Northeast Power Coordinating Council

2018 Long Range Adequacy Overview

Approved by the RCC

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Conducted by the

NPCC CP-8 Working Group

NPCC CP-8 WORKING GROUP

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

TABLE OF CONTENTS

APPENDICES

PAGE

INTRODUCTION

This study evaluated, on a consistent basis, the long-range adequacy of Northeast Power Coordinating Council's (NPCC) and neighboring Regions' plans to meet their Loss of Load Expectation (LOLE) planning criteria [1] through a multi-area probabilistic assessment for the period from 2019 to 2023, based on the reported *NERC 2018 Long-Term Reliability Assessment* [2] (LTRA) data.

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program [3] was selected by NPCC for its analysis. GE Energy Consulting was retained by the Working Group to conduct the simulations. MARS version 3.22.8 was used for the assessment.

The database developed by the NPCC CP-8 Working Group's *NPCC Reliability Assessment for Summer 2018*, April 18, 2018, [4] was used as the starting point for this Overview. Working Group members reviewed the existing data and revised reflect the conditions expected for the 2018-2023 period, consistent with the information reported for the *NERC 2018 Long-Term Reliability Assessment*.

This report is organized in the following manner: after a brief Introduction, general modeling assumptions are presented followed by a summary provided by each Area describing their specific representation. The results and observations of the Overview are then presented.

The Overview's Objective and Scope of Work are shown in Appendix A. Appendix B summarizes the Area Generation and Load assumptions used in the analysis.

[1] See: Directory No. 1- Section 5.2 https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf
[2] See: http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
[3] See: http://geenergyconsulting.com/practice-area/software-products/mars
[4] See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx , Appendix VIII

MODEL ASSUMPTIONS

The assumptions used in NPCC's Long Range Adequacy Overview are consistent with the assumptions of the following recently completed Area studies:

Area Studies

New York

The Comprehensive System Planning Process (CSPP) is the New York ISO's biennial ten-year planning process comprised of four components: 1) Local Transmission Planning Process (LTPP); 2) Reliability Planning Process (RPP); and 3) Congestion Assessment and Resource Integration Study (CARIS); and 4) Public Policy Transmission Planning Process (PPTPP). The CSPP also provides for cost allocation and cost recovery in certain circumstances for regulated reliability, economic, and public policy transmission projects, as well as the coordination of interregional planning activities.

The RPP consist of two evaluations:

1. The Reliability Needs Assessment (RNA). The NYISO performs a biennial study in which it evaluates the resource and transmission adequacy and transmission system security of the New York BPTF over a ten-year Study Period. Through this evaluation, the NYISO identifies Reliability Needs in accordance with applicable Reliability Criteria. This report is reviewed by NYISO stakeholders and approved by the Board of Directors.
2. The Comprehensive Reliability Plan (CRP). After the RNA is complete, the NYISO requests the submission of market-based solutions to satisfy the Reliability Need. The NYISO also identifies a Responsible TO and requests that the TO submit a regulated backstop solution and that any interested entities submit alternative regulated solutions to address the identified Reliability Needs. The New York ISO evaluates the viability and sufficiency of the proposed solutions to satisfy the identified Reliability Needs and evaluates and selects the more efficient or cost-effective transmission solution to the identified need. In the event that market-based solutions do not materialize to meet a Reliability Need in a timely manner, the New York ISO triggers regulated solution(s) to satisfy the need. The NYISO develops the CRP for the ten year Study Period that sets forth its findings regarding the proposed solutions. The CRP is reviewed by the New York ISO stakeholders and approved by the Board of Directors.

Summary of 2018 RNA

The *2018 Reliability Needs Assessment* (RNA) assesses the resource adequacy and transmission security of the New York Control Area (NYCA) Bulk Power Transmission Facilities (BPTF) from year 2019 through 2028, the Study Period of this RNA.

