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Northeast Power Coordinating Council

Reliability Assessment

For

Winter 2020-21

FINAL REPORT

Approved by the RCC

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Conducted by the

NPCC CO-12 & CP-8 Working Groups

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

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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 NPCC for the 2020-21 Winter Operating Period. Portions of this report are based on work previously completed for the NPCC Reliability Assessment for the Winter 2019-20 Operating Period[1]. This assessment is based on estimates of demand, resource and transmission project's availability reported for the winter December 2020 – March 2021 period as of November 2, 2020, and can serve as the basis to bracket plausible supply, demand an operational COVID-19 impacts.

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 as a chapter in this report and supporting documentation is provided in Appendix VIII.

The results of the CO-12 and CP-8 Working Groups' studies indicate that NPCC and the associated Balancing Authority Areas have adequate generation and transmission capabilities for the upcoming Winter Operating Period. Necessary strategies and procedures are in place to deal with operational problems 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.

Aspects that the CO-12 Working Group has examined to determine the reliability and adequacy of NPCC for the season are discussed in detail in the specific report sections. The following *Summary of Findings* addresses the significant points of the report discussion. These findings are based on projections of electric demand requirements, available supply resources and the most current transmission configurations. This report evaluates NPCC's and the associated Balancing Authority (BA) areas', ability to deal with the differing resource and transmission configurations within the NPCC region and the associated Balancing Authority areas' preparations to deal with the possible uncertainties identified within this report.

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

Summary of Findings

- The NPCC forecasted coincident peak demand[2] of 109,133 MW is anticipated to occur on the week beginning January 17, 2021 and is 30 MW less than the forecasted 2019-20 coincident peak of 109,163 MW. The capacity outlook indicates a forecasted coincident peak Net Margin of 20,640 MW (or 18.9%) in terms of the 109,133 MW forecasted peak demand. Unless otherwise noted, all forecasted demand is a normal (50/50) net peak forecast.
- The NPCC 2019-20 coincident winter peak demand of 103,969 MW occurred on December 19, 2019 at HE18 EST.
- The minimum percentage of forecasted Net Margin available to NPCC is 18.9%, for the week beginning January 17, 2021 and the maximum forecasted NPCC Net Margin of 44.4% occurs during the week beginning March 28, 2021.
- During the NPCC forecasted peak week of January 17, 2021, the Area forecasted Area Net Margins, in terms of normal forecasted demand, ranges from 4.8% in Québec to 41.0% in New York.
- When comparing the forecasted peak week from the previous winter (January 19, 2020) to this winter's expected peak week (January 17, 2021), the forecasted NPCC installed capacity has increased by 474 MW.
- The Maritimes area anticipates adequate resources to meet demand for the winter 2020-21 period. A normal winter 2020-21 peak demand of 5,621 MW has been forecasted for the week beginning January 31, 2021 with a projected net margin of 340 MW (6.1%). This winter peak demand forecast is 93 MW higher than the winter peak demand forecast of 2019-20 and is 286 MW higher than the actual peak of 5,335 MW for winter 2019-20.
- Under extreme peak demand and certain outage scenario conditions, planning and Emergency Operating Mitigations could be relied upon in the Maritimes. These could include, but are not limited to, use of interruptible load programs, curtailment of export energy sales, purchase of Emergency Energy from neighboring areas in accordance with Interconnection Agreements, reduction in 30-min Operating Reserve or public appeals.

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

- The Region continues to assess the impacts of the evolving COVID-19 pandemic to ensure a highly reliability and secure Northeastern North American Bulk Power System (BPS). Area-specific impacts and risks for Winter 2020-21, as well as operational and planning mitigations are detailed in Chapter 6 – Operational Readiness.
- New England is forecasting adequate resources to meet the normal peak demand for the 2020-21 winter period. A normal peak demand of 20,166 MW is forecast to occur for the week beginning January 10, 2021, with a projected net margin of 5,086 MW (25.2%). During the 2018-2019 Winter Operating Period, the Independent System Operator of New England (ISO-NE) implemented a periodic 21-Day Energy Assessment that was published to provide Market Participants with early indications of potential fuel scarcity conditions and help inform fuel procurement decisions. ISO-NE will continue to produce this assessment during the Winter 2020-2021 Operating Period. New England continues to survey fossil-fueled generators on a weekly basis in order to monitor and confirm their current and expected fuel availability throughout the 2020-2021 Winter Operating Period. If conditions require more frequent updates, these surveys may be sent daily. During this same period, ISO-NE also requests that all gas-fired generators confirm adequate gas supply and transportation nominations in order to meet their day-ahead obligations. Beginning October 1, 2020, the ISO-NE Day Ahead Market (DAM) bidding offer window closure was shifted from 10:00 to 10:30, based upon Market Participant feedback, to provide additional time for price discovery and competition in the natural gas commodity marketplace, along with increased coordination on the NY-NE interface considering New York Independent System Operator (NYISO) DAM results. During the 2020-2021 Winter Operating Period, ISO-NE will continue to participate in weekly NPCC conference calls to share information on current and forecast system operating conditions. ISO-NE will also continue to coordinate and communicate with the regional natural gas industry regarding planned outages, unplanned outages, and real-time operating conditions to promote the reliability of the Bulk Electric System (BES).
- The NYISO anticipates adequate resources to meet demand for the 2020-21 winter season. A capacity margin of 9,899 MW (41.0%) is expected for the normal demand forecast of 24,130 MW during the NPCC peak week of January 17, 2021. The normal demand forecast is the same as the previous year's forecast and 877 MW greater than the actual 2019-20 winter peak of 23,253 MW. The NYISO also conducted a loss of gas installed capacity assessment to determine the impact on operating margins should gas shortages arise. It found that 5,191 MW of gas fired

generation with non-firm supply are at risk. Should all of this capacity not be available during a peak load time, the projected operating margin would be reduced to 4,708 MW (19.5%).

- The IESO anticipates adequate resources to meet the Ontario demand for the 2020-21 Winter Operating Period. The forecasted Ontario winter peak is 20,837 MW for week beginning January 17, 2021 with a corresponding net margin of 3,070 MW (or 14.7%). This is the forecasted minimum Net Margin for the winter 2020-21 period. Ontario's 2019-20 winter peak demand was 20,974 MW, which was 141 MW lower than the peak forecast (21,115 MW) and occurred December 19, 2019. As part of an electricity trade agreement with Québec, in exchange for 500 MW of capacity in the winter months, Ontario will be receiving up to two terawatt hours of clean import energy annually to help reduce greenhouse gas over peak hours.
- The Québec Area anticipates adequate resources to meet demand for the winter 2020-21 season. The current 2020-21 normal peak forecast is 38,695 MW (30 MW higher than the demand forecast presented in the prior winter assessment) and the forecasted operating margin is 1,861 MW (4.8%) for the peak operating week. This decrease in demand is mainly attributed to lower peak demand for heating space use. An extreme forecast has also been evaluated and the projected Net Margin is 844 (2.1%). Compared to what was anticipated for winter 2019-20, the forecasted Installed Capacity is expected to have decreased by 211 MW by December 2020. If peak demands are higher than expected, a number of measures are available to the System Control personnel.
- Under Base Case conditions, only the Maritimes Area is expected to use their Operating Procedures (reducing 30-min reserve and initiating interruptible loads) designed to mitigate resource shortages, during the 2020-21 winter period and assuming the expected peak load forecast[3]. The conclusions of the CP-8 assessment are included as Chapter 9 in this report; the full report is included in Appendix VIII.

The results of the CO-12 and CP-8 Working Groups' studies indicate that NPCC and the associated Balancing Authority areas have adequate generation and transmission capabilities for the upcoming Winter Operating Period. Necessary strategies and procedures are in place to deal with operational problems and emergencies as they may develop. However, the resource and transmission assessments in this report are based

[3] The expected peak load level results were based on the probability-weighted average of the seven load levels simulated.

upon 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.

2. Introduction

The NPCC Task Force on Coordination of Operation (TFCO) established the CO-12 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 conditions as requested by the TFCO.

For the 2020-21 Winter Operating Period[4] the CO-12 Working Group:

- Examined historical winter 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.
- The NPCC CP-8 Working Group has done a probabilistic assessment of the implementation of operating procedures for the 2020-21 Winter Operating Period. The full CP-8 assessment report is included as Appendix VIII.
- Reported potential sensitivities that may impact resource adequacy on a Reliability Coordinator (RC) area basis. These sensitivities included 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 both normal and extreme forecasts while accounting for 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.

[4] For this report, the Winter Operating Period evaluation will include operating conditions from the week beginning November 29, 2020 through the week beginning March 28, 2021.

- Reviewed the evolving impacts and associated Area responses to the COVID-19 pandemic.
- Coordinated with other parallel, seasonal operational assessments, including the NERC Reliability Assessment Subcommittee (RAS) Seasonal Reliability Assessments.

3. Demand Forecasts for Winter 2020-21

The coincident forecasted peak demand for NPCC over the 2020-21 Winter Operating Period is 109,133 MW, which is expected during the week beginning January 17, 2021. The NPCC Winter 2019-20 coincident peak demand of 103,969 MW occurred on December 19, 2019 at HE18 EST. Demand and Capacity forecast summaries for NPCC, Maritimes, New England, New York, Ontario, and Québec are included in Appendix I.

Ambient temperatures and persistent winter conditions are important variables impacting the demand forecasts. However, unlike the summer demand forecasts, the non-coincident winter peak demand varies only slightly from the coincident peak forecast. This is mainly because the drivers that impact the peak demand are concentrated into a specific period in time. In winter, the peak demands are determined mainly by low temperatures along with the reduced hours of daylight that occur over the first few weeks of January. While the peak demands appear to be confined to a few weeks in January, each area is aware that reduced margins could occur during any week of the operating period as a result of weather variables and forecasted conditions.

In the operational planning time-frame, the impact of ambient weather conditions on load forecasts can be demonstrated by various means. The Maritimes and IESO represent the resulting load forecast uncertainty in their respective areas as a mathematical function of the base load. ISO-NE updates the Load Forecast 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 wind speed to the load response and increases the load by a MW factor for each degree below the base value. TransÉnergie, the Québec system operator, updates forecasts on an hourly basis within a 12 day horizon based on local weather, wind speed, cloud cover, sunlight incidence and type and intensity of precipitation over nine regions of the Québec Balancing Authority area.

The method each Reliability Coordinator area 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 area forecasts.

Summary of Reliability Coordinator Area Forecasts

Maritimes

Winter 2020-21 Forecasted Peak: 5,621 MW (normal) and 6,031 MW (extreme), week beginning January 31, 2021

Winter 2019-20 Forecasted Peak: 5,528 MW (normal) and 5,929 MW (extreme), week beginning January 5, 2020

Winter 2019-20 Actual Peak: 5,335 MW on February 21, 2020 at HE7 EST

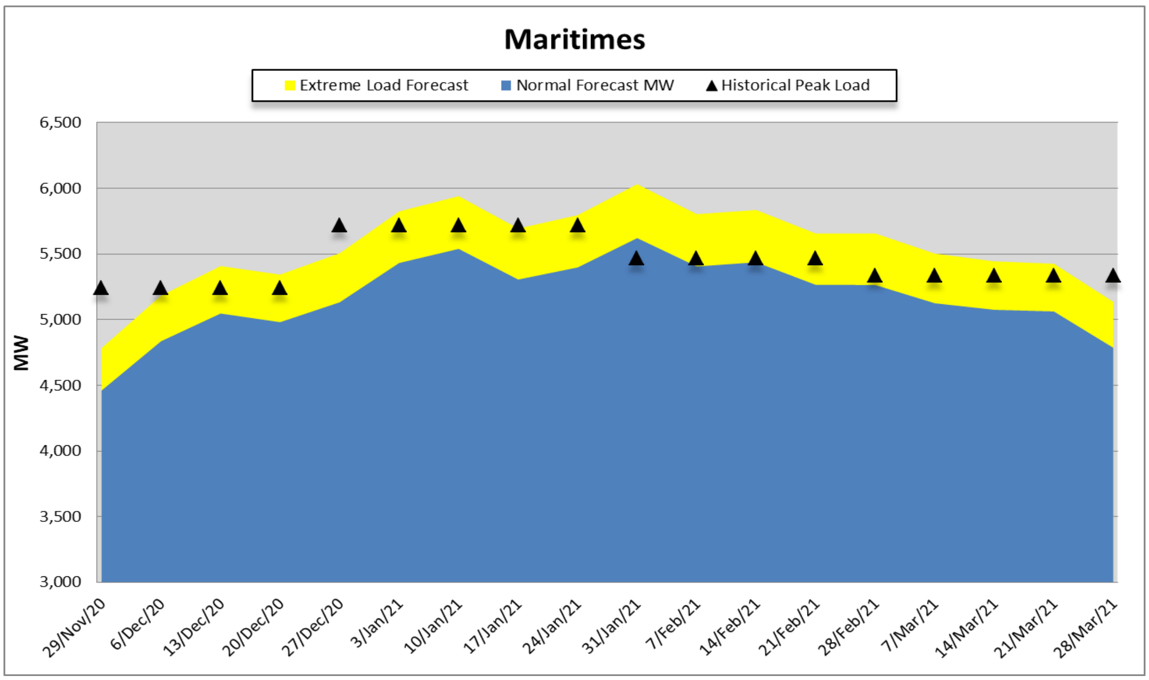


Figure 3-1: Maritimes Winter 2020-21 Weekly Demand Profile[5][6]

[5] The Maritimes Area Historical Peak Load profile data provided is based on the historical monthly peak.

[6] The Maritimes Area Historical Peak Load profile ranges from 2000-2019.

New England

Winter 2020-21 Forecasted Peak: 20,166 MW (normal) and 20,806 MW (extreme), weeks beginning January 3 - 17, 2020

Winter 2019-20 Forecasted Peak: 20,476 MW (normal) and 21,173 MW (extreme), weeks beginning January 5 - 19, 2019

Winter 2019-20 Actual Peak: 18,913 MW on December 19, 2019 at HE18 EST

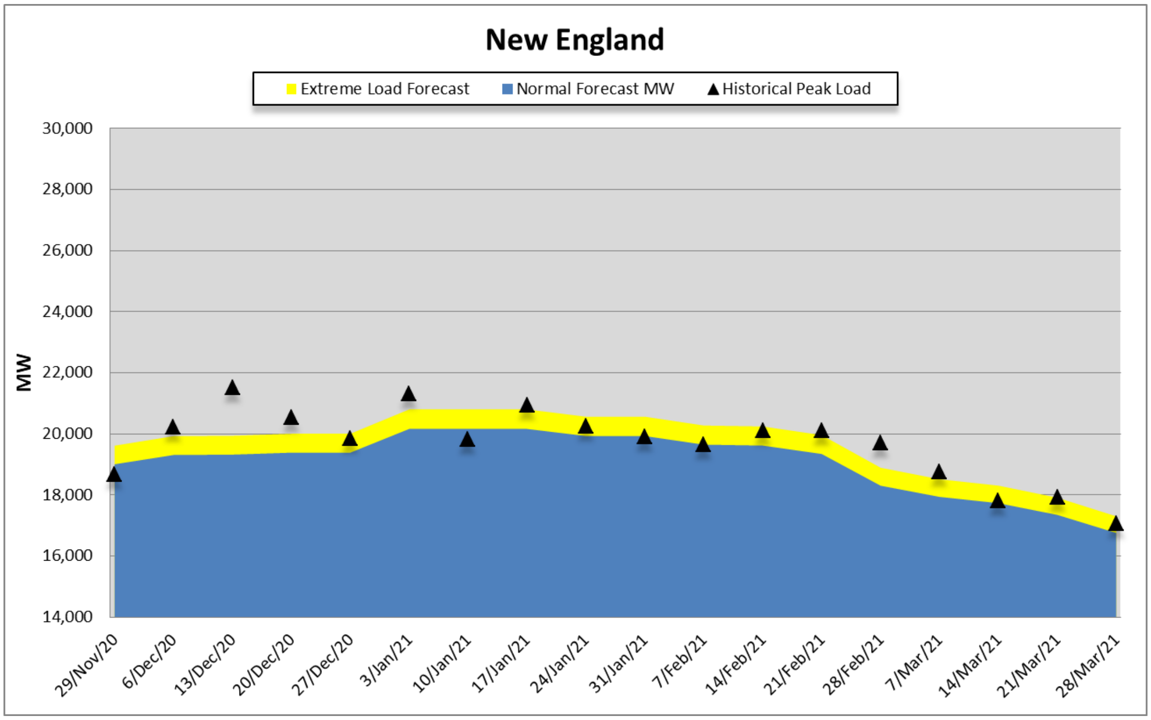


Figure 3-2: New England Winter 2020-21 Weekly Demand Profile[7][8]

[7] The winter Peak Load Exposure (PLE) period is three (3) weeks, starting from the first full week of January, not inclusive of the week with the New Year's holiday. The seasonal peak loads are projected in the annual ISO New England Capacity, Energy, Loads, and Transmission (CELT) Report. The forecasted 2020/2021 winter peak demand is during the weeks beginning January 3, 10, and 17, 2021.

[8] The New England Area Historical Peak Load profile ranges from 2012-2019.

New York

Winter 2020-21 Forecasted Peak: 24,130 MW (normal) and 25,459 MW (extreme) during the weeks of December 6, 2020 through February 21, 2021, although it is expected that the winter peak could occur at any time during the months of December through February.

Winter 2019-20 Forecasted Peak: 24,123 MW (normal) and 25,724 MW (extreme) during the months of December 2019 through February 2020

Winter 2019-20 Actual Peak: 23,253 MW on December 19, 2019 at HE18 EST

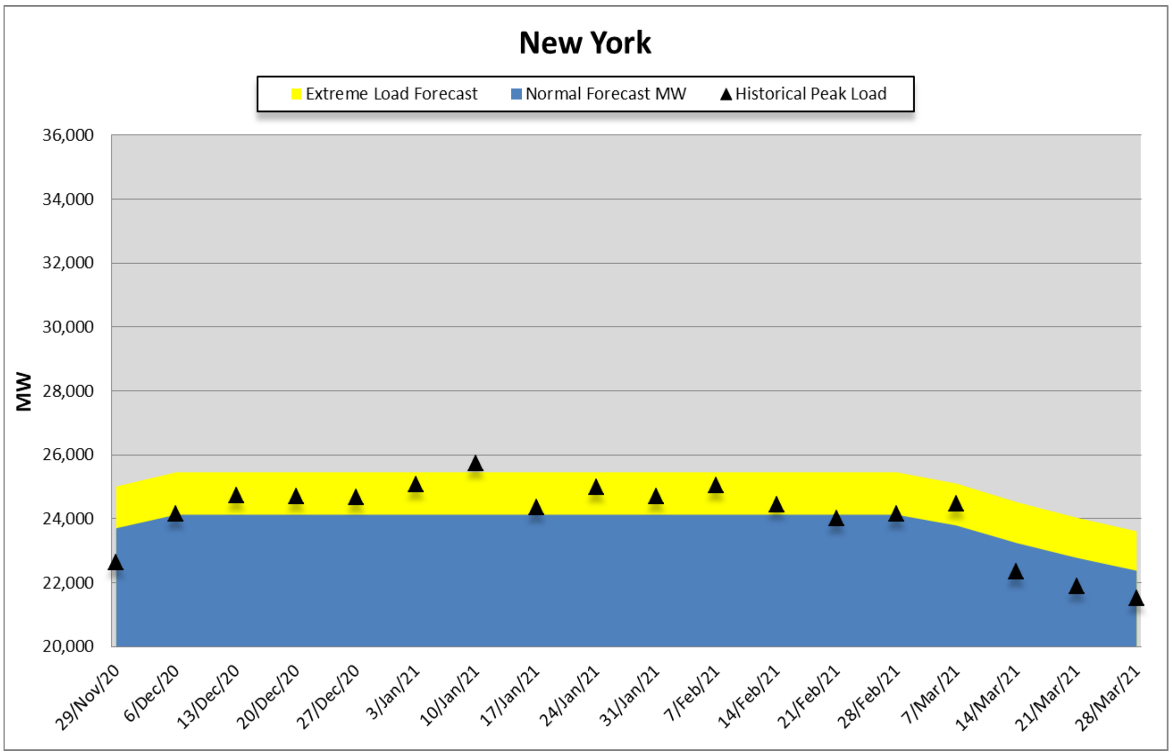


Figure 3-3: New York Winter 2020-21 Weekly Demand Profile[9]

[9] The New York Area Historical Peak Load profile ranges from 2006-2019.

Ontario

Winter 2020-21 Forecasted Peak: 20,837 MW (normal) and 22,543 MW (extreme), week of January 17, 2021

Winter 2019-20 Forecasted Peak: 21,115 MW (normal) and 22,288 MW (extreme), week of January 5, 2020

Winter 2019-20 Actual Peak: 20,974 MW, on December 19, 2019 at HE18 EST

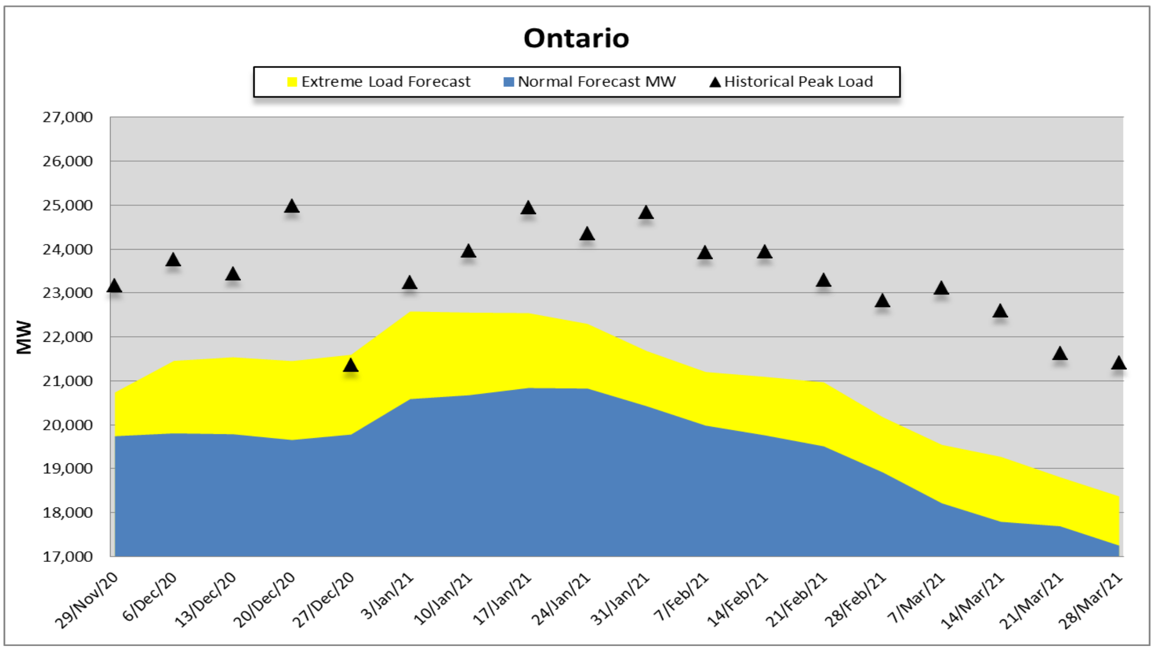


Figure 3-4: Ontario Winter 2020-21 Weekly Demand Profile[10]

[10] The Ontario Area Historical Peak Load profile ranges from 2002-2019.

Québec

Winter 2020-21 Forecasted Peak: 38,695 MW (normal) and 40,812 MW (extreme 90/10), week of January 17, 2021

Winter 2019-20 Forecasted Peak: 38,665 MW (normal) and 41,847 MW (extreme 94/6), week of January 19, 2020

Winter 2019-20 Actual Peak: 36,160 MW, on December 19, 2019 at HE19 EST.

