce 10-min Reserve [59]	-	0.000	0.080	0.190	0.011	-	0.001	1.199	2.761	0.158
Appeals	-	-	0.079	0.176	0.004	-	-	1.190	2.589	0.054
Disconnect Load	-	-	0.046	0.084	0.002	-	-	0.689	1.236	0.023

As shown in **Table 3**, under Severe Case conditions, the New York Area shows a cumulative likelihood of activation of their demand response programs and reducing 30-min reserve requirements (0.5 days/period) during the 2024 summer period to mitigate resource shortages.

For the highest load levels forecast (having approximately a 7% chance of occurring), the New England, New York, and Ontario, Areas show greater cumulative likelihoods of using more of their Operating Procedures designed to mitigate resource shortages during the 2024 summer period for the Severe Case Scenario.

The 50/50 peak load results were based on the probability-weighted average of all seven load levels simulated. The highest load level results were based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring.

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[58] Initiate Interruptible Loads for the Maritimes Area (implemented only for the Area), Voltage Reduction for all the other Areas.

[59] New York initiates Appeals prior to reducing 10-min Reserve.

2. INTRODUCTION

This report was prepared by the CP-8 Working Group and estimates the use of NPCC Area Operating Procedures designed to mitigate resource shortages from May through September 2024.

The development of this CP-8 Working Group's assessment is in response to recommendation (5) from the *June 1999 Heat Wave - NPCC Final Report*, August 1999 that states:

"The NPCC Task Force on Coordination of Planning (TFCP) should explore the use of a multi-area reliability study tool as a part of an annual resource adequacy review to gain insight into the effects of maintenance schedules and transmission constraints on regional reliability."

The CP-8 Working Group's efforts are consistent with the NPCC CO-12 Working Group's development of the *NPCC Reliability Assessment for Summer 2024*, April 2024. The CP-8 Working Group's Objective, Scope of Work, and Schedule is shown in **Appendix A**.

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program was used for the analysis and GE Energy was retained by NPCC to conduct the probabilistic simulations. **Appendix E** provides an overview of General Electric's Multi-Area Reliability Simulation (MARS) Program; version 5.0.2186 was used for this reliability assessment.

3. STUDY ASSUMPTIONS

The database developed by the CP-8 Working Group for the *NPCC 2024 Summer Reliability Assessment* [60] was used as the starting point for this reliability analysis. Working Group members reviewed the existing data and revised to reflect system conditions expected for the 2024 summer period.

3.1 Demand

3.1.1 Load Assumptions

Each area provided annual or monthly peak and energy forecasts for 2024 Summer. Ontario provided the hourly demand forecast based on actual 2023 weather. **Table 4** summarizes each Area's summer 50/50 peak load level assumptions for the study period.

Table 4: Assumed NPCC Areas 2024 50/50 Summer Peak Demand

Area	Month	Peak Load (MW)
Québec	August	22,910
Maritimes Area	May	3,558
New England	July	24,553 [61]
New York	July	31,766
Ontario	August	25,104

Specifics related to each Area's peak demand forecast used in this assessment are described below.

Maritimes

The Maritimes Area demand is the maximum of the hourly sums of the individual sub-area load forecasts. Except for the Northern Maine sub-area which uses a simple scaling factor, all other sub-areas use a combination of some or all of efficiency trend analysis, anticipated weather conditions, econometric modelling, and end use modeling to develop their load forecasts. Load forecast uncertainty is modeled in the Area's resource adequacy analysis. The load forecast uncertainty factors were developed by applying statistical methods to a comparison of historical forecast values of load to the actual loads experienced.

New England

ISO New England's long-term energy model is an annual model of ISO-NE Area total energy, using real income, the real price of electricity, economics, and weather variables as drivers. Income is a proxy for all economic activity.

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[60] See: Seasonal Assessment (npcc.org)

[61] This is the CELT 2024 50/50 net peak load reflecting Behind-the-Meter PV and passive demand response resources (energy efficiency) from the 2024 CELT for the summer of 2024. The load modeled in MARS is the gross peak minus energy efficiency (27,424 – 1,775 = 25,649). ISONE provides BTM PV as separate profiles for the NPCC probabilistic assessment which is reflected as the net peak load.

The long-term peak load model is a monthly model of the typical daily peak demand for each month, and produces forecasts of weekly, monthly, and seasonal peak demands over a 10-year period. Daily peak demands are modeled as a function of energy, weather, and a time trend on weather for the summer months to capture the increasing sensitivity of peak demand to weather due to the increasing cooling load.

The 50/50 demand forecast is based on weekly weather distributions and the monthly model of typical daily peak demand. The weekly weather distributions are built using 30 years of temperature data at the time of daily electrical peaks (for non-holiday weekdays). A reasonable approximation for “normal weather” associated with the winter peak is approximately 11.0 °F and for the summer peak is 90 °F. The atypical higher peak demand forecast, which has a 10 percent chance of being exceeded, is associated with weather at the time of the winter peak of approximately 6 °F and summer peak of 94°F.

The 2024 CELT gross 50/50 summer peak demand forecast is 27,424 MW [62] for the summer of 2024. This gross summer peak demand reflects a forecast of peak demand for New England system without accounting for the reductions from energy efficiency programs and behind-the-meter PV (BTM PV). Active demand resources, energy efficiency, and BTM PV are reconstituted into the historical hourly loads to ensure the proper accounting of impacts from these resources, which are both forecast separately. The 2024 peak reduction from the BTM PV is 1,097 MW and energy efficiency resources are expected to be 1,775 MW based on the 2024 CELT report for the summer of 2024.

New York

The New York ISO employs a multi-stage process to develop load forecasts for each of the eleven zones within the New York Control Area. In the first stage, baseline energy and peak models are built based on projections of end-use intensities and economic variables. End-use intensities modeled include those for lighting, refrigeration, cooking, heating, cooling, and other plug loads. Appliance end-use intensities are generally defined as the product of saturation levels (average number of units per household or commercial square foot) and efficiency levels (energy usage per unit or a similar measure). End-use intensities specific to New York are estimated from appliance saturation and efficiency levels in both the residential and commercial sectors. These intensities include the projected impacts of energy efficiency programs and improved codes & standards. Economic variables considered include Gross Domestic Product, households, population, and commercial and industrial employment. In the second stage, the incremental impacts of additional policy-based energy efficiency, behind-the-meter solar PV and distributed generation are deducted from the forecast; and the incremental impacts of electric vehicle usage and other electrification are added to the forecast. The impacts of net electricity consumption of energy storage units due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of behind-the-meter energy storage units are deducted from the peak forecasts. In the final stage, the New York ISO aggregates load forecasts by Zone.

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[62] This value is based on the final forecast values published in the 2024 CELT on May 1, 2024 under this link: https://www.iso-ne.com/celt

Ontario

The Ontario IESO demand forecast for the CP-8 Working Group probabilistic assessment is based on the 2021 actual weather and therefore may differ from the demand forecast in other Ontario IESO publications.[63] The demand forecast assumed in the development of the NPCC CO-12 Working Group assessment of the *NPCC Reliability Assessment for Summer 2024* is consistent with the Ontario IESO Reliability Outlook published on March 21, 2024.[64]

Québec

The load forecast is consistent with the "*2023 NPCC Québec Comprehensive Review of Resource Adequacy*."[65] The sales forecast represents the aggregation of the forecast of three sectors – domestic, commercial, and large industrial. The type of model used to forecast are different for each sector. Specifically, forecasts are based on statistically adjusted end-use and/or standard econometric models. They consider weather variables, economic indicators forecasts, demographics, demand side management, and different information about large industrial customers. This forecast is weather normalized and prospective effects of climate change are taken into account through the most recent CMIP simulations.

The requirements are obtained by adding transmission and distribution losses to the sales forecasts. The monthly peak demand is then calculated by modeling load factors for base load and evaluating contribution to peak from new end-uses/sectors (EVs, PV, etc.).

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a historical database of temperatures (1971 to present), adjusted to account for climate change using the most recent CMIP simulations. Moreover, each year of historical climatic data is shifted up to ±9 days to gain information on conditions that occurred during either a weekend or a weekday. The base case scenario is the arithmetical average of the peak hour in each of these scenarios. Load uncertainty is due to the uncertainty in economic and demographic variables affecting demand forecast and to residual errors from the models.

Overall uncertainty is defined as the independent combination of climatic uncertainty and load uncertainty. This Overall Uncertainty, expressed as a percentage of standard deviation over total load, is lower during the summer than during the winter.

3.1.2 Load Model in MARS

Since the 2022 NPCC Summer Reliability assessment, the CP-8 Working Group used the historical hourly load shape based on the summer of 2021 for the months of May – September. The selection of the summer

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[63] Additional information describing Ontario's demand forecasting may be found at: http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook.

[64] See: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2024Mar.ashx

[65] See: Microsoft Word - 2023 Québec Comprehensive Review Report_RCC.docx (npcc.org)

hourly load shape assumption is revaluated on a periodic basis.[66] On a region-wide basis, the 2021 hourly load shape appears to be similarly stressful as the 2023 hourly load shape with an indication that the NPCC-wide coincident peak may be higher and presents a higher count of high-load days. The CP-8 Working Group compared the results of this assessment for both the 2021 and 2023 hourly load shape assumptions, finding materially larger results from 2021.

The loads for each Area were modeled on an hourly, chronological basis, using the 2021 hourly load shape. The MARS program modified the hourly loads through time to meet each Area's specified peaks and energies.

Figure 1 shows the diversity in the NPCC area monthly 50/50 peak load shapes used in this analysis, with the 2021 load shape assumption.

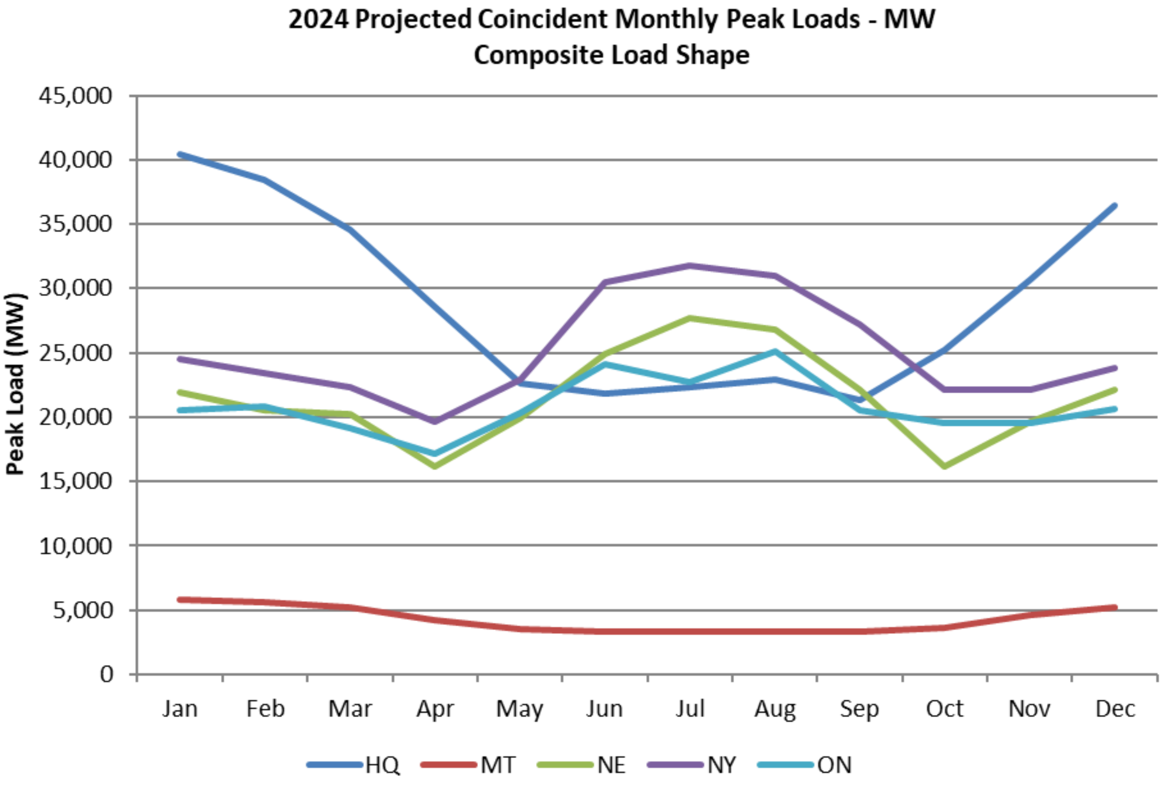

Figure 1: 2024 Projected Monthly 50/50 Peak Loads for NPCC

The effects on reliability of uncertainties in the peak load forecast due to weather and/or economic conditions are captured through the load forecast uncertainty model within MARS program.

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[66] See: https://www.npcc.org/library/publications/other

The NPCC Areas provide a projection for peak loads and energies that are modified by the 2021 load shape [67] to meet the provided peak and energy targets; the Load Forecast uncertainty is determined by each NPCC Area and is illustrated in **Table 5**.

The program computes the reliability indices at each of the specified load levels and calculates weighted-average values based on input probabilities of occurrence. For this study, seven load levels were modeled based on the monthly peak load forecast uncertainty provided by each Area.

For example, if the 50/50 Load July monthly peak load for Ontario is “y”, then the Higher Load value assumed for that month based on **Table 5** would be calculated as y*1.101, as highlighted.

The seven peak load levels represent the expected peak load level and one, two and three standard deviations above and below that 50/50 peak load level.

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

Table 5 shows the load variation assumed for each of the seven load levels modeled and the probability of occurrence for the summer peak month in each Area. The probability of occurrence is the weight given to each of the seven load levels; it is equal to half of the sum of the two areas on either side of each standard deviation point under the probability distribution curve.