The *2018 Reliability Needs Assessment* finds that the Reliability Criteria are met throughout the Study Period:

a. From the resource adequacy perspective, the New York Control Area is within the Loss of Load Expectation (LOLE) criterion (one day in 10 years, or 0.1 days per year) throughout the Study Period; therefore, the New York ISO identifies no resource adequacy related Reliability Need. The trend of load decrease continues; for example, the summer peak baseline load forecast is 1,464 MW lower in 2023 as compared with the 2016 Reliability Needs Assessment. When recent and planned capacity deactivations were included in the calculation for comparison, the net statewide surplus increased by 1,817 MW as compared with the 2016 Reliability Needs Assessment
b. The NYISO identifies no Reliability Need resulting from the transmission security evaluations. Preliminary evaluations identified a transmission security Reliability Need on a BPTF facility in eastern Long Island, which was subsequently addressed by the transmission owner via an LTP update.

In addition, the 2018 RNA provides analysis of risks to the BPTF under certain scenarios to assist stakeholders and developers in developing and proposing market-based and regulated reliability solutions, as well as policy makers to formulate state policy. Scenarios are variations on the RNA Base Case to assess the impact of possible changes in key study assumptions, such as higher load forecast (i.e., not including the benefits of retail solar photovoltaic and of energy efficiency programs), capacity removal, and additional transmission build-outs (e.g., transmission driven by public policy), which, if they occurred, could change the timing, location, or degree of violations of applicable Reliability Criteria on the NYCA system during the Study Period.

As reflected in the 2018 RNA scenarios, a higher load level or additional capacity removal could cause resource adequacy criterion violations.

In addition to the above-referenced scenarios, the New York ISO also discusses the risks associated with the cumulative impact of environmental laws and regulations, which may affect the flexibility in plant operation and may make fossil-fueled plants energy-limited resources. A number of recent state policies and initiatives, along with various Department of Environmental Conservation rulemakings are underway that have the potential to significantly change the resource mix in the New York Control Area. These include the Clean Energy Standard, the Offshore Wind Master Plan, the Large-Scale Renewable Program and Zero Emission Credits Program for the James A. FitzPatrick, R.E Ginna and Nine Mile Point nuclear power plants. The New York ISO will continue to monitor these and other developments to determine whether changing system resources and conditions could impact the reliability of the Bulk Power Transmission Facilities.

As part of its ongoing Reliability Planning Process, the ISO monitors and tracks the progress of market-based projects and regulated backstop solutions, together with other resource additions and retirements, consistent with its obligation to protect confidential information under its Code of Conduct. The other tracked resources include: 1) units interconnecting through the New York ISO's interconnection processes; 2) the development and installation of local transmission facilities; 3) additions, mothballs or retirements of generators; 4) the status of mothballed/retired facilities; 5) the continued implementation of New York State energy efficiency programs, solar PV installations, additions due to the Clean Energy Standard, and similar programs; 6) participation in the NYISO demand response programs; and 7) the impact of new and proposed environmental regulations on the existing generation fleet.

New England

The Regional System Plan (RSP) is ISO New England's planning efforts to identify the region's electricity needs and actions for meeting these needs in order to maintain reliable and economic operation of New England's bulk power system over a ten-year horizon. No less than once every three years, ISO New England initiates an effort to develop its RSP. The last RSP was published in 2017 (*2017 Regional System Plan* or RSP 17). RSP 17 identified the region's electricity needs and plans for meeting these needs for 2017 through 2026.

In support of the efforts with the RSP, ISO New England annually 1) updates the peak demand and energy forecast for the next ten years; 2) develops a forecast of long-term savings in peak and energy from state-sponsored energy-efficiency (EE) programs, and the anticipated growth and impact of behind-the-meter photovoltaic (BTM PV) resources that do not participate in wholesale markets; 3) identifies the Installed Capacity Requirements (ICR) for the purpose of procuring adequate amount of capacity through the Forward Capacity Market (FCM) to meet the New England resource adequacy planning criterion.