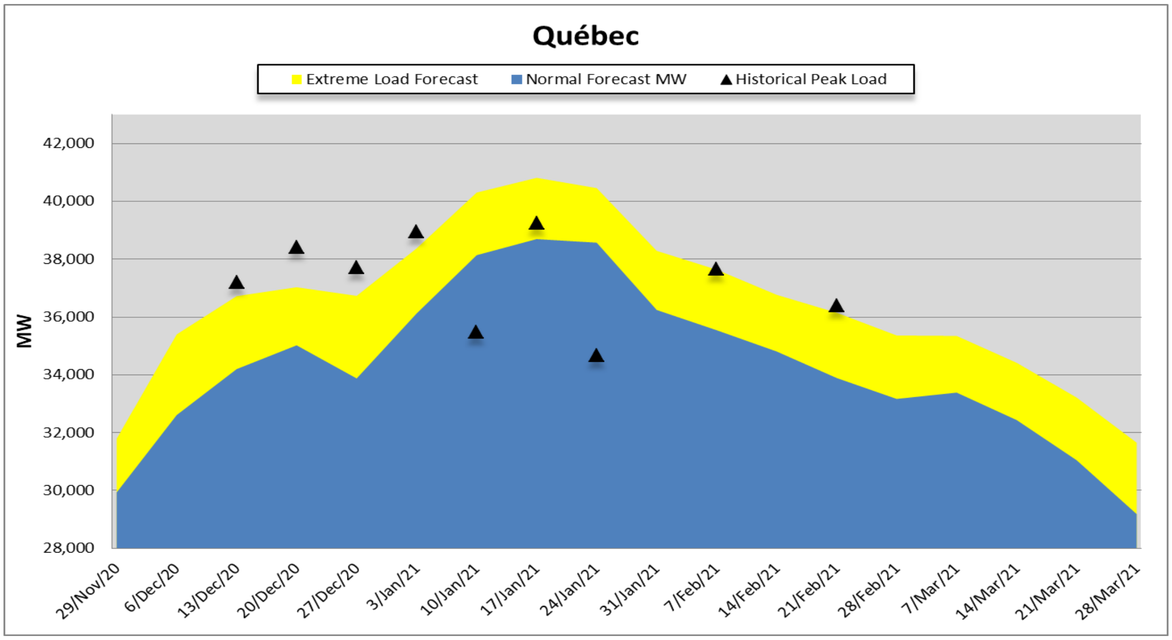


Figure 3-5: Québec Winter 2020-21 Weekly Demand Profile[11]

[11] The Quebec Area Historical Peak Load profile ranges from 2003-2019.

4. Resource Adequacy

NPCC Summary for Winter 2020-21

The assessment of resource adequacy indicates the week with the highest forecasted coincident NPCC demand is the week beginning January 17, 2021 (109,133 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** is the NPCC Load and Capacity summary for the 2020-21 Winter Operating Period. Appendix I, Tables **AP-2** through **AP-6**, contain the load and capacity summary for each NPCC Reliability Coordinator area. Each entry in Table **AP-1** is simply the aggregate of the corresponding entry for the five NPCC Reliability Coordinator areas.

Table 4-1 below summarizes the NPCC forecasted load and resource adequacy for the peak week beginning January 17, 2021 compared to the winter 2019-20 forecasted peak week beginning January 19, 2020.

Table 4-1: Resource Adequacy Comparison of Winter Forecasts

All values in MW	2020-21	2019-20	Difference
Installed Capacity	167,865	167,391	474
Net Interchange	302	1,169	-867
Dispatchable Demand-Side Management	2,158	2,355	-197
Total Capacity	**170,325**	**170,915**	**-590**
Demand	109,133	109,163	-30
Interruptible Load	2,691	2,377	314
Maintenance/De-rate	21,522	21,661	-139
Required Reserve	8,885	8,885	0
Unplanned Outages	12,835	12,851	-16
Net Margin	**20,640**	**20,732**	**-92**
Week Beginning	17-Jan-21	19-Jan-20	-

**Note: Net Interchange value offered as the summation of capacity backed imports and exports for the NPCC region.*

The revised Net Margin for the 2020-21 Winter Operating Period has decreased by 92 MW from the previous winter (2019-20).

The NPCC forecasted capacity outlook indicates a coincident peak Net Margin of 20,640 MW (18.9%) with respect to the 109,133 MW forecasted normal peak demand. When considering extreme coincident peak demand, the forecasted extreme Net Margin is 14,460 MW (12.5%).

The following sections detail the 2020-21 winter capacity analysis for each Reliability Coordinator Area.

Maritimes

The Maritimes Area declared Installed Capacity is scheduled to be available for the winter period; the Net Margins calculated include impacting factors such as wind, ambient temperature, and hydro flows that may derate generation and reflect expected out-of-service units. Imports into the Maritimes area are not included unless they have been confirmed as released capacity from their source. Therefore, unless additional forced generator outages were to occur, there would not be any further reduction in the net Installed Capacity. As part of the winter 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 4-2** conveys the Maritimes anticipated operable capacity margins for the normal and extreme winter peak load forecasts of the Winter Operating Period.

Table 4-2: Maritimes Operable Capacity for 2020-21

Winter 2020-21	Normal Forecast	Extreme Forecast
Installed Capacity (+)	**7,729**	**7,729**
Net Interchange (+)	43	43
Dispatchable Demand-Side Management (+)	0	0
Total Capacity	**7,771**	**7,771**
Interruptible Load (+)	293	293
Known Maintenance & Derates (-)	882	882
Operating Reserve Requirement (-)	893	893
Unplanned Outages (-)	328	328
Peak Load Forecast (-)	5,621	6,031
Net Margin (MW)	**340**	**-70**
Net Margin (%)	**6.1%**	**-1.2%**

If the Maritimes real-time peak demand becomes higher than forecasted, the System Operator may implement operating procedures to maintain system reliability, as outlined in the Maritimes section of Operational Readiness for winter 2020-21.

New England

To determine the region's capacity risks, ISO-NE assesses the difference between New England's installed capacity and operable capacity under normal load forecasts. Some of these factors include fuel deliverability risks for natural-gas-fired generation and the difference between a generator's seasonal claimed capability (SCC) value and its capacity supply obligation (CSO). The SCC is recognized as a generator's maximum output established through seasonal audits, whereas its CSO is its obligation to satisfy its share of New England's installed capacity requirement (ICR) by generating the megawatts that cleared through a Forward Capacity Auction (FCA) within the Forward Capacity Market. **Table 4-3** shows the variation in operable capacity margins for January 2021, recognizing these factors.

Table 4-3: New England Installed and Operable Capacity for Normal Forecast

Normal Load Forecast	Jan - 2021	Jan - 2021
	CSO	**SCC**
Operable Capacity + Non-commercial Capacity	30,478	33,711
Net Interchange (+)	1,025	1,025
Dispatchable Demand-Side Management (+)	533	381
Total Capacity	**32,036**	**35,117**
Peak Load Forecast	20,166	20,166
Interruptible Load (+)	0	0
Known Maintenance & Derates (-)	318	321
Operating Reserve Requirement (-)	2,305	2,305
Unplanned Outages and Gas at Risk (-)	6,687	7,239
Net Margin (MW)	**2,560**	**5,086**
Net Margin (%)	**12.7%**	**25.2%**

ISO-NE also compares the installed capacity with operable capacity under extreme load forecasts to further determine New England's capacity risks. This broadened approach helps identify potential capacity concerns for the upcoming capacity period and prepare for severe demand conditions. This analysis, shown in **Table 4-4** for January 2021, shows the further reduction in the operable capacity margin recognizing these factors. If forecasted extreme winter conditions materialize and generators do not achieve their SCC, New England may need to rely more heavily on import capabilities from neighboring areas, as well as implement emergency operating procedures to maintain system reliability.

Table 4-4: New England Installed and Operable Capacity for Extreme Forecast

Extreme Forecast	Jan - 2021	Jan - 2021
	CSO	SCC
Operable Capacity + Non-commercial Capacity	30,478	33,711
Net Interchange (+)	1,025	1,025
Dispatchable Demand-Side Management (+)	533	381
Total Capacity	**32,036**	**35,117**
Peak Load Forecast	20,806	20,806
Interruptible Load (+)	0	0
Known Maintenance & Derates (-)	318	321
Operating Reserve Requirement (-)	2,305	2,305
Unplanned Outages and Gas at Risk (-)	7,531	8,202
Net Margin (MW)	**1,076**	**3,483**
Net Margin (%)	**5.2%**	**16.7%**

New York

New York determines its operating margin by comparing the normal 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 are counted at nameplate for Installed Capacity and seasonal derates are applied. Net Interchange is based on projected capacity transactions external to the New York Control Area (NYCA). Dispatchable Demand-Side Management consists of Special Case Resources (SCRs) while Interruptible Load includes NYISO's Emergency Demand Response Program (EDRP). 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. Beginning November 2015, the NYISO started procuring operating reserve of two times the largest single generating source contingency (2,620 MW) to ensure compliance with a New York State Reliability Council (NYSRC) Rule. Unplanned Outages are based on expected availability of all thermal units and SCRs in the NYCA based on historic availability. Historic availability factors in all forced outages including those due to weather and availability of fuel. **Table 4-5** presents a conservative scenario comparing the normal and extreme operating margins for upcoming winter period.

The NYISO conducted a loss of gas installed capacity assessment to determine the impact on operating margins should gas shortages arise. It found that 5,191 MW of gas fired generation with non-firm supply are at risk. Should all of this capacity not be available during a peak load time, the projected operating margin would drop from 9,899 MW (41%) to 4,708 MW (19.5%).

Table 4-5: New York Operable Capacity Forecast

Winter 2020-21	Normal Forecast (MW)	Extreme Forecast (MW)
Installed Capacity (+)	40,943	40,943
Net Interchange (+)	496	496
Dispatchable Demand-Side Management (+)	839	839
Total Capacity	**42,278**	**42,278**
Interruptible Load (+)	13	13
Known Maintenance & Derates (-)	3,118	3,118
Operating Reserve Requirement (-)	2,620	2,620
Unplanned Outages (-)	2,524	2,524
Peak Load Forecast	24,130	25,459
Net Margin (MW)	**9,899**	**8,570**
Net Margin (%)	**41.0%**	**35.5%**

Ontario

Looking at the 2020-21 Winter Operating Period, considering existing and planned capacity coming in-service, the Ontario reserve requirement is met under both normal and extreme weather conditions, as indicated in **Table 4-6.**

Table 4-6: Ontario Operable Capacity Forecast

Winter 2020-21	Normal Forecast (MW)	Extreme Forecast (MW)
Installed Capacity (+)	39,004	39,004
Net Interchange (+)	-500	-500
Dispatchable Demand-Side Management (+)	688	688
Total Capacity	**39,192**	**39,192**
Known Maintenance & Derates (-)	12,301	12,301
Operating Reserve Requirement (-)	1,567	1,567
Unplanned Outages (-)	1,417	1,417
Peak Load Forecast	20,837	22,543
Net Margin (MW)	**3,070**	**1364**
Net Margin (%)	**14.7%**	**6.0%**

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 deratings, environmental and regulatory restrictions.

The results in **Table 4-7** indicate that occurrences of unserved energy are not expected over the winter 2020-21 period. Based on these results, it is anticipated that Ontario will be energy adequate for the normal weather scenario for the review period.

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

Month	Forecast Energy Production Capability (GWh)	Forecast Energy Demand (GWh)
Oct 2020	16,038	10,875
Nov 2020	16,140	11,195
Dec 2020	17,998	12,459
Jan 2021	17,731	13,187
Feb 2021	15,694	11,893
Mar 2021	16,495	11,863

Québec

The Québec area anticipates adequate resources to meet demand for the 2020-21 Winter Operating Period. The current 2020-21 peak forecast (normal) is 38,695 MW and the forecasted operating margin is 1,821 MW for the area peak week. This includes known maintenance and derates of 4,753 MW, including scheduled generator maintenance and wind generation derating. **Table 4-8** shows the factors included in the operating margin calculation. An extreme forecast scenario has also been evaluated and the margin anticipated is 844 MW.

Table 4-8: Québec Operable Capacity Forecasts

Winter 2020-21	Normal Forecast (MW)	Extreme Forecast (MW)
Installed Capacity	46,478	46,478
Net Interchange	-761	-761
Dispatchable Demand-Side Management (+)	250	250
Total Capacity	**45,967**	**45,967**
Interruptible Load (+)	2,342	2,342
Known Maintenance & Derates (-)	4,753	4,753
Operating Reserve Requirement (-)	1,500	1,500
Unplanned Outages (-)	1,500	1,500
Peak Load Forecast	38,695	40,812
Net Margin	**1,861**	**844**
Net Margin (%)	**4.8%**	**2.1%**

If Québec real-time peak demands are higher than forecasted, a number of measures are available to the System Control personnel and are listed in Chapter 6: Operational Readiness.

Québec'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 multiannual reservoirs (water reserves lasting more than one year). Due to the multi-year reservoirs, a single year of low water inflow cannot adversely impact the reliability of energy supply. However, a series of consecutive dry years may require some operating measures, such as the reduction of exports or capacity purchase 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 (2) consecutive years of low water inflows totalling 64 TWh, or a sequence of four (4) years totalling 98 TWh, and having a 2% probability of occurrence. The use of operating measures and the hydro reservoirs will 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.[12]

[12] http://www.regie-energie.qc.ca/audiences/TermElecDistrPlansAppro_Suivis.html

Projected Capacity Analysis by Reliability Coordinator Area

The table below summarizes projected capacity and margins by Reliability Coordinator area. Appendix I shows these projections for the entire Winter Operating Period, respecting normal demand forecasts.

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

Area	Measure	Week Beginning Sundays	Installed Capacity MW	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	Load Forecast MW	Interruptible Load MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW
NPCC	NPCC Peak Week	17-Jan-21	167,865	302	2,158	170,325	109,133	2,691	21,522	8,885	12,835	20,640
Maritimes	Peak Week	31-Jan-21	7,729	43	0	7,771	5,621	293	882	893	328	397
	Lowest Net Margin	10-Jan-21	7,729	42	0	7,771	5,539	242	981	893	328	329
	NPCC Peak Week	17-Jan-21	7,729	42	0	7,771	5,305	336	981	893	328	657
New England	Peak Week	17-Jan-21	33,711	1,025	381	35,117	20,166	0	369	2,305	7,066	5,211
	Lowest Net Margin	3-Jan-21	33,711	1,025	381	35,117	20,166	0	321	2,305	7,244	5,081
	NPCC Peak Week	17-Jan-21	33,711	1,025	381	35,117	20,166	0	369	2,305	7,066	5,211
New York	Peak Week	17-Jan-21	40,943	496	839	42,278	24,130	13	3,118	2,620	2,524	9,899
	Lowest Net Margin	7-Mar-21	40,943	496	839	42,278	23,793	13	4,051	2,620	2,462	9,365
	NPCC Peak Week	17-Jan-21	40,943	496	839	42,278	24,130	13	3,118	2,620	2,524	9,899
Ontario	Peak Week	17-Jan-21	39,004	-500	688	39,192	20,837	0	12,301	1,567	1,417	3,070
	Lowest Net Margin	7-Feb-21	39,004	-500	716	39,220	19,981	0	13,247	1,401	1,569	3,022
	NPCC Peak Week	17-Jan-21	39,004	-500	688	39,192	20,837	0	12,301	1,567	1,417	3,070
Québec	Peak Week	17-Jan-21	46,478	-761	250	45,967	38,695	2,342	4,753	1,500	1,500	1,861
	Lowest Net Margin	17-Jan-21	46,478	-761	250	45,967	38,695	2,342	4,753	1,500	1,500	1,861
	NPCC Peak Week	17-Jan-21	46,478	-761	250	45,967	38,695	2,342	4,753	1,500	1,500	1,861

Generation Resource Changes through Winter 2020-21

The following table lists the recent and anticipated generation resource additions, commissioning delays and retirements. Generation adjustments may be reflected as an increase or decrease in MW output, recognizing changes due to mechanical, environmental or performance audits.

Table 4-10: Resource Changes from Winter 2019-20 through Winter 2020-21

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/Retirement Date
Maritimes	Wocawson Energy Project	18	Wind	Q4 2020
	ReEnergy	-37	Biomass	Q4 2019
	Net Total	**-19**		
New England	Yarmouth 1 & 2	-118	Oil	Q1 2020
	Ipswich Diesels	-12	Oil	Q3 2020
	Sanford Solar	61	Solar	Q4 2020
	Weaver Wind	73	Wind	Q4 2020
	Solar Projects (various)	62	Solar	Q2-Q4 2020
	Seasonal Adjustments	+115		
	Net Total	**181**		
New York	Cricket Valley	1177.2	Natural Gas	Q1 2020
	Indian Point 2	-1299	Nuclear	Q2 2020
	Somerset	-655.1	Coal	Q1 2020
	Cassadaga Wind	126	Wind	Q4 2020
	West Babylon 4	-52.4	Oil	Q4 2020
	Seasonal ICAP Adjustments	-168.7		
	Net Total	**-872**		
Ontario	Henvey Inlet Wind Farm	300	Wind	Q4 2020
	Romney Wind Energy Center	60	Wind	Q4 2020
	Napanee Generating Station	985	Gas	Q1 2020
	Calstock (expiring contract)	-38	Biofuel	Q4 2020
	Seasonal Adjustments	88		

Area	Generation Facility	Nameplate Capacity (MW)	Fuel Type	In Service/Retirement Date
Quebec	**Net Totals**	**1,395**		
	Saint-Narcisse	-17.4	Hydro	Q4-2020
	Mitis	-4.8	Hydro	Q4-2020
	Sept-Chutes	-21.6	Hydro	Q4-2020
	Chutes Hemmings	-27.3	Hydro	Q4-2020
	Drummondville	-13.0	Hydro	Q4-2020
	Grand-Mère	-66.0	Hydro	Q4-2020
	Biomass addition	24.2	Biomass	Q4-2020
	IREQ	1.5	Solar	Q4-2020
	La Citière	8	Solar	Q4-2020
	Nordais Matane	-57	Wind	Q4-2020
	Nordais Cap-Chat	-42.8	Wind	Q4-2020
	Adjustments Wind	-7.8	Wind	Q4-2020
	Adjustments Hydro	12.6	Hydro	Q4-2020
	Total additions	**46.3**		
	Total retirements	**-257.7**		
	Net Change	**-211.4**		

Maritimes

Since the 2019-20 Winter Operating Period, there has been a net decrease of 19 MW of installed capacity in the Maritimes. Scheduled to be put in service by early November 2020 is a new 18 MW Wocawson wind facility in New Brunswick. However, with the retirement of hydro and diesel/oil fired units in Northern Maine during the 2020-21 winter operating period, the net total is a 19 MW decrease.

New England

Since the 2019-20 Winter assessment period, ISO-NE has retired a few smaller oil units. New generation consists primarily of over 120 MW of new solar projects and new wind plants. The seasonal adjustments value of 115 MW reflects an increase in the SCC on seasonal audit results.

New York

Since the 2019-20 winter season, generation capacity in New York has decreased. The losses of the coal-powered steam unit Somerset (655 MW nameplate) and the nuclear-powered steam unit Indian Point 2 (1,299 MW nameplate) are offset by the addition of the large combined-cycle gas plant, Cricket Valley (1,177 MW nameplate). In addition, it is expected that Cassadaga Wind (126 MW nameplate) will come in to service, and the oil unit West Babylon 4 (52 MW nameplate) will retire in Q4 of 2020.

Ontario

By the end of the 2020-21 Winter Operating Period, the total capacity in Ontario is expected to increase by 1,395 MW. This is the net result of 985 and 360 MW of new gas and wind capacity being added to the system, 88 MW of Seasonal Adjustments and 38 MW of capacity reduction due to contract expiry.

Québec

The Installed Capacity is estimated at 46,478[13] MW, a net 211 MW decrease since last winter. A few older hydro generating stations have been decommissioned (Saint-Narcisse, Mitis, Sept-Chutes, Chute-Hemmings, Drummondville, Grand-Mère) for a decrease of 150 MW. Small biomass generators have been connected to the grid for a net increase of 24.2 MW in Installed Capacity. Almost 10 MW of solar generation is expected to be in service by the end of 2020. As Quebec's system is winter peaking, its impact at the peak time period is not significant. A few Wind Power Plants decommissioning and adjustments have reduced the Installed Wind Capacity by 107.6 MW since the last winter assessment. Finally, seasonal hydro adjustments have caused an increase of 12.6 MW of hydro resources. The result is a net decrease in Installed Capacity since winter 2019-20 assessment.

[13] This value may not exactly correspond to the value published in Hydro-Québec's annual report because it was calculated using assumptions that are specific to the current report.

Fuel Infrastructure by Reliability Coordinator Area

The following figures 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: Installed Generation Fuel Type by Reliability Coordinator Area

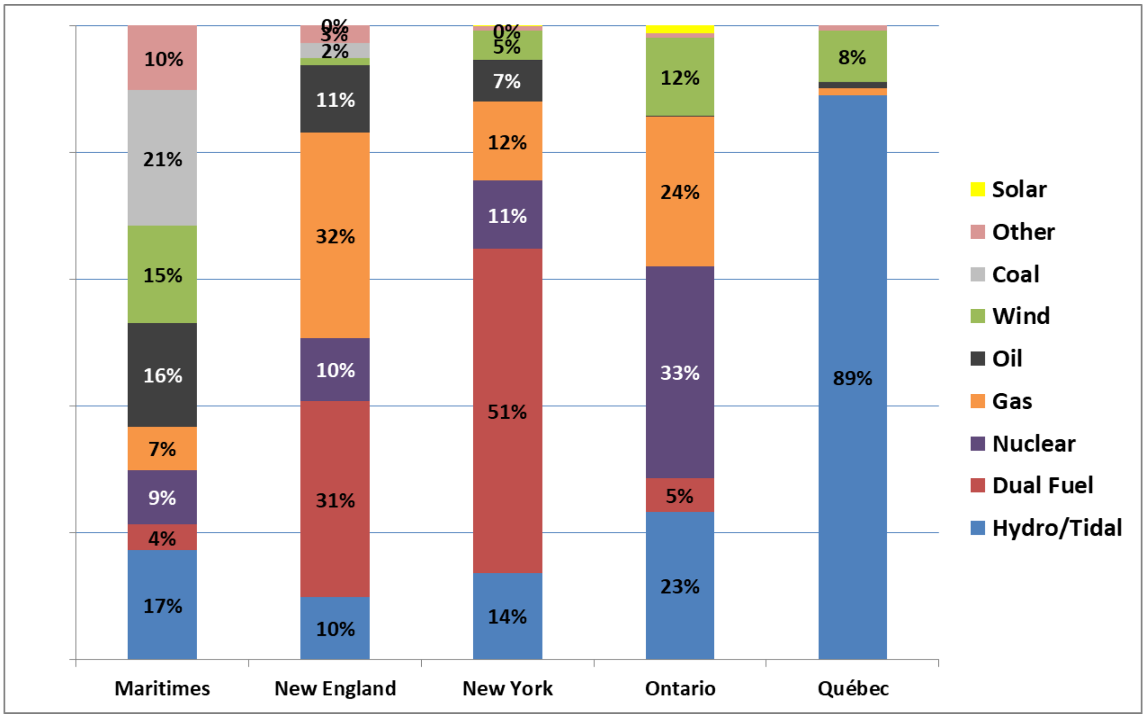
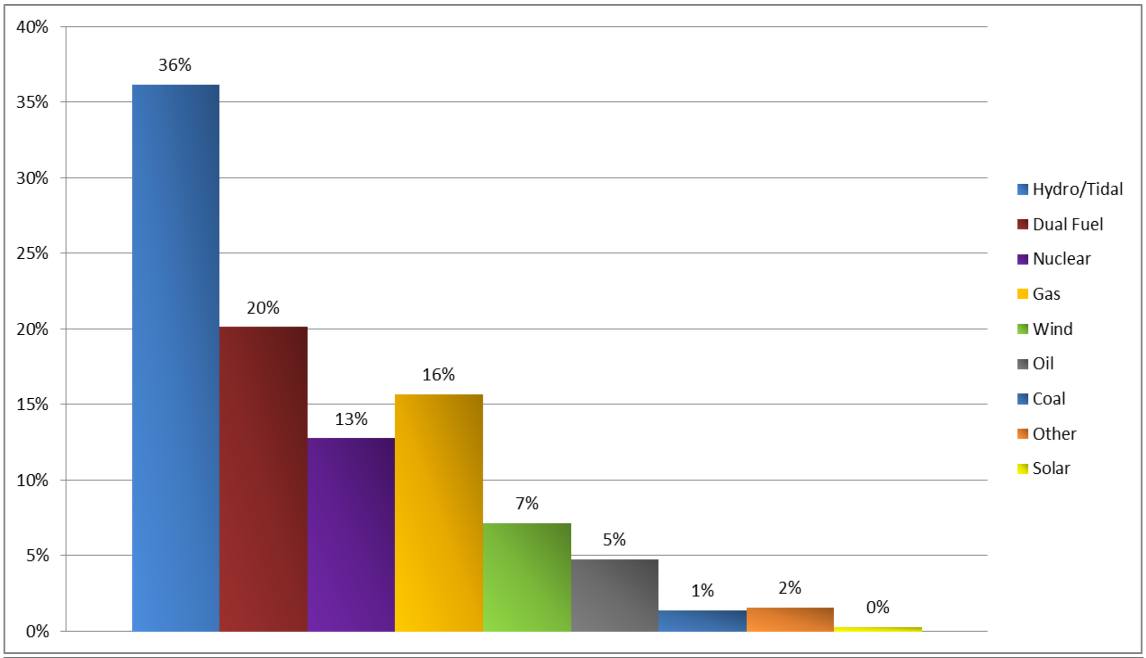


Figure 4-2: Installed Capacity Fuel Profiles for NPCC



Wind and Solar Capacity Analysis by Reliability Coordinator Area

For the upcoming 2020-21 Winter Operating Period, wind and solar capacity accounts for approximately 7.5% of the total NPCC Installed Capacity during the coincident peak load. This breaks down to 7.2% and 0.3% solar. Solar capacity is derated to zero for all areas since it is expected peak load will occur during a time near or after sunset. Reliability Coordinators have distinct methods of accounting for both of these 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.