Table 5: Per Unit Variation in Peak Load by Load Level Assumed for the Each Area’s Peak Month

Area	Per-Unit Variation in Load						
	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	Level 7
HQ	**1.157**	**1.089**	**1.039**	**1.000**	**0.959**	**0.928**	**0.902**
MT	**1.138**	**1.092**	**1.046**	**1.000**	**0.954**	**0.908**	**0.862**
NE	**1.209**	**1.098**	**1.008**	**0.919**	**0.901**	**0.856**	**0.851**
NY	**1.119**	**1.080**	**1.036**	**0.989**	**0.940**	**0.887**	**0.833**
ON	**1.145**	**1.101**	**1.051**	**1.000**	**0.947**	**0.895**	**0.850**
Probability of Occurrence	**0.0062**	**0.0606**	**0.2417**	**0.3830**	**0.2417**	**0.0606**	**0.0062**

The results for this study are reported for two peak load conditions: 50/50 and higher load levels. The values for the 50/50 peak load conditions are derived from computing the reliability at each of the seven

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[67] Ontario demands provided were already adjusted for 2021 weather.

load levels and computing a weighted-average expected value based on the specified probabilities of occurrence.

The indices for the higher peak loads provide a measure of the reliability in the event of higher-than-expected peak loads. The higher load level results were based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring. These values are highlighted in **Table 5**.

While the higher peak load, as defined for this study, may be different for NPCC Areas for their own studies, the Working Group finds these higher peak load levels are appropriate for a probabilistic reliability assessment for a range of conditions across the NPCC region**.**

3.2 Resources

Table 6 below summarizes the 2024 summer capacity assumptions for each the NPCC Areas modeled in the analysis for the Base Case Scenario; the assumptions are consistent with the development of the NPCC CO-12 Working Group's, *NPCC Reliability Assessment for Summer 2024*,[60] dated April 2024.

Additional adjustments were made for the Severe Scenario, as explained in Section 3.7 of this report.

Table 6: Resource Assumptions at 2024 Summer Peak - Base Case (MW)

	QC	MT	NE	NY	ON
Assumed Capacity [68]	35,250	7,424	28,820	36,919	33,819
Demand Response [69]	0	317	560	1,281	1,018
Net Imports [70]	-2,486	-72	1,194	1,502	617
50/50 Peak Load	22,910	3,558	24,553	31,766	25,104
Reserve (%) [71]	43.0	115.6	24.5	25.0	37.2
Scheduled Maintenance [72]	-	1,190	11	52	0

Details regarding the NPCC Area's assumptions for generating unit availability are described in the respective Area's most recent *NPCC Comprehensive Review of Resource Adequacy*.[73] The MARS modelling details for each type of resource in each Area are provided in **Appendix E** of the report.

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[68] Assumed Capacity - the total generation capacity assumed to be installed at the time of the summer peak.

[69] Demand Response: the amount of "controllable" demand expected to be available for reduction at the time of 50/50 peak demand. New England's value reflects the amount of active demand capacity resources. New York value represents the Special Case Resource (SCR) amount.

[70] Net Imports: the amount of expected firm, long-firm imports at the time of the summer peak. The value is positive for imports and negative for exports.

[71] Reserve = ((Capacity + Net imports + Demand Response) – Peak Load) / Peak Load.

[72] Maintenance scheduled at time of peak.

[73] See: Resource Adequacy (npcc.org)

In addition, the NPCC Areas provided the following information:

New England

The generating resources include the existing units and planned resources that are expected to be available for the 2024 summer period. The rating used for commercial resources is based on their ratings are based on their Seasonal Claimed Capability. For non-commercial resources that plan to be commercial during the study period their Forward Capacity Market Capacity Supply Obligation is used. Settlement Only Generating resources are not included in this assessment, however, they do participate in the Energy Market and help serve New England's system loads.

The resources assumed in this assessment also include 560 MW of active demand capacity resources and 1,194 MW of net firm capacity imports from the neighboring areas. These demand resources and firm imports are based on their Capacity Supply Obligations associated with the 3rd Annual Reconfiguration Auction for Capacity Commitment Period (CCP) of 2024-2025. [74]

New York

Detailed availability assumptions used for the New York units can be found in the New York ISO Technical Study Report entitled *Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2024 – 2025 Capability Year*, dated January 18, 2024, [75] and the *New York Control Area Installed Capacity Requirement for the Period May 2024 - April 2025* New York State Reliability Council, December 08, 2023, report. [76]

Ontario

Generating unit availability was based on the Ontario IESO *Reliability Outlook - An Adequacy Assessment of Ontario's Electricity System from April 2024 to September 2025*, dated March 21, 2024. [77] Capacity acquired in the Ontario IESO's December 2023 capacity auction has added 1,867 MW of capacity for the summer of 2024 including 600 MW of imports.

Québec

The planned resources are consistent with the *2023 NPCC Québec Comprehensive Review of Resource Adequacy*. [78] The planned outages for the summer period are reflected within this reliability assessment. The number of planned generating unit outages is consistent with observed historical values.

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[74] The 2024-2025 CCP starts on June 1, 2024, and ends on May 31, 2025.

[75] See:2024-2025-LCR-Report.pdf (nyiso.com)

[76] See: https://www.nysrc.org/wp-content/uploads/2023/12/2024-25-IRM-Resolution-12-8-2023-final.pdf

[77] See: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2024Mar.ashx

[78] See: https://www.npcc.org/content/docs/public/library/resource-adequacy/2023/2023-quebec-comprehensive-review-of-resource-adequacy.pdf

Maritimes

Generating unit availability reflects planned outages forecast to occur during the summer period.

3.3 Transfer Limits

Figure 2 depicts the transmission system that was modeled within this reliability assessment, showing both Area and assumed Base Case transfer limits for the summer 2024 period.

Maritimes

Within the Maritimes Area, the areas of Nova Scotia, PEI, and Northern Maine are each connected internally only to New Brunswick. Only New Brunswick is interconnected externally with Québec and USA Maine areas.

New England

The New England transmission system consists of mostly 115 kV, 230 kV, and 345 kV transmission lines. The lines in northern New England generally are longer and fewer in number than those in southern New England. The region has 13 interconnections with neighboring power systems. Nine interconnections are with New York (two 345 kV ties; one 230 kV tie; one 138 kV tie; three 115 kV ties; one 69 kV tie; and one 330 MW, ±150 kV high-voltage direct-current (HVDC) tie—the Cross-Sound Cable interconnection).

New England and the Maritimes (New Brunswick Power Corporation) are connected through two 345 kV AC ties, the second of which was placed in service in December 2007. New England also has two HVDC interconnections with Québec (Hydro-Québec). One is a 120 kV AC interconnection (Highgate in northern Vermont) with a 225 MW back-to-back HVDC converter station, which converts alternating current to direct current and then back to alternating current. The second is a ±450 kV HVDC line with terminal configurations allowing up to 2,000 MW to be delivered at Sandy Pond in Massachusetts (Phase II) and 1,200 MW of reverse export capability.

New York

The New York wholesale electricity market is divided into 11 pricing or load zones and is interconnected to Ontario, Québec, New England, and PJM. The transmission network is comprised of 765 kV, 500 kV, 345 kV, 230 kV as well as 138 kV and 115 kV lines. These transmission lines exceed 11,000 circuit miles in total. Reflecting current conditions at the time of this analysis, the Neptune cable from PJM to New York was derated to 660 MW for the duration of the summer period.

Ontario

The Ontario transmission system is mainly comprised of a 500 kV transmission network, a 230 kV transmission network, and several 115 kV transmission networks. It is divided into ten zones and there are nine major internal interfaces. Ontario has interconnections with Manitoba, Minnesota, Québec, Michigan, and New York.

Québec

The Québec Area is a separate Interconnection from the Eastern Interconnection, into which the other NPCC Areas are interconnected. Hydro-Québec in its transmission activities, the main Transmission Owner and Operator in Québec, has interconnections within Ontario, New York, New England, and the Maritimes.

There are back-to-back HVDC links with New Brunswick at Madawaska and Eel River, with New England at Highgate (in New England) and with New York at Châteauguay. The Radisson – Nicolet – Sandy Pond HVDC line interconnects Québec with New England. Radial load can be picked up in the Maritimes by Québec at Madawaska and at Eel River and at the Stanstead substation feeding the Vermont Electric Cooperative in northern New England. Moreover, in addition to the Châteauguay HVDC back-to-back interconnection to New York, generation can be radially connected to the New York system through Line 7040. The Variable Frequency Transformer (VFT) at Langlois substation connects into the Cedar Rapids Transmission system, down to New York State at Dennison. The Outaouais HVDC back-to-back converters and accompanying transmission to the Ottawa, Ontario area is now in service. Other ties between Québec and Ontario consist of radial generation and load that can be switched on either system.

Transfer limits between and within some NPCC Areas are indicated in **Figure 2** with seasonal ratings (S- summer, W- winter) where appropriate. Details regarding the sub-Area representation for Ontario [79], New York [79], and New England [80] are provided in the respective references.

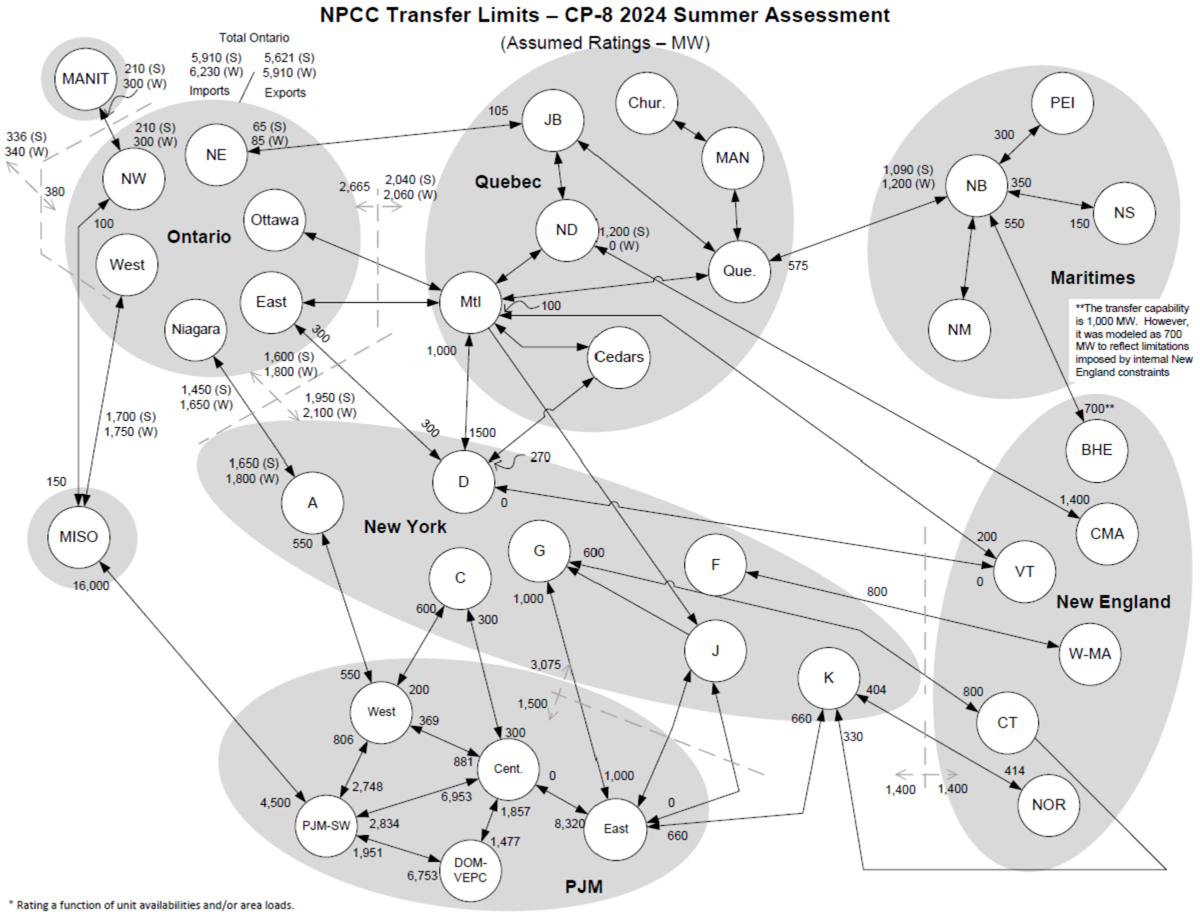

Figure 2: Assumed Transfer Limits

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[79] See: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/TTCMethodology2018dec.pdf?la=en.

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

Note: With the Variable Frequency Transformer operational at Langlois (Cdrs), Hydro- Québec can import up to 100 MW from New York.[81]

The acronyms and notes used in **Figure 2** are defined as follows:

Chur.	- Churchill Falls	NOR	- Norwalk – Stamford	RF	- ReliabilityFirst
MANIT	- Manitoba	BHE	- Bangor Hydro Electric	NB	- New Brunswick
ND	- Nicolet-Des Cantons	Mtl	- Montréal	PEI	- Prince Edward Island
JB	- James Bay	C MA	- Central MA	CT	- Connecticut
MAN	- Manicouagan	W MA	- Western MA	NS	- Nova Scotia
NE	- Northeast (Ontario)	NBM	- Millbank	NW	- Northwest (Ontario)
MRO	- Midwest Reliability Organization	VT	- Vermont	CSC	- Cross Sound Cable
		Que	- Québec Centre	Cdrs	- Cedars
NM	- Northern Maine				

3.4 Operating Procedures to Mitigate Resource Shortages

Each Area takes defined steps as their reserve levels approach critical levels. These steps consist of load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves. **Table 7** summarizes the load relief assumptions modeled for each NPCC Area.