To quantify the operational risks from the long-standing concerns about the region's reliance on New England's natural gas infrastructure and the expected increasing dependency in the coming years as older oil, coal, and nuclear generators retire, in 2017 ISO New England conducted an Operational Fuel Security Analysis to assess potential reliability consequences of various future fuel-mix scenarios for winter 2024/2025. The study calculated whether sufficient fuel, including natural gas, liquefied natural gas (LNG), and oil, would be available for the system to satisfy electricity demand and to maintain power system reliability throughout an entire winter by assuming various levels of resource retirements, LNG availability, oil tank inventories, imported electricity, and renewable resources. The results of this analysis will be used by ISO New England and NEPOOL to formulate market mechanisms to address energy/fuel security issues in the region. [5]

Based on this year's forecast, the net energy for load, accounting for both energy efficiency (EE) programs and Behind-The-Meter Photovoltaic (BTM PV) resources, is projected to decrease by 0.9 percent per year. The 50/50 net summer peak forecast [6] is 25,511 MW for 2019, and declines to 24,942 MW for 2023. The EE resources are projected to grow at an average rate of 305 ~330 MW per year during the next five-year period. The BTM PV, including rooftop solar, comprises approximately two-thirds of the total PV capacity, and is estimated to reduce peak load by 721 MW by 2019, and 945 MW by 2023.

[5] See: (https://www.iso-ne.com/static-assets/documents/2018/01/a02_operation_fuel_security_analysis_presentation.pdf)

[6] Net of EE and BTM PV.

Since the 2017 LRAO 1,522 MW of combined cycle units and 120 MW of Gas Turbines unit have been placed in-service. A total of approximately 1,101 MW of capacity are expected to be added to the system by 2019. This consists primarily of 1,012 MW of natural gas-fired generation, of which the largest projects are the Medway Peaking Project (195 MW), Bridgeport Harbor Expansion (484 MW), and the Canal 3 unit (333 MW).

Brayton Point Station, which was a 1,535 MW coal and oil/gas plant, retired on June 1, 2017. The 680 MW Pilgrim Nuclear Power Station is planned for retirement in June 2019.

On March 23, 2018, Exelon submitted to ISO New England a Retirement De-List Bid(s) for the Mystic Station, notifying the ISO of Exelon's intention to retire the generators when the existing Capacity Supply Obligations (CSO) expire on May 31, 2022. The Mystic Station consists of four units, designated as Units 7, 8, 9, and "Mystic Jet", and have an aggregate nominal summer capacity rating of 2,274 MW. This retirement comes at a time when ISO New England and New England stakeholders are grappling with a growing threat to the reliable operation of New England's BPS, posed by the region's increasing reliance on natural gas-fired generation despite essentially minimal growth in regional gas pipeline capacity. The problem is most critical during the winter months, when the region's pipelines are delivering firm gas to the regional gas local distribution companies. Given New England power system's evolving resource mix and fuel delivery infrastructure, ISO New England is concerned that there may be insufficient energy available to the New England power system during extended cold winter weather conditions to satisfy electricity demand. To address this energy security concern, ISO New England has commenced efforts to develop solutions to be accomplished in the near-term, mid-term, and longer-term development horizons.

In the near-term, ISO New England is revising its Operating Procedure No. 21, Energy Inventory Accounting and Actions During an Energy Emergency (OP-21), by the addition of an energy emergency forecasting and reporting protocol to improve situational awareness. This reporting protocol will establish energy alert thresholds similar to those used in NERC Standards, encouraging proactive measures to avoid certain forecasted conditions. The revision to OP-21 is expected to be completed before 2019. In addition, ISO New England is formalizing a framework for specific opportunity costs to be incorporated into energy market supply offer, which would promote additional energy available during tight winter fuel scarcity events. The first phase of this project, targeted for implementation in the 4th quarter 2018, focuses on addressing the energy opportunity costs of resources, such as oil-fired and dual-fuel, with fuel supply limitations over a relatively short (e.g., seven day) period. The second phase will evaluate a more comprehensive approach to opportunity-cost modeling.