Table 4-11 below illustrates the nameplate of wind and solar capacity in NPCC for the 2020-21 Winter Operating Period for each of the NPCC Reliability Coordinators. The Maritimes, IESO, NYISO 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. 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 4-12 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 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 4-11: NPCC Wind and Solar Capacity and Applied Derates

Reliability Coordinator area	Nameplate Wind Capacity Winter (MW)	Wind Capacity After Applied Derating Factor (MW)	Nameplate Solar Capacity (MW)	Solar Capacity After Applied Derating Factor (MW)
Maritimes	1,188	331	1	0
New England	1,333	389	1,517	0
New York*	1,985	536	32	0
Ontario	4,486	1,696	478	0
Québec	3,772	1,352	10	0
Total	**12,746**	**4,299**	**2,038**	**0**

**Total wind nameplate capacity in New York is 1,985 MW; however, only 1,739 MW participates in the ICAP market.*

Table 4-12: Behind-the-Meter Solar PV

Reliability Coordinator area	Installed Behind-the-Meter Solar PV (MW)	Impact of BTM Solar PV on Peak Load (MW)
Maritimes	0	0
New England	2,298	0
New York	2,040	0
Ontario	2,195	0
Québec	6	0
Total	**6,539**	**0**

Maritimes

Wind projected capacity is derated to its demonstrated output for each summer or winter capability period. In New Brunswick and 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. For those that have not been in service that length of time (three years), the deration of wind capacity in the Maritimes area is based upon results from the Sept. 21, 2005 NBSO report, "Maritimes Wind Integration Study". This wind study showed that the effective capacity from wind projects, and their contribution to loss of load expectation (LOLE) was equal to or better than their seasonal capacity factors.

The Northern Maine Independent System Administrator (NMISA) uses a fixed capacity factor of 30% for both the summer and winter assessment periods.

Nova Scotia applies a 19% capacity value to installed wind capacity (81% derated). This figure is based on the effective load carrying capability (ELCC) of wind determined through a Loss of Load Expectation (LOLE) study. 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 2020-21 winter assessment period, New England derated the 1,333 MW of wind resources by ~70% because of established winter claimed-capability audits (CCAs). Recognizing that wind resources could provide more power than the derated value, ISO New England produces a daily seven-day wind forecast, which provides an aggregate wind power forecast for each hour of the seven-day period. ISO-NE also utilizes system functions and control room displays to improve situational awareness for system operators.

New England continues to observe sustained growth in distributed photovoltaic (PV) resources. Load reduction from PV can be observed during the midday hours of sunny winter days; however, with the winter peak demand occurring after sunset, ISO-NE fully derates the PV resources.

New York

For the 2020-21 winter season there is projected to be 1,739 MW of nameplate wind and 32 MW of nameplate solar installed capacity in New York. The nameplate capacity is counted at full value towards the Installed Capacity for New York and is derated by 67.73%

for wind and 100% for solar based on historical performance data when determining operating margins.

Ontario

The nameplate capacity of transmission connected wind and solar facilities total 4,486 MW and 478 MW respectively.

For Ontario, monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators at the time of the weekday peak. WCC values in percentage of installed capacity are determined from a combination of actual historic median wind generator contribution over the last 10 years at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. The top 5 contiguous demand hours are determined by the frequency of demand peak occurrences over the last 12 months.

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 at the top 5 contiguous demand hours of the day for each winter and summer season, or shoulder period month. A dataset comprising ten years of simulated solar production history is used for this purpose. As actual solar production data becomes available in future, the process of combining actual historical solar data and the simulated 10-year historical solar data will be incorporated into the SCC methodology, until 10 years of actual solar data is accumulated at which point the use of simulated data will be discontinued.

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 generation reduces the need for grid supplied electricity by generating electricity on the distribution system. Since the majority of embedded generation is solar powered, embedded generation is divided into two separate components – solar and non-solar. Non-solar embedded generation includes generation fueled 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 model.

Québec

In the Québec area, wind generation plants are owned and operated by Independent Power Producers (IPPs). Nameplate capacity is 3,772 MW for the 2020-21 winter peak period, de-rated by 64 percent for an expected 1,352 MW contribution. By the end of 2020, Hydro-Québec expects to commission its first two photovoltaic solar generating stations that will be connected to the grid and will have a total installed capacity of 9.5 As Quebec's system is winter peaking, its impact at the peak time period is not significant. Behind-the-meter installed solar generation is estimated at 6 MW for the upcoming winter period.

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 January 13, 2020. Definitions of the terms are included in Appendix II (Load and Capacity Tables definitions).

Table 4-13: Summary of Forecasted Demand Response Programs

Reliability Coordinator Area	DDSM Resources (MW)	Interruptible Loads (MW)	Total (MW)
Maritimes	0	336	**336**
New England	381	0	**381**
New York	839	13	**852**
Ontario	688	0	**688**
Québec	250	2,342	**2,592**
Total	**2,158**	**2,691**	**4,849**

In the Load and Capacity tables presented in Appendix I, the Dispatchable Demand-Side Management values are accounted for on the resources side (included in Total Capacity) and the Interruptible Loads values are accounted for on the demand side as load modifier.

The total forecasted 2020-21 Winter demand response available for NPCC is 4,849 MW, a 117 MW increase from the forecasted 4,732 MW of winter demand response available during 2019-20.

Maritimes

Interruptible loads are forecast on a weekly basis and range between 242 and 353 MW. The values can be found in **Table AP-2** and are available for use when corrective action is required within the Area.

New England

In New England, 381 MW of active demand resources are projected to be available on peak for the 2020-21 winter assessment period. In addition to active demand resources, 3,207 MW of passive demand resources (i.e., energy-efficiency measures and conservation) are treated as demand reducers in this report and are accounted for in the load forecast of 20,166 MW. Passive demand measures include installed products, equipment, and systems, as well as services, practices, and strategies, at end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. The amount of energy efficiency is based on capacity supply obligations in the Forward Capacity Market.

New York

The NYISO has three demand response programs to support system reliability. The NYISO currently projects 852 MW of total demand response available for the 2020-21 winter season.

The Emergency Demand Response Program (EDRP) is categorized as Interruptible Load. It 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 is categorized as Dispatchable Demand-Side Management. It 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 and resources procured through the Demand Response (DR) auction. 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 embedded generation. The load modifiers are incorporated into the demand forecast.

For the winter assessment period, the capacity of the demand response program consists of 571 MW of DR auction participants with the balance of 117 MW being made up by dispatchable loads.

Québec

The Québec Area has various types of Demand Response resources specifically designed for peak shaving during winter operating periods, having an estimated combined impact of 2,592 MW under winter peak conditions (2020-21).

1. The Interruptible load programs are mainly designed for large industrial customers treated as supply-side resources, totaling 1,730 MW for the 2020-21 winter period. Interruptible load programs are usually used in situations where either the load is expected to reach high levels or when resources are expected to be insufficient to meet peak load demand. Before the peak period, generally during the fall season, all customers are regularly contacted in order to reaffirm their commitment to provide capacity when called, during peak periods.

2. The area is also developing some interventions in demand response (e.g., direct control load management and others) to its customers. One of these programs will expand the existing interruptible load program for commercial buildings which has already shown great results. This program has an anticipated impact of 310 MW in 2020-21. Another similar program for residential customers is under development and should gradually rise from 57 MW for winter 2020-2021 to 621 MW for winter 2030-2031.

3. New dynamic rate options for residential and small commercial or institutional customers will also contribute to reducing peak load during winter periods by 79 MW for winter 2020-2021, increasing to 195 MW for winter 2030 2031.

4. Data centers specialized in blockchain applications, which are part of new developments in the commercial sector, are required to reduce their demand during peak hours at Hydro-Quebec Distribution's request. Their contribution as a resource is expected to be around 166 MW for winter 2020-2021.

5. The voltage reduction program consists of 250 MW that allows the system operator to strategically reduce voltage across designated portions of its distribution system, within regulatory guideline in order to reduce peak demand. This 250 MW is accounted in the "Dispatchable Demande-Side Management" column of the Load and Capacity table presented in **Table AP-6**.

In addition, Energy Efficiency and Conservation programs are implemented throughout the year by Hydro-Québec Distribution and by the provincial government, through its Ministry of Natural Resources. Energy Efficiency and Conservation programs are integrated in the assessment area's demand forecasts.

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 Balancing Authority Areas of NPCC under normal and peak 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.

Inter-Regional Transmission Adequacy

Ontario – Manitoba Interconnection

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

Ontario – Minnesota Interconnection

The Ontario – Minnesota interconnection consists of one 115 kV interconnection point. 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 interconnection points, one 230/115 kV interconnection point, and one 230 kV interconnection point. 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 230/345 kV "B" and "C" PAR controlled lines are currently out-of-service and expected to remain so at least through the end of the winter season.

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. The table below summarizes the transfer capabilities between Areas:

Table 5-1: Interconnection Total Transfer Capability Summary

Area	Total Transfer Capability (MW)
Transfers from Maritimes to	
Québec	770
New England	1,000
Transfers from New England to	
Maritimes	550
New York	1,730
Québec	1,370
Transfers from New York to	
New England	2,230
Ontario	1,900
PJM	2,165
Québec	1,199
Transfer from Ontario to	
MISO	2,200
New York	2,100
Québec	2,170
Transfers from Québec to	
Maritimes	773 + radial loads
New England	2,275
New York	1,999
Ontario	2,955

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 Winter 2020-21 Operating Period under normal and peak demand configurations and have provided the following review as well as identified transmission improvements listed in **Table 5-2**.

Table 5-2: NPCC – Recent and Future Transmission Additions

NPCC Sub-Area	Transmission Project	Voltage (kV)	In Service
Maritimes	-	-	-
New England	F107 (Portsmouth – Madbury)	115	Q2 2020
	Brayton Point 4T Transformer	345/115	Q2 2020
	1346 (SW Hartford – Newington)	115	Q3 2020
	Glenbrook Statcom	15	Q2 2021
	Golden Hills Reactor	345	Q4 2021
New York	Buchanan North (reconfiguration)	345	Q3 2020
	Sta. 255 (Henrietta, new station)	345	Q4 2020
Ontario	Bruce A Breaker Replacements	230	Q4 2020
	Richview Breaker Replacements	230	Q4 2020
	Lennox 500kV Shunt Reactors (1 of 2)	500	Q4 2020
Québec	Synchronous Variable Compensator at Manicouagan substation taken out permanently	735	Q1-2020

Maritimes

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

A 500 MW (475 MW received in Nova Scotia) High Voltage Direct Current (HVDC) undersea cable link (Maritime Link) between Newfoundland, Labrador and Nova Scotia was installed in late 2017; however, the 153 MW firm capacity contract from the Muskrat Falls hydro development in Labrador is not expected until mid-2021. The firm capacity contract is expected to facilitate the retirement of a 148 MW coal-fired unit in Nova Scotia by mid-2021. Currently, the Maritime Link is being used as an additional tie line providing minimal energy flow between Nova Scotia and Newfoundland.

New England

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 BES and reduced transmission congestion, enabling economic power to flow more easily around the entire region. The improvements support decreased energy costs and increased power system flexibility.

The F107 line (Portsmouth – Madbury) provides additional support to the import-constrained New Hampshire Seacoast area. Once the F107 line goes into service, generator must–run requirements for the Seacoast area will be significantly lower and local area fast-start peakers can be utilized in emergency scenarios as opposed to normal operating conditions.

Brayton Point's new 4T 345/115kV transformer further supports increased transfers between Rhode Island and Southeast Massachusetts. This transmission addition is a small piece of the SEMA (Southeastern Massachusetts) Project. Over the next few years there will also be new substations, transmission lines, and reconductoring of old transmission lines to further increase transfer capabilities into the area. This will alleviate local area generator must-runs that are necessary due to the recent retirement of area generation.

The 1346 line (Newington – S.W. Hartford) provides additional support to Western Connecticut Import/Export Interface. With the addition of new Western Connecticut generating stations, Connecticut becomes export constrained during certain line outages.

The 1346-line project will alleviate some of these constraints and allow for increased transfers out of western Connecticut.

Both Glenbrook statcoms are being replaced this year. They play an instrumental role in regulating voltage in the Norwalk/Stamford, Connecticut sub-area. During low load periods, a unit commitment may be necessary to avoid high voltage concerns when the Glenbrook Statcoms are not available. Replacing the statcoms this year will help continue to reduce the number of generator must-runs required in overnight and lighter load periods. This allows the commitment of more economical units versus out-of-merit/cost options solely for voltage support.

The Golden Hills 345kV Reactor is a fixed 160 MVAR shunt to offset cable charging for the 349XY cables (Golden Hills – Mystic) This reactor helps reduce exposure to high voltage during light load periods. Unlike the rest of the 345kV reactors in Boston, the Golden Hills Reactor will be fixed instead of variable. This device is intended to be switchable and not required to always be in-service as a cable compensator. It was determined this reactor was a solution to the “Boston 2028 Needs Assessment” which identified transmission reinforcements required to reliably serve the area’s needs.

New York

Since the last Winter Operating Period, one significant transmission modification has come into service, and one more is planned for completion in the coming Winter Operating Period. In Q3 of 2020 the Buchanan North station was reconfigured following the retirement of Indian Point 2. In addition, the new 345 kV Station 255 (Henrietta) between Niagara and Rochester is expected to be in service at the end of Q4 2020.

Ontario

For this Winter Operating Period, Ontario’s transmission system is expected to be adequate with planned transmission system enhancements and scheduled transmission outages under normal and extreme conditions. Ontario has an expected coincident import capability of approximately 5,200 MW.

Two major breaker replacements projects are currently ongoing at the Bruce 230kV station and the Richview 230kV station. The purpose of these projects is to replace aging infrastructure and not intended to materially improvement transmission capability.

By Q4 2020, one of two 500kV line-connected shunt reactors will be installed at Lennox TS. The need for these reactors stem from the operational challenges due to high voltages in eastern Ontario and the Greater Toronto Area during low-demand periods. The IESO currently manages these situations by removing 500kV circuits out of service in the most impacted areas.

The Phase Angle Regulator (PAR) connected to the 230kV Ontario-NY interconnection circuit L33P remains out of service (forced) with an in-service date expected to be March 2022. Having the PAR and by association L33P out of service has resulted in a tighter band of operation on our New York-St. Lawrence interconnection, and within Ontario at St. Lawrence. These constraints impact our ability to import from NY through the New York-St. Lawrence interconnection and from Quebec through the Beauharnois interconnection. The long-term outage also requires more focused management of area resources in real-time, and introduces complexity in responding to forced outages and planning maintenance outages.

Outages affecting neighboring jurisdictions can be found in **Table 5-3**: Area Transmission Outage Assessment. Based on the information provided, Ontario does not foresee any transmission issues for the winter season.

Québec

One of the two synchronous compensators at Manicouagan substation is taken out of service permanently. It reduces the Manicouagan-Québec corridor limit by 200 MW if not addressed, but the transfer capability limit has been re-optimized to negate the reduction in the corridor limit. Therefore, this issue does not create a bottle-neck in the corridor in the short term. In the long-term, there is a 735 KV transmission line project currently expected in 2022 which would improve the transfer capability of the corridor beyond its current limit.

Area Transmission Outage Assessment

The section below outlines any known scheduled outages on interfaces between Reliability Coordinators.

Table 5-3: Area Transmission Outage Assessment

Maritimes

No planned outages to materially impact the transfer capabilities at this time.

New England

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
New York	NY-NE NE-NY (PV20 Line)	2020/12/07	2020/12/11	~100 MW reduction in limits with NY
New York	NY-NE NE-NY (398 Line)	2020/12/08	2020/12/10	NY-NE reduced by up to 600 MW NE-NY reduced by up to 700 MW
New York	NY-NE NE-NY (393/ 312 Line)	2021/02/17	2021/02/19	NY-NE reduced by up to 700 MW NE-NY reduced by up to 300 MW
New York	NY-NE NE-NY (393/ 312 Line)	2021/03/01	2021/03/20	NY-NE reduced by up to 700 MW NE-NY reduced by up to 300 MW

New York

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
PJM	Hopatcong-Ramapo 500 (5018 line)	2021/02/01	2021/02/06	PJM-NY limited to 1250 (-200 Import) NY-PJM limited to 1200 (-650 Export)
PJM	Ramapo 345 PAR 3500 & 4500	2021/02/01	2021/02/06	PJM-NY limited to 2150 (-750 Import) NY-PJM limited to 1250 (-600 Export)
PJM	Ramapo 500/345 BK 1500	2021/02/01	2021/02/06	PJM-NY limited to 1250 (-200 Import) NY-PJM limited to 1200 (-650 Export)

Ontario

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
New York	NY St. Lawrence (L33P)	2018/04/30	2021/11/01	Dependent on dispatch
MISO	J5D	2020/11/23	2020/12/11	400 MW (Export) / 300 MW (Import)
New York	PA27	2021/11/30	2021/12/03	0 MW (Export) / 0 MW (Import)
MISO	B3N	2020/12/14	2020/12/18	450 MW (Export) / 400 MW (Import)
Quebec	B5D	2021/01/18	2021/01/29	50 MW (Export) / 400 MW (Import)
New York	PA302	2021/02/16	2021/02/19	1100 MW (Export) / 1050 MW (Import)

Québec

Impacted Area	Interface Impacted	Planned Start	Planned End	Reduction in Limit
-	-	-	-	-

6. Operational Readiness for Winter 2020-21

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 through 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 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 tested on a continual basis throughout the year and have increased in frequency due to the current COVID-19 pandemic. NPCC also conducts Weekly Conference Calls to review a seven-day outlook for the Region, including largest contingencies, 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 NPCC TFCO has reviewed the findings and recommendations of the 2019 FERC and NERC Staff Report, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018*[14]. Some Areas have already incorporated recommendations of the report into their Winter preparedness programs, including (but not limited to) enhancing pre-seasonal generator readiness surveys.

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

In addition to coordinated regional activities, NPCC Reliability Coordinator-specific readiness activities as well as COVID-19 Pandemic Impacts and Responses, are detailed below.

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[14]The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018 (July 18, 2019), https://www.ferc.gov/legal/staff-reports/2020/07-18-19-ferc-nerc-report.pdf

Maritimes

Voltage Control

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

Operational Procedures

The Maritimes area is a winter peaking system and does not anticipate any operational issues. Some of these ascertain planning and Emergency Operating mitigations, or Energy Emergency Alerts could be needed under extreme peak demand and certain outage scenarios within these procedures include the following:

- Use of interruptible load curtailments
- Purchase of Emergency Energy in accordance with Interconnection Agreements
- Curtailment of export energy sales
- Public Appeals
- Shedding of Firm Load

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.

Winter Preparation

As part of the winter 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.

Wind Integration

Monitoring of thermal unit dispatch under high wind / low load periods (e.g. shoulder season overnight hours) is an area of focus; work to assess steam unit minimum loads and minimum steam system configurations is ongoing.

New England

Zonal Load Forecasting

New England continues to use the Metrix Zonal load forecast, which produces a zonal load forecast for the eight regional load zones through the current operating day and up to six days in advance. This forecast enhances reliability by taking into account 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 5 degrees Fahrenheit (°F), while the Hartford-area temperature is forecasted at 30 °F. This zonal forecast approach provides a better New England load forecast, resulting in an improved reliability commitment across the region.

Natural Gas Supply

Because natural gas continues to be the predominant fuel source in New England to produce electricity, ISO-NE continues to closely monitor factors affecting the deliverability of natural gas throughout the winter reliability assessment period. ISO-NE has reviewed natural gas pipeline maintenance schedules and determined that they should have no adverse impact on gas availability for the 2020-21 assessment period. However, ISO-NE does anticipate the potential for various amounts of single-fuel, gas-only power plants to be temporarily unavailable during cold or extreme winter weather or during force majeure conditions on the regional gas infrastructure. As needed, ISO-NE would mitigate generator fuel deliverability issues with real-time supplemental commitment and the use of emergency procedures.

ISO-NE currently utilizes the pay-for-performance (PFP) market design[15].PFP aims to create strong financial incentives for all capacity suppliers, without exception, to maximize their performance and availability during scarcity conditions (i.e., during operating-reserve deficiencies). ISO-NE also calculates the Energy Market Opportunity Cost (EMOC) to improve resource-specific mitigation procedures by calculating an estimated daily opportunity cost for oil and dual fuel resource with limitations on energy production over a 7-day horizon. Since December 3, 2019, this calculation is performed

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[15] Information and additional matierals about the pay-for-performance market design is available at ISO New England's web page, *Forward Capacity Market Pay-for-Performance (FCM PFP) Project,* https://www.iso-ne.com/participate/support/participant-readiness-outlook/fcm-pfp-project.

twice per day – once before the close of the Day Ahead market, the second after the Day Ahead market closes.

New England continues to survey fossil-fueled generators on a weekly basis in order to monitor and confirm their current and expected fuel availability throughout the 2020-2021 Winter Operating Period. If conditions require more frequent updates, these surveys may be sent daily. During this same period, ISO-NE also requests that all gas-fired generators confirm adequate gas supply and transportation nominations in order to meet their day-ahead obligations.

During the 2020-2021 Winter Operating Period, ISO-NE will continue to participate in weekly NPCC conference calls to share information on current and forecast system operating conditions. ISO-NE will also continue to coordinate and communicate with the regional natural gas industry through various working groups including the Electric Gas Operations Committee (EGOC), the ISO-RTO Council (IRC) Electric Gas Coordination Task Force (EGCTF), and other ad-hoc communications to promote the reliability of the Bulk Electric System (BES).

ISO-NE has several procedures that can also be invoked to mitigate regional fuel-supply emergencies adversely affecting the power generation sector:

1. Operating Procedure No. 4 (OP 4), Action During a Capacity Deficiency, establishes criteria and guidelines for actions during capacity deficiencies resulting from generator and transmission contingencies and prescribes actions to manage operating-reserve requirements[16].

2. Operating Procedure No. 7 (OP 7), Action in an Emergency, 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 ISO-NE deems needing resolution through an appropriate action in either an isolated or widespread area of New England[17].

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[16] ISO New England, Operating Procedure No. 4, *Action During a Capacity Deficiency* (April 27, 2020), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

[17] ISO New England, Operating Procedure No. 7, *Action in an Emergency* (December 11, 2019), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op7/op7_rto_final.pdf.

3. Operating Procedure No. 21 (OP 21), Energy Inventory Accounting and Action During an Energy Emergency, helps mitigate the adverse impacts on bulk power system reliability resulting from the loss of operable capacity due to regional fuel-supply deficiencies that can occur anytime[18]. Fuel-supply deficiencies are the temporary or prolonged disruption to regional fuel-supply chains for coal, natural gas, liquefied natural gas (LNG), and heavy and light fuel oil.

OP 21 was modified in the fall of 2018 to allow for an enhanced energy-alert procedure, which includes the following:

- Development of an energy forecasting and reporting framework to establish energy-alert thresholds based on an energy assessment over the next 21 days of operation that includes fuel availability and allowable emissions availability, as well as the anticipated availability of fuel infrastructure and supplies
- Establishing forecast-alert thresholds the ISO would issue on the basis of its energy assessments
- Use of the forecasting and reporting process to inform the declaration of Energy Alerts and Energy Emergencies, which would allow for proactive responses in advance of an Energy Emergency declaration.

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's (NYSRC) Installed Reserve Margin (IRM) of 18.2% for the 2020-21 winter season.

The 2019-20 winter peak was 23,253 MW, 870 MW (3.6%) lower than the forecast of 24,123 MW. The current 2020-21 peak forecast is 24,130 MW, 146 MW (0.03%) less than

[18] ISO New England, Operating Procedure No. 21, *Energy Inventory Accounting and Actions During an Energy Emergency* (October 2, 2020), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf.

the previous year. This forecast load is 6.2% lower than the all-time winter peak load of 25,738 MW set in winter 2013-14 on January 7, 2014.

There are two higher-than-expected scenarios forecast. One is a forecast without the impacts of energy efficiency programs. The second is a forecast based on extreme weather conditions, set to the 90th percentile of typical peak-producing weather conditions. These are 24,523 MW and 25,459 MW respectively.

The lower forecasted growth in energy usage can largely be attributed to the projected impact of existing statewide energy efficiency initiatives and the growth of distributed behind-the-meter energy resources encouraged by New York State energy policy programs such as the Clean Energy Fund (CEF), the NY-SUN Initiative, and other programs developed as part of the Reforming the Energy Vision (REV) proceeding. The NYISO expects that these and other programs currently being developed to further implement the 2015 New York State Energy Plan will continue to affect forecasted seasonal peak demand and energy usage for the foreseeable future.