Table 7: NPCC Operating Procedures - 2024 Summer Load Relief Assumptions (MW)

Actions	QC	MT	NE	NY [82]	ON
1. Curtail Load	-	-	-	-	-
Public Appeals	-	-	-	-	1%
SCR	-	-	-	867	-
SCR Load / Man. Volt. Red.	-	-	-	0.35 %	-
2. No 30-min Reserves	500	162	625	655	473
3. Voltage Reduction	-	-	259	1.4%	0.96%
Interruptible Load [83]	-	317	-	267	1,018
4. No 10-min Reserves	750	415	-	-	945
Appeals / Curtailments	-	-	-	74	-
5. 5% Voltage Reduction	-	-	-	-	0.72%
No 10-min Reserves	-	-	980	910	-
Appeals / Curtailments	-	-	-	-	-

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 7** was a reasonable approximation for this reliability assessment.

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[81] See: https://www.oasis.oati.com/HQT/.

[82] Values for New York's SCR Program has been derated to account for historical availability.

[83] Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others.

The need for an Area to begin implementing these Operating Procedures is modeled in MARS by evaluating the daily Loss of Load Expectation (LOLE) 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 peak load, and as a per unit of the available capacity for the hour.

3.5 Assistance Priority

All Areas received assistance on a shared basis in proportion to their deficiency. In this analysis, each step was initiated simultaneously in all Areas and sub-areas. The methodology used is described in **Appendix E** - Multi-Area Reliability Simulation Program Description - Resource Allocation Among Areas (Section E.3).

3.6 Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of the PJM-RTO and MISO (Midcontinent Independent System Operator) was modeled. Their assumptions are summarized in **Table 8**.

Table 8: PJM and MISO 2024 Base Case Assumptions [84]

	PJM	MISO
50/50 Peak Load (MW)	151,129	92,463
Peak Month	July	July
Assumed Capacity (MW)	196,594	103,492
Purchase/Sale (MW)	-1,780	939
Reserve (%)	33.8	17.9
Weighted Unit Availability (%)	87.7	83.8
Operating Reserves (MW)	3,400	3,906
Curtailable Load (MW)	7,397	4,557
No 30-min Reserves (MW)	2,765	2,670
Voltage Reduction (MW)	2,201	2,200
No 10-min Reserves (MW)	635	1,236
Appeals (MW)	400	400
Load Forecast Uncertainty (%)	100.0 +/- 5, 10, 15	100.0 +/- 3.7, 7.3, 11

Figure 3 shows the 2024 summer Projected Monthly 50/50 Peak Loads for NPCC, PJM, and the MISO for the 2023 Load Shape assumption.

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[84] Load and capacity assumptions for MISO based on NERC's Electricity and Supply Database (ES&D) available at: http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx.

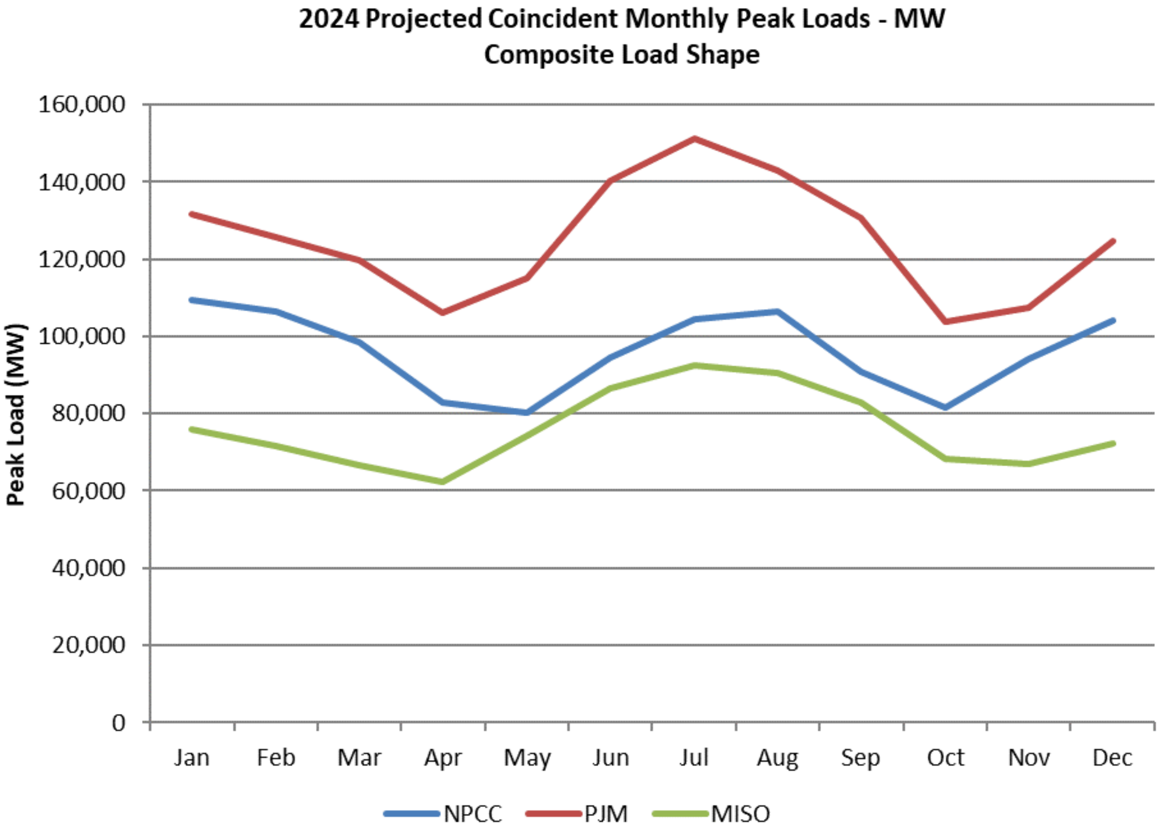

Figure 3: 2024 Projected Monthly 50/50 Summer Peak Loads - 2023 Load Shape

Beginning with the *2015 NPCC Long Range Adequacy Overview,* (LRAO)[85] the MISO region (minus the recently integrated Entergy region) was included in the 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 in the model.

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

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[85] See: https://www.npcc.org/content/docs/public/library/resource-adequacy/2016/2015longrangeoverviewrccapproveddecember1.pdf

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.[86] 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, dated January 2023.[87] Load Forecast Uncertainty was modeled consistent with recent PJM planning models[88] 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.

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 in aggregate, with the appropriate timing and transfer values changing within the model, consistent with PJM's regional Transmission Expansion Plan.[89]

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[86] Please refer to PJM Manuals 19 and 20 at http://www.pjm.com/~/media/documents/manuals/m19 redline.ashx and http://www.pjm.com/~/media/documents/manuals/m20-redline.ashx for technical specifics.

[87] See: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2023-load-report.ashx

[88] See: https://www.pjm.com/-/media/planning/res-adeq/2023-pjm-reserve-requirement-study.ashx

[89] See: http://www.pjm.com/planning.aspx.

3.7 Study Scenarios

This study evaluated two cases (Base Case and Severe Case); a summary description is provided in **Tables 9 and 10**.

Table 9: Base Case and Severe Case Assumptions for NPCC Area

	Base Case Assumptions	**Severe Case – Additional Constraints**
System	- As-Is System for the year 2024 - Transfers allowed between Areas - 2021 Load Shape adjusted to Area's year 2024 50/50 & higher load forecast assumptions	- Transfer capability between NPCC and the MISO- 'Other' reduced by 50%.
Maritimes	- ~ 1,207.3 MW of available installed wind generation capacity (modeled using probabilistically selected annual hourly 2017 wind shapes) until June 2024 - 90 MW for export contracts assumed - ~301 MW of demand response (interruptible load) available	- Wind capacity de-rated by half (~ 604 MW) during July and August due to calm weather - Natural gas fueled units de-rated by half (~234 MW) for July and August due to supply disruptions (dual fuel units assumed to revert to oil)
New England[90]	- Existing and planned generation resources and load forecast (including Energy Efficiency and BTM-PV forecast) for the summer of 2024 consistent from the 2024 ISO-NE Capacity, Energy, Loads, and Transmission (CELT) Report - Active Demand Capacity Resources and Imports based on 2024-2025 Capacity Commitment Period 3rd Annual Reconfiguration Auction held in 2024	- Assumed 50% reduction to the import capabilities of external ties - Maintenance overrun by 4 weeks
New York	- Updated Load Forecast – (NYCA - 31,765.6 MW; NYC – 11,170.6 MW; LI – 5,080.3 MW - Assumptions consistent with the New York Installed Capacity Requirements for May 2024 through April 2025 [91]	- Outages in southeastern New York (500 MW) - 50% reduction in effectiveness of SCR programs - 330 MW of reduced transfer capability into Long Island - 300 MW of reduced transfer capability into New York City from PJM
Ontario	- Forecast consistent with the planned scenario (existing and planned resources) in the IESO's Reliability Outlook – An adequacy assessment of Ontario's Electricity System from April 2024 to September 2025[92]	- ~800 MW of maintenance extended into the summer period - ~ 800 MW of additional maintenance in September - Hydroelectric capacity and energy 10% lower than the Base Case
Québec	- Planned resources and load forecast consistent with the 2023 NPCC Québec Comprehensive Review of Resource Adequacy for the summer 2024 period – including ~5,599 MW of scheduled maintenance and restrictions - Wind generation derated 100% for the summer period- ~2,689 MW of sales to neighboring areas	- ~1,000 MW of capacity assumed to be unavailable for the summer peak period

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[90] New England assumptions consistent with the New England 2024 CELT Report published on May 1, 2024

[91] See: Locational Minimum Installed Capacity Requirements Study for the 2024-2025 Capability Year (nyiso.com)

[92] See: Reliability Outlook (ieso.ca)

Table 10: Base Case and Severe Case Assumptions for Neighboring Areas

	Base Case Assumptions	Severe Case Assumptions
PJM-RTO	- As-Is System for the 2024 summer period, based on the PJM 2023 Reserve Requirement Study [93] - 2021 Load Shapes and Load Forecast Uncertainty adjusted to the 2023 forecast provided by PJM - Operating Reserve 3,400 MW (30-min. 2,765 MW; 10-min. 635 MW)	- Load Forecast Uncertainty increased by one percent (1%) - Forced Outage rates increased for all units by one percent (1%) - ~5,000 MW of additional high ambient temperature generator derates (June-August) - 90% compliance of Demand Response (DR) +Energy Efficiency (EE) resources
MISO [94]	- As-Is System for the 2024 summer period – Based on the NERC Electricity Supply & Demand (ES&D) database [95] - 2021 Load Shapes and Load Forecast Uncertainty adjusted to the most recent monthly forecast provided by PJM - Operating reserve 3,906 MW (30-min. 2,670 MW; 10-min. 1,236 MW)	

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[93] See: 2023 PJM Reserve Requirement Study

[94] Does not include the Entergy region (MISO South).

[95] See: Electricity Supply & Demand (ES&D) (nerc.com)

4. STUDY RESULTS

4.1 Base Case Scenario

Figure 4 shows the estimated need for the indicated Operating Procedures in days/period for the May through September 2024 period for the 50/50 peak load (probability-weighted average of all the seven load levels simulated) for the Base Case. Detailed results from the MARS simulations are provided in Appendices B, C and D.

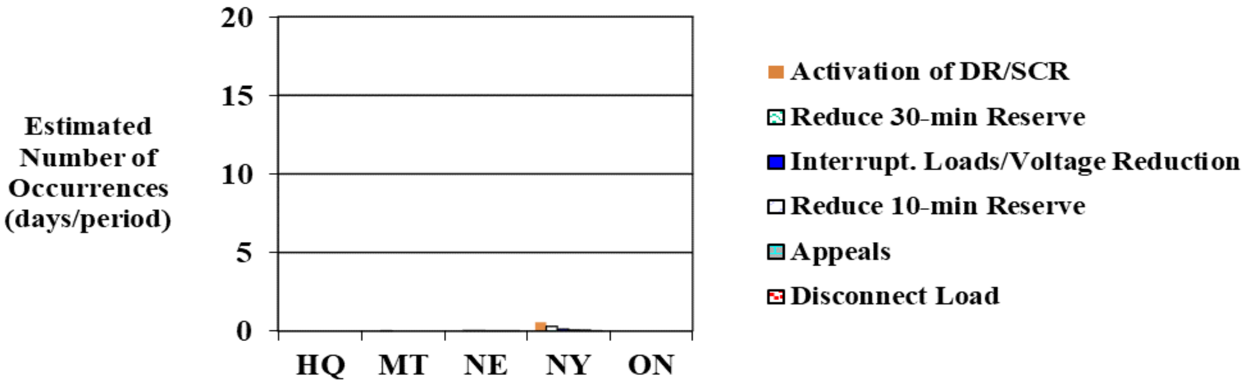

Figure 4: Estimated Use of Operating Procedure for Summer 2024
Base Case Assumptions – 50/50 Peak Load Level

Figure 5 shows the corresponding results for the highest peak loads (based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring) for the Base Case. Detailed results from the MARS simulations are provided in Appendices B, C and D.