In the mid-term, ISO New England has developed a Tariff-based approach, applicable for the Capacity Commitment Periods (CCP) 2022-2023 through 2024-2025, for reliability reviews and retention of resources wanting to delist to help maintain regional energy security. Assessment criteria that may require retaining a resource in the Forward Capacity Market to address regional fuel-security risks with a corresponding timing and integration of fuel-security reliability reviews of resource delist requests, Forward Capacity Auction pricing treatment, and allocation of associated costs for retained fuel-security resources have been developed and filed with the Federal Energy Regulatory Commission. To promote energy availability during 2023-2024 through 2024-2025, ISO New England is evaluating an interim compensation treatment for these CCPs associated with reliability reviews for fuel security. The stakeholder process to develop this interim compensation treatment is scheduled to span from the fourth quarter 2018 through the first quarter 2019.

In the long-term, under a FERC Order, ISO New England is to develop and file with the commission improvements to its market design to better address regional fuel security for CCPs beyond 2024-2025 by July 1, 2019. Currently, ISO New England has initiated the process and is discussing the problem statement and proposed conceptual approaches with the stakeholders.

Approximately 2,700 MW of new resources are expected to be added to the New England system by 2019. These new capacities consist primarily of natural gas-fired generation. The Brayton Point Station (1,535 MW), consisting of three coal-fired units and a dual-fuel (oil/gas) unit, retired in 2017. The planned retirement of the 680 MW Pilgrim Nuclear Power Station is expected by June of 2019.

There are a number of new transmission projects planned and under construction that are needed to maintain reliability in New England. The most significant one is the Greater Boston project. The project includes new 345 kV circuits between Scobie-Tewksbury and Wakefield-Woburn, a new 345/115 kV autotransformer at Mystic and replaces a 345/115 kV autotransformer at Woburn, and a +/- 200 MVAR 345 kV interconnected STATCOM in Maine that will also help to address concerns with the potential for system separation due to significant contingencies in southern New England. This project is under construction with many elements already in service. The Wakefield-Woburn 345 kV line may be delayed due to siting concerns, which will be managed through operating actions until the facility is placed in service expected by December 2019. There are no unanticipated delays associated with the remainder of this project that would have a significant impact on overall system reliability. Information on this project can be found at: http://www.iso-ne.com/system-planning/key-study-areas/greater-boston.

Solutions to address time sensitive needs in Southeastern Massachusetts/Rhode Island (SEMA/RI) have been developed. There is limited 345 kV work related to this project, comprising of separating two circuits that share common towers, the installation of a new 345/115 kV autotransformer at Brayton Point, and the replacement of an existing 345/115 kV autotransformer at Kent County. The remainder of the project is comprised of 115 kV upgrades. The most significant 115 kV upgrade is the installation of a new Grand Army switching station that brings together four 115 kV lines. Additional 115 kV upgrades include the separation of circuits that are located on common towers, line reterminations at existing substations, upgrading terminals at existing stations, line rebuilds and reconductorings, new capacitor banks, and the installation of a few new 115 kV lines. Construction has begun with this project, but none of its components have been placed in service. All components of the project are expected to be in service by December 2021. There are no unanticipated delays associated with this project.[7]

The Greater Hartford Central Connecticut projects are under construction or already in service. There is limited 345 kV work associated with this project. The 345 kV work consists of new circuit breaker additions and upgrading existing terminal equipment. New 345/115 kV autotransformers are being installed at Barbour Hill and Haddam substations. Additional 115 kV upgrades include the separation of circuits that are located on common towers, line reterminations at existing substations, upgrading terminals at existing stations, line rebuilds and reconductorings, new capacitor banks, and the installation of a few new 115 kV lines. Much of this project has already been placed in service, and the remainder of the project is expected to be completed by June 2019. There are no unanticipated delays associated with this project. [8]