No unique operational problems were observed from NYISO capability assessment studies. 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 communicates to neighboring control areas both the capacity-backed import and export transactions that are expected for the NYCA in the upcoming month. Discrepancies identified by neighboring control areas are resolved. During the 2020-21 winter season, the New York Balancing Authority expects to have 853 MW of net import capacity available.

The NYISO anticipates sufficient resources 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) are designed to 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 resource can be called upon to provide response. Special Case Resources are required to respond when notice has been provided in accordance with NYISO's procedures; response from EDRP is voluntary for all events.

NYISO is monitoring the potential for natural gas supplies to electric generators to be affected by natural gas infrastructure maintenance scheduled through the end of December. Potential risk to the Bulk Power System is mitigated by extensive dual-fuel generator capability. Generator preparations are informed by prior winter experience and include increased on-site fuel reserves, firm contracts with suppliers of back-up fuel, aggressive replenishment plans, and proactive pre-winter maintenance.

In addition to the resources evaluated hitherto, Emergency Operating Procedures are available to provide up to 3,257 MW of resources should the need arise. Reducing Operating Reserves to zero is also an option in extenuating circumstances to avoid load shed.

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. Total energy storage nameplate capacity is projected to be 207 MW including both wholesale and behind-the-meter capacity.

Winter Readiness

The NYISO Market Mitigation and Analysis Department performed reviews of several generating stations to discuss past winter operations and preparations for winter 2020-21. Their visits focused on units with low capacity factors. A pre-visit questionnaire included assessments of natural gas availability during peak conditions, issues associated with burning or obtaining oil, emissions limitations, preventative maintenance plans, causes of failed starts, programs to improve performance, and programs in place to insure switchyard reliability. They found that generators have increased generation testing, cold-weather preventative maintenance, fuel capabilities, and fuel switching capabilities to improve winter operations.

In the winter of 2013-14, the NYISO instituted a Cold Weather Survey. This survey is sent to all generators and assesses their primary and secondary fuel inventories. This survey is sent prior to the winter season to get baseline numbers and then on a weekly basis. In addition, the survey is sent on days in which extreme temperatures are forecast, in order to enhance real-time situational awareness. The survey allows operators to monitor gas nominations, oil inventories, and expected oil replenishment schedules for all dual-fuel, gas-fired, and oil-fired generators prior to each cold day. This procedure will be in place for winter 2020-21.

Gas Electric Coordination

Enhanced Operator visualization of the gas system is in place in the NYISO Control Center. Weekly and daily dashboards are issued during cold weather conditions indicating fuel and capacity margin status. An emergency communication protocol is in place to communicate electric reliability concerns to pipelines and gas distribution centers during tight electric operating conditions.

The NYISO conducted a loss of gas installed capacity assessment to determine the impact on operating margins should gas shortages arise. It found that 5,191 MW of gas fired generation with non-firm supply are at risk. Should all of this capacity not be available during a peak load time, the project operating margin would drop from 9,899 MW (41.0%) to 4,708 MW (19.5%).

The NYISO continues to work on improving gas-electric coordination to enhance reliability and availability of gas fueled units in the future. The NYISO is also considering potential market changes to provide incentives to generators to maintain alternate fuel availability.

Ontario

Base Load

Ontario will continue to experience potential surplus baseload conditions during the Outlook period. However, the magnitude and the frequency of the SBG are reduced with the nuclear refurbishment process in flight since 2016. It is expected that SBG will continue to be managed effectively through existing market mechanisms, which includes intertie scheduling, the dispatch of grid-connected renewable resources and nuclear maneuvers or shutdown.

Voltage Control

Ontario does not foresee any voltage management issues this winter season. However, as high voltage situations arise during periods of light load, the removal of at least one 500 kV circuit may be required to help reduce voltages. Planning procedures are in place to ensure adequate voltage control devices are available during outage conditions when voltage control conditions are more acute. To address high voltage issues on a more permanent basis, the IESO has requested additional high voltage reactors at Lennox TS with a target in-service date of Q4-2020.

Distributed Energy Resources (DERs)

With contributions from DERs growing in Ontario, the IESO has seen periods where these resources have significantly reduced demand by offsetting the load on the distribution system and, in some cases, supplying enough energy to flow energy back into the transmission system. This creates challenges in how the IESO forecasts Ontario demand and in changing transmission flow patterns across the province. The rising penetration of DERs means that more data needs to be shared between the IESO and LDCs and DER operators to provide the control room visibility required to improve forecasting and dispatch.

Operating Procedures

Ontario expects to have sufficient electricity to meet its forecasted demand. To prepare for the peak seasons, the IESO meets with gas pipeline operators every six months to discuss gas supply and planned maintenance on the gas and electric systems. Since winter 2015-16, the IESO has formalized a Unit Readiness program that exercises units which have been offline for a significant length of time to ensure their readiness for peak periods.

Québec

Extreme load weather and extreme temperatures

Extreme cold weather results in a large load pickup over the normal demand forecast. This situation is addressed at the planning stage through TransÉnergie's Transmission Design Criteria. When designing the system, one particular criterion requires that both steady state and stability assessments be made with winter scenarios involving demands 4,000 MW higher than the normal weather peak demand forecast. This is equivalent to 110% of peak winter demand. This ensures that the system is designed to carry the resulting transfers while conforming to all design criteria. Resources needed to feed the load during such episodes must be planned and provided by Hydro-Québec Distribution, the Load Serving Entity.

On an operations horizon, if peak demands are higher than expected, a number of measures are available to the System Control personnel. Operating Instruction 33199-I-001 lists such measures:

- Limitations on non-guaranteed wheel through and export transactions

- Operation of hydro generating units at their near-maximum output (away from optimal efficiency, but still allowing for reserves)
- Use of import contracts with neighbouring systems
- Use of interruptible load programs
- Reducing 30-minute reserve and stability reserve
- Applying voltage reduction
- Making public appeals
- Ultimately, using cyclic load shedding to re-establish reserves

Most of the Québec area hydro generators are located in the north of the province, where extremely cold ambient temperatures often occur during winter periods. Specific Design requirements are implemented to ensure that extreme ambient temperature does not affect operations. In case of any issues that might arise in real time, Maintenance Notices are issued to operators to handle such concerns.

Voltage Control

Voltage support in the southern part of the system (load area) might be a concern during Winter Operating Periods, especially during episodes of heavy load. Hydro-Québec Production (the largest producer on the system) ensures that maintenance on generating units is finished by December 1, and that all possible generation is available. This, along with yearly testing of reactive capability of the generators, ensures maximum availability of both active and reactive power.

Voltage variations on the high voltage transmission system are also of some concern. These are normal variations due to changes in transmitted power from North to South during load pickup and interconnection ramping. In this situation, the system has to meet a specific Transmission Design Criterion concerning voltage variations on the system. This criterion quantifies acceptable voltage variations due to load pickup and/or interconnection ramping. All planning and operating studies must now conform to this criterion.

Outages

One of the two Synchronous Compensators at Manicouagan substation is taken out of service permanently. It reduces the Manicouagan-Québec corridor limit by 200 MW if not addressed, but the transfer capability limit has been re-optimized to negate the reduction in the corridor limit. Therefore, this issue does not create a bottle-neck in the corridor in the short term.

COVID-19 Pandemic Impacts and Responses

NPCC

The international outbreak of Coronavirus disease (COVID-19) was declared a pandemic by the World Health Organization (WHO) in March 2020 and has continued to progress during the development of this report. In response, NPCC and its stakeholders have implemented several procedures and plans to address the associated impacts. NPCC activated its pandemic response plan as a result and continues to hold regular Emergency Preparedness Conference Calls with regional RC's (including PJM and MISO) regarding the latest entity efforts and policies to ensure the safe and reliable operation of interconnected systems. These calls are expected to continue indefinitely throughout the COVID-19 pandemic, as necessary.

The full scope of the pandemic is highly variable and its effects to the region are dependent upon continuing governmental public health and regulatory response(s). The region continues to assess the evolving situation to fully understand the short and long-term impacts to ensure a highly reliable and secure Northeastern North American bulk power system (BPS).

NPCC Reliability Coordinator-specific impacts and responses are detailed below.

Maritimes

As a result of the response to the COVID-19 pandemic, the Maritimes' entities are currently experiencing slight shifts in the timing and ramping of peak load. To date, the Maritimes' entities have experienced a slight decrease in load. Residential load has increased, but commercial and industrial load have decreased as a result of the COVID-19 pandemic. Weather is still the main driver of load profiles. The effects of the COVID-19 pandemic on load patterns, energy usage, and peak demands will continue to be evaluated as the situation unfolds.

The Maritimes' entities have created and enacted system operator contingency plans to ensure health and safety of personnel and continued reliable operation of the power grid. The entities are evaluating contingency plans for T&D and Generation planned work, planned maintenance, and forced outages to proceed conservatively while mitigating short term and longer term reliability risks. Contingency plans are re-evaluated constantly as the COVID-19 pandemic evolves.

The Maritimes' entities continue to monitor the ongoing spread of COVID-19 and remain focused on the health and safety of employees, consultants, contractors, and their families. Response teams are monitoring the situation, coordinating with authorities, and keeping employees informed via regular business updates.

New York

Due to the outbreak of the novel COVID-19 virus in New York State, the NYISO has taken numerous precautions so that power grid operations and wholesale electricity markets remain fully operational. Our priorities are the health and safety of our employees and reliability of New York's electric system. We continue to take necessary precautions as outlined in our Pandemic Response and business continuity plans to reduce possible risks from COVID-19.

Demand remains lower than typically-expected levels across the New York Control Area (NYCA). Notable trends during the weeks of September 20th through October 10th were:

- NYCA-wide overall energy use averaged approximately 3-5% below expected demand levels. Peak energy use for the NYCA averaged between 4-6% below expected values.

- Overall energy use in New York City (Zone J) averaged between 7-9% below typical demand levels for the three-week period.

- For weekdays between September 28th and October 9th, New York City hourly demand was about 5% below expected levels during the 12 a.m. – 3 a.m. hours and 11-12% below expected levels during the 6 a.m. – 8 a.m. hours.

- During the same time period, NYCA-wide weekday reductions in electric consumption ranged from 2-3% during the 12 a.m. – 4 a.m. hours to about 5-8% during the 6 a.m. - 9 a.m. hours.

The reduction in electric demand from commercial customers is driving the reduction. Residential energy use has increased, especially during the midday. During peak hours over a cold snap it is possible that there will be no reduction in load from the peak forecast. As such, no adjustments were made to the normal and extreme peak load forecasts.

The NYISO continues to monitor and assess changes in electricity demand level and consumption patterns to further refine daily and longer-term demand forecasts. This ongoing assessment includes evaluating demand patterns, updating economic forecasts, and engaging with local utilities.

New England

In regards to potential COVID-19 concerns, ISO-NE continues to stay in contact with System Operators in other parts of the country/world to hear what they're experiencing and how it might apply in New England, as well as sharing our experiences with them. Additionally, ISO-NE is producing a weekly analysis of the impact the response to COVID-19 is having on region-wide system demand, posted every Tuesday on its external web site.[19] ISO-NE first observed an impact on system demand during the third week of March 2020, when a regional response to the pandemic began. Loads were approximately 3 to 5% lower, on average, until air conditioning demand was more prevalent starting in June. From June through mid-September, average loads were normal to slightly higher-than-normal due to additional cooling load and the expansion of reopening of commercial and industrial facilities. Through October, actual load continues to trend toward what would be expected in the absence of COVID-19. Regional re-opening strategies have expanded to their greatest extent so far.

ISO Forecasters have seen demand for electricity return to near pre-pandemic levels this fall, as students and teachers across the region return to school in various in-person and hybrid environments. The ISO will continue to monitor conditions as the New England states reassess and update the phases of their reopening procedures. As of October 27, 2020, as cases are on the rise throughout the region, any actions taken by state governments will likely impact system load.

ISO-NE collaborates with fuel suppliers and transportation companies (pipelines) through various working groups including the Electric Gas Operations Committee (EGOC), the ISO-RTO Council (IRC) Electric Gas Coordination Task Force (EGCTF), and other ad-hoc communications to share practices and observations on a wide range of experiences. During 2020, as the industry continues to face the COVID-19 pandemic, meetings have been convened more frequently to compare and contrast policies used to ensure safe and reliable operation of all of our interconnected systems. Our discussions centered around two major topics, one being the safety of essential staff and the other being the continuity of operation. Every participant in the meetings reported some level of altered operating posture, but also reported no degradation of service or capabilities to operate. These meetings will continue through the winter and spring, until COVID-19 runs its course.

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[19] https://www.iso-ne.com/markets-operations/system-forecast-status/estimated-impacts-of-covid-19-on-demand/

Approximately 70% of ISO New England's workforce continues to work remotely in response to the COVID-19 pandemic. Those employees working on-site continue to adhere to established social distancing and other health and safety protocols. ISO New England expects this arrangement to continue for at least the rest of 2020, especially as the number of COVID cases have recently begun to tick upward. We remain focused on the health and well-being of our employees, and are prepared to adjust to any changing conditions and guidance from state and federal public health agencies.

ISO-NE continues to:

- Limit control room access only to control room staff

- Split system operations shifts between our main control center and our back-up center, minimizing the potential of cross contamination between crews and allowing for more frequent control room cleaning

- Coordinate with transmission companies, as well as other ISOs and RTOs to share best practices and situational awareness

- Communicate with resource owners to understand any challenges to their staffing or business operations

Ontario

The coronavirus and the ensuing public health and policy responses, have had significant effects on Ontarians' behavior and economic activity. Initially, these effects had a profound impact on electricity consumption patterns. The stay-in-place order and the closure of non-essential businesses caused overall electricity consumption to drop. With more people working from home, residential consumption increased and as the summer temperature increased, the residential sector air conditioning load caused the system to be much more weather sensitive and pushed up peak demands. Coupled with the temporary suspension of the Industrial Conservation Initiative1 (ICI), the 2020 summer peaks were the highest they had been since 2013. Commercial loads have dropped but the declines have not offset the increase in residential loads. This means peaks have trended higher than previously. These conditions will persist through this winter, leading to higher winter peaks than previously expected. With the staged re-opening of the economy, commercial and industrial loads have picked back up and consumption patterns are gradually returning to pre-COVID levels. Going forward, the re-opening of schools will further boost electricity demand across the province. However, many Ontarians will remain working from home, impacting the demand for electricity across the various sectors.

Overall, Ontario's electricity system is well-positioned for 2020-21 Winter Operating Period. While COVID-19 has affected demand for electricity, its impacts have been far reaching across the sector. A number of planned outages that were scheduled at the beginning of the pandemic were deferred. We are now observing an increase in total outage volume as work schedules return to pre-COVID levels with asset owners. Currently, it is expected that the planned outage volume will continue to trend higher than normal for the remainder of the year to account for some of the higher priority maintenance and project work that was deferred. The IESO remains flexible in balancing risks to the power system and maintaining reliability with prioritization of asset owner critical work.

Québec

The COVID-19 pandemic (induced by the SARS-CoV-2 virus) has had impacts on the Québec system demand. The load profile is lower (around 300 MW for industrial power average level consumption, and around 200 MW for the residential and commercial power consumption) than for the years before and it is more stable.

But, the load profile is more stable and the load rise is less steepened in the morning. We can suppose that for short term (up to 10 days in advance) load forecasting, this change is advantageous.

It seems like that the fall season is confirming this trend, but the restart of industrial activities and the risk of new waves of contaminations are uncertainties to consider in the life span of these new load profiles. Having mentioned the uncertainty factors, the pandemic impact on the Québec system has been negligible so far, and steps are taken to assure that we are up to the task of addressing any eventual event. Hydro-Quebec's source of energy provides a robust flexibility to the system which allows it rapidly and easily adopt to different load profiles.

7. Post-Seasonal Assessment and Historical Review

Winter 2019-20 Post-Seasonal Assessment

The sections below describe each Reliability Coordinator area's winter 2019-20 operational experiences.

The NPCC coincident peak of 103,969 MW occurred on December 19, 2019 HE18 EST. It was 5,194 MW lower (4.76%) than the forecasted load of 109,163 MW.

Maritimes

The Maritimes system demand during the NPCC coincident peak was 4,789 MW. Maritimes actual peak was 5,335 MW on February 21, 2020 at HE7 EST.

All major transmission and interconnections were in service.

New England

The New England system actual peak demand of 18,913 MW occurred on December 19, 2019 HE18 EST.

Due to an overall milder winter weather pattern, ISO-NE did not experience any extended cold weather days and was not required to issue any energy-alerts per OP21 or capacity deficiency alerts per OP 4 procedures.

New York

The actual peak demand of 23,253 MW occurred on December 19, 2019 HE17 EST.

During the 2019-20 Winter Operating Period, the NYISO did not experience transmission or reactive capability issues and was not required to utilize firm load shedding or emergency operating procedures.

Ontario

The actual peak demand was 20,974 MW on December 19, 2019 HE18 EST. This was slightly less than the originally forecasted 21,115 MW.

There were no significant operational issues observed during the 2019-20 Winter Operating Period.

Québec

During the NPCC coincident peak, the Québec demand was 36,040 MW and the actual peak demand of 36,160 MW occurred on December 19, 2019 at HE19 EST. The internal demand forecast was 38,965 MW for the 2019-20 Winter Operating Period.

At the time of the Québec peak, net exports of 4,312 MW were sustained by the Québec Balancing Authority. Interruptible industrial loads were not required for the peak hour and appeals to the public were not required during the 2019-20 Winter Operating Period.

The actual peak demand for the Winter 2019-20 (36,160 MW) was a lot lower than the historical peak demand of 39,240 MW that occurred during the 2013-14 Winter Operating Period.

Historical Winter Demand Review

The table below summarizes historical non-coincident winter peaks for each NPCC Balancing Authority area over the last ten years along with the forecasted normal coincident peak demand for Winter 2020-21. Highlighted values are record demand that occurred during the NPCC Winter Operating Period over the last 10 years.

Table 7-1: Ten Year Historical Winter Peak Demands (MW)

Winter	Maritimes	New England	New York	Ontario	Québec	NPCC Coincident Demand	Date
2009-10	5,205	20,791	24,074	22,045	34,659	-	-
2010-11	5,252	21,495	24,654	22,733	37,717	-	-
2011-12	4,963	19,926	23,901	21,649	35,481	-	-
2012-13	5,431	20,877	24,658	22,610	38,797	111,127	23-Jan-13
2013-14	5,467	21,453	25,738	22,774	39,240	111,801	2-Jan-14
2014-15	5,314	20,583	24,648	21,814	38,950	108,092	8-Jan-15
2015-16	5,237	19,545	23,317	20,836	37,650	102,466	15-Feb-16
2016-17	5,418	19,647	24,164	20,688	37,200	104,335	16-Dec-16
2017-18	5,344	20,631	25,081	20,906	38,410	109,117	5-Jan-18
2018-19	5,265	18,913	24,728	21,525	38,364	109,218	21-Jan-19
2019-20	5,335	18,913	23,253	20,974	36,160	103,969	19-Dec-19
2020-21 Forecasted	5,621	20,166	24,130	20,837	38,695	109,133	17-Jan-21

*NPCC Coincident Peak data is unavailable prior to the 2012-13 Winter Operating Period.

The following table presents the all-time peak demand for each NPCC Area with the corresponding date and time.

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

Reliability Coordinator Area	Load (MW)	Date and time
Maritimes	5,716	January 16, 2004 HE8 EST
New England	22,818	January 15, 2004 HE19 EST
New York	25,738	January 7, 2014 HE19 EST
Ontario	24,979	December 20, 2004 HE18 EST
Québec	39,240	January 22, 2014 HE8 EST

8. 2020-21 Winter Reliability Assessments of Adjacent Regions

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

https://rfirst.org/ProgramAreas/ESP/

For reviews of the other NERC Regional Entities and Assessment Areas, please go to:

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

9. CP-8 2020-21 Winter 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 the November 2020 through March 2021 period. Please refer to Appendix VIII (page 25 – Table 9) for a description of the Base Case and Severe Case Assumptions.

<u>Base Case Scenario</u>

Under Base Case conditions, only the Maritimes Area estimates a likelihood of using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and initiating interruptible loads) during the 2020/21 winter period for the expected load forecast (representing the probability weighted average of all seven load levels).

<u>Extreme Peak Load</u>

The results for the extreme load forecast (representing the second to highest load level, having approximately a 6% chance of occurring) estimates a likelihood of the Maritimes Area using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and initiating interruptible loads, and reducing 10-min reserve) during the 2020/21 winter period.

The results are primarily driven by Nova Scotia's forecast load and corresponding reserve margin expectations.

<u>Severe Case Scenario</u>

The Maritimes Area estimated use of operating procedures increases assuming Severe Case conditions, especially for the extreme load forecast; again, these results are primarily driven by Nova Scotia's forecast load and corresponding reserve margin expectations. The Hydro-Quebec and Ontario Areas show use of their operating procedures (activation of DR/SCR, reduction of 30-min reserve) for the Severe Case, extreme load forecast assumptions.

Appendix I – Winter 2020-21 Normal Load and Capacity Forecasts

Yellow highlighting indicates the peak week on the table. Blue highlighting indicates the NPCC coincident peak week.

Table AP-1 - NPCC Summary

Area NPCC
Revision Date October 28, 2020

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 %
29/Nov/20	167,869	65	2,231	170,165	96,850	2,708	26,363	8,885	11,793	38,156	28,982	**29.9%**	27,371	**28.3%**
6/Dec/20	167,869	297	2,186	170,352	100,691	2,660	22,532	8,885	12,013	34,545	28,891	**28.7%**	28,243	**28.0%**
13/Dec/20	167,804	297	2,186	170,287	102,485	2,673	21,604	8,885	11,622	33,226	28,364	**27.7%**	28,364	**27.7%**
20/Dec/20	167,804	297	2,186	170,287	103,175	2,641	20,204	8,885	12,343	32,547	28,321	**27.4%**	28,321	**27.4%**
27/Dec/20	167,864	297	2,186	170,347	102,306	2,609	20,106	8,885	12,756	32,862	28,903	**28.3%**	27,996	**27.4%**
3/Jan/21	167,865	302	2,186	170,353	106,435	2,606	20,278	8,885	13,123	33,401	24,238	**22.8%**	24,238	**22.8%**
10/Jan/21	167,865	302	2,158	170,325	108,646	2,597	20,608	8,885	13,107	33,715	21,676	**20.0%**	21,676	**20.0%**
17/Jan/21	167,865	302	2,158	170,325	109,133	2,691	21,522	8,885	12,835	34,357	20,640	**18.9%**	20,640	**18.9%**
24/Jan/21	167,865	302	2,186	170,353	108,854	2,657	20,754	8,885	12,227	32,981	22,289	**20.5%**	22,289	**20.5%**
31/Jan/21	167,865	303	2,186	170,353	106,351	2,648	21,903	8,719	12,488	34,391	23,540	**22.1%**	23,540	**22.1%**
7/Feb/21	167,865	303	2,186	170,353	104,710	2,664	23,074	8,719	12,034	35,108	24,480	**23.4%**	24,480	**23.4%**
14/Feb/21	167,865	303	2,186	170,353	103,756	2,703	22,734	8,719	11,651	34,385	26,197	**25.2%**	26,197	**25.2%**
21/Feb/21	167,865	303	2,186	170,353	102,141	2,667	22,215	8,719	11,073	33,288	28,873	**28.3%**	28,873	**28.3%**
28/Feb/21	167,865	302	2,186	170,353	99,784	2,637	23,337	8,719	9,652	32,989	31,499	**31.6%**	31,499	**31.6%**
7/Mar/21	167,865	302	2,186	170,353	98,456	2,674	26,121	8,719	9,189	35,310	30,542	**31.0%**	30,542	**31.0%**
14/Mar/21	167,865	302	2,186	170,353	96,282	2,705	26,528	8,719	8,415	34,943	33,114	**34.4%**	32,866	**34.1%**
21/Mar/21	167,865	302	2,186	170,353	93,932	2,722	27,950	8,719	7,564	35,514	34,909	**37.2%**	33,273	**35.4%**
28/Mar/21	167,865	298	2,231	170,394	90,356	2,655	25,596	8,985	8,019	33,615	40,093	**44.4%**	36,117	**40.0%**

Key

Highlighted week beginning 17-Jan-21 denotes the NPCC forecasted coincident peak demand and minimum Revised Net Margin.
Highlighted week beginning 28-Mar-21 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 October 28, 2020

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	Normal Forecast MW	Interruptible Load MW	Known Maint./Derat. MW [1]	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
29/Nov/20	7,728	37	0	7,765	4,460	353	1,164	893	328	1,273	**28.5%**
6/Dec/20	7,728	37	0	7,765	4,835	305	1,014	893	328	1,000	**20.7%**
13/Dec/20	7,728	37	0	7,765	5,047	318	1,014	893	328	801	**15.9%**
20/Dec/20	7,728	37	0	7,765	4,981	286	1,014	893	328	835	**16.8%**
27/Dec/20	7,728	37	0	7,765	5,132	254	982	893	328	684	**13.3%**
3/Jan/21	7,729	42	0	7,771	5,431	251	981	893	328	389	**7.2%**
10/Jan/21	7,729	42	0	7,771	5,539	242	981	893	328	272	**4.9%**
17/Jan/21	7,729	42	0	7,771	5,305	336	981	893	328	600	**11.3%**
24/Jan/21	7,729	42	0	7,771	5,397	302	890	893	328	564	**10.5%**
31/Jan/21	7,729	43	0	7,771	5,621	293	882	893	328	340	**6.1%**
7/Feb/21	7,729	43	0	7,771	5,405	309	994	893	328	460	**8.5%**
14/Feb/21	7,729	43	0	7,771	5,437	348	994	893	328	468	**8.6%**
21/Feb/21	7,729	43	0	7,771	5,265	312	975	893	328	623	**11.8%**
28/Feb/21	7,729	42	0	7,771	5,264	282	975	893	328	593	**11.3%**
7/Mar/21	7,729	42	0	7,771	5,125	319	1,008	893	328	736	**14.4%**
14/Mar/21	7,729	42	0	7,771	5,075	350	1,008	893	328	817	**16.1%**
21/Mar/21	7,729	42	0	7,771	5,062	367	899	893	328	955	**18.9%**
28/Mar/21	7,729	38	0	7,766	4,786	300	1,011	893	328	1,049	**21.9%**

Key

Highlighted week beginning 17-Jan-21 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 28-Mar-21 denotes week with the largest forecasted NPCC “Revised Net Margin”.
Highlighted number denotes forecasted Winter 2020-21 Peak Load for Maritimes.