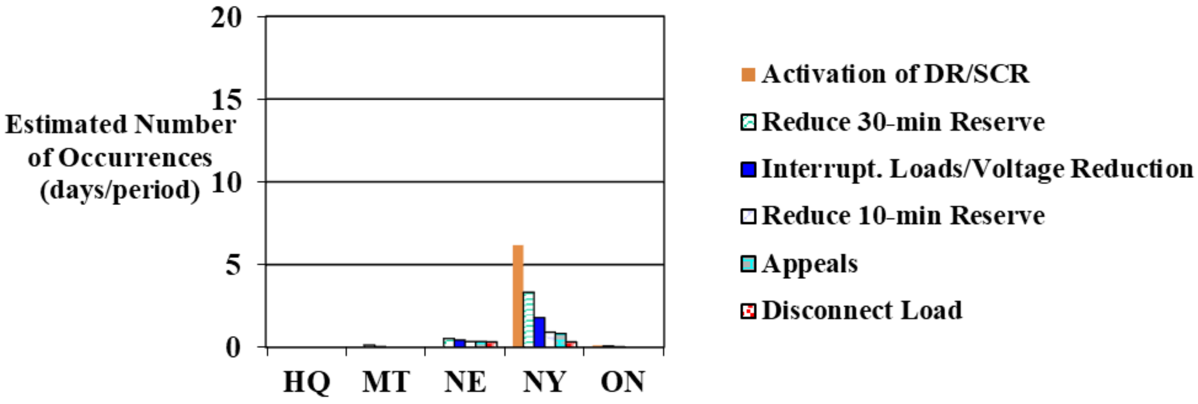

Figure 5: Estimated Use of Operating Procedures for Summer 2024
Base Case Assumptions - Highest Peak Load Levels

4.2 Severe Resource Case Scenario

Figure 6 shows the estimated use of Operating Procedures for the NPCC Areas for the 50/50 peak load (probability-weighted average of all the seven load levels simulated) for the Severe Resource Case. Detailed results from the MARS simulations are provided in Appendices B, C and D.

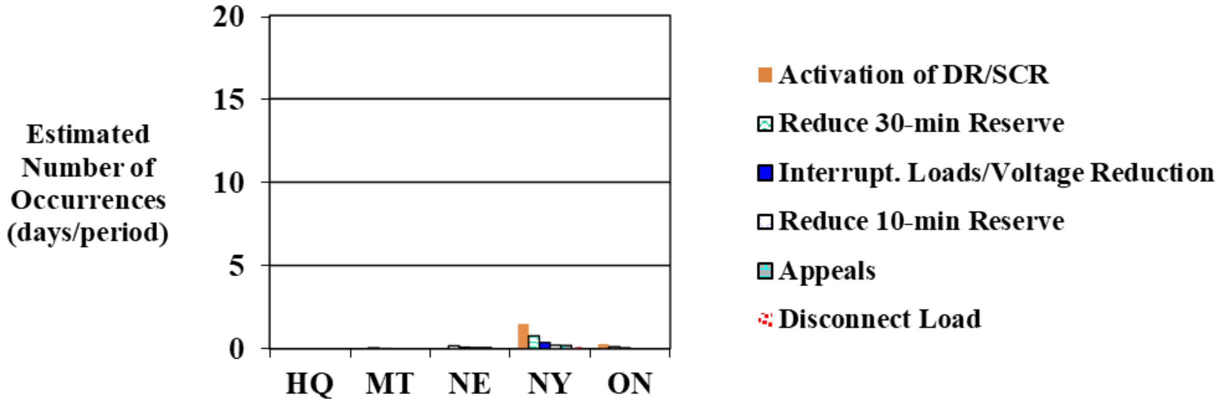

Figure 6: Estimated Use of Operating Procedure for Summer 2024
Severe Case Assumptions – 50/50 Peak Load Level

Figure 7 shows the estimated use of the indicated Operating Procedures for the Severe Case for the highest peak load level (based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring).

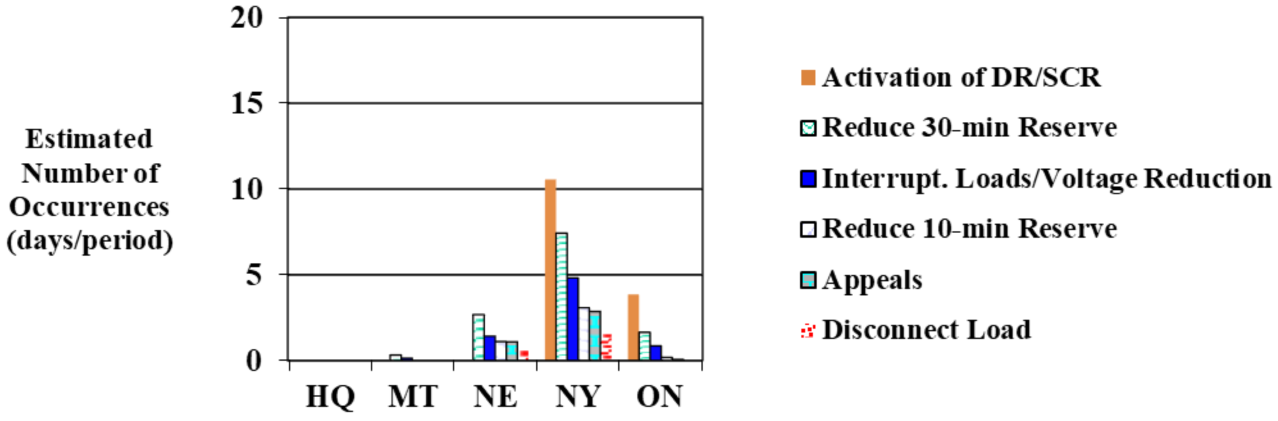

Figure 7: Estimated Use of Operating Procedure for Summer 2024
Severe Case Assumptions – Highest Peak Load Levels

5. HISTORICAL REVIEW

Table 11 compares NPCC Area's actual 2023 summer peak demands against the previous forecast assumptions based on the 2023 NPCC Summer Assessment.

Table 11: Comparison of NPCC 2023 Actual and Forecast Summer Peak Loads

Area	Date	Actual Peak (MW)	Forecast Peak [96] (MW)		
			50/50 Peak	Higher Peak	Month
Québec	September 06, 2023	22,780 [97]	22,859	23,900	Aug
Maritimes	July 06, 2023	3,389	3,612	3,845	June
New England	September 07, 2023	23,521 [98]	24,664[99]	26,479	Aug
New York	September 06, 2023	30,206	32,049	33,883	Aug
Ontario	September 05, 2023	23,713	22,439	24,420	July

A summary review of the last summer demand and main operational issues are presented below, while a detailed historical weather review is presented in **APPENDIX G**.

5.1 Operational Review

Québec

The Québec Area actual internal peak demand for summer 2023 and all-time summer peak demand occurred on September 6, 2023, at HE18 EDT and was 22,780 MW. The Québec actual internal demand coincided the same time as the NPCC coincident peak demand. Currently, transfers to other areas were approximately 33,218 MW.

During last summer, Québec faced its most severe forest fire season in modern history, surpassing the previous record set in 1923. The wildfires began on May 28th, 2023, with transmission lines starting to trip.

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[96] https://www.npcc.org/content/docs/public/library/reports/seasonal-assessment/2023/npcc-2023-summer-reliability-assessment.pdf

[97] Represents the all-time Québec Summer Peak Demand.

[98] This is the ISO-NE planning version of the peak load that includes load served by Settlement Only Generators (SOGs) and may be slightly different than the peak loads reported by operations that does not include SOGs. See: https://www.iso-ne.com/static-assets/documents/2023/02/2023_smd_hourly.xlsx

[99] New England's peak value is based on the 2023 CELT forecast that takes into account the impacts from behind-the-meter PV load reduction, and passive demand resources (energy efficiency) for the summer of 2023.

Throughout June and July of 2023, several 735kV lines tripped. Higher than usual temperature is the main contributor to the last year's historical peak occurrence, but other factors such as higher residential consumption due to teleworking "might have contributed" as well. Although Québec had its historical summer peak last year, it is important to emphasize the fact that Hydro-Québec's system is designed for a winter peaking load of almost two times the historical summer peaking load.

Maritimes

The Maritimes Area load is the mathematical sum of the forecast or actual peak loads of the sub-areas (New Brunswick, Nova Scotia, Prince Edward Island, and the area served by the Northern Maine Independent System Operator).

The Maritimes summer peak load was 3,544 MW and occurred on July 24, 2023, at HE17 EDT. The Maritime Provinces did not experience any unexpected extreme or adverse weather conditions; all major transmission lines were in-service.

New England [100]

The New England peak demand value of 23,521 MW [101] was observed on September 7, 2023, HE18 EDT. Peak loads were generally in line with forecasts given the weather conditions on the peak day. The mean temperature for the summer of 2023 was 0.2°F below normal.

ISO-NE declared three (3) Emergency Procedure Events in the summer of 2023: OP-4, M/LCC 2, Minimum Generation Emergency on July 5, 2023, and M/LCC 2 on August 21, 2023.

New York [102]

Key observations from summer 2023 include:

- Western NY Public Policy project was effective at reducing Zone A congestion and supply bottling
- The system topology associated with Segment A construction resulted in some congestion into Zone F during the higher load periods
- The system topology associated with Segment B reduced congestion across the UPNY-SENY interface
- Overall, it was a cool, wet, summer in NY
- Surplus capacity in real time was lower due to the 2023 Peaker unit retirements
- The net load peaks continue to shift later in the afternoon due to BTM solar
- Historic Canadian wildfires impacted solar production in late May and early June

Daily mean temperatures were near the 20-year average in May, below average in June and August, and above average in July. Highest Temperatures: 93 °F at NYC - Central Park and 93 °F at Albany. 6 days with

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[100] See: 2023-09-26-egoc-a3.1-iso-ne-2023-summer-review.pdf

[101] This is the ISO-NE planning version of the peak load that includes load served by Settlement Only Generators (SOGs) and may be slightly different than the peak loads reported by operations that does not include SOGs.

[102] See: https://www.nysrc.org/wp-content/uploads/2023/10/7.3.3-Summer-2023-NYISO-Hot-Weather-Operating-Conditions-Final-10-3-23-EC-v1-Attachment-7.3.3.pdf.

highs above 90 °F at NYC - Central Park (average is 16 days/year from 1991 –2020) and 8 days with highs above 90 °F at Albany (average is 9 days/year from 1991 –2020). [103]

Total net energy (GWh) was below 50/50 projections, primarily driven by deficits in May, June and August; the peak load was below the 50/50 projection. The Summer 2023 actual peak load was 30,206 MW September 6, 2023, HE18 EDT. There was one days with peak loads over 30,000 MW. The only other days with peak loads above 29,000 MW occurred during the September 2023 Heat Wave.

New York ISO Operations participated in regional coordination conference calls and worked with New York Transmission Owners to restore out of service equipment to support peak loads, including local reliability commitments per New York State Reliability Council Reliability Rules. New York Transmission Owners did activate utility (retail) demand response programs; there was no need for emergency actions such as emergency purchases or statewide voltage reduction. However, there was a small amount of utility voltage reduction and utility public appeals for local transmission and distribution needs. Natural gas pipeline and LDC Operational Flow Orders (OFOs) were observed during high load periods.

Wildfire Smoke Impacts – June 2023

- Largest solar generation reductions occurred on June 6th and 7th
- BTM Solar generation was reduced by approximately 800 MW on Wednesday, June 6th during the midday (10 AM to 2 PM) hours
- Combined peak generation reduction was about 1,466 MW over the two days, resulting in combined peak generation of about 4,405 MW
- Temperatures were also suppressed as actual values were a few degrees lower than forecast, contributing to some Day-Ahead load over-forecasts

September Heat Wave

- Only official Heat Wave of the summer occurred from September 5th to 7th
    - Temperatures exceeded 90 F at NYC – Central Park and Albany each day, peaking at 93°in both locations
- High humidity levels combined with the temperatures resulted in the three highest load days of the year
    - Dew Points were in the upper-60s to lower-70s throughout the state
- Daily peak load levels
    - September 5th: 29,141 MW
    - September 6th: 30,206 MW (Season Peak)
    - September 7th: 29,373 MW
- Highest September load levels since the same week in 2018

Ontario

The 2023 summer peak demand of 23,713 MW occurred on September 5, 2023, at HE 17 EDT The peak day was the Tuesday following Labour Day and the second hottest day of the month with temperatures exceeding 30°C and the humidex over 40°C. With the start of fall term of elementary and secondary school

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[103] See: National Weather Service – New York City Office New York, NY (weather.gov).

the next day there was additional load on the system that would not be present during the summer months. The Industrial Conservation Initiative (ICI) – a peak pricing program – reduced peak demand for the day by 1,500 to 1,700 MW as participating loads curbed their consumption. The system does remain more temperature sensitive than prior to COVID due to the continuation of work from home. Going forward demand will continue to evolve due to the electrification of home heating and transportation.

6. CONCLUSIONS

Base Case Scenario Summary

50/50 Peak Load Level

Under the Base Case Scenario and 50/50 peak load level, only the New York Area shows a likelihood greater than 0.5 days/period of using their Operating Procedures such as activating their demand response programs designed to mitigate resource shortages [104] during the 2024 summer period.

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

Highest Peak Load Levels

Under the Base Case Scenario and higher peak load level assumptions, the New England Area shows a likelihood of using their Operating Procedures reducing 30-min reserve requirements to mitigate resource shortages.

The New York Area shows a cumulative likelihood of activating their demand response programs, reducing their 30-min reserve, initiating voltage reductions, and reducing 10-min reserve, and initiating public appeals to mitigate shortages for the 2024 summer period for the Base Case Scenario assuming the highest peak load levels.

The highest peak load level results were based exclusively on only the two highest load levels of the seven load levels modeled, having approximately a combined seven percent chance of occurring.