The Southwest Connecticut projects are closely linked to the GHCC project and are also under construction or already in service. 345 kV work is limited to the addition of a new circuit breaker and a shunt reactor. There are no new 345/115 kV autotransformers being installed. The 115 kV upgrades include the separation of circuits that are located on common towers, line reterminations at existing substations, upgrading terminals at existing stations, line rebuilds and reconductorings, new capacitor banks, and the installation of a few new 115 kV lines. The project also includes a new synchronous condenser at Stony Hill that replaces previously installed DVAR in the area. Much of this project has already been placed in service. All remaining components, other than two components expected in service by September 2020, are expected to be completed by December 2018. There are no unanticipated delays associated with this project.

Transmission projects have improved regional reliability and continue to support the efficient operation of the markets. The completed Interstate Reliability Project and the Greater Boston Reliability Project that is expected to be completed by 2019, represent the most recent major 345 kV projects required to meet regional reliability.

Ontario

The Ontario assumptions used in this study are consistent with the assumptions used in the latest *18-Month Outlook*, [9] the *NERC 2018 Long-Term Reliability Assessment* [10] and the *Ontario 2018 Comprehensive Review of Resource Adequacy*. [11]

Over the assessment period (2019-2023), Ontario peak demand is expected to increase on average by about 0.14% annually and the energy demand is to increase by about 0.1%. Ontario demand is broadly

[7] Information on this project can be found at: https://www.iso-ne.com/system-planning/key-study-areas/swct
[8] Information on this project can be found at: https://www.iso-ne.com/system-planning/key-study-areas/greater-hartford
[9] See: http://www.ieso.ca/sector-participants/planning-and-forecasting/18-month-outlook
[10] See: http://www.nerc.com/page.php?cid=4|61
[11] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

shaped by a number of factors: economic growth, population growth, energy efficiency savings, price impacts and embedded generation. Each factors' impact varies based on the season and whether it is peak, energy or minimum demand.

Ontario expects to add about 1,700 MW of new resources to the grid over the assessment period, of which just about 1 GW is natural gas and the balance is renewable resources such as wind and solar.

Ontario expects to retire about 1,400 MW of existing resources over this period, of which about 1 GW is nuclear and the balance is natural gas resources. Major nuclear refurbishments are scheduled during this period and treated as outages. The development of the refurbishment programs was informed by Ontario's past experience and the plan will be implemented in a way that minimizes risk.

There are two main demand management mechanisms in Ontario: Demand Response and Dispatchable Loads. In order to reflect reality of demand management programs, the IESO uses effective demand management values instead of gross values. The effective values are based on historical behaviors.

Québec

The Québec assumptions used in this study are consistent with the *NERC 2018 Long-Term Reliability Assessment.* [12]

The demand forecast average annual growth is 0.8 percent during the five-year period. Energy efficiency and conservation programs are integrated in the demand forecasts. Demand forecasts also consider the load shaving resulting from the residential dual energy space heating program. The impact of this program on peak load demand is estimated to be around 530 MW during the assessment period.

Demand Response (DR) programs in the Québec Area are specifically designed for peak-load reduction during winter operating periods and are mostly interruptible demand programs for large industrial customers. The Québec Area continues to develop new DR programs, including Direct Control Load Management and others. Total DR expected to be available during the peak for the 2022–2023 winter period is projected to be approximately 2,350 MW, including 1,780 MW of interruptible load program mainly for large industrial customers, 500 MW of interruptible charges in commercial buildings and 250 MW of voltage reduction as an emergency operating procedure.

About 400 MW of new available capacity is expected to be in service by 2023. Works are underway on the La Romaine-4 unit (245 MW), which is expected be fully operational in 2020. No retrofitting of hydro units is considered over the assessment period. The integration of small hydro units also accounts for 54 MW of new capacity during the assessment period. Additionally, 43 MW (13 MW on-peak value) of wind capacity and 89 MW of biomass are expected to be in service by 2021. There is no unit retirement planned during the assessment period.