Notes

(1) Known Maint./Derate include wind.
(2) Week beginning 31-Jan-21 denotes the forecasted Maritimes Winter 2020-21 Peak Week.

Table AP-3 – New England

Area ISO-NE
Revision Date October 26, 2020

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW [1]	Net Interchange MW [2]	Dispatchable DSM MW	Total Capacity MW	Normal Forecast MW [3]	Interruptible Load MW [4]	Known Maint./Derat. MW [5]	Req. Operating Reserve MW [6]	Unplanned Outages MW [7]	Net Margin MW	Net Margin %
29/Nov/20	33,711	793	426	34,930	19,009	0	1,745	2,305	5,927	5,944	**31.3%**
6/Dec/20	33,711	1,025	381	35,117	19,313	0	812	2,305	6,030	6,657	**34.5%**
13/Dec/20	33,711	1,025	381	35,117	19,325	0	1,104	2,305	5,966	6,417	**33.2%**
20/Dec/20	33,711	1,025	381	35,117	19,390	0	312	2,305	6,520	6,590	**34.0%**
27/Dec/20	33,711	1,025	381	35,117	19,390	0	301	2,305	6,933	6,188	**31.9%**
3/Jan/21	33,711	1,025	381	35,117	20,166	0	321	2,305	7,244	5,081	**25.2%**
10/Jan/21	33,711	1,025	381	35,117	20,166	0	321	2,305	7,239	5,086	**25.2%**
17/Jan/21	33,711	1,025	381	35,117	20,166	0	369	2,305	7,066	5,211	**25.8%**
24/Jan/21	33,711	1,025	381	35,117	19,933	0	384	2,305	6,533	5,962	**29.9%**
31/Jan/21	33,711	1,025	381	35,117	19,933	0	294	2,305	6,477	6,108	**30.6%**
7/Feb/21	33,711	1,025	381	35,117	19,652	0	314	2,305	6,122	6,724	**34.2%**
14/Feb/21	33,711	1,025	381	35,117	19,622	0	873	2,305	5,766	6,551	**33.4%**
21/Feb/21	33,711	1,025	381	35,117	19,346	0	873	2,305	5,233	7,360	**38.0%**
28/Feb/21	33,711	1,025	381	35,117	18,308	0	1,253	2,305	3,978	9,273	**50.6%**
7/Mar/21	33,711	1,025	381	35,117	17,941	0	1,298	2,305	3,622	9,951	**55.5%**
14/Mar/21	33,711	1,025	381	35,117	17,736	0	1,245	2,305	2,911	10,920	**61.6%**
21/Mar/21	33,711	1,025	381	35,117	17,352	0	2,098	2,305	2,200	11,162	**64.3%**
28/Mar/21	33,711	1,025	426	35,162	16,759	0	1,230	2,305	2,700	12,168	**72.6%**

Key

Highlighted week beginning 17-Jan-21 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 28-Mar-21 denotes week with the largest forecasted NPCC "Revised Net Margin".

Highlighted numbers denote forecasted Winter 2020-21 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 2020-2021 capacity commitment period.

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

(3) Preliminary load forecast assumes net Peak Load Exposure (PLE) of 20,166 MW and does include 3,207 MW credit for Energy Efficiency (EE) and 0 MW of behind-the-meter PV (BTM PV)

(4) On peak, 579 MW of Active Demand Capacity Resource (ADCR) is considered available for economic dispatch, which has been taken into account in Dispatchable DSM MW

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

(6) 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.

(7) 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 October 27, 2020

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW	Net Interchange MW [1]	Dispatchable DSM MW	Total Capacity MW	Load Forecast MW	Interruptible Load MW	Known Maint./Derat. MW	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
29/Nov/20	41,008	496	839	42,343	23,709	13	2,776	2,620	2,551	10,700	**45.1%**
6/Dec/20	41,008	496	839	42,343	24,130	13	3,057	2,620	2,532	10,017	**41.5%**
13/Dec/20	40,943	496	839	42,278	24,130	13	2,972	2,620	2,534	10,035	**41.6%**
20/Dec/20	40,943	496	839	42,278	24,130	13	2,972	2,620	2,534	10,035	**41.6%**
27/Dec/20	40,943	496	839	42,278	24,130	13	2,972	2,620	2,534	10,035	**41.6%**
3/Jan/21	40,943	496	839	42,278	24,130	13	2,777	2,620	2,547	10,217	**42.3%**
10/Jan/21	40,943	496	839	42,278	24,130	13	2,591	2,620	2,559	10,391	**43.1%**
17/Jan/21	40,943	496	839	42,278	24,130	13	3,118	2,620	2,524	9,899	**41.0%**
24/Jan/21	40,943	496	839	42,278	24,130	13	3,056	2,620	2,528	9,957	**41.3%**
31/Jan/21	40,943	496	839	42,278	24,130	13	3,253	2,620	2,515	9,773	**40.5%**
7/Feb/21	40,943	496	839	42,278	24,130	13	3,253	2,620	2,515	9,773	**40.5%**
14/Feb/21	40,943	496	839	42,278	24,130	13	2,854	2,620	2,542	10,145	**42.0%**
21/Feb/21	40,943	496	839	42,278	24,130	13	2,327	2,620	2,577	10,637	**44.1%**
28/Feb/21	40,943	496	839	42,278	24,130	13	2,327	2,620	2,577	10,637	**44.1%**
7/Mar/21	40,943	496	839	42,278	23,793	13	4,051	2,620	2,462	9,365	**39.4%**
14/Mar/21	40,943	496	839	42,278	23,245	13	4,525	2,620	2,430	9,471	**40.7%**
21/Mar/21	40,943	496	839	42,278	22,783	13	5,065	2,620	2,394	9,429	**41.4%**
28/Mar/21	40,943	496	839	42,278	22,380	13	4,117	2,620	2,457	10,717	**47.9%**

Key

Highlighted week beginning 17-Jan-21 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 28-Mar-21 denotes week with the largest forecasted NPCC “Revised Net Margin”.
Highlighted number denotes forecasted Winter 2020-21 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
(2) Week beginning 17-Jan-21 denotes the New York Peak Week

Table AP-5 – Ontario

Area Ontario
Revision Date October 5, 2020

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW [1]	Net Interchange MW	Dispatchable DSM MW	Total Capacity MW	Load Forecast MW [2]	Interruptible Load MW	Known Maint./ Derat./Bottled Cap. MW [3]	Req. Operating Reserve MW	Unplanned Outages MW [4]	Net Margin MW	Net Margin %
29/Nov/20	38,944	-500	716	39,160	19,740	0	13,177	1,567	1,487	3,189	**16.2%**
6/Dec/20	38,944	-500	716	39,160	19,805	0	12,134	1,567	1,623	4,031	**20.4%**
13/Dec/20	38,944	-500	716	39,160	19,784	0	11,775	1,567	1,294	4,740	**24.0%**
20/Dec/20	38,944	-500	716	39,160	19,653	0	11,572	1,567	1,461	4,907	**25.0%**
27/Dec/20	39,004	-500	716	39,220	19,778	0	11,863	1,567	1,461	4,551	**23.0%**
3/Jan/21	39,004	-500	716	39,220	20,585	0	11,886	1,567	1,504	3,678	**17.9%**
10/Jan/21	39,004	-500	688	39,192	20,674	0	12,105	1,567	1,481	3,365	**16.3%**
17/Jan/21	39,004	-500	688	39,192	20,837	0	12,301	1,567	1,417	3,070	**14.7%**
24/Jan/21	39,004	-500	716	39,220	20,825	0	11,600	1,567	1,338	3,890	**18.7%**
31/Jan/21	39,004	-500	716	39,220	20,424	0	12,543	1,401	1,668	3,184	**15.6%**
7/Feb/21	39,004	-500	716	39,220	19,981	0	13,247	1,401	1,569	3,022	**15.1%**
14/Feb/21	39,004	-500	716	39,220	19,760	0	12,613	1,401	1,515	3,931	**19.9%**
21/Feb/21	39,004	-500	716	39,220	19,509	0	12,550	1,401	1,435	4,325	**22.2%**
28/Feb/21	39,004	-500	716	39,220	18,914	0	13,120	1,401	1,269	4,516	**23.9%**
7/Mar/21	39,004	-500	716	39,220	18,211	0	13,926	1,401	1,277	4,405	**24.2%**
14/Mar/21	39,004	-500	716	39,220	17,790	0	13,663	1,401	1,246	5,120	**28.8%**
21/Mar/21	39,004	-500	716	39,220	17,689	0	13,799	1,401	1,142	5,189	**29.3%**
28/Mar/21	39,004	-500	716	39,220	17,248	0	13,577	1,667	1,034	5,694	**33.0%**

Key

Highlighted week beginning 17-Jan-21 denotes the NPCC forecasted coincident peak demand.
Highlighted week beginning 28-Mar-21 denotes week with the largest forecasted NPCC “Revised Net Margin”.
Highlighted number denotes forecasted Winter 2020-21 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 17-Jan-21 denotes the Ontario Peak Week

Table AP-6 – Québec

Area Québec
Revision Date 25-09-2020

Control Area Load and Capacity

Week Beginning Sundays	Installed Capacity MW [1]	Net Interchange MW [2]	Dispatchable DSM MW	Total Capacity MW	Load Forecast MW	Extreme Load Forecast	Historical Peak Load	Interruptible Load MW	Known Maint./Derat. MW [3]	Req. Operating Reserve MW	Unplanned Outages MW	Net Margin MW	Net Margin %
29/Nov/20	46,478	-761	250	45,967	29,932	31,790		2,342	7,501	1,500	1,500	7,876	**26.3%**
6/Dec/20	46,478	-761	250	45,967	32,608	35,397		2,342	5,515	1,500	1,500	7,186	**22.0%**
13/Dec/20	46,478	-761	250	45,967	34,199	36,721	37,200	2,342	4,739	1,500	1,500	6,371	**18.6%**
20/Dec/20	46,478	-761	250	45,967	35,021	37,029	38,410	2,342	4,334	1,500	1,500	5,954	**17.0%**
27/Dec/20	46,478	-761	250	45,967	33,876	36,731	37,717	2,342	3,988	1,500	1,500	7,445	**22.0%**
3/Jan/21	46,478	-761	250	45,967	36,123	38,373	38,950	2,342	4,313	1,500	1,500	4,873	**13.5%**
10/Jan/21	46,478	-761	250	45,967	38,137	40,303	35,481	2,342	4,610	1,500	1,500	2,562	**6.7%**
17/Jan/21	46,478	-761	250	45,967	38,695	40,812	39,240	2,342	4,753	1,500	1,500	1,861	**4.8%**
24/Jan/21	46,478	-761	250	45,967	38,569	40,457	34,659	2,342	4,824	1,500	1,500	1,916	**5.0%**
31/Jan/21	46,478	-761	250	45,967	36,243	38,288		2,342	4,931	1,500	1,500	4,135	**11.4%**
7/Feb/21	46,478	-761	250	45,967	35,542	37,636	37,650	2,342	5,266	1,500	1,500	4,501	**12.7%**
14/Feb/21	46,478	-761	250	45,967	34,807	36,767		2,342	5,400	1,500	1,500	5,102	**14.7%**
21/Feb/21	46,478	-761	250	45,967	33,891	36,148	36,380	2,342	5,490	1,500	1,500	5,928	**17.5%**
28/Feb/21	46,478	-761	250	45,967	33,168	35,361		2,342	5,662	1,500	1,500	6,479	**19.5%**
7/Mar/21	46,478	-761	250	45,967	33,386	35,346		2,342	5,838	1,500	1,500	6,085	**18.2%**
14/Mar/21	46,478	-761	250	45,967	32,436	34,415		2,342	6,087	1,500	1,500	6,786	**20.9%**
21/Mar/21	46,478	-761	250	45,967	31,046	33,213		2,342	6,089	1,500	1,500	8,174	**26.3%**
28/Mar/21	46,478	-761	250	45,967	29,183	31,652		2,342	5,661	1,500	1,500	10,465	**35.9%**

Key

Highlighted week beginning 17-Jan-21 denotes the NPCC forecasted coincident peak demand.

Highlighted week beginning 28-Mar-21 denotes week with the largest forecasted NPCC “Revised Net Margin”.

Highlighted number denotes forecasted Winter 2020-21 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 65% 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 account for the capacity values for derated 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 Production. 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 normal Demand Forecast Methodology (Appendix IV).

Interruptible Loads

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

Known Maintenance/Derates

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

Individual Reliability Coordinator area particularities

Maritimes

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

New England

Known maintenance includes all known planned outages as publically reported in 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 reductions 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 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 and 50% of the second-largest contingency.

New England

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

New York

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

Ontario

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

Québec

The required operating reserve consists of 100% of the largest first contingency and 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 take into account 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 on the basis of historical unplanned outage data and will also include values for natural gas-at-risk 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/derates – 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 for certain 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.

New England

Net margin is the operable capacity margin for ISO-NE. The operable capacity margin is calculated in the monthly Current Year and First Future Year Annual Maintenance Schedule (AMS) report.

Bottled Resources

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

This is used primarily in the summer capacity period. It takes into account the fact that the margin available in Maritimes and Québec exceeds the transfer capability to the rest of NPCC since Québec and Maritimes are winter peaking.

Revised net margin (Table AP-1, 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 Forecasted Winter Transfer Capabilities

The following table represents the forecasted transfer capabilities between Reliability Coordinator Areas represented as Total Transfer Capability (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. This 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 services 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 (MW)	ATC (MW)	Comments
Québec			
Eel River (NB)/Matapédia (QC) Edmundston (NB)/Madawaska (QC)	335 435	335 435	Eel River winter rating is 350 MW. When Eel River converter losses and line losses to the Québec border are taken into account, Eel River to Matapédia transfer is 335 MW. Madawaska HVDC winter rating is 435 MW.
Total	**770**	**770**	The NB to HQ-HVDC transfer capability is limited to 650 MW due to Load loss limitations in the Maritimes.
New England			
Orrington, Keene Road	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.
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	The transfer capability is dependent upon New England system load levels and generation dispatch. If key generators are online and New England system load levels are acceptable, the transfers to New York could exceed 1,200 MW. ISO-NE planning assumptions are based on an interface limit of 1,200 MW.
NNC Cable (Northport-Norwalk Harbor Cable)	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. The Cross Sound Cable is a DC tie and is not included in the Feasible simultaneous transfer capability with NY.
Total	**1,730**	**1,730**	

Interconnection Point	TTC (MW)	ATC (MW)	Comments
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)	Comments
New England			
Northern AC Ties (393, 398, E205W, PV20, K7, K6 and 690 lines)	1,700	1,500	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. The Cross Sound Cable is a DC tie and is not included in the Feasible Simultaneous Transfer capability with NY.
Total	**2,230**	**2,030**	
Ontario			
Lines PA301, PA302, BP76, PA27, L33P, L34P	1,900	1,600	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 taken into account.
Total	**1,900**	**1,600**	
PJM			
PJM AC Ties	1,850	1,550	New York applies a 300 MW Transmission Reliability Margin (TRM).
NYC/PJM Linden VFT	315	315	
Total	**2,165**	**1,865**	
Québec			
Chateauguay (QC)/Massena (NY)	1,000	1,000	
Cedars / Quebec	199	199	
Total	**1,199**	**1,199**	

Transfers from Ontario to

Interconnection Point	TTC (MW)	ATC (MW)	Comments
New York			
Lines PA301, PA302, BP76, PA27, L33P, L34P	2,100	1,900	The TRM is 200 MW.
Total	**2,100**	**1,900**	
MISO **Michigan**			
Lines L4D, L51D, J5D, B3N	1,750	1,550	The TRM is 200 MW.
Total	**1,750**	**1,550**	
Québec			
NE / RPD – KPW Lines D4Z, H4Z	110	100	The 110 MW reflects an agreement through the TE-IESO Interconnection Committee. The TRM is 10 MW.
Ottawa / BRY – PGN Lines X2Y, Q4C	140	140	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	**2,170**	**2,130**	

Interconnection Point	TTC (MW)	ATC (MW)	Comments
MISO **Manitoba, Minnesota**			
NW / MAN Lines K21W, K22W	300	275	The TRM is 25 MW.
NW / MIN Line F3M	150	130	The TRM is 20 MW
Total	**450**	**405**	

Transfers from Québec to

Interconnection Point	TTC (MW)	ATC (MW)	Comments
Matapédia (QC)/Eel River (NB)	350 + radial loads	350 + radial loads	Eel River HVDC winter rating is 350 MW. Radial load transfer amount is dependent on local loading and is reviewed annually
Madawaska (QC)/Edmundston (NB)	423 + radial loads	423 + radial loads	Madawaska winter rating is 435 MW. When Madawaska converter losses and line losses to the New Brunswick border are taken into account, Madawaska to St-André transfer is 423 MW. Radial load transfer amount is dependent on local loading and is reviewed annually.
Total	**773 + radial loads**	**773 + 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 The value estimated at peak load is 1,400 MW.
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	Beauharnois G.S. is used for Québec needs under peak load conditions, in which case transfer is limited to Châteauguay capacity (1000 MW).
Les Cèdres (Qc)/Dennison (NY)	199	199	Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 199 MW and 160 MW respectively. However, the TTC of both points of delivery combined is 325 MW, the maximum capacity of Les Cèdres substation.
Total	**1,999**	**1,999**	

Interconnection Point	TTC (MW)	ATC (MW)	Comments
Ontario			
Les Cèdres (Qc)/Cornwall (Ont.)	160	160	Points of delivery Dennison (NY) and Cornwall (Ont.) have a maximum capacity of 199 MW and 160 MW respectively. 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	Beauharnois Generating Station is used for Québec needs under peak load conditions in which case no export is expected on this path at peak time.
Brookfield/Ottawa (Ont.)	250	250	Only one of H9A or D5A can be in services at any time. The transfer capability reflects usage of D5A.
Rapide-des-Iles (Qc)/Dymond (Ont.)	85	85	This represents Line D4Z capacity. There is no capacity to export to Ontario through Line H4Z.
Bryson-Paugan (Qc)/Ottawa (Ont.)	410	410	Limitations on the Québec system under peak load conditions restrict deliveries as follows P33C - 345 MW and X2Y – 65 MW. 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	**2,955**	**2,955**	

Import Transfers from Regions External to NPCC

Interconnection Point	TTC (MW)	ATC (MW)	Rationale for Constraint
MISO (Michigan) / ONT			
Lines L4D, L51D, J5D, B3N	1,750	1,550	The TRM is 200 MW
Total	**1,750**	**1,550**	
MISO (Manitoba-Minnesota) / ONT			
NW / MAN Lines K21W, K22W	368	343	Flows into Ontario include flows on circuit SK1 of 68 MW. The TRM on the K21W, K22W interface is 25 MW.
NW / MIN Line F3M	100	80	The TRM is 20 MW.
Total	**468**	**423**	
PJM / New York			
PJM AC Ties	2,750	2,450	The TRM is 300 MW
PJM/NYC Linden VFT	315	315	
PJM/Long Island Neptune Cable	660	660	
PJM/NYC HTP DC/DC Tie	660	660	
Total	**4,385**	**4,085**	

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 Operator). 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. Nova Scotia uses 5% as the Extreme Load Forecast Margin while the rest of the Maritimes uses 9% after similar analysis on their part.

New England

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

ISO'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 20 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 25 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[20] 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 79.9 and CDD (cooling degree days, base 65°F) of 16.6. The extreme summer peak demand forecast, or "90/10", which has a 10% chance of being exceeded, is associated with a WTHI of 81.8 and CDD of 19.5.

The reference winter peak demand forecast, or "50/50", is associated with an effective temperature (which includes the effect of both dry-bulb temperature and wind speed) of 5.2 and HDD (heating degree days, base 65 °F) of 57. The extreme winter peak demand forecast or "90/10", is associated with an effective temperature of -1.7 and HDD of 61.7.[21]

From a short-term load forecast perspective, New England utilizes a Metrix Zonal load forecast, which produces a zonal load forecast for the eight regional load zones for up to

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

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

six days in advance through the current operating day. This forecast enhances reliability on a zonal level by taking into account conflicting weather patterns, for example, when the Boston zone is forecasted to be five degrees while the Hartford area is forecast to be thirty degrees. This zonal forecast ensures an accurate reliability commitment on a regional level. The loads for the eight zones are then summed to estimate a total New England load, adding an additional New England load forecast to its Advanced Neural Network (ANN) models and Similar-Day (SimDay) analyses).

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 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 extreme 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 extreme 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 a number of drivers. These drivers include weather effects, economic data, conservation, embedded generation and calendar variables. 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, minimum and peak demand, including zone and system wide projections. 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. 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, labor market drivers and industrial indicators are utilized to generate the forecast of demand. The impact of conservation measures are 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 extreme weather scenario, Ontario uses the maximum value from the sorted history.

The variable generation capacity in Table 4 is the total installed capacity expected during the operating period, with the variable generation resources expected in-service outlined in Table 3. For determining wind and solar derating factors, Ontario uses seasonal contribution factors based upon median historical hourly production values. The wind contribution factor is 37.8% for the winter and 13.7% for the summer. The solar contribution factor is 0% for the winter and 13.8% for the summer.

Québec

Hydro-Québec's demand and energy-sales forecasting is Hydro-Québec Distribution's responsibility. First, the energy-sales forecast is built upon the forecast from four different consumption sectors – domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, energy efficiency, and different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.

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

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a 47-year temperature database (1971−2017), adjusted by 0.30°C (0.54°F) per decade starting in 1971 to account for climate change. Moreover, each year of historical climatic data is shifted up to ±3 days to gain information on conditions that occurred during either a weekend or a weekday. Such an exercise generates a set of 329 different demand scenarios. Weather uncertainty is calculated from these 329 demand scenarios (energy and peak). 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 is lower during the summer than during the winter. For example, at the summer peak, weather conditions uncertainty is about 450 MW, equivalent to one standard deviation. During winter, this uncertainty is about 1,500 MW.

TransÉnergie – the Québec system operator – then determines the Québec Balancing Authority Area forecasts using Hydro-Québec Distribution's 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. TransÉnergie 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 taken into account on a short-term basis.

Appendix V - NPCC Operational Criteria and Procedures

<u>NPCC Directories Pertinent to Operations</u>

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 Directory #12 - "Underfrequency Load Shedding Requirements"

Description: This document presents the basic criteria for the design and implementation of under frequency load shedding programs to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements to prevent system collapse due to load-generation imbalance.

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.

<u>NPCC Procedures Pertinent to Operations</u>

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 - Web Sites

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

https://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

Reliability*First* Corporation

http://www.rfirst.org

Hydro-Québec TransÉnergie

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

Appendix VII - References

CP-8 2020-21 Winter Multi-Area Probabilistic Reliability Assessment

NPCC Reliability Assessment for Winter 2019-20

Appendix VIII – CP-8 2020-21 Winter Multi-Area Probabilistic Reliability Assessment – Supporting Documentation

Northeast Power Coordinating Council, Inc.

Multi-Area Probabilistic Reliability Assessment

For

Winter 2020 - 2021

Approved by the RCC

December 1, 2020

Conducted by the

NPCC CP-8 Working Group

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The CP-8 Working Group acknowledges the efforts of Messrs. Eduardo Ibanez and Mitch Bringolf, GE Energy Consulting, and Patricio Rocha-Garrido, the PJM Interconnection, and thanks them for their assistance in this analysis.