Severe Case Scenario Summary

50/50 Peak Load Level

The New York Area shows a cumulative likelihood of activation of their demand response programs and reducing 30-min reserve (0.5 days/period) during the 2024 summer period for the Severe Case Scenario assuming the 50/50 peak load level.

The New England Area shows a likelihood of using their Operating Procedures reducing 30-min reserve requirements to mitigate resource shortages.

The 50/50 peak load level results were based on the probability-weighted average of all the seven load levels simulated. The probabilistic results indicate that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during the Summer of 2024.

Highest Peak Load Levels

The New England, New York, and Ontario, Areas show greater cumulative likelihoods of using more of their Operating Procedures designed to mitigate resource shortages during the 2024 summer period for the Severe Case Scenario assuming the highest peak load levels.

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[104] Likelihoods of less than 0.5 days/period are not considered significant.

The highest peak load level results were based exclusively on only the two highest load levels of the seven modeled, having approximately a combined seven percent chance of occurring.

Québec

The Québec Area is not expected to require use of their operating procedures designed to mitigate resource shortages during the Summer of 2024. The Québec Area is winter peaking and has a large reserve margin for the summer period; as a result, Québec did not demonstrate any measurable amounts of cumulative LOLE,[46] LOLH,[47] or EUE[48] risks over the summer May – September period for all the scenarios modeled.

LOLH and EUE can provide insight on system reliability because of their ability to measure loss of load duration and magnitude. EUE is helpful in quantifying the reliability risk impacts of weather or other natural events.

Ontario

The severe case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.03 days/period), with associated cumulative LOLH (0.06 hours/period) and EUE (30 MWh/period) with the highest risk occurring in Aug, correlated to the availability of their external imports at the time of Ontario’s peak load. Negligible cumulative LOLE, LOLH and EUE risks were estimated over the May to September summer period for the other scenarios modeled.

New England

The severe case, highest peak load level conditions resulted in a small estimated cumulative LOLE risk (0.69days/period), with associated LOLH (2.8 hours/period) and EUE (1,604 MWh/period) with the highest risk occurring in July and August. Negligible cumulative LOLE (<0.022 days/period), LOLH (<0.08hours/period) and EUE (<17 MWh/period) risks were estimated over the summer May to September period for the other scenarios modeled.

New York

The severe case, highest peak load level conditions resulted in an estimated cumulative LOLE risk (1.2 days/period), with associated LOLH (4.3 hours/period) and EUE (3,424 MWh/period) with the highest risk highest risk occurring in July and August. Negligible cumulative LOLE (<0.023 days/period), LOLH (<0.0.07 hours/period) and EUE (39 MWh/period) risks were estimated over the summer May to September period for the other scenarios modeled.

Maritimes Area

The Maritimes Area is winter peaking. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer May – September period for all the scenarios modeled.

APPENDIX A

OBJECTIVE, SCOPE OF WORK AND SCHEDULE

A.1 Objective

On a consistent basis, evaluate the near-term seasonal resource adequacy of NPCC Areas' reflecting NPCC Area and neighboring regional plans proposed to meet their respective resource adequacy planning criteria. The potential effects of proposed market mechanisms in NPCC and neighboring regions expected to provide for future adequacy will be included in the evaluation.

In meeting this objective, the CP-8 Working Group (WG) will use the G.E. Multi-Area Reliability Simulation (MARS) program, incorporating, to the extent possible, a detailed reliability representation for regions bordering NPCC for the 2024 - 2025 time period, consistent with the NPCC CO-12 WG's corresponding reliability assumptions.

A.2 Scope

The near-term seasonal analyses will update the current CP-8 Working Group's G.E. MARS database to develop a model suitable for the 2024 - 2025 time period in order to estimate the resource adequacy of NPCC Areas and neighboring Regions under Base Case (likely available resources and transmission) and Area identified Severe Case assumptions for the May to September 2024 summer and November 2024 to March 2025 winter seasonal periods, 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 load response programs;
- historical hourly load shape analysis (considering the impact of DER and PV forecasts); and,
- as appropriate, the reliability impacts that the existing and anticipated market rules may have on the assumptions, including the input data.

Reliability for the near-term seasonal analyses (2024 – 2025) will be measured by estimating the use of NPCC Area operating procedures used to mitigate resource shortages, including expected reliability metrics and analysis supporting related NERC Reliability Assessment Subcommittee, probabilistic analysis requirements.

A.3 Schedule

The 2024 Summer Reliability Assessment report combining the results of the CP-8 WG Summer Probabilistic Multi-Area Reliability Assessment, and the corresponding CO-12 WG 2024 Summer Reliability Assessment will be developed and approved by the NPCC Task Forces on Coordination of Operations and Planning no later than by April 19, 2024.

APPENDIX B

DETAILED STUDY RESULTS (days/month)

Table 12: Base Case Assumptions - Expected Need for Indicated Operating Procedures (days/month)

Base Case	Québec				Maritimes Area				New England					New York					Ontario			
	30-min	VR	10-min	Appeal /Disc	30-min	IL	10-min	Appeal /Disc	30-min	VR	10-min	Appeal	Disc	30-min	VR	Appeal	10-min	Disc	30-min	VR	10-min	Appeal /Disc
2021 Load Shape-50/50 Load Level																						
May	-	-	-	-	0.005	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	0.001	-	-	-	-	-	-	-	-	0.022	0.011	0.005	0.004	0.002	-	-	-	-
July	-	-	-	-	0.009	0.003	-	-	0.020	0.018	0.015	0.015	0.015	0.124	0.058	0.029	0.026	0.011	-	-	-	-
Aug	-	-	-	-	0.003	-	-	-	0.014	0.011	0.008	0.008	0.007	0.151	0.059	0.030	0.027	0.011	0.004	0.002	-	-
Sep	-	-	-	-	0.002	-	-	-	-	-	-	-	-	0.002	-	-	-	-	-	-	-	-
May-Sep	-	-	-	-	0.020	0.007	-	-	0.034	0.030	0.023	0.023	0.022	0.300	0.128	0.064	0.057	0.023	0.004	0.002	-	-
2021 Load Shape-Highest Load Levels																						
May	-	-	-	-	0.040	0.014	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	0.005	0.003	-	-	0.008	0.008	0.004	0.004	0.004	0.315	0.152	0.069	0.064	0.026	-	-	-	-
July	-	-	-	-	0.051	0.019	0.001	-	0.295	0.276	0.223	0.223	0.219	1.421	0.830	0.422	0.380	0.156	-	-	-	-
Aug	-	-	-	-	0.026	0.007	-	-	0.211	0.163	0.120	0.119	0.106	1.579	0.811	0.420	0.384	0.150	0.052	0.024	0.004	-
Sep	-	-	-	-	0.014	0.004	-	-	-	-	-	-	-	0.007	0.001	0.001	0.001	0.001	-	-	-	-
May-Sep	-	-	-	-	0.135	0.047	0.001	-	0.515	0.447	0.348	0.346	0.329	3.322	1.794	0.912	0.829	0.332	0.053	0.024	0.004	-

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (“IL” - initiate Interruptible Loads for the Maritimes Area).
"10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Disc" - and disconnect customer load.

Table 13: Severe Case Scenario - Expected Need for Indicated Operating Procedures (days/month)

Severe Case Results																									
	Québec					Maritimes	Area				New England					New York					Ontario				
	30-min	VR	10-min	Apl	Disc	30-min	IL	10-min	Apl	Disc	30-min	VR	10-min	Apl	Disc	30-min	VR	Apl	10-min	Disc	30-min	VR	10-min	Apl	Disc
2021 Load Shape-50/50 Load Level																									
May	-	-	-	-	-	0.005	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	0.001	-	-	-	-	0.060	0.031	0.024	0.024	0.011	0.048	0.025	0.012	0.011	0.004	0.004	-	-	-	-
July	-	-	-	-	-	0.028	0.010	-	-	-	0.079	0.042	0.032	0.032	0.020	0.361	0.180	0.115	0.107	0.052	0.034	0.014	0.001	-	-
Aug	-	-	-	-	-	0.022	0.006	-	-	-	0.057	0.030	0.023	0.023	0.015	0.270	0.132	0.064	0.058	0.027	0.074	0.042	0.010	0.003	0.001
Sep	-	-	-	-	-	0.002	-	-	-	-	0.000	-	-	-	-	0.002	0.000	0.000	0.000	0.000	-	-	-	-	-
May-Sep	-	-	-	-	-	0.058	0.019	-	-	-	0.197	0.102	0.080	0.079	0.046	0.681	0.337	0.190	0.176	0.084	0.111	0.057	0.011	0.004	0.002
2021 Load Shape-Highest Load Levels																									
May	-	-	-	-	-	0.040	0.014	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	0.005	0.003	-	-	-	0.871	0.458	0.366	0.366	0.169	0.672	0.361	0.172	0.159	0.063	0.057	0.012	-	-	-
July	-	-	-	-	-	0.150	0.071	0.001	-	-	1.156	0.625	0.486	0.480	0.296	2.773	2.239	1.678	1.580	0.774	0.452	0.199	0.017	0.004	0.001
Aug	-	-	-	-	-	0.120	0.046	-	-	-	0.860	0.445	0.348	0.344	0.224	3.216	1.869	0.909	0.849	0.399	0.979	0.585	0.141	0.050	0.022
Sep	-	-	-	-	-	0.014	0.004	-	-	-	0.000	-	-	-	-	0.012	0.002	0.001	0.001	0.001	-	-	-	-	-
May-Sep	-	-	-	-	-	0.328	0.139	0.001	-	-	2.887	1.528	1.199	1.190	0.689	6.674	4.471	2.761	2.589	1.236	1.488	0.796	0.158	0.054	0.023

Notes: "30-min"- reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (“IL” - initiate Interruptible Loads for the Maritimes Area).
"10-min" - and reduce 10-minute Reserve Requirement; "Apl" - and initiate General Public Appeals; "Disc" - and disconnect customer load.

APPENDIX C DETAILED STUDY RESULTS (hours/month)

Table 14: Base Case Assumptions - Expected Need for Indicated Operating Procedures (hours/month)

Base Case																						
	Québec				Maritimes Area				New England					New York					Ontario			
	30-min	VR	10-min	Appeal /Disc	30-min	IL	10-min	Appeal /Disc	30-min	VR	10-min	Appeal	Disc	30-min	VR	Appeal	10-min	Disc	30-min	VR	10-min	Appeal /Disc
2021 Load Shape-50/50 Load Level																						
May	-	-	-	-	0.016	0.004	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	0.011	0.004	-	-	0.001	0.001	0.000	0.000	0.000	0.081	0.039	0.016	0.014	0.004	0.000	-	-	-
July	-	-	-	-	0.046	0.016	0.000	-	0.089	0.078	0.063	0.063	0.060	0.501	0.231	0.108	0.097	0.037	0.000	-	-	-
Aug	-	-	-	-	0.012	0.002	-	-	0.052	0.034	0.023	0.023	0.019	0.520	0.195	0.092	0.080	0.027	0.011	0.005	0.001	0.000
Sep	-	-	-	-	0.009	0.002	-	-	-	-	-	-	-	0.004	0.000	0.000	0.000	0.000	-	-	-	-
May-Sep	-	-	-	-	0.095	0.028	0.000	-	0.142	0.113	0.086	0.086	0.079	1.106	0.465	0.216	0.192	0.068	0.011	0.005	0.001	0.000
2021 Load Shape-Highest Load Levels																						
May	-	-	-	-	0.132	0.038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	0.034	0.021	-	-	0.014	0.014	0.007	0.007	0.007	1.167	0.569	0.235	0.212	0.061	0.000	-	-	-
July	-	-	-	-	0.270	0.102	0.001	-	1.331	1.173	0.941	0.940	0.905	6.396	3.400	1.588	1.436	0.548	0.001	-	-	-
Aug	-	-	-	-	0.129	0.025	-	-	0.774	0.511	0.341	0.339	0.278	5.872	2.753	1.302	1.158	0.389	0.158	0.074	0.010	0.001
Sep	-	-	-	-	0.074	0.024	-	-	-	-	-	-	-	0.018	0.003	0.001	0.001	0.001	-	-	-	-
May-Sep	-	-	-	-	0.640	0.210	0.001	-	2.120	1.698	1.290	1.286	1.190	13.453	6.726	3.126	2.807	0.999	0.159	0.074	0.010	0.001

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (“IL” - initiate Interruptible Loads for the Maritimes Area).
"10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Disc" - and disconnect customer load.