[12] See: http://www.nerc.com/page.php?cid=4|61

Maritimes

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

Growth in both demand and capacity resources will be essentially flat over the time frame of this review. Late in 2017, Nova Scotia completed the Maritimes Link project, an undersea HVDC cable link between Nova Scotia and the Canadian Province of Newfoundland and Labrador. [13]

Associated energy from the Muskrat Falls Hydro Electric project is currently expected to begin to flow across the Maritimes Link starting mid-2020. Because the 153 MW of firm hydro resource additions associated with this interconnection will coincide with the retirement of the same amount of coal fired capacity, the impact on resource adequacy within the Maritimes Area will be minimal.

The assumptions used in this study are consistent with the *2018 NPCC Maritimes Area Interim Review of Resource Adequacy*; [14] the results indicate that the Maritimes Area will comply with the NPCC resource adequacy criterion.

PJM-RTO

The annual PJM Reserve Requirement Study (RRS) calculates the reserve margin that is required to comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and ReliabilityFirst Corporation (RFC) in compliance with Standard BAL-502-RFC-02. This study is conducted each year in accordance with the process outlined in PJM Manual 20 (M-20), PJM Resource Adequacy Analysis. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to reliably serve customer load with sufficient reserves.

The results of the RRS provide key inputs to the PJM Reliability Pricing Model (RPM). The results of the RRS are also incorporated into PJM's Regional Transmission Expansion Plan (RTEP) process, pursuant to Schedule 6 of the PJM Operating Agreement, for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.

[13] See: http://www.emeranl.com/en/home/themaritimelink/infrastructure.aspx

[14] See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx

Load Representation

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

Load Shape

For the past several years, the Working Group has been using different load shapes for the different seasonal assessments. The Working Group considered the 2002 load shape to be representative of a reasonable expected coincidence of area load for the summer assessments. Likewise, the 2003 – 2004 load shape has been used for the winter assessments. The selection of these load shapes was based on a review of the weather characteristics and corresponding loads of the years from 2002 through 2008:

- ✓ a 2002/03 load shape representative of a winter weather pattern with a typical expectation of cold days; and,
- ✓ a 2003/04 load shape representative of a winter weather pattern that includes a consecutive period of cold days.

Review of the results for both load shape assumptions indicated only slight differences in the results. The Working Group agreed that the weather patterns associated with the 2003/04 load shape are representative of weather conditions that stress the system, appropriate for use in future winter assessments. Upon review of subsequent winter weather experience, the Working Group agreed that the 2003/04 load shape assumption be again used for this analysis.

For a study such as this that focuses on the entire year rather than a single season, the Working Group agreed to develop a composite load shape from the historical hourly loads for 2002, 2003, and 2004. January through March of the composite shape was based on the data for January through March of 2004. The months of April through September were based on those months for 2002, and October through December was based on the 2003 data.

Before the composite load model was developed by combining the various pieces, the hourly loads for 2003 and 2004 were adjusted by the ratios of their annual energy to the annual energy for 2002. This adjustment removed the load growth that had occurred from 2002, from the 2003 and 2004 loads, so as to create a more consistent load shape throughout the year.

The resulting load shape was then adjusted through the study period to match the monthly or annual peak and energy forecasts. The impacts of Demand-Side Management programs were included in each Area's load forecast.

Load Forecast Uncertainty

Load forecast uncertainty was also modeled. The effects on reliability of uncertainties in the load forecast, due to weather and 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 (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

While the per unit variations in Area and sub-Area load can vary on a monthly and annual basis, Table 1 shows the values assumed for January 2019, corresponding to the assumed occurrence of the NPCC system peak load (assuming the composite load shape) and for August 2019, corresponding to the NPCC summer peak load. Table 1 also shows the probability of occurrence assumed for each of the seven load levels modeled.