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 November 2020 through March 2021 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 simulations.

The assumptions used in this probabilistic study are consistent with the CO-12 Working Group's study, "*NPCC Reliability Assessment for Winter 2020-21*", December 2020 [1], and summarized in Table 1.

Table 1: Assumed Load and Base Case Capacity for Winter 2020/21

Area	Expected Peak [2] (MW)	Extreme Peak [3] (MW)	Available Capacity [4] (MW)	Peak Month
Québec (HQ)	38,775	42,110	41,599	January
Maritimes Area (MT)	5,496	6,002	7,527	January
New England (NE)	20,166 [5]	20,937	31,062 [6]	January
New York (NY)	24,130	25,945	41,639	January
Ontario (ON)	20,835	21,684	35,019	January

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

[2] The expected peak load forecast represents each Area's projection of mean demand over the study period based on historical data analysis.

[3] The extreme peak load forecast is determined at two standard deviations higher than the mean, which has a 6.06 percent probability of occurrence.

[4] Available Capacity represents Area's effective capacity at the time of the peak; it takes into account firm imports and exports, reductions due to deratings, Active Demand Response, and scheduled outages.

[5] This is the net peak forecast reflecting the reduction from passive demand response resources and the peak reduction impacts from BTM PV. Gross peak = 23,373 MW; Passive DR = 3,207 MW; BTM PV reduction = 0; Net peak = 20,166 MW.

[6] Total generation = 33,460 - Active DR (579 MW) + Net import (1,024 MW) - Gas at risk (4,000 MW) = 29,905 MW (Net).

The study was conducted for two load scenarios: expected load level scenario and extreme load level scenario. The expected load level was based on the probability-weighted average of seven load levels simulated, while the extreme load represents the second highest load level of the seven levels simulated (see section 3.1.2). The extreme load level has a six percent chance of occurring. While the extreme load as defined for this study may be different than the extreme load defined by the Areas in their own studies, the Working Group finds this load level appropriate for providing an assessment of the extreme condition in NPCC. Details of information provided by each Area for the forecasts are presented in Section 3.1 of this report.

For each of the two demand scenarios described above, two different system conditions were considered: Base Case assumptions and Severe Case assumptions. Details regarding the two sets of assumptions are described in Section 3.7 of this report.

Table 2 shows the estimated use of demand response programs and operating procedures under the Base Case assumptions for the expected load level and the extreme load level scenarios for the November 2020 – March 2021 period. Occurrences greater than 0.5 days/period are highlighted. [7]

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

	HQ	MT	NE	NY	ON	HQ	MT	NE	NY	ON
	Expected Load Level					Extreme Load Level				
Reduce 30-min Reserve	0.004	2.846	-	-	-	0.060	15.778	-	-	-
Initiate Interruptible Loads/Voltage Reduction [8]	-	1.445	-	-	-	0.007	8.884	-	-	-
Reduce 10-min Reserve [9]	-	0.088	-	-	-	0.001	0.793	-	-	-
Appeals	-	0.002	-	-	-	-	0.033	-	-	-
Disconnect Load	-	0.002	-	-	-	-	0.033	-	-	-

[7] Rounded to the nearest whole occurrence, likelihoods of less than 0.5 days/period are not considered significant.
[8] Initiate Interruptible Loads for the Maritimes Area (implemented only for the Area), Voltage Reduction for all the other Areas.
[9] New York initiates Appeals prior to reducing 10-min Reserve.

Under Base Case conditions, only the Maritimes Area shows a likelihood of using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and initiating interruptible loads) during the 2020/21 winter period for the expected load forecast (representing the probability weighted average of all seven load levels). The results for the extreme load forecast (representing the second to highest load level, having approximately a 6% chance of occurring) also estimates a need for the Maritimes reducing 10-min reserve, as well. These results are primarily driven by Nova Scotia's forecast load and corresponding reserve margin expectations.

Table 3 shows the estimated use of demand response programs and operating procedures under the Severe Case assumptions for the expected load level and the extreme load level scenarios for the November 2020 - March 2021 period. Occurrences greater than 0.5 days/period are highlighted. [5]

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

	HQ	MT	NE	NY	ON	HQ	MT	NE	NY	ON
	Expected Load Level					Extreme Load Level				
Reduce 30-min Reserve	0.025	9.094	-	-	-	0.363	42.030	-	-	-
Initiate Interruptible Loads/Voltage Reduction [10]	0.008	4.979	-	-	-	0.114	26.824	-	-	-
Reduce 10-min Reserve [11]	0.002	0.479	-	-	-	0.035	3.656	-	-	-
Appeals	0.000	0.019	-	-	-	0.001	0.237	-	-	-
Disconnect Load	0.000	0.019	-	-	-	0.001	0.237	-	-	-

As shown in Table 3, the Maritimes Area risk increases assuming Severe Case conditions, especially for the extreme load forecast; again, these results are primarily driven by Nova Scotia's forecast load and corresponding reserve margin expectations. The extreme load level represents the second to highest load level, having approximately a 6% chance of occurring.

[10] Initiate Interruptible Loads for the Maritimes Area (implemented only for the Area), Voltage Reduction for all the other Areas.
[11] 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 November 2020 through March 2021.

The CP-8 Working Group's efforts are consistent with the NPCC CO-12 Working Group's study, "*NPCC Reliability Assessment for Winter 2020 - 2021*", December 2020. 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 simulations. APPENDIX C provides an overview of General Electric's Multi-Area Reliability Simulation (MARS) Program; version 3.30.1531 was used for this assessment.

3. STUDY ASSUMPTIONS

The database developed by the CP-8 Working Group for the "*NPCC Reliability Assessment for Summer 2020*" [12] was used as the starting point for this analysis. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the winter 2020/21 assessment period.

3.1 Demand

3.1.1 Load Assumptions

Each area provided annual or monthly peak and energy forecasts for winter 2020/21. Table 4 summarizes each Area's winter expected peak load assumptions for the study period.

Table 4: Assumed NPCC Areas 2020/21 Winter Peak Demand

Area	Month	Peak Load (MW)
Québec	January	38,775
Maritimes Area	January	5,496
New England	January	20,166 [13]
New York	January	24,130
Ontario	January	20,835

Specifics related to each Area’s 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.

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

[13] This is the net peak forecast reflecting the reduction from passive demand response resources and the peak reduction impacts from BTM PV. Gross peak = 23,373 MW; Passive DR = 3,207 MW; BTM PV reduction = 0; Net peak = 20,166 MW.

New England

ISO-New England develops an independent demand forecast for its Balancing Authority (BA) area using historical hourly demand data from individual member utilities, which is based upon revenue quality metering. This data is then used to develop historical demand data on which the regional peak demand and energy forecasts are subsequently based. From this, ISO-New England develops a forecast of both state and system seasonal peak and energy demands. The peak demand forecast for the region and the states can be considered a coincident peak demand forecast. For the first time this year, ISO-New England developed transportation and electrification and heating electrification forecasts, and included them in the demand forecast. This demand forecast is referred to as the Gross Demand Forecast (Without Reductions) within the ISO-New England 2020 Load Forecast. [14]

The gross reference (50/50) winter peak forecast is 23,737 MW for the winter of 2020/21. It corresponds to a dry bulb temperature of 7.0°F, which is the 95th percentile of a weekly weather distribution and is consistent with the median of the dry-bulb value at the time of the winter peak over the last 25 years. The reference demand forecast is based on the reference economic forecast, which reflects the regional economic conditions that are expected that would most likely to occur.

In addition to the annual update to ISO-New England's forecast for both peak demand and energy, ISO-New England also forecasts the anticipated growth and impact of Behind-The-Meter Photovoltaic (BTM PV) resources within the BA area that do not participate in wholesale markets. ISO-New England's BTM PV forecast is developed annually with stakeholder input from the Distributed Generation Forecast Working Group. For the BTM PV forecast, the resources are considered to be those with typically 5 MW or less in nameplate capacity that are interconnected to the distribution system (typically 69 kilovolts or below) according to state-jurisdictional interconnection standards. The 2020 BTM PV forecast can be found using the following link: https://www.iso-ne.com/static-assets/documents/2020/03/final-2020-pv-forecast.pdf.

Around 3,965 MW (AC nameplate rating) of installed PV resources are expected within New England by the end of 2020; the majority of them (~2,298 MW) are BTM PV resources. Their contribution to reducing system peaks, however, is diminished during the winter period, because New England's daily forecasted winter peak typically occurs during the evening hours, when the PV contribution is significantly reduced.

ISO-New England also develops a forecast of long-term savings in peak and energy use for the BA area and for each state stemming from state-sponsored Energy-Efficiency (EE) programs.

[14] See: https://www.iso-ne.com/static-assets/documents/2020/04/forecast_data_2020.xlsx.

Examples of EE measures include the use of more efficient lighting, motors, refrigeration, HVAC equipment, control systems, and industrial process equipment. ISO-New England's forecast of EE resources is developed with stakeholder input from the Energy-Efficiency Forecast Working Group. Data used to create the EE forecast originates from state-regulated utilities, energy-efficiency program administrators, and state regulatory agencies. The EE forecast is based on averaged production costs, peak-to-energy ratios, and projected budgets of state-sponsored energy-efficiency programs.

The 2020 EE forecast can be found using the following link: https://www.iso-ne.com/static-assets/documents/2020/04/eef2020_final_fcst.pdf . The amount of EE resources is expected to be around 3,207 MW for the 2020/21 winter.

New York

The NYISO employs a multi-stage process to develop load forecasts for each of the eleven zones within the NYCA. 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 ("GDP"), households, population, and commercial and industrial employment. Projected long-term weather trends from the *NYISO Climate Change Impact Study Phase I* [15] are included in the end-use models. 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 NYISO aggregates load forecasts by Zone.

These forecasts are based on information obtained from the New York State Department of Public Service (DPS), the New York State Energy Research and Development Authority (NYSERDA), state power authorities, Transmission Owners, the U.S. Census Bureau, and the U.S. Energy Information Administration.

[15] See: https://www.nyiso.com/documents/20142/10773574/NYISO-Climate-Impact-Study-Phase1-Report.pdf

The baseline and topline forecasts reflect a combination of information provided by Transmission Owners for their respective territories and forecasts prepared by the New York ISO. [16]

Ontario

The IESO demand forecast includes the impact of conservation, time-of-use rates, and the effects of distributed energy resources.

Québec

The load forecast is consistent with the assumptions used in the "NERC *2020 Québec Long-Term Reliability Assessment*." [17] Québec's demand and energy-sales forecasting is Hydro-Québec Distribution's responsibility. First, the energy-sales forecast is built on the forecast from four different consumption sectors – domestic, commercial, small and medium-size industrial and large industrial. The model types used in the forecasting process are different for each sector and are based on end-use and/or econometric models. They consider weather variables, economic-driver forecasts, demographics, energy efficiency, and different information about large industrial customers. This forecast is normalized for weather conditions based on an historical trend weather analysis.

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

Load Forecast Uncertainty (LFU) includes weather and load uncertainties. Weather uncertainty is due to variations in weather conditions. It is based on a 49-year database of temperatures (1971-2019), adjusted by +0.3 °C (+0.5 °F) per decade starting in 1971 to account for climate change. Moreover, each year of historical climatic data is shifted up to ±3 days to gain information on conditions that occurred during either a weekend or a weekday. Such an exercise generates a set of 343 different demand scenarios. The base case scenario is the arithmetical average of the peak hour in each of these 343 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. As an example, at the summer peak,

[16] See: https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf/

[17] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

weather conditions uncertainty is about 470 MW, equivalent to one standard deviation. During winter, this uncertainty is 1,580 MW.

3.1.2 Load Model in MARS

The loads for each Area were modeled on an hourly, chronological basis, using the 2003/04 winter load shape. The MARS program modified the hourly loads through time to meet each Area's specified peaks and energies.

In 2006, the Working Group reviewed and agreed that the weather patterns associated with the 2003/04 winter are representative of weather conditions that stress the system and are appropriate for use in future winter assessments.

The growth rate in each month's peak was used to escalate Area loads to match the Area's winter demand and energy forecasts.

Figure 1 shows the diversity in the NPCC area load shapes used in this analysis, with the 2003/04 load shape assumptions.

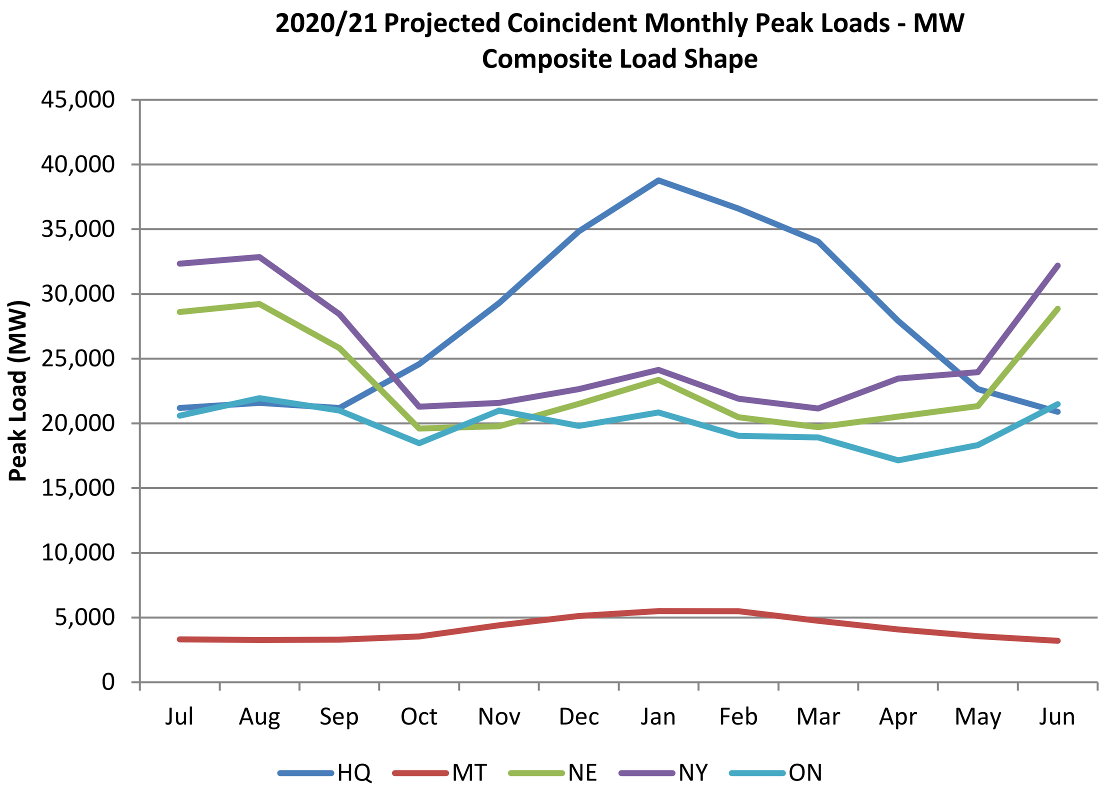

Figure 1: 2020/21 Projected Monthly Peak Loads for NPCC

The effects on reliability of uncertainties in the peak load forecast due to weather and/or economic conditions were captured through the load forecast uncertainty model in MARS. 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 load forecast uncertainty provided by each Area.

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

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

Table 5 shows the load variation assumed for each of the seven load levels modeled and the probability of occurrence for the winter 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 Load by Load Level Assumed for the month of January 2021

Area	Per-Unit Variation in Load						
	Level 1	Level 2	Level 3	Level 4	Level 5	Level 6	Level 7
HQ	1.086	1.086	1.043	1.000	0.959	0.916	0.911
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.071	1.033	0.985	0.963	0.935	0.865	0.800
NY	1.118	1.075	1.036	1.000	0.967	0.938	0.913
ON	1.076	1.051	1.025	1.000	0.976	0.954	0.939
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 load conditions: expected and extreme. The values for the expected load conditions are derived from computing the reliability at each of the seven load levels and computing a weighted-average expected value based on the specified probabilities of occurrence.

The indices for the extreme load conditions provide a measure of the reliability in the event of higher than expected loads and were computed for the second-to-highest load level. They represent a load level two standard deviation higher than the expected load level, with a six percent probability of occurrence. These values are highlighted in Table 5.

While the extreme load as defined for this study may be different than the extreme load defined by the Areas in their own studies, the Working Group finds this load level appropriate for providing an assessment of the extreme condition in NPCC.

3.2 Resources

Table 6 below summarizes the winter 2020/21 capacity assumptions for the NPCC Areas used in the analysis for the Base Case Scenario and are consistent with the assumptions used in the NPCC CO-12 Working Group, "*NPCC Reliability Assessment for Winter 2020-21*", December 2020.

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

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

	HQ	MT	NE	NY	ON
Assumed Capacity [18]	41,599	7,527	29,459	41,639	35,019
Demand Response [19]	1,732	277	579	839	688
Net Imports/Exports [20]	171	-69	1,024	-116	-500
Reserve (%)	12.2	40.7	54.0 [21]	77.4	67.9
Scheduled Maintenance [22]	-	10	-	3,992	0

[18] Assumed Capacity - the total generation capacity assumed to be installed at the time of the winter peak. For New England, this is the amount of generation capacity assumed available after reflecting the reduction from gas-fired generation assumed due to fuel supply (4,000 MW).

[19] Demand Response: the amount of “controllable” demand expected to be available for reduction at the time of peak. New York value represents the SCR amount. For New England, this represents the Active Demand Capacity Resources.

[20] Net Imports / Exports: the amount of expected firm imports and exports at the time of the winter peak. The value is positive for imports and negative for exports.

[21] Based on the values shown in Table 1 – 31,062/20,166 = 154%.

[22] Maintenance scheduled at time of peak.

Details regarding the NPCC Area's assumptions for generator unit availability are described in the respective Area's most recent NPCC Review of Resource Adequacy. [23] In addition, the following Areas provided the following:

New England

The generating resources include the existing units and planned resources that are expected to be available for the 2020-21 winter, and their ratings are based on their Seasonal Claimed Capability. Settlement Only Generating (SOG) resources are not included in this assessment, but they do participate in the energy market and help serve New England system loads.

The resources assumed in this assessment also include the Active Demand Capacity Resources and capacity imports from the neighboring areas. The Active Demand Capacity Resources and imports are based on their Capacity Supply Obligations associated with the 3rd Annual Reconfiguration Auction for Capacity Commitment Period (CCP) of 2020 - 2021. [24]

New York

Detailed availability assumptions used for the New York units can be found in the New York ISO Technical Study Report "*Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2020 – 2021 Capability Year - January 8, 2020*" [25] and the "*New York Control Area Installed Capacity Requirement for the Period May 2020 to April 2021*" New York State Reliability Council, December 6, 2019 report. [26]

Ontario

Generating unit availability was based on the Ontario "*Reliability Outlook - An adequacy assessment of Ontario's electricity system From October 2020 To March 2022*" (September 22, 2020). [27]

Québec

The planned resources are consistent with the "*NERC 2020 Long-Term Reliability Assessment*." [28] The planned outages for the winter period are reflected in this assessment. The number of planned outages is consistent with historical values. The MARS modelling details for each type of resource in each Area are provided in Appendix D of the report.

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[23] See: https://www.npcc.org/library/resource-adequacy.

[24] The 2020-2021 CCP starts on June 1, 2020 and ends on May 31, 2021.

[25] See: https://www.nyiso.com/documents/20142/8583126/LCR2020-Report.pdf/4c9309b2-b13e-9b99-606a-7af426d93a47

[26] See: http://www.nysrc.org/PDF/Reports/2020%20IRM%20Study%20Body%20Final%2012-9-19.pdf

[27] See: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2020Sep.pdf?la=en

[28] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

Maritimes
Planned outages forecast to occur during the period are reflected in this assessment.

3.3 Transfer Limits

Figure 2 depicts the system that was represented in this assessment, showing Area and assumed Base Case transfer limits for the winter 2020/21 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 345 kV, 230 kV, and 115 kV transmission lines, which in northern New England generally are longer and fewer in number than in southern New England. The region has 13 interconnections with neighboring power systems in the United States and Eastern Canada. Nine interconnections are with New York (NYISO) (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 converter station, which converts alternating current to direct current and then back to alternating current. The other is a ±450 kV HVDC line with terminal configurations allowing up to 2,000 MW to be delivered at Sandy Pond in Massachusetts (i.e., Phase II).

There are no anticipated transmission additions/upgrades for the upcoming winter.

New York
The New York wholesale electricity market is divided into 11 pricing or load zones and is interconnected to Ontario, Quebec, 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 miles in total.

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 nine major internal interfaces in the Ontario transmission system. 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. TransÉnergie, the main Transmission Owner and Operator in Québec, has interconnections with Ontario, New York, New England, and the Maritimes.

There are back to back HVDC links with New Brunswick at Madawaska and Eel River (in New Brunswick), with New England at Highgate (in New England) and with New York at Châteauguay. The Radisson – Nicolet – Sandy Pond HVDC line ties Québec with New England. Radial load can be picked up in the Maritimes by Québec at Madawaska and at Eel River and at Stanstead feeding Citizen's Utilities in New England. Moreover, in addition to the Châteauguay HVDC back to back interconnection to New York, radial generation can be 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 are now in service. Other ties between Québec and Ontario consist of radial generation and load to be switched on either system.

Transfer limits between and within some Areas are indicated in Figure 2 with seasonal ratings (S- summer, W- winter) where appropriate. Details regarding the transmission representation for Ontario [29], New York [30], and New England [31] are provided in the respective references.

[29] See: http://www.ieso.ca/localContent/ontarioenergymap/index.html.

[30] See: http://www.nysrc.org/pdf/Reports/2019%20IRM%20Study%20Appendices%20-Final%20Report[6816].pdf.

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

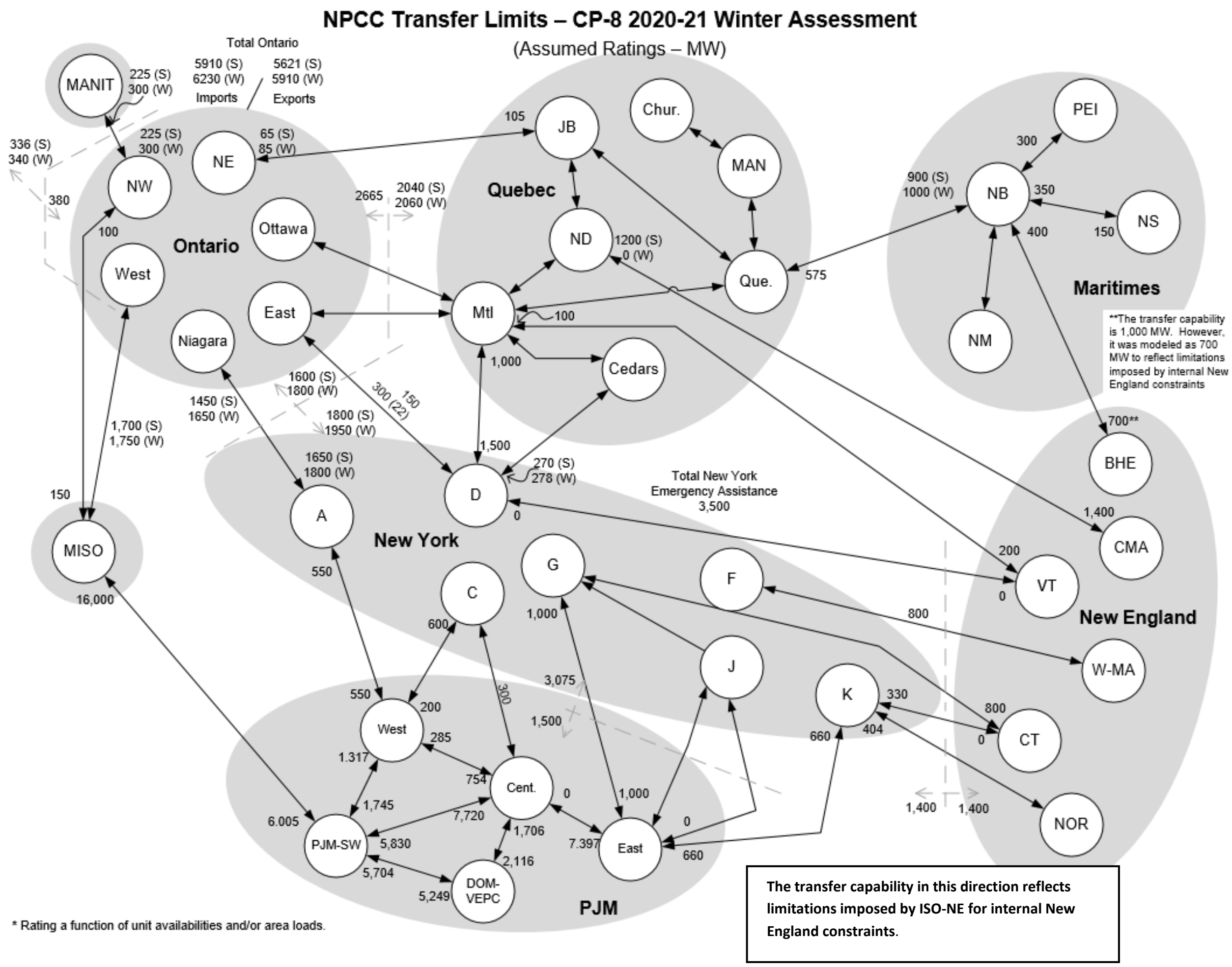

Figure 2: Assumed Transfer Limits

Note: With the Variable Frequency Transformer operational at Langlois (Cdrs), Hydro- Québec can import up to 100 MW from New York. [32]

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
NM	- Northern Maine	Que Centre	- Québec Centre	Cdrs	- Cedars

[32] See: http://www.oasis.oati.com/HQT/HQTdocs/2014-04_DEN_et_CORN-version_finale_en.pdf.