Table 15: Severe Case Scenario - Expected Need for Indicated Operating Procedures (hours/month)

Severe Case Results																									
	Québec					Maritimes		Area			New England					New York					Ontario				
	30-min	VR	10-min	Apl	Disc	30-min	IL	10-min	Apl	Disc	30-min	VR	10-min	Apl	Disc	30-min	VR	Apl	10-min	Disc	30-min	VR	10-min	Apl	Disc
2021 Load Shape-50/50 Load Level																									
May	-	-	-	-	-	0.016	0.004	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	0.011	0.004	-	-	-	0.254	0.135	0.105	0.104	0.040	0.187	0.093	0.043	0.039	0.013	0.010	0.002	0.000	-	-
July	-	-	-	-	-	0.181	0.062	0.001	-	-	0.373	0.199	0.151	0.148	0.091	1.623	0.886	0.509	0.456	0.191	0.116	0.045	0.003	0.001	0.000
Aug	-	-	-	-	-	0.113	0.035	-	-	-	0.238	0.130	0.100	0.099	0.058	0.980	0.453	0.217	0.197	0.083	0.282	0.161	0.032	0.009	0.004
Sep	-	-	-	-	-	0.009	0.002	-	-	-	0.000	-	-	-	-	0.004	0.001	0.000	0.000	0.000	-	-	-	-	-
May-Sep	-	-	-	-	-	0.330	0.107	0.001	-	-	0.865	0.463	0.355	0.351	0.188	2.794	1.433	0.769	0.693	0.287	0.409	0.207	0.035	0.009	0.004
2021 Load Shape-Highest Load Levels																									
May	-	-	-	-	-	0.132	0.038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	0.034	0.021	-	-	-	3.733	2.013	1.565	1.564	0.592	2.709	1.366	0.633	0.582	0.199	0.145	0.025	0.000	-	-
July	-	-	-	-	-	0.998	0.434	0.003	-	-	5.541	2.974	2.256	2.214	1.363	16.573	12.267	7.558	6.808	2.845	1.613	0.661	0.050	0.009	0.003
Aug	-	-	-	-	-	0.668	0.262	-	-	-	3.564	1.939	1.491	1.480	0.863	12.469	6.573	3.155	2.904	1.211	3.869	2.251	0.461	0.131	0.058
Sep	-	-	-	-	-	0.074	0.024	-	-	-	0.000	-	-	-	-	0.028	0.005	0.002	0.001	0.001	-	-	-	-	-
May-Sep	-	-	-	-	-	1.907	0.779	0.003	-	-	12.838	6.926	5.313	5.259	2.818	31.778	20.212	11.347	10.297	4.256	5.627	2.937	0.511	0.140	0.061

Notes: "30-min"- reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction ("IL" - initiate Interruptible Loads for the Maritimes Area).
"10-min" - and reduce 10-minute Reserve Requirement; "Apl" - and initiate General Public Appeals; "Disc" - and disconnect customer load.

APPENDIX D DETAILED STUDY RESULTS (MWh/month)

Table 16: Base Case Assumptions - Expected Need for Indicated Operating Procedures (MWh/month)

Base Case																						
	Québec				Maritimes Area				New England					New York					Ontario			
	30-min	VR	10-min	Appeal /Disc	30-min	IL	10-min	Appeal /Disc	30-min	VR	10-min	Appeal	Disc	30-min	VR	Appeal	10-min	Disc	30-min	VR	10-min	Appeal /Disc
2021 Load Shape-50/50 Load Level																						
May	-	-	-	-	0.5	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	0.6	0.2	-	-	0.1	0.1	0.0	0.0	0.0	66.1	29.2	10.4	9.3	1.9	0.0	-	-	-
July	-	-	-	-	2.1	0.7	0.0	-	43.3	25.3	18.0	17.9	13.7	418.6	202.1	85.9	78.3	24.3	0.0	-	-	-
Aug	-	-	-	-	0.3	0.0	-	-	26.9	10.6	6.4	6.3	3.6	337.4	144.3	56.7	50.4	12.5	5.7	2.7	0.3	0.1/0.0
Sep	-	-	-	-	0.3	0.1	-	-	-	-	-	-	-	0.6	0.0	0.0	0.0	0.0	-	-	-	-
May-Sep	-	-	-	-	3.9	1.1	0.0	-	70.2	36.1	24.5	24.3	17.3	822.5	375.6	153.0	138.0	38.7	5.7	2.7	0.3	0.1/0.0
2021 Load Shape-Highest Load Levels																						
May	-	-	-	-	5.2	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	2.7	1.3	-	-	1.3	1.2	0.6	0.6	0.6	978.9	437.0	155.9	139.4	28.5	0.0	-	-	-
July	-	-	-	-	13.7	5.1	0.0	-	647.8	379.4	269.9	268.4	205.1	6075.2	3015.9	1282.6	1171.2	363.6	0.1	-	-	-
Aug	-	-	-	-	4.6	0.6	-	-	402.3	159.3	96.5	94.9	53.9	4703.5	2139.8	840.1	749.3	184.8	85.1	40.1	4.5	0.8/0.3
Sep	-	-	-	-	3.2	0.9	-	-	-	-	-	-	-	4.0	0.4	0.3	0.2	0.1	-	-	-	-
May-Sep	-	-	-	-	29.4	9.1	0.0	-	1051.4	539.9	367.0	363.9	259.6	11761.5	5593.2	2278.9	2060.1	577.0	85.3	40.1	4.5	0.8/0.3

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (“IL” - initiate Interruptible Loads for the Maritimes Area).
"10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Disc" - and disconnect customer load.

Table 17: Severe Case Scenario - Expected Need for Indicated Operating Procedures (MWh/month)

Severe Case Results																									
	Québec					Maritimes		Area			New England					New York					Ontario				
	30-min	VR	10-min	Apl	Disc	30-min	IL	10-min	Apl	Disc	30-min	VR	10-min	Apl	Disc	30-min	VR	Apl	10-min	Disc	30-min	VR	10-min	Apl	Disc
2021 Load Shape-50/50 Load Level																									
May	-	-	-	-	-	0.5	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	0.6	0.2	-	-	-	239.6	120.5	89.2	89.2	24.4	169.3	82.5	33.6	30.5	8.7	3.6	0.5	0.0	-	-
July	-	-	-	-	-	8.5	2.9	0.0	-	-	356.9	187.5	137.9	135.1	54.5	1981.1	1067.4	498.7	447.3	166.1	60.6	21.1	1.3	0.2	0.1
Aug	-	-	-	-	-	4.2	0.9	-	-	-	222.9	109.2	77.9	77.1	28.2	863.5	439.2	180.5	165.3	54.2	244.8	124.2	20.1	4.8	1.9
Sep	-	-	-	-	-	0.3	0.1	-	-	-	0.0	-	-	-	-	1.0	0.1	0.0	0.0	0.0	-	-	-	-	-
May-Sep	-	-	-	-	-	14.2	4.2	0.0	-	-	819.3	417.1	305.0	301.4	107.2	3014.8	1589.3	712.8	643.1	229.0	309.1	145.8	21.3	5.0	2.0
2021 Load Shape-Highest Load Levels																									
May	-	-	-	-	-	5.2	1.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
June	-	-	-	-	-	2.7	1.3	-	-	-	3564.2	1802.0	1335.9	1335.1	365.8	2502.5	1229.3	501.6	456.7	130.1	53.9	7.2	0.1	-	-
July	-	-	-	-	-	54.3	19.2	0.2	-	-	5339.7	2807.0	2063.6	2022.7	816.2	26673.5	15714.5	7457.3	6692.7	2485.6	876.0	314.5	18.8	3.5	1.1
Aug	-	-	-	-	-	32.7	10.6	-	-	-	3336.5	1634.0	1166.8	1154.7	422.4	12487.2	6537.3	2691.4	2468.2	808.7	3474.0	1773.5	297.6	71.4	28.8
Sep	-	-	-	-	-	3.2	0.9	-	-	-	0.0	-	-	-	-	8.3	1.2	0.3	0.2	0.1	-	-	-	-	-
May-Sep	-	-	-	-	-	98.1	33.1	0.2	-	-	12240.4	6243.1	4566.4	4512.5	1604.3	41671.5	23482.3	10650.7	9617.8	3424.5	4403.9	2095.2	316.5	74.9	29.8

Notes: "30-min"- reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (“IL” - initiate Interruptible Loads for the Maritimes Area)
"10-min" - and reduce 10-minute Reserve Requirement; "Apl" - and initiate General Public Appeals; "Disc" - and disconnect customer load

APPENDIX E

MULTI-AREA RELIABILITY PROGRAM DESCRIPTION

General Electric's Multi-Area Reliability Simulation (MARS) program [105] allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

E.1 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 great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies that govern system operation.

E.2 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)
- Need for initiating Operating Procedures (days/year or days/period)

The Working Group used both the daily LOLE and Operating Procedure indices for this analysis.

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.

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.

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[105] See: https://www.gevernova.com/consulting/software/mars

E.3 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. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area 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 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.

E.4 Generation

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

Thermal
Energy-limited
Cogeneration
Energy-storage
Hourly resources

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management impacts are modeled as load modifiers.

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 levelize 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.

Thermal Unit

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 is 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 the 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; 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 on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of 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 so as 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.

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 on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM

Energy-storage units and demand-side management impacts are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

E.5 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.

E.6 Contracts

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides 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 scheduled only to the extent that the sending Area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

APPENDIX F

MODELING DETAILS

F.1 Resources

Details regarding the NPCC Area's assumptions for resources are described in the respective Area's most recent *NPCC Comprehensive Review of Resource Adequacy*. [106] In addition, the NPCC Areas provided the following additional information:

New England

The New England generating unit ratings were consistent with their seasonal capability published in the 2024 CELT report. [107] Active Demand Capacity Resources and capacity imports are based on their Capacity Supply Obligations of the latest Reconfiguration Auction of Capacity Commitment Period of 2024-2025.

New York

The Base Case assumes that the New York City and Long Island localities will meet their respective locational installed capacity requirements as described in the New York ISO Report entitled [75] - *Locational Installed Capacity Requirements Study covering the New York Control Area for the 2024 – 2025 Capability Year*, dated January 18, 2024, and that New York State will meet the capacity requirements described in the *New York Control Area Installed Capacity Requirements for the Period May 2024 – April 2025*, New York State Reliability Council, Technical Study Report, dated December 08, 2023.[76]

Existing Resources

All in-service New York generation resources were modeled. The New York unit ratings were based on the Dependable Maximum Net Capability (DMNC) values from the 2023 Load & Capacity Data of the NYISO (Gold Book). [108]

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the planned scenario in the Ontario IESO *Reliability Outlook: An Adequacy Assessment of Ontario's Electricity System from April 2023 to September 2024*, (released March 23, 2023). [109]

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[106] See: https://www.npcc.org/program-areas/rapa/resource-adequacy.

[107] See: http://www.iso-ne.com/celt.

[108] See: https://www.nyiso.com/documents/20142/2226333/2023-Gold-Book-Public.pdf/c079fc6b-514f-b28d-60e2-256546600214

[109] See: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2024Mar.ashx

Québec

The Planned resources are consistent with the *2023 NPCC Québec Comprehensive Review of Resource Adequacy*.[110]

Maritimes

Resources in the Maritimes Area are winter DMNC ratings de-rated for the summer period.

F.2 Resource Availability

New England

This probabilistic reliability 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 average data for the same class of unit.

New York

Detailed availability assumptions used for the New York units can be found in the New York ISO Technical Study Report [111] entitled *Locational Minimum Installed Capacity Requirements Study covering the New York Balancing Area for the 2024 – 2025 Capability Year,* New York ISO, dated January 18, 2024, and the *New York Control Area Installed Capacity Requirement for the Period May 2024 - April 2025*New York State Reliability Council report, dated December 08, 2023.[76]

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the Ontario IESO *Reliability Outlook: An Adequacy Assessment of the Ontario's Electricity System from April 2023 to September 2024*, dated March 23, 2023.[112]

Québec

The planned outages for the summer period are reflected in this assessment. The number of planned outages is consistent with historical values.

Maritimes

Individual generating unit maintenance assumptions are based on approved maintenance schedules for the study period. Forced outage rates are based on the individual unit's historical data. If historical data is not available, forced outage rates are modeled based on generators of similar size and fuel type in the Area.

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[110] See: Microsoft Word - 2023 Québec Comprehensive Review Report_RCC.docx (npcc.org)

[111] See: 04ee02a1-3a67-f4df-ff8a-0c1a5c9cf7da (nyiso.com)

[112] See: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2024Mar.ashx

F.3 Thermal

New England

The Seasonal Claimed Capability as established through the Claimed Capability Audit is used to represent the non-intermittent thermal resources. The Seasonal Claimed Capability for intermittent thermal resources is based on their median net real power output during Reliability Hours.

New York

Installed capacity values for thermal units are based on seasonal Dependable Maximum Net Capability (DMNC) test results. 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. A nominal MW value for the summer assessment representing historical maintenance during the summer peak period is also modeled.

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 the summer, these values are de-rated accordingly.

F.4 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).

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; in New Brunswick enough storage is available for full rated capability during daily peak load periods. In Nova Scotia, hydro resources are assumed to have an effective load carrying capability of 95% based on a LOLE analysis.

F.5 Solar

New England

Most of the solar resource development in New England is the state-sponsored distributed Behind-the-Meter (BTM) PV that does not participate in wholesale markets but reduces the system load observed by ISO New England. The BTM PV are modeled as a load modifier on an hourly basis, based on the 2002 historical hourly weather profile.

New York

New York provides 8,760 hours of historical solar profiles for each year of the most recent five-year calendar period for each solar plant based on production data. 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.

Ontario

Historical hourly profiles are used to model solar generation.

Québec

The actual solar installed capacity is estimated at approximately 10 MW and does not affect the load monitored from a network perspective. For the summer period, solar power generation is derated by 100 percent.

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.

F.6 Wind

New England

New England models the wind resources using the Seasonal Claimed Capability as determined based on their median net real power output during Reliability Hours (hours ending 14:00 – 18:00).

New York

New York provides 8,760 hours of historical wind profiles for each year of the most recent 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

Historical hourly load profiles are used to model wind generation.

Québec

Wind capacity credit is set for the wintertime as the system is winter peaking. Capacity credit of wind generation is based on a historical simulated data adjusted, with actual data of all wind plants in service in 2015. For the summer period, wind power generation is derated by 100 percent.

Maritimes

The Maritimes Area provides an hourly historical wind profile for each of its four sub-areas based on actual wind shapes for the period from 2012 through 2019. 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.