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

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

Table 1(a)
Per Unit Variation in Load Assumed (Month of January 2019)

Area	**Per-Unit Variation in Load**						
HQ	1.088	1.088	1.044	1.000	0.958	0.916	0.909
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.093	1.038	0.997	0.963	0.940	0.850	0.800
NY	1.043	1.031	1.016	0.998	0.975	0.944	0.905
ON	1.058	1.043	1.023	1.000	0.972	0.944	0.928
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Table 1(b)
Per Unit Variation in Load Assumed (Month of August 2019)

Area	**Per-Unit Variation in Load**						
HQ	1.064	1.064	1.032	1.000	0.975	0.954	0.933
MT	1.138	1.092	1.046	1.000	0.954	0.908	0.862
NE	1.260	1.130	0.974	0.974	0.897	0.886	0.851
NY	1.120	1.086	1.043	0.992	0.935	0.877	0.822
ON	1.152	1.108	1.052	0.999	0.951	0.903	0.857
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

Generation

Generator Unit Availability
Details regarding the NPCC area's assumptions for generator unit availability are described in the latest NPCC Seasonal Multi-Area Probabilistic Assessment. [15]

Capacity and Load Summary
Figures 1 through 6 summarize area capacity and load assumed in this Overview at the time of area peak for the period 2019 to 2023. Area peak load is shown against the initial area generating capacity (includes demand resources modeled as resources), adjusted for purchases, retirements, and additions. New England generating capacity also includes active Demand Response, based on the Capacity Supply Obligations obtained through ISO-NE's Forward Capacity Market three years in advance. More details can be found in Appendix B.