3.4 Operating Procedures to Mitigate Resource Shortages

Each Area takes defined steps as their reserve levels approach critical levels. These steps consist of those 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 reduced operating reserves. Table 7 summarizes the load relief assumptions modeled for each NPCC Area.

Table 7: NPCC Operating Procedures – 2020/21 Winter Load Relief Assumptions (MW)

Actions	HQ	MT	NE	NY [33]	ON
1. Curtail Load Public Appeals RT-DR / SCR SCR Load / Man. Volt. Red.	1,732 - - -	- - - -	- - - -	- - 581 0.20 %	- 1% - -
2. No 30-min Reserves	500	233	625	655	473
3. Voltage Reduction Interruptible Load [34]	250 -	- 277	202 -	1.0% 207	1.3% 716
4. No 10-min Reserves Appeals / Curtailments	750 -	505 -	- -	- 80	945 -
5. 5% Voltage Reduction No 10-min Reserves Appeals / Curtailments	- - -	- - -	- 980 -	- 1,310 -	0.6% - -

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 analysis.

The need for an Area to begin 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 load, and as a per unit of the available capacity for the hour.

[33] Values for New York's SCR Program has been derated to account for historical availability.
[34] Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others.

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 C - Multi-Area Reliability Simulation Program Description - Resource Allocation Among Areas (Section C.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. The assumptions are summarized in Table 8.

Table 8: PJM and MISO 2020/21 Base Case Assumptions [35]

	PJM	MISO
Peak Load (MW)	129,632	78,852
Peak Month	January	January
Assumed Capacity (MW)	184,219	109,358
Purchase/Sale (MW)	681	-1,497
Reserve (%)	48.8	41.0
Weighted Unit Availability (%)	87.2	84.2
Operating Reserves (MW)	3,400	3,906
Curtailable Load (MW)	8,047	3,338
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 +/- 3.7, 7.3, 11	100.0 +/- 2.6, 5.3, 7.9

Figure 3 shows the winter 2020/21 Projected Monthly Expected Peak Loads for NPCC, PJM and the MISO for the 2003/04 Load Shape assumption.

[35] 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.

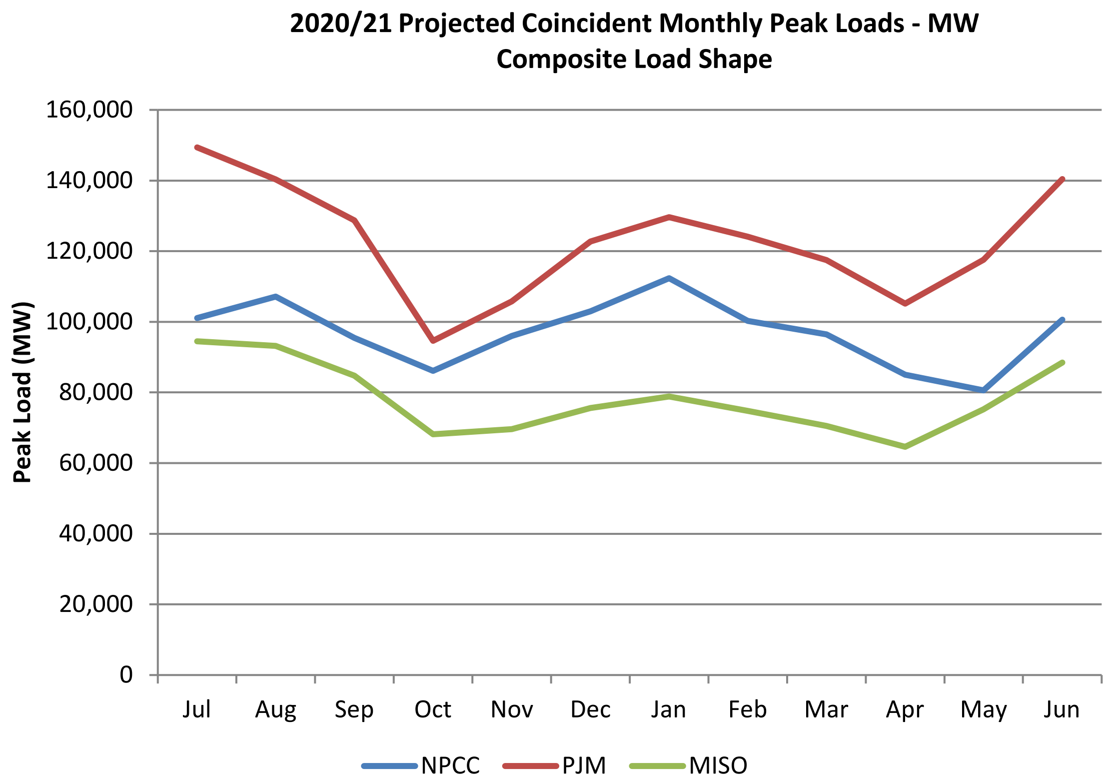

Figure 3: 2020/21 Projected Monthly Winter Peak Loads – 2003/04 Load Shape

Beginning with the "*2015 NPCC Long Range Adequacy Overview*", (LRAO) [36] 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 MISO 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.

[36] 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. [37] The hourly load shape is based on observed 2003/04 calendar year values, which reflects representative weather and economic conditions for a winter peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, January 2020. [38] Load Forecast Uncertainty was modeled consistent with recent planning PJM models [39] 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 the model is based on, sampling size, and how many years ahead 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 as 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. All activities of the TEAC can be found at the pjm.com web site. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, consistent with PJM's regional Transmission Expansion Plan. [40]

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[37] 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.
[38] See: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx?la=en.
[39] See: https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx .
[40] See: http://www.pjm.com/planning.aspx.

3.7 Study Scenarios

The 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 the NPCC Area

	Base Case Assumptions	Severe Case – Additional Constraints
System	- As-Is System for the 2020-2021 period - Transfers allowed between Areas - 2003/04 Load Shapes adjusted to the Area's year 2020 forecast (expected & extreme assumptions)	- As-Is System for the 2020/21 period - Transfers allowed between Areas - Transfer capability between NPCC and MRO/RFC-'Other' reduced by 50%. - 2003/04 Load Shape adjusted to Area's year 2020 forecast (expected & extreme assumptions)

Maritimes	- ~ 1,224 MW of installed wind generation (modeled using 2019 calendar hourly wind, including 164 MW of formally energy only units in Nova Scotia) - 69 MW export contracts assumed - 260 MW of demand response (interruptible load) available in the Maritimes during the winter period	- Wind capacity is de-rated by half (1,224 MW to 612 MW) for every hour in December, January and February to simulate icing conditions - 50% natural gas capacity curtailment (532 to 266 MW) assumed for winter 2020/21 to simulate a reduction in gas supply for December, January, and February (assuming dual fuel units revert to oil)
New England	Resource and load consistent with the 2020 CELT report data for Winter 2020/2021: - ~ 33,460 MW of existing and planned generation resources modeled - ~ 3,207 MW of energy efficiency resources - ~579 MW of Active demand capacity resources - ~ 1,024 MW of capacity import - ~ 4,000 MW of gas-fired generation at risk due to fuel supply assumed unavailable	- Assume 50% reduction to the import capabilities of external ties - Maintenance overrun by 4 weeks - ~ 4,600 MW of gas-fired generation at risk due to fuel supply assumed unavailable
New York	- Updated Load Forecast - (NYCA Winter 2020/21 peak load forecast – 24,130 MW; NYC 7,621 MW; LI – 3,393 MW) - Assumptions consistent with New York Installed Capacity Requirements for May 2020 through April 2021 - ~ 271 MW of units deactivated	- Extended Maintenance in southeastern New York (500 MW) - 600 MW of assumed Cable transmission reduction across HVDC facilities - 4,000 MW of generation assumed unavailable across fleet due to fuel delivery issues.
Ontario	- Forecast consistent with the Ontario *Reliability Outlook - An adequacy assessment of Ontario's electricity system From October 2020 To March 2022, September 22, 2020* [41] - Demand forecast based on 2003/2004 actual weather	- ~800 MW of maintenance extended into the winter period - Hydroelectric capacity and energy 10% lower than the Base Case
Québec	- Resources and load forecast are consistent with the Québec 2020 NERC Long-Term Reliability Assessment - including about 1,400 MW of scheduled maintenance and restrictions - 3,778 MW of installed wind capacity (3,674 MW modeled with a 36% peak contribution) and 108 MW with a 30% peak contribution) representing a total peak contribution of 1,354 MW - 1,600 MW of available capacity imports - ~1040 MW of firm capacity exports	- ~1,000 MW of capacity assumed to be unavailable for the winter peak period

[41] See: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2020Sep.pdf?la=en .

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

	Base Case Assumptions	Severe Case Assumptions
PJM-RTO	- As-Is System for the 2020/21 winter period – consistent with the PJM 2019 Reserve Requirement Study [42] - 2003/04 Load Shapes adjusted to the 2020 forecast provided by PJM - Load forecast uncertainty based on PJM 2019 Reserve Requirement Study - Operating Reserve 3,400 MW (30-min. 2,765 MW; 10-min. 635 MW)	- Gas-fired only capacity not having firm pipeline transportation, assumed ~6,400 MW unavailable - One percentage point increase in load forecast uncertainty - Ice Storm; ice blocking fuel delivery to all units. Unit outage event ~8,400 MW
MISO [43]	- As-Is System for the 2020/21 winter period - based on NERC ES&D database, updated by the MISO, compiled by PJM staff - 2003/04 Load Shapes adjusted to the most recent monthly forecast provided by PJM - 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)	

[42] 2019 PJM Reserve Requirement Study (RRS), dated October 8, 2019 - available at this link on PJM Web site: https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx.

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

4. STUDY RESULTS

4.1 Base Case Scenario

Figure 4 shows the estimated need for the indicated operating procedures in days/period for the November 2020 through March 2021 period for the expected load (probability-weighted average of the seven load levels simulated) for the Base Case. Detailed results from MARS runs are provided in Appendix B.

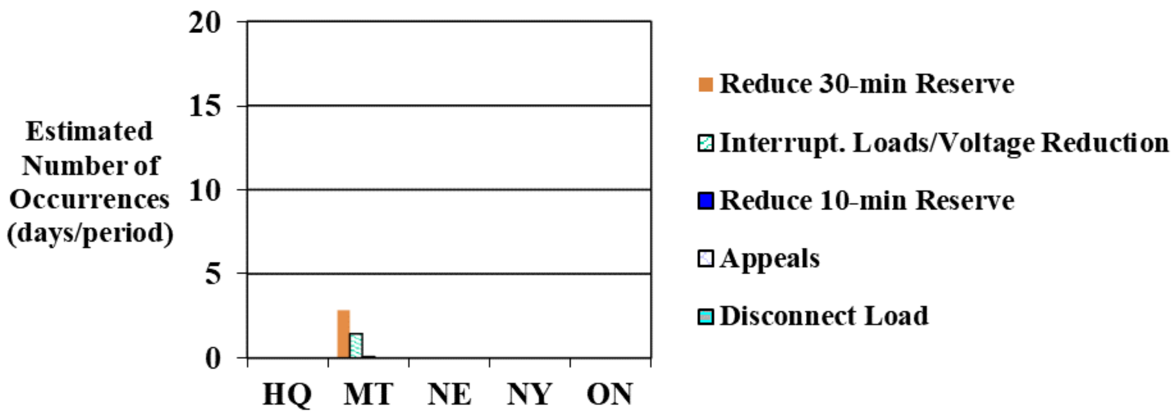

**Figure 4: Estimated Use of Operating Procedure for Winter 2020/21
Base Case Assumptions - Expected Load Level**

Figure 5 shows the corresponding results for the extreme load (representing the second to highest load level, having approximately a 6% chance of occurring) for the Base Case. Detailed results from MARS runs are provided in Appendix B.

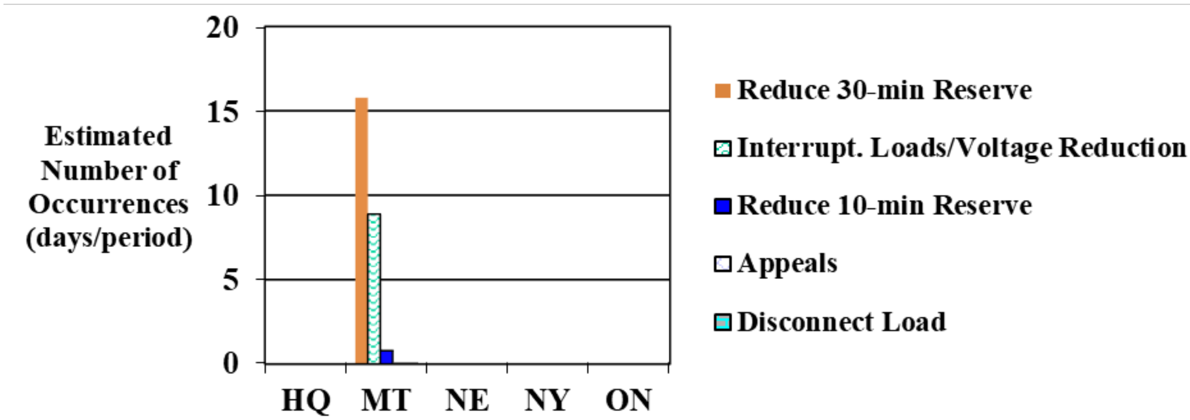

**Figure 5: Estimated Use of Operating Procedures for Winter 2020/21
Base Case Assumptions - Extreme Load Level**

4.2 Severe Case Scenario

Figure 6 shows the estimated use of operating procedures for the NPCC Areas for the expected load (probability-weighted average of the seven load levels simulated) for the Severe Case. Detailed results from MARS runs are provided in Appendix B.

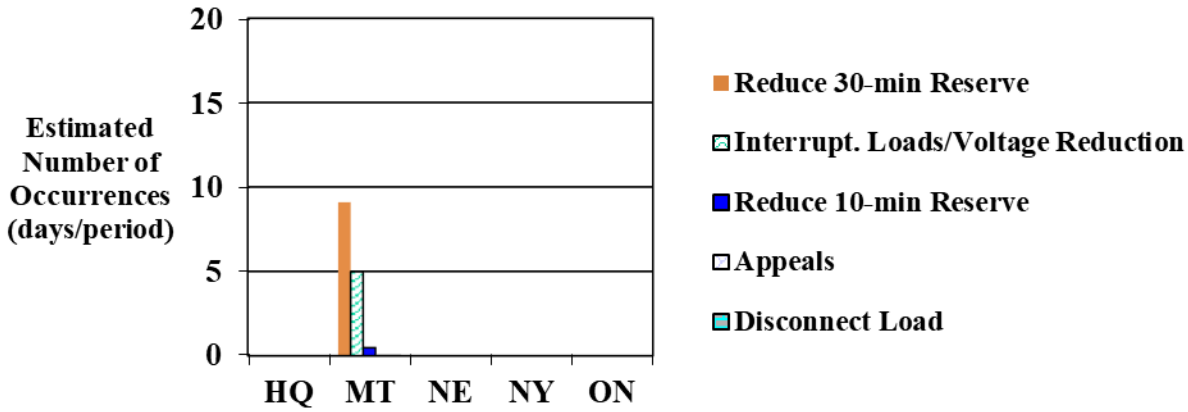

Figure 6: Estimated Use of Operating Procedure for Winter 2020/21 Severe Case Assumptions - Expected Load Level

Figure 7 shows the estimated use of the indicated operating procedures for the Severe Case for the extreme load level (representing the second to highest load level, having approximately a 6% chance of occurring).

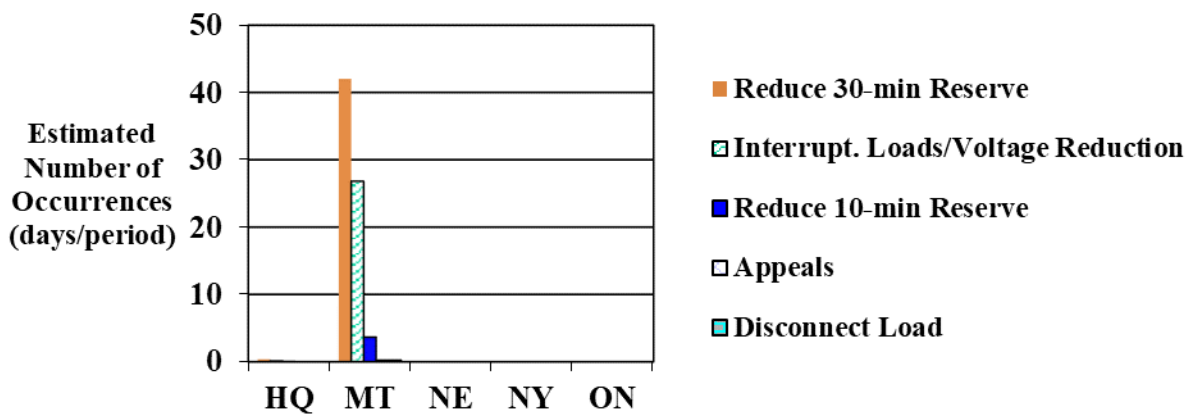

Figure 7: Estimated Use of Operating Procedure for Winter 2020/21 Severe Case Assumptions - Extreme Load Level

5. HISTORICAL REVIEW

Table 11 compares NPCC Area's actual 2019/20 winter peak demands against the forecast assumptions.

Table 11: Comparison of NPCC 2019-20 Actual and Forecast Winter Peak Loads

Area	Date	Actual (MW)	Forecast (MW)		
			Expected Peak	Extreme Peak	Month
Québec	December 19, 2019	36,160	38,783	42,041	January
Maritimes	February 21, 2020	5,335	5,466	5,969	January
New England	December 19, 2019	18,913 [44]	20,476 [45]	21,355	January
New York	December 19, 2019	23,253	24,123	24,871	January
Ontario	December 19, 2019	20,974	21,115	22,022	January

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

5.1 Operational Review

Québec

The actual internal winter peak demand of 36,160 MW occurred on Thursday, December 19, 2019 at hour ending 19:00 EST. The corresponding total winter peak demand (including exports) was 40,472 MW. At that time, interruptible industrial loads were not required and net exports of 4,312 MW were sustained.

The Quebec area historical internal peak demand of 39,031 MW occurred on Wednesday, January 22, 2014 hour ending 8:00.

[44] This is the net peak value – see: https://www.iso-ne.com/static-assets/documents/2020/03/march-2020-coo-report.pdf.

[45] This is the net peak forecast reflecting the reduction from passive demand response resources and the load reduction impact from the Behind-the-Meter PV.

Maritimes

The Maritimes Area load is the mathematical sum of the forecasted 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).

Maritimes 2019/20 winter peak was 5,335 MW on February 21, 2020 at hour ending 7:00 EST. The Maritime Provinces did not experience any unexpected extreme or adverse weather conditions; all major transmission lines were in-service.

New England [46]

The New England winter average temperature of +4.3°F was consistent with NOAA's seasonal outlook issued November 21, 2019 of above normal temperatures. The system peak demand of 18,913 MW occurred on December 19, 2019 hour ending 18:00 EST.

There were minimal reductions in natural gas availability to generation. Fuel oil usage was minimal and the supplies remained steady throughout the winter. Generation fleet and transmission system performed well, and surplus generation capacity was available throughout the winter

There were no MLCC-2 (Abnormal Conditions Alert) or OP-4 (Capacity Deficiency) actions were implemented throughout the winter.

New York [47]

The 2019/20 actual winter peak demand of 23,253 MW occurred on Tuesday, December 19, 2019, hour ending 18:00 EST. New York ISO fuel surveys indicated sufficient alternate fuel inventory; forced outages and derates on were substantially less than forecast (2,299 MW vs 3,043 MW):

- ✓ No activations of SCR/EDRP required;
- ✓ No need for emergency actions (voltage reduction, public appeals, etc.); and,
- ✓ No need for emergency purchases

The New York all time winter peak load of 25,738 MW occurred on Tuesday, January 7, 2014.

Ontario

Ontario's peak demand for 2019/20 winter was 20,974 MW on December 19,2019 hour ending 18:00 EST. December's weather was slightly milder than normal, particularly in the southern part of the province. Usually, the month has a peak day temperature near -10.0 °C and December 2019's

[46] See: https://www.iso-ne.com/static-assets/documents/2020/03/march-2020-coo-report.pdf..

[47] See: http://www.nysrc.org/PDF/MeetingMaterial/ECMeetingMaterial/EC%20Agenda%20252/7.3.1%202019%20-%202020%20Cold%20Weather%20Operating%20Conditions%20-%20NYSRC%20-%20April%209-Attachment%207.3.1.pdf

coldest day had an afternoon high of -9.6 °C. December can have unpredictable results depending on how the timing of the weather and the holidays interact. Demand peaked on Thursday, December 19, the coldest day of the month. The demand peak (20,974 MW) was consistent with December peaks over the past decade.

6. CONCLUSIONS

Under Base Case conditions, only the Maritimes Area shows a likelihood of using their operating procedures designed to mitigate resource shortages (reducing 30-min reserve and initiating interruptible loads) during the 2020/21 winter period for the expected load forecast (representing the probability weighted average of all seven load levels). The results for the extreme load forecast (representing the second to highest load level, having approximately a 6% chance of occurring) also includes an estimate of the Maritimes Areas need for reducing 10-min reserve. The results are primarily driven by Nova Scotia’s forecast load and corresponding reserve margin expectations.

The Maritimes Area estimated use of operating procedures increases assuming Severe Case conditions, especially for the extreme load forecast; again, these results are primarily driven by Nova Scotia’s forecast load and corresponding reserve margin expectations.

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 include 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 2020 - 2021 time period.

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 2020 - 2021 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 2020 summer and November 2020 to March 2021 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; 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 (2020 – 2021) will be measured by estimating the use of NPCC Area operating procedures used to mitigate resource shortages.

A.3 Schedule

A report combining the results of the CP-8 WG Summer Probabilistic Multi-Area Reliability Assessment and the CO-12 WG Summer Reliability Assessment will be developed by the CO-12 and CP-8 Working Groups and approved no later than April 17, 2020.

Similarly, report combining the results of the CP-8 WG Winter Probabilistic Multi-Area Reliability Assessment and the CO-12 WG Winter Reliability Assessment will be approved no later than December 1, 2020.

APPENDIX B

DETAILED STUDY RESULTS

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

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
Expected Load																						
Nov	-	-	-	-	0.005	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	0.386	0.190	0.014	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	0.004	0.000	0.000	-	1.002	0.525	0.037	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	0.808	0.388	0.031	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	0.646	0.341	0.006	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	0.004	0.000	0.000	-	2.846	1.445	0.088	0.002	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Extreme Load																						
Nov	-	-	-	-	0.051	0.013	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	2.551	1.338	0.132	0.005	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	0.060	0.007	0.001	-	5.442	3.149	0.347	0.016	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	4.798	2.558	0.258	0.011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	2.938	1.827	0.055	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	0.060	0.007	0.001	-	15.778	8.884	0.793	0.033	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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.
Occurrences 0.5 or greater are highlighted.

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

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
Expected Load																									
Nov	-	-	-	-	-	0.005	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	1.666	0.867	0.084	0.003	0.003	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	0.025	0.008	0.002	0.000	0.000	3.758	2.153	0.220	0.010	0.010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	3.019	1.617	0.169	0.006	0.006	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	0.646	0.341	0.006	0.000	0.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	0.025	0.008	0.002	0.000	0.000	9.094	4.979	0.479	0.019	0.019	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Extreme Load																									
Nov	-	-	-	-	-	0.051	0.013	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dec	-	-	-	-	-	8.884	5.341	0.681	0.039	0.039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jan	0.363	0.114	0.035	0.001	0.001	16.005	10.707	1.636	0.123	0.123	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	14.152	8.936	1.283	0.074	0.074	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	2.938	1.827	0.055	0.001	0.001	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nov-Mar	0.363	0.114	0.035	0.001	0.001	42.030	26.824	3.656	0.237	0.237	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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.