F.7 Demand Response

New England

The energy efficiency programs are expected to provide 1,775 MW of load relief during the peak hours. 560 MW of active demand capacity resources participate in the ISO New England capacity market and are offered into the energy market on a daily basis 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

The Installed Capacity (ICAP) Special Case Resource program allows demand resources that meet certification requirements to offer Unforced Capacity ("UCAP') to Load Serving Entities. The load reduction capability of Special Case Resources ("SCRs") may be sold in the ICAP Market just like any other ICAP Resource; however, SCRs participate through Responsible Interface Parties, which serve as the interface between the NYISO and the resources. Responsible Interface Parties also act as aggregators of SCRs. SCRs that have sold ICAP are obligated to reduce their system load when called upon by the New York ISO with two or more hours notice, provided the NYISO notifies the Responsible Interface Party a day ahead of the possibility of such a call. In addition, enrolled SCRs are subject to testing each Capability Period to verify their capability to achieve the amount of enrolled load reduction. Failure of an SCR to reduce load during an event or test results in a reduction in the amount of UCAP that can be sold in future periods and could result in penalties assessed to the applicable Responsible Interface Party in accordance with the ICAP/SCR program rules and procedures. Curtailments are called by the New York ISO when reserve shortages are anticipated or during other emergency operating conditions. Resources may register for either EDRP or ICAP/SCR but not both. In addition to capacity payments, Responsible Interface Parties are eligible for an energy payment during an event, using the same calculation methodology as EDRP resources.

SCRs are modeled as an Operating Procedure step activated to minimize the probability of customer load disconnection. The MARS program models the New York ISO operations practice of only activating operating procedures in zones from which are capable of being delivered.

For this study, 1281 MW of SCRs were modeled based on registrations. At the time of the summer peak, this amount was discounted to 896.5 MW based on historical availability.

Ontario

The demand measures assumed are up to 799 MW for the summer period.

Québec

No demand response is expected for the summer period.

Maritimes

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

APPENDIX G

PREVIOUS SUMMER REVIEW

Weather

Highlights - (June - August 2023) [113]

The meteorological summer (June-August) average temperature for the contiguous U.S. was 73.0°F, 1.6°F above average, ranking 15th warmest on record. Temperatures were above average across much of the West and in parts of the Upper Midwest, Southern Plains, Northeast and along the Gulf of Mexico and East Coast. Temperatures were below average in parts of the west-central Plains, Ohio Valley, and Southeast. Louisiana ranked warmest on record, while Texas and Florida each ranked second warmest for this summer season. Four additional states ranked among their top-10 warmest on record for this period.

The contiguous U.S. average maximum (daytime) temperature during June-August was 85.7°F, 1.3°F above the 20th century average, ranking in the warmest third of the historical record. Daytime temperatures were above average across much of the southern U.S. and eastern Plains, and from the Northwest to the Great Lakes and in small pockets across the Mid-Atlantic. Near- to below-average temperatures were observed across much of the Great Basin, Ohio and Tennessee valleys and Northeast, and in parts of the northern Rockies, western Plains and Southeast. Louisiana ranked warmest on record while Texas ranked second warmest, with four additional states experiencing a top-10 warmest June-August for daytime temperatures.

The contiguous U.S. average minimum (nighttime) temperature during this three-month period was 60.3°F, 1.9°F above the 20th century average, ranking 10th warmest in the historical record. Above-average nighttime temperatures were observed across much of the U.S., while near- to below-normal temperatures were observed in much of the Ohio Valley and in parts of the Southwest, central Plains, Upper Midwest, and Southeast. Louisiana, Florida, and Maine ranked second warmest on record, while Texas, Vermont and New Hampshire ranked third warmest on record for nighttime temperatures. Eight additional states ranked among their top-10 warmest June-August during this summer season.

Based on REDTI, the contiguous U.S. temperature-related energy demand during June-August was 184 percent of average and was the 12th-highest value on record.

The contiguous U.S. summer precipitation total was 8.35 inches, 0.03 inch above average, ranking in the middle third of the June-August record.

Precipitation was above average across much of California, the interior West and Northeast, and in parts of the central to northern Plains, Ohio Valley, and Southeast. Wyoming, Vermont, and New Hampshire each ranked wettest on record, while five additional states ranked among their top-10 wettest during the June–August period.

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[113] See: https://www.ncdc.noaa.gov/sotc/national/202308.

The U.S. Climate Extremes Index (USCEI) for the summer period was 11 percent above average, ranking in the upper third of the 114-year period of record.

On the regional scale, the Northeast, Southeast, Northwest, and Southwest ranked above average while the South ranked much-above average for this June-August period. Each of these regions experienced elevated extremes in warm minimum temperatures while the Northwest, Southwest, South and Southeast experienced elevated extremes in warm maximum temperatures. In addition, the Northeast saw extremes in days with precipitation and wet PDSI, while the Southeast had elevated 1-day precipitation extremes and the Northwest and Southwest experienced elevated extremes in days with precipitation. Conversely, the Ohio Valley and Upper Midwest were 78 percent and 68 percent below average, each ranking as their sixth lowest summer period on record, respectively.

Northeast Region

June [114]

June was consistently cool across the Northeast and featured variable amounts of precipitation, as well as multiple rounds of reduced air quality.

The Northeast's average temperature for June was 63.7 degrees F, 1.8 degrees F cooler than normal. All twelve Northeast states wrapped up June on the cool side of normal, with average temperatures ranging from 4.0 degrees F below normal in West Virginia, its ninth coolest June since 1895, to 0.4 degrees F below normal in Vermont.

June precipitation in the Northeast totaled 4.46 inches, 101 percent of normal. For the 12 Northeast states, precipitation ranged from 59 percent of normal in Connecticut to 156 percent of normal in Maine. This June ranked as West Virginia's 17th driest on record but among the 20 wettest Junes for three states: Maine, seventh wettest; New Hampshire, 13th wettest; and Vermont, 17th wettest.

The U.S. Drought Monitor from June 6 showed 20 percent of the Northeast in moderate drought and 47 percent as abnormally dry. During the first three weeks of June, drought and abnormally dry conditions generally persisted or deteriorated in many parts of the Northeast. Severe drought was introduced in south-central Pennsylvania and central Maryland, while moderate drought and/or abnormal dryness expanded in West Virginia, Maryland, Pennsylvania, New Jersey, New York, and Connecticut. This was due to increasing precipitation deficits, low streamflow, below-normal groundwater levels, declining soil moisture, and impacts on agriculture and water resources. The main exception was northern New England, which saw some improvement due to abundant rain. During the last week of the month, locally heavy rainfall chipped away at drought and dryness across much of the region, with drought and/or abnormal dryness contracting in the Mid-Atlantic states and New York. The U.S. Drought Monitor from June 27 showed 1 percent of the Northeast in severe drought, 24 percent in moderate drought, and 40 percent as abnormally dry.

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[114] NOAA National Centers for Environmental Information, Monthly National Climate Report for June 2023, published online July 2023, retrieved on March 18, 2024 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202306

The first two days of June featured highs in the 90s in northern areas, allowing a few sites to have one of their 10 warmest June temperatures on record. The weather pattern from around June 3 to 10 featured a stalled upper-level low pressure system near northern New England and a high-pressure system over the central U.S., producing northerly winds over much of the Northeast and ushering cooler-than-normal air and thick smoke from wildfires burning in the province of Quebec Canada. Air Quality Alerts were in place for several days as the air smelled of smoke. The air quality index, which ranges from 1 to 500, reached 151 (unhealthy), 201 (very unhealthy), or even 301 (hazardous) in most Northeast states, with some locations approaching 500. Multiple locations had their poorest air quality since Environmental Protection Agency records began in 1999 including New York City. Visibilities were reduced to as little as a half-mile at times, leading to flight delays and, in some cases, temporary ground stops at major airports such Newark, LaGuardia, Kennedy, and Philadelphia. Major sporting events and outdoor activities were cancelled, while outdoor spaces such as zoos and parks were closed in some areas. Daily high temperatures were slightly cooler due to the thick smoke.

There were generally limited opportunities for meaningful rainfall during this period; however, enough rain fell on June 8 to end Binghamton, New York's driest 30-day period on record: 0.04 inches of precipitation from May 21 to June 7. Closer to the upper low, Maine was mostly spared from the worst of the poor air quality but saw numerous showers and cool temperatures. For instance, Caribou, Maine, had its longest streak of June days with a high less than 60 degrees F with seven such days from June 3 to 9. Parts of the Northeast saw additional rounds of wildfire smoke, mostly aloft, through mid-month. June wrapped up as it began—with a significant amount of wildfire smoke pouring into the region. While not as intense as the early-June event, air quality between June 28 and 30 reached unhealthy levels in multiple states and very unhealthy levels in Pennsylvania. Smoke hung in the air, reducing visibilities, leading to closures of things such as pools and camps, and sending outdoor activities inside. While the wildfire smoke was likely the biggest story of the month, there were a few other notable events. Several rounds of severe storms, on June 12, June 16, and from June 25 to 27, produced small hail and downed trees and wires in multiple parts of the region.

July [115]

July was a warm, wet month for the Northeast, with near-daily severe weather and several devastating flash flooding events.

The Northeast had its seventh warmest July since records began in 1895 with an average temperature of 72.5 degrees F, 2.3 degrees F above normal. State average temperature departures for July ranged from 0.7 degrees F above normal in West Virginia to 4.4 degrees F

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[115] NOAA National Centers for Environmental Information, Monthly National Climate Report for July 2023, published online August 2023, retrieved on March 18, 2024 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202307

above normal in Maine. This July ranked as the warmest on record for Maine and among the 10 warmest Julys for nine additional states: New Hampshire, second warmest; Connecticut, Massachusetts, and Vermont, third warmest; Delaware, fourth warmest; New York, sixth warmest; Rhode Island, seventh warmest; Maryland, eighth warmest; and New Jersey, 10th warmest. Caribou, Maine, experienced its all-time warmest month on record this July with an average temperature of 71.5 degrees F, beating the old record of 70.9 degrees F set in 2018.

It was the fourth wettest July since recordkeeping began for the Northeast, which picked up 6.14 inches of precipitation, 141 percent of normal. July precipitation for the 12 Northeast states ranged from 101 percent of normal in West Virginia to 250 percent of normal in Connecticut. This July ranked among the 20 wettest Julys on record for nine states: Connecticut and Vermont, second wettest; Rhode Island, third wettest; Massachusetts and New Hampshire, fourth wettest; New York, ninth wettest; Pennsylvania, 12th wettest; Delaware, 14th wettest; and Maine, 19th wettest. Hartford, Connecticut, had its wettest July on record with 13.93 inches of precipitation, surpassing the old record of 11.24 inches from 1938. Similarly, Albany, New York, had a record wet July with 10.70 inches of precipitation, besting the old record of 9.91 inches from 2009.

The U.S. Drought Monitor from July 4 showed 1 percent of the Northeast in severe drought, 19 percent in moderate drought, and 41 percent as abnormally dry. Multiple parts of the Northeast saw excessively wet conditions during July, alleviating drought, and dryness but also, in some locations, causing flash flooding. Severe drought eased in south-central Pennsylvania and shrank in coverage in central Maryland. Meanwhile, moderate drought was erased from Vermont, Connecticut and contracted in New York, Pennsylvania, New Jersey, Maryland, and West Virginia. Additionally, abnormal dryness eased in Vermont, Massachusetts, and Delaware, and contracted in the rest of the Northeast. The U.S. Drought Monitor from August 1 showed 1 percent of the Northeast in severe drought, 3 percent in moderate drought, and 11 percent as abnormally dry. Heavy rain during July boosted streamflow for most areas. The main exceptions were parts of eastern West Virginia, central Maryland, south-central Pennsylvania, and western New York, which generally saw less precipitation and continued to report below-normal flows.

Multiple Air Quality Alerts were issued in July, particularly on July 17 and 18 when a plume of smoke, this time from wildfires burning in western Canada, reduced air quality and produced hazy skies in the Northeast. Air quality reached unhealthy levels in several areas including parts of Pennsylvania and New York. Severe thunderstorms and/or flooding affected the Northeast almost every day during July. Data from the Iowa Environmental Mesonet shows that a few National Weather Service offices including those in Philadelphia, Pennsylvania; New York, New York; and Burlington, Vermont, issued their greatest number of flash flood warnings for any month since records began in the mid-1980s. Several states saw significant flood damage ranging from destroyed roads to hundreds of uninhabitable homes to complete losses of thousands of acres of crops. Damage assessments are ongoing; however, some very preliminary data indicates losses in the millions for multiple areas.

On July 4, flash flooding targeted southern New England where vehicles became stuck in floodwaters, requiring water rescues of some occupants. A series of downbursts produced widespread wind damage in parts of western New Jersey. Numerous trees were felled, which downed power lines, blocked roads, and damaged homes. On July 9 and 10 extreme rainfall of over 5 inches inundated several locations in an area stretching from southeastern Pennsylvania to Vermont and western New Hampshire. Two areas in particular, the state of Vermont and New York's Hudson Valley, saw some of the heaviest rain, between 5 and 9 inches. A CoCoRaHS site near Middlesex, Vermont, saw 8.03 inches of rain in two days, qualifying as a 500-year storm event, with a 0.2 percent chance of occurring in a given year. Preliminary data indicates that Middlesex's two-day rainfall total was the greatest two-day rainfall for July in Vermont, with several other CoCoRaHS sites rounding out the top 10. Meanwhile, the National Weather Service COOP site in West Point, New York, saw 9.50 inches of rain in a day, a 200-year storm event with a 0.5 percent chance of occurring in a given year. That single day rainfall amount was more than the site typically sees in all of June and July combined. Preliminary data indicates that West Point's rainfall for July 10 ranks as the greatest daily rainfall total for July in New York, with another COOP, Shrub Oak, having the fifth greatest. Both Vermont and southeastern New York saw devastating flooding, with a rare Flash Flood Emergency issued for a few areas, signifying a dangerous, life-threatening situation. Several waterways in Vermont reached major flood stage, with water levels at a few locations reaching five highest on record. For instance, preliminary data shows that the Winooski River at Montpelier crested at 21.35 feet, its second highest level since records began in the early 1900s. The Lamoille River at Johnson and Otter Creek at Rutland reached similar milestones. There were significant flooding impacts in Vermont and southeastern New York. Floodwaters inundated roads and buildings, trapping people, with over 100 rescues in Vermont. A few Vermont roads remained closed for more than three weeks, with chunks of some roads washed away. Due to potential contamination of municipal and private water supplies from floodwaters, multiple Vermont communities issued boil water advisories and residents were advised to have well water tested before consuming. Vermont officials also advised people to stay out of bodies of water due to possible contamination from things like sewage and chemicals, as well as various flooding-related hazards such as strong undercurrents or unseen debris below the surface. Notable flooding and impacts also occurred in other areas that saw extreme rainfall or were downstream from those areas including eastern Pennsylvania, western Connecticut, and western Massachusetts. Dozens of beaches in New England, most in Massachusetts, were closed due to unsafe water quality caused by high levels of bacteria. Heavy rain runoff causing sewers to overflow is likely to have contributed.