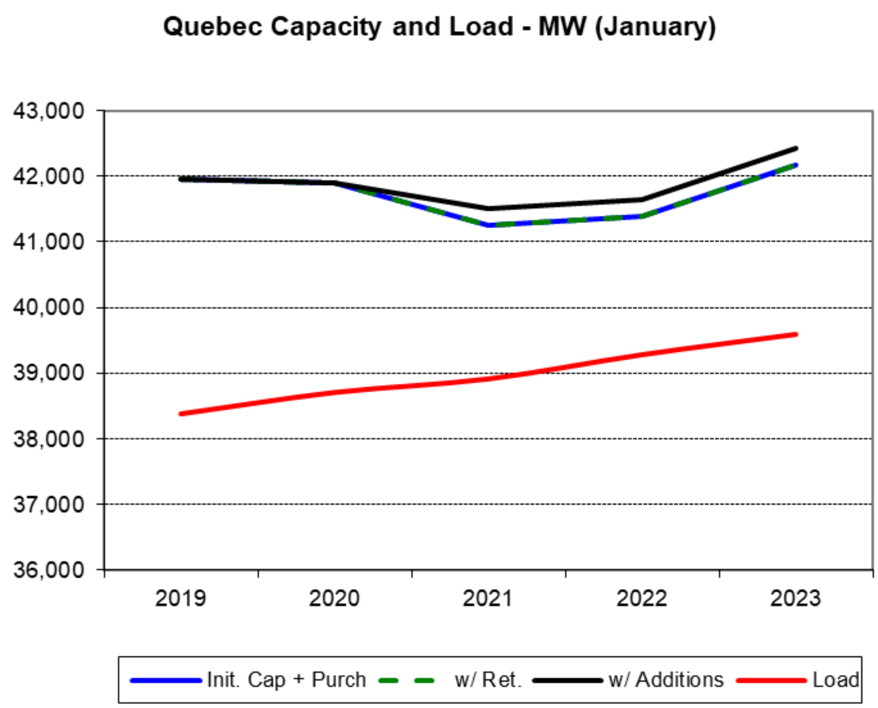


Figure 1 – Quebec Area Capacity and Load

[15] See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx

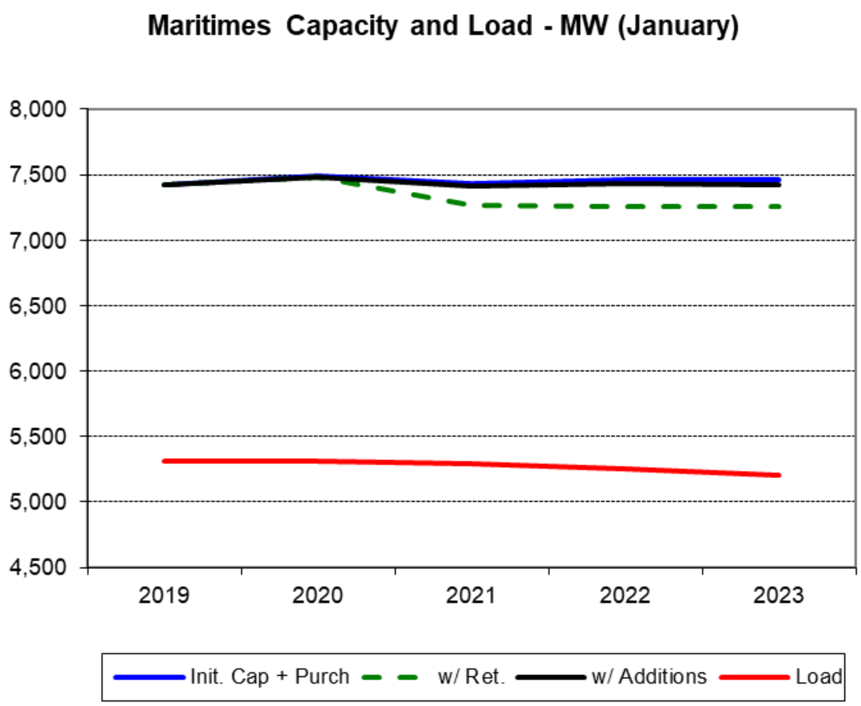


Figure 2 – Maritimes Capacity and Load

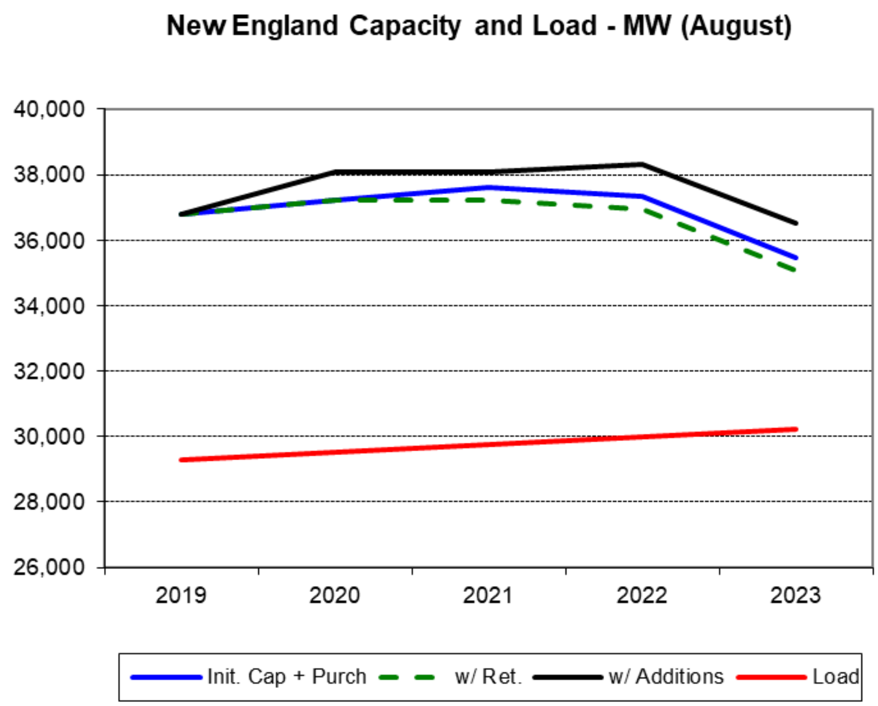


Figure 3 – New England Area Capacity and Load