Occurrences 0.5 or greater are highlighted.

APPENDIX C

MULTI-AREA RELIABILITY PROGRAM DESCRIPTION

General Electric's Multi-Area Reliability Simulation (MARS) program [48] allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

C.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.

C.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

[48] See: http://ge-energyconsulting.com/practice-area/software-products/mars

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.

C.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.

C.4 Generation

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

Thermal
Energy-limited
Cogeneration
Energy-storage
Demand-side management

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.

C.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, through the use of state transition rates.

C.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 D

MODELING DETAILS

D.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*". [49] In addition, the following Areas provided the following:

New England

The New England generating unit ratings were consistent with their seasonal capability as reported in the 2020 CELT report. [50] Active Demand Capacity Resources and capacity imports are based on their Capacity Supply Obligations of the 3rd annual Reconfiguration Auction of Capacity Commitment Period of 2020-2021.

New York

The Base Case assumes that the New York City and Long Island localities will meet their locational installed capacity requirements as described in the New York ISO Technical Study Report "*Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2020 – 2021 Capability Year - January 8, 2020*" [51] and the "*New York Control Area Installed Capacity Requirement for the Period May 2020 to April 2021*" New York State Reliability Council, December 6, 2019 report. [52]

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 "*2020 Load & Capacity Data of the NYISO*" (Gold Book). [53]

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the Ontario "*Reliability Outlook - An adequacy assessment of Ontario's electricity system From October 2020 To March 2022*" (September 22, 2020). [54]

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[49] See: https://www.npcc.org/library/resource-adequacy

[50] See: https://www.iso-ne.com/static-assets/documents/2020/04/2020_celt_report.xlsx.

[51] See: https://www.nyiso.com/documents/20142/8583126/LCR2020-Report.pdf/4c9309b2-b13e-9b99-606a-7af426d93a47.

[52] See: http://www.nysrc.org/PDF/Reports/2020%20IRM%20Study%20Body%20Final%2012-9-19.pdf.

[53] See: https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf/.

[54] See: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2020Sep.pdf?la=en.

Québec

The Planned resources are consistent with the "*NERC 2020 Long-Term Reliability Assessment*. [55]

Maritimes

Resources in the Maritimes Area are modeled with winter DMNC ratings.

D.2 Resource Availability

New England

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

New York

Detailed availability assumptions used for the New York units can be found in the New York ISO Technical Study Report "*Locational Minimum Installed Capacity Requirements Study covering the New York Control Area for the 2020 – 2021 Capability Year - January 8, 2020*" [56] and the "*New York Control Area Installed Capacity Requirement for the Period May 2020 to April 2021*" New York State Reliability Council, December 6, 2019 report. [57]

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the normal weather, planned scenario in the Ontario "*Reliability Outlook - An adequacy assessment of Ontario's electricity system From October 2020 To March 2022*" (*September* 22, 2020). [58]

Québec

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

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[55] See: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.

[56] See: https://www.nyiso.com/documents/20142/8583126/LCR2020-Report.pdf/4c9309b2-b13e-9b99-606a-7af426d93a47.

[57] See: http://www.nysrc.org/PDF/Reports/2020%20IRM%20Study%20Body%20Final%2012-9-19.pdf.

[58] See: http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2020Sep.pdf?la=en.

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

D.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 historical 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.

Quebec
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 Dependable Maximum Net Capability (DMNC). During summer, these values are de-rated accordingly.

D.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 historical median net real power output during Reliability Hours (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 8760 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).

Quebec

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

Maritimes

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

D.5 Solar

New England

The majority of solar resource development in New England is the state-sponsored distributed resources that does not participate in wholesale markets but reduces the system load observed by ISO New England. They 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.

Summer capacity values for solar units are based on average production during hours 14:00 to 18:00 for the months of June, July, and August. Winter capacity values for solar units are based on average production during hours 16:00 to 20:00 for the months of December, January, and February.

Ontario
Historical hourly profiles are used to model solar generation.

Québec
In the Québec area, the peak contribution of behind-the-meter generation (solar) is estimated at less than 1 MW for winter 2020 - 201 and doesn't affect the load monitored from a network perspective. A 9.5 MW solar resource (Photovoltaic) will be installed by the end of 2020. The expected value at the peak time period is, however, not significant.

Maritimes
At this time, solar capacity in the Maritimes is behind the meter and netted against load forecasts. It does not currently count as capacity.

D.6 Wind

New England
New England models the wind resources using the Seasonal Claimed Capability as determined based on their historical median net real power output during Reliability Hours (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.

Summer capacity values for wind units are based on average production during hours 14:00 to 18:00 for the months of June, July, and August. Winter capacity values for wind units are based on average production during hours 16:00 to 20:00 for the months of December, January, and February.

Ontario
Historical hourly profiles are used to model wind generation.

Québec
The expected capacity at winter peak is 36% of the Installed (Nameplate) capacity of most wind generation, except for a small amount (roughly 104 MW) which has a 30% capacity at winter peak time. For the summer period, wind power generation is derated by 100%.

Maritimes
Each sub-area within the Maritimes has a series of annual wind shapes corresponding to years from 2012 through 2018. The model randomly selects from all those shapes and 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.

The data is considered typical having had substantially all the existing Maritimes Area wind resources by that time and no major outages due to icing or other abnormal weather or operating problems.

D.7 Demand Response

New England
The passive non-dispatchable energy efficiency resources demand resources are expected to provide ~3,207 MW of load relief during the peak hours. About 579 MW of Active Demand Capacity Resources are expected to be available to offer to sell demand-reductions in the energy market.

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, 854 MW of SCRs were modeled. At the time of the winter peak, this amount was discounted to 581 MW, based on historical availability.

Ontario
The demand measures are up to 790 MW for the winter period.

Québec
Demand Response (DR) programs in the Québec Area specifically designed for peak-load reduction during winter operating periods are mainly interruptible load programs, totaling 2,592 MW for the 2020-21 winter period. This includes 250 MW of voltage reduction.

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

APPENDIX E

PREVIOUS WINTER REVIEW

E.1 Weather

Highlights - (January - March 2020) [59]
The year-to-date (January-March) average contiguous U.S. temperature was 39.3°F, 4.1°F above average, ranking eighth warmest on record.

Above-average temperatures blanketed much of the Lower 48 with much-above to record warmth across the eastern half of the contiguous United States. North Carolina and Florida ranked warmest on record for the first three months of the year with eight additional states from South Carolina to New England ranking second warmest for this January-March period.

The contiguous U.S. average maximum (daytime) temperature during January-March was 49.6°F, 3.5°F above the 20th century average, ranking in the warmest third of the historical record. Above-average conditions were observed across most of the Lower 48 with pockets of near-average temperatures across the Southwest and central Rockies. All 48 states ranked above- to much-above-average for this three-month period with Massachusetts, Rhode Island, and New Jersey ranking second warmest for daytime temperatures.

The contiguous U.S. average minimum (nighttime) temperature during January-March was 28.9°F, 4.7°F above the 20th century average, ranking third warmest on record. Above-average conditions blanketed much of the western half of the Continental U.S., while much-above- to record temperatures were observed from New Mexico to the Great Lakes and to the East Coast. Ten Eastern states ranked warmest for overnight temperatures during the first three months of 2020. No state ranked near-to or below-average for this period.

Based on NOAA's Residential Energy Demand Temperature Index (REDTI), the contiguous U.S. temperature-related energy demand during January-March was 24 percent of average and was the fourth lowest value on record.

The U.S. Climate Extremes Index (USCEI) for the year-to-date was 51 percent above average and ranked 12th highest in the 111-year period of record. Extremes in warm maximum and minimum temperatures, wet PDSI [60] values, and days with precipitation were the major contributors to this elevated CEI value. The USCEI is an index that tracks extremes (falling in the upper or lower 10

[59] NOAA National Centers for Environmental Information, State of the Climate: National Climate Report for March 2020, published online April 2020, retrieved on October 22, 2020 from https://www.ncdc.noaa.gov/sotc/national/202003.

[60] https://climatedataguide.ucar.edu/climate-data/palmer-drought-severity-index-pdsi.

percent of the record) in temperature, precipitation and drought across the contiguous United States. ◦On the regional scale, The Ohio Valley and the Northeast ranked highest on record for this three-month period while the Southeast ranked second highest. Most of the elevated to record-levels in extremes were due to large regions of warm maximum and minimum temperatures, as well as wet PDSI and days with precipitation. The Northeast experienced extremes in warm maximum temperatures across the entire region while the Southeast had 100% coverage for extremes in warm minimum temperatures. The Upper Midwest and Ohio Valley regions also experienced 100 percent coverage for extremes in wet PDSI.

Northeast Region

December [61]

The Northeast's average temperature for December was 30.2 degrees F (-1.0 degrees C), 1.7 degrees F (0.9 degrees C) warmer than normal. All twelve states wrapped up the month on the warm side of normal, with departures ranging from 0.2 degrees F (0.1 degrees C) above normal in Massachusetts to 4.6 degrees F (2.6 degrees C) in West Virginia, the state's 16th warmest December.

In December, the Northeast received 4.17 inches (105.92 mm) of precipitation, which was 119 percent of normal. Maine was the lone drier-than-normal state seeing 94 percent of normal precipitation. For the remaining states, precipitation ranged from 102 percent of normal in Vermont to 170 percent of normal in Massachusetts. This December ranked among the 20 wettest on record for four states: Massachusetts, seventh wettest; Rhode Island, ninth wettest; Connecticut, 10th wettest; and New Jersey, 19th wettest. In addition, Kennedy Airport, New York, had its wettest December on record.

The U.S. Drought Monitor released on December 5 showed 2 percent of the region as abnormally dry. These areas included southern New Jersey, southeastern Pennsylvania, parts of Delaware, and southern and eastern Maryland. Conditions improved during the month for most areas, with abnormal dryness easing in southern New Jersey and southeastern Pennsylvania by December 10 and in southern Maryland by December 17. However, abnormal dryness lingered in eastern Maryland and southern Delaware through month's end. The U.S. Drought Monitor released on January 2, 2020, showed less than 1 percent of the region as abnormally dry.

A significant storm moved through the region from December 1 to 3. The greatest storm snow totals of 24 inches (61 cm) or more occurred in eastern New York and New England, with a maximum of 36 inches (91 cm) in southern New Hampshire. Snowfall rates of 2 inches (5 cm) per hour were observed in several locations. Albany, New York, reported snow for 39 consecutive

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[61] NOAA National Centers for Environmental Information, State of the Climate: National Climate Report for December 2018, published online January 2019, retrieved on November 3, 2019 from https://www.ncdc.noaa.gov/sotc/national/201812.

hours. When it was over, the site had amassed 22.6 inches (57.4 cm) of snow, ranking among the five largest snowstorms for December and as one of the ten all-time largest snowstorms on record. The storm also produced freezing rain, with ice accumulations of up to 0.40 inches (1 cm) in western Maryland, central Pennsylvania, and the western half of New York. Post-Thanksgiving travel was severely impacted. There were hundreds of vehicle accidents, including several large crashes. For instance, in western Maryland, a pileup involving more than 25 vehicles shut down Interstate 68 for four hours. In central New York, icy road conditions contributed to a crash involving at least 10 vehicles on Interstate 81 and caused a section of Interstate 86 to be closed. Air travel was also hampered. Hundreds of flights were cancelled and thousands were delayed, in some cases for more than three hours. In Buffalo, New York, a plane slid off a taxiway after landing. The storm also resulted in power outages and school closures in the region. Another storm from December 13 to 14 produced mixed precipitation across the region. The greatest rain totals of 3 to 5 inches (76 to 127 mm) were generally in southern Maine, where a few locations experienced flash flooding. Portland, Maine, picked up 3.40 inches (86.36 mm) of rain on December 14, making it the site's third wettest December day. This was only 0.10 inches (2.54 mm) short of the record, which stands at 3.50 inches (88.90 mm) set on December 18, 2012, and December 4, 1990. In portions of the Northeast, icy roads contributed to crashes, including an 11-vehicle crash on Interstate 95 in central Maine. In addition, all lanes along a stretch of Interstate 68 in western Maryland were shut down for a period of time due to hazardous driving conditions.

A storm system from December 16 to 17 brought rain, ice, and snow to the region. Up to 3.25 inches (82.55 mm) of rain caused flooding in parts of West Virginia, with some road and school closures. Other areas, including the Eastern Panhandle of West Virginia, eastern Pennsylvania, and northern New Jersey, saw up to 0.50 inches (1.27 cm) of ice accumulation, which downed tree limbs and wires and led to power outages. Snow accumulations were generally less than 8 inches (20 cm). Behind the storm, an Arctic front brought intense snow squalls and strong winds and ushered bitterly cold air into the region. The squalls likely contributed to a pileup involving nearly 60 vehicles on Interstate 80 in central Pennsylvania that resulted in two deaths, sent dozens of people to the hospital, and caused the westbound lanes closed for more than a day. Snow squalls were also blamed for a series of crashes involving more than a dozen vehicles on the New York State Thruway in central New York. At the end of the month, from December 29 to 31, a storm system brought a variety of weather conditions to the Northeast. Portions of northern New Jersey, Long Island, and coastal Connecticut saw up to 2 inches (51 mm) of rain, while freezing rain caused 0.25 to 0.50 inches (6 to 13 mm) of ice accumulation in eastern/northern New York and western/central Massachusetts and snow totals topped a foot (30 cm) in southern Maine. Lightning and hail were also reported in northern Connecticut and central Massachusetts. The main impact was scattered power outages due to downed tree branches and wires.

January [62]

The Northeast had its 10th warmest January since 1895. The region's average temperature of 29.9 degrees F (-1.2 degrees C) was 6.7 degrees F (3.7 degrees C) warmer than normal. This January ranked among the fifteen warmest Januarys on record for all twelve Northeast states: Rhode Island, sixth warmest; Connecticut, seventh warmest; New Jersey, eighth warmest; Maine, Massachusetts, New Hampshire, and New York; ninth warmest; Delaware and Maryland, 10th warmest; Vermont, 11th warmest; Pennsylvania, 12th warmest; and West Virginia, 14th warmest. State departures ranged from 6.0 degrees F (3.3 degrees C) above normal in Delaware and Maryland to 7.2 degrees F (4.0 degrees C) above normal in Connecticut, Rhode Island, and Vermont. On January 12, Boston, Massachusetts; Bridgeport, Connecticut; and Providence, Rhode Island, had their warmest January day on record.

The Northeast wrapped up January with 2.88 inches (73.15 mm). of precipitation, which was 93 percent of normal. Ten of the twelve states were drier than normal, with January precipitation ranging from 37 percent of normal in Rhode Island to 106 percent of normal in West Virginia. This January ranked as the sixth driest on record for Rhode Island, the 10th driest for Massachusetts, and the 17th driest for Connecticut.

Unusually mild temperatures were reported across the region on January 11 and 12. High temperatures ranged from 50 to 80 degrees F (10 to 27 degrees C) in many areas. On January 11, Charleston, West Virginia, reported a high of at least 80 degrees F (27 degrees C) for only the second time on record in the month of January. On January 12, Boston, Massachusetts; Providence, Rhode Island; and Bridgeport, Connecticut, had their warmest January day on record with highs of 74 degrees F (23 degrees C), 70 degrees F (21 degrees C), and 69 degrees F (21 degrees C), respectively. In fact, it was the first time on record that Providence reported a high of 70 degrees F (21 degrees C) in the month of January. Numerous other sites such as Pittsburgh, Pennsylvania; Albany, New York; and Wilmington, Delaware, had one of their top 10 warmest January days on record. Low temperatures were also mild, ranking among the 10 warmest on record for January at several sites including Beckley, West Virginia, and Islip, New York.

In addition to the unusual warmth on January 11, strong to severe thunderstorms, with wind gusts up to 63 mph (28 m/s), downed trees and powerlines and caused some damage to buildings in West Virginia. At the opposite end of the region, northern Maine saw mixed precipitation, with Caribou having its eighth snowiest January day on January 12. A storm on January 25 dropped up to 3 inches (76 mm) of rain on the region. Some of the greatest amounts were in southeastern Pennsylvania and Delaware where some roads were flooded. Several higher-elevation locations in Pennsylvania, as well as northern Maine, saw freezing rain accumulation of up to 0.40 inches (10

[62] NOAA National Centers for Environmental Information, State of the Climate: National Climate Report for December 2019, published online January 2020, retrieved on October 22, 2020 from https://www.ncdc.noaa.gov/sotc/national/201912.

mm), leading to hazardous travel. The first inch of snow typically falls in late December in Washington, D.C.; Wilmington, Delaware; and Philadelphia, Pennsylvania, and in early January in Atlantic City, New Jersey. With mild temperatures in December and January, the first inch of snow had not arrived at these sites as of January 31, around a month late. When (or if) it does fall, the first inch of snow will rank among the ten latest on record for all four sites.

February [63]

The Northeast had its 11th warmest February since 1895 with an average temperature of 30.1 degrees F (-1.1 degrees C), 3.9 degrees F (2.2 degrees C) above normal. All twelve Northeast states ranked this February among their 20 warmest on record: New Jersey and Rhode Island, third warmest; Connecticut, Delaware, and Maryland, fifth warmest; Massachusetts, sixth warmest; Pennsylvania, 10th warmest; Maine and New York, 15th warmest; New Hampshire and Vermont, 16th warmest; and West Virginia, 18th warmest. State departures ranged from 2.5 degrees F (1.4 degrees C) above normal in Maine to 5.8 degrees F (3.2 degrees C) above normal in New Jersey. This winter was the seventh warmest on record for the Northeast with an average temperature of 30.1 degrees F (-1.1 degrees C), 4.1 degrees F (2.3 degrees C) above normal. It was also one of the ten warmest winters on record for all twelve Northeast states: Rhode Island, fourth warmest; Maryland and West Virginia, fifth warmest; Connecticut, Delaware, Maine, Massachusetts, and New Jersey, sixth warmest; New Hampshire and Pennsylvania, seventh warmest; New York, eighth warmest; and Vermont, 10th warmest. In addition, Allentown, Pennsylvania, had its warmest winter on record.

The Northeast had a wetter-than-normal February with 3.29 inches (83.57 mm) of precipitation, which was 121 percent of normal. State precipitation amounts ranged from 99 percent of normal in Rhode Island to 166 percent of normal in West Virginia, making it the state’s 10th wettest February. Winter was also wetter than normal in the Northeast. The region received 10.49 inches (266.45 mm) of precipitation, 114 percent of normal. All twelve states saw above-normal precipitation with totals ranging from 102 percent of normal in Maine to 140 percent of normal in West Virginia, which was the state’s 14th wettest winter.

Back-to-back storms from February 5 to 8 brought an extreme mix of weather conditions to the Northeast. A rare tornado outbreak occurred on February 7 in Maryland where five tornadoes touched down: an EF-0 and four EF-1s. This was the state’s largest winter tornado outbreak. Prior to this, there had only been four February tornadoes in Maryland between 1950 and 2019. For Cecil, Montgomery, and Carroll counties, it was the first February tornado on record. The tornadoes downed trees, destroyed outbuildings, and damaged roofs and siding of some buildings.

[63] NOAA National Centers for Environmental Information, State of the Climate: National Climate Report for February 2020, published online March 2020, retrieved on October 22, 2020 from https://www.ncdc.noaa.gov/sotc/national/202002.

Portions of Delaware, southeastern Pennsylvania, and New Jersey also saw damaging severe thunderstorms. To the west, West Virginia saw flood-inducing heavy rain, with the greatest totals approaching 4 inches (102 mm). There were road closures, some evacuations, and reports of water in houses. Meanwhile, northern locations received heavy snow, with the greatest totals of more than 12 inches (30 cm) in New York and northern New England. Thundersnow and snowfall rates of 2 to 3 inches (5 to 8 cm) per hour were reported in central New York, where several roads were shut down due to accidents. Some parts of New York and New England also saw 0.25 to 0.50 inches (6 to 13 mm) of ice accumulation. As the storm rapidly strengthened, it set the record for the lowest February air pressure in Hartford (based on preliminary data) and produced damaging wind gusts of up to 80 mph (36 m/s), particularly in coastal areas. The strong winds downed trees and wires, knocked out power to more than 86,000 customers in Massachusetts, and caused whiteout conditions in northern Maine.

A major lake effect snow event occurred from February 27 to March 1. The greatest snow totals were 48 inches (122 cm) east of Lake Ontario and 34.5 inches (87.6 cm) east of Lake Erie. A site near South Rutland, NY, received 44.6 inches (113.3 cm) of snow from February 28 to 29, making it the site's third largest two-day snowfall on record. Snowfall rates of up to 3 inches (8 cm) per hour and thundersnow were reported. Wind gusts of up to 60 mph (27 m/s) created blizzard conditions east of Lake Ontario, led to lakeshore flooding along both Ontario and Erie's shorelines, and resulted in power outages. February's warmth contributed to low snowfall totals in southern and eastern parts of the region. Twelve of the 35 major climate sites had their least snowy February on record. It was the first time in Baltimore, Maryland's 128 years of recordkeeping that that site saw no snow during February.

Winter was unusually mild in the Northeast, with a third of the major climate sites having one of their five warmest winters on record. The coldest temperature observed this winter in Washington, D.C. was 22 degrees F (-6 degrees C) and at Dulles Airport was 15 degrees F (-9 degrees C), which were the warmest minimum temperatures for winter on record. Buffalo, New York, did not record a single-digit temperature until February 14, the second latest date on record. The mild winter affected winter recreation businesses, transportation budgets, private snow removal and landscaping companies, and others. Some areas also saw an early start to spring. The USA Phenology Network estimated that spring leaf out occurred 24 days earlier than usual in Washington, D.C. and New York City and 16 days early in Philadelphia, Pennsylvania.

March [64]

It was the fourth consecutive warmer-than-normal month in the Northeast. The region had its 10th warmest March on record with an average temperature of 39.5°F (4.2°C), which was 5.1°F (2.8°C) above normal. All twelve Northeast states wrapped up March on the warm side of normal, with average temperature departures ranging from 2.8°F (1.6°C) above normal in Maine to 5.9°F (3.3°C) above normal in Maryland. Eleven of the states ranked this March among their 20 warmest: Delaware, fourth warmest; Maryland and New Jersey, sixth warmest; Pennsylvania and Rhode Island, eighth warmest; Massachusetts, ninth warmest; Connecticut and West Virginia, 10th warmest; New York, 11th warmest; and New Hampshire and Vermont, 14th warmest. Beckley, West Virginia, recorded its hottest March day since 1896 with a high temperature of 85°F (29°C), beating the previous record of 83°F (28°C) from 1907.

During March, the Northeast received 3.34 inches (84.84 mm) of precipitation, which was 95 percent of normal. Precipitation for the twelve Northeast states ranged from 71 percent of normal in Maryland to 122 percent of normal in Pennsylvania, which was the only wetter-than-normal state. Three major climate sites tied/set their greatest number of March days with measurable precipitation. Those sites were Huntington and Charleston, West Virginia, which saw 21 days and 20 days, respectively, with measurable precipitation, and Wilmington, Delaware, which had 18 days of measurable precipitation.

The Northeast started March without abnormal dryness and drought; however, increasing precipitation deficits, low streamflow, and below-normal groundwater levels led to the introduction of abnormal dryness in the Northeast in mid-March. The abnormally dry areas included the northern half of New Jersey, part of southeastern New York, southern and eastern Connecticut, Rhode Island, and part of southeastern Massachusetts. Some of these locations also experienced brush fires. The U.S. Drought Monitor released on March 19 showed six percent of the Northeast was abnormally dry. The following week, heavy precipitation allowed abnormal dryness to ease in a few locations, particularly Connecticut and part of New Jersey. However, abnormally dry conditions lingered in southeastern Massachusetts, most of Rhode Island, southeastern New York and northeastern New Jersey. The U.S. Drought Monitor released on March 26 showed three percent of the Northeast was abnormally dry.

Portland, Maine, recorded its earliest 70°F (21°C) day on record on March 9. The previous record was March 14 in 1946. On March 28 and 29, strong to severe thunderstorms produced golf ball to tennis ball-sized hail in western Pennsylvania and quarter to golf ball-sized hail in Massachusetts,

[64] NOAA National Centers for Environmental Information, State of the Climate: National Climate Report for March 2020, published online April 2020, retrieved on October 22, 2020 from https://www.ncdc.noaa.gov/sotc/national/202003 .

which is unusual for March. Eleven of the Northeast's 35 major climate sites set or tied their record for least snowy March. In addition, it was the first time on record with no measurable snow in both February and March for Bridgeport, Connecticut; Islip and Kennedy Airport, New York; and Allentown and Harrisburg, Pennsylvania. According to the USA National Phenology Network, spring leaf out occurred 23 days earlier than usual in Boston, Massachusetts, and eight days earlier than usual in Pittsburgh, Pennsylvania.