On July 15 and 16 with wet antecedent conditions and heavy rainfall, multiple parts of the Northeast were primed for flash flooding. Between 4 and 8 inches of rain fell in portions of eastern Pennsylvania, where floodwaters swept away vehicles resulting in at least five deaths. 5.23 inches of rain fell in two hours on New York's Long Island, easily surpassing a 200-year storm event and leading to multiple impassable roads and stranded vehicles. Islip, on Long Island, saw 4.65 inches of rain, its wettest July day since 1963. In rain-soaked Vermont, an additional 4 inches of rain caused a mudslide that destroyed a house and caused several others to be evacuated. In New Hampshire, where as much as 6.50 inches of rain fell, more than 125 roads maintained by state or local governments sustained major damage, with chunks of roads washed away. Officials in that state warned residents that floodwaters could have contaminated wells and that swimming areas could have higher levels of bacteria due to runoff from heavy rain. Additionally, an EF-0 tornado caused tree damage in Worcester County, Massachusetts.

On July 21 and 24, there were several reports of straight-line winds causing damage in parts of New York, Pennsylvania, and West Virginia. For instance, a microburst with winds of up to 100 mph destroyed two barns and uprooted trees in central New York, while a microburst winds of up of to 70 mph downed trees which fell onto cars in Brooklyn, New York.

Additionally, there was a report of tennis ball-sized hail (2 inches) in Warren County, Pennsylvania, the county's largest hailstone since 1985.

August [116]

Much of the Northeast experienced a cool, soggy August, which also featured a notable amount of severe weather.

The Northeast's average temperature for August was 67.7 degrees F, 1.0-degree F cooler than normal. For the 12 Northeast states, average temperatures for August ranged from 1.4 degrees F below normal in Maine and New York to 0.5 above normal in Maryland, with 10 states being cooler than normal. The region's summer average temperature was 67.8 degrees F, 0.3 degrees F cooler than normal. State average temperatures for summer ranged from 1.3 degrees F below normal in West Virginia to 0.5 degrees F above normal in Maine and Vermont, with seven states being cooler than normal. Summer 2023 ranked as the 20th warmest summer since records began in 1895 for Maine and Massachusetts.

The Northeast had its 12th wettest August on record, picking up 5.25 inches of precipitation, 130 percent of normal. State precipitation totals for August ranged from 56 percent of normal in Delaware to 171 percent of normal in Maine, with nine of the 12 states being wetter than normal. This August was among the 20 wettest Augusts for four states: Maine, fourth wettest; New York, eighth wettest; Vermont, ninth wettest; and New Hampshire, 11th warmest. The Northeast had its third wettest summer since recordkeeping began with 16.26 inches of precipitation, 127 percent of normal. Nine of the 12 states were wetter than normal, with precipitation ranging from 89 percent of normal in Maryland to 160 percent of normal in New Hampshire. Summer 2023 was record wet in New Hampshire and Vermont and among the 20 wettest on record for six other states: Maine and Massachusetts, second wettest; New York, fourth wettest; Connecticut, ninth wettest; Rhode Island, 10th wettest; and Pennsylvania, 13th wettest. Albany, New York, had its wettest summer since records began in 1874 with 18.89 inches of precipitation, beating the old record for 18.51 from 2009.

The U.S. Drought Monitor from August 1 showed 1 percent of the Northeast in severe drought, 3 percent in moderate drought, and 11 percent as abnormally dry. Sufficient precipitation fell to allow drought and abnormal dryness to contract in multiple areas, particularly New York and the northern half of Pennsylvania. The U.S. Drought Monitor from August 29 showed 2 percent of the Northeast in moderate drought and 9 percent as abnormally dry.

On August 7 to 8, a widespread severe weather event unfolded across the region, with 14 tornadoes – six in New York (including one that traveled into New York from Pennsylvania), five in Pennsylvania, two in Massachusetts, and one each in New Jersey and West Virginia. All tornadoes were rated EF-0 or EF-1 except one. An EF-3 caused significant damage to buildings, trees, and a ski resort along a 16-mile path in Lewis County, New York, the county's strongest tornado since records began in 1950. There were also at least 15 distinct areas of notable straight-line wind damage, with winds of up to 110 mph. Storm reports for the tornadoes and straight-line winds noted snapped and uprooted trees that blocked roads and damaged homes, removal of shingles and broken windows, destroyed outbuildings, flattened corn fields, and power outages. Softball-sized (4 in.) hail was reported in Washington County, Maryland, while Preston

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[116] NOAA National Centers for Environmental Information, Monthly National Climate Report for August 2023, published online September 2023, retrieved on March 18, 2024 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202308

County, West Virginia, saw tennis ball-sized (2.5 in.) hail, each county's largest hailstone on record (since 1950. Additionally, some storms produced extreme rainfall. For instance, over 3.50 inches of rain in an hour led to significant flash flooding in Dorchester County, Maryland, where a rare Flash Flood Emergency, signifying a dangerous, life-threatening situation, was issued by the National Weather Service. Numerous roads were closed, with waist-deep water in some areas and multiple water rescues. Similarly, as much as 7 inches of rain in Onondaga County, New York, flooded buildings, shut down sections of major roads, led to water rescues, and caused part of a mall roof to collapse.

From August 12 to 13, another widespread severe weather event took place in the Northeast, with seven weak (EF-0 or EF-1) tornadoes - five in Pennsylvania and one each in New York and Connecticut. Straight-line winds of up to 90 mph were also noted in a handful of locations. The storms downed hundreds of trees and damaged roofs and outbuildings. Baseball-sized (3 in.) hail fell in Washington County, Pennsylvania, while lime-sized hail was reported in Piscataquis County, Maine, qualifying as each county's largest hailstone since records began in 1950.

On August 18, Southern New England was the focal point for severe weather. There were five tornadoes – three in Massachusetts and one each in Rhode Island and Connecticut. The strongest one was an EF-3, making it Rhode Island's strongest tornado since at least 1986. The tornadoes snapped or uprooted hundreds of trees, a few of which fell on homes rendering them uninhabitable.

During August, there were 30 confirmed tornadoes in the Northeast, seven times the region's August average of four tornadoes (based on 1998-2022 data). Several states also saw more tornadoes than usual this month including Pennsylvania, 12 tornadoes compared to an average of two; New York, seven tornadoes compared to an average of one; Massachusetts, five tornadoes compared to an average of zero; New Jersey, three tornadoes compared to an average of zero; Connecticut, two tornadoes compared to an average of zero. The Northeast's summer tornado count was 47, more than double its summer average of 21 tornadoes and approaching the annual average of 49 tornadoes (annual data based on 1998-2022). The summer tornado count breaks down as follows: 22 in Pennsylvania, seven each in Massachusetts and New York, five in New Jersey, two in Connecticut, and one each in Delaware, Vermont, New Hampshire, Rhode Island, and West Virginia.

September [117]

September started with record warm temperatures and ended with record wet conditions.
The Northeast had its 10th warmest September since records began in 1895 with an average temperature of 63.5 degrees F, which was 1.9 degrees F above normal. Average temperatures for September in the 12 Northeast states ranged from 0.3 degrees F in West Virginia to 4.4 degrees F above normal in Maine. This September ranked among the 20 warmest Septembers on record for 10 states: Vermont, third warmest; Maine and New Hampshire, fourth warmest; Rhode Island, fifth warmest; Massachusetts, eighth warmest;

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[117] NOAA National Centers for Environmental Information, Monthly National Climate Report for September 2023, published online October 2023, retrieved on March 18, 2024 from https://www.ncei.noaa.gov/access/monitoring/monthly-report/national/202309

Connecticut, 10th warmest; New Jersey, 13th warmest; Delaware, 17th warmest; and Maryland and New York, 20th warmest. On September 6, Dulles Airport, Virginia, recorded a high of 100 degrees F, its hottest September temperature on record. On September 8, Islip, New York, and Caribou, Maine, had their warmest low temperatures on record for September at 77 degrees F and 67 degrees F, respectively.
The Northeast received 4.04 inches of precipitation during September, which was 100 percent of normal. September precipitation for the 12 Northeast states ranged from 71 percent of normal in West Virginia to 215 percent of normal in Connecticut, with eight states being wetter than normal. This September ranked among the 20 wettest on record for five states: Connecticut, fourth wettest; New Jersey, ninth wettest; Delaware, 14th wettest; Rhode Island, 18th wettest; and Massachusetts, 20th wettest. Kennedy Airport, New York, experienced its wettest September on record with 13.01 inches of precipitation, beating the old record of 9.65 inches set in 1975. Much of this precipitation fell on September 29, which became Kennedy Airport's all-time wettest day for any month on record with 8.05 inches of rain. Similarly, LaGuardia Airport, New York, also had its wettest September on record with 12.76 inches of precipitation, surpassing its old record of 10.28 inches from 2004.

The U.S. Drought Monitor from September 5th showed 2 percent of the Northeast in moderate drought and 5 percent as abnormally dry. Interior parts of the Northeast including western West Virginia, western Pennsylvania, and western New York saw increasing precipitation deficits, below-normal streamflow, and declining soil moisture, leading to the expansion of abnormal dryness. However, heavy precipitation, particularly in late September, chipped away at drought and dryness in the Mid-Atlantic. The U.S. Drought Monitor from September 26th showed 1 percent of the Northeast in moderate drought and 10 percent as abnormally dry. At times during September, USGS 7-day average streamflow and/or groundwater levels were below normal or lower for western New York, northwestern Pennsylvania, and an area stretching from eastern West Virginia into southern New Jersey, with a couple of gauges reporting record low flows or levels.

The first 10 days of September were unusually mild, with highs ranging from 80 degrees F to 100 degrees F and lows in the 60s and 70s. Dulles Airport, Virginia, saw its hottest September temperature on record, while Islip, New York, and Caribou, Maine, had record warm low temperatures for September. The high and/or low temperatures at several other sites ranked among the 10 warmest for September, in some cases for multiple days.

On September 11th, the National Weather Service issued a Flash Flood Emergency for part of central Massachusetts due to significant flash flooding from 9.50 inches of rain. There were dozens of evacuations and water rescues as floodwaters swamped buildings and roads. Hundreds of homes were damaged in the event.

On September 13th, four weak tornadoes damaged trees and roofs in southern New England. From mid to late September, two tropical systems affected the Northeast. Hurricane Lee produced rough surf and rip currents along the East Coast from around September 13 to 16 as it traveled in the Atlantic Ocean toward eventual landfall in western Nova Scotia. The highest wind gusts ranged from 40 to 60 mph in coastal Massachusetts and Maine, which saw the greatest impacts. Downed trees and wires led to tens of thousands of power outages in Maine, including around 30 percent of customers in Washington County.

That county also saw the greatest rainfall totals of up to 6.50 inches, resulting in flooded roads and basements. One storm-related death and a few injuries were reported in Maine.

Tropical Storm Ophelia formed along the southeast U.S. coast on September 22nd and made landfall in North Carolina on September 23rd. Ophelia's remnants drifted south and merged with another storm, helping produce an extreme rainfall event that led to major flash flooding in the New York City metro area on September 29th. The greatest rainfall totals ranged from 4 to 9 inches, in some cases more than a month's worth of rain in a single day. Kennedy Airport, New York, picked up 8.05 inches of rain, making it the site's all-time wettest day since its records began in 1948 and qualifying as a 100-year storm event with a 1 percent chance of occurring in any given year. The rainfall pushed the airport's September total to 13.01 inches, which ranked as the wettest September and fourth all-time wettest month for the site. Central Park, New York, recorded 5.48 inches of rain, ranking as its ninth all-time wettest day since recordkeeping began in 1869. The site picked up 2.98 inches of that in two hours, which equates to a 25-year storm event with a 4 percent chance of occurring in any given year. Travel became nearly impossible as the rain flooded roadways including portions of major thoroughfares such as FDR Drive. Some motorists abandoned vehicles, while others became trapped, with dozens of water rescues reported. Bus service was suspended in some areas as dozens of buses got stuck in floodwaters, while around half of New York City's subway system was partially or fully shut down. Meanwhile, at LaGuardia Airport, floodwaters entered a terminal and swamped the refueling area, leading to flight delays and cancellations, and at Kenney Airport, flight delays topped 3 hours. Multiple buildings including basement apartments and at least 150 schools experienced flooding. Additionally, smoke from wildfires burning in Canada returned to the Northeast in late September and lingered into early October, producing hazy skies and, in some locations, reduced air quality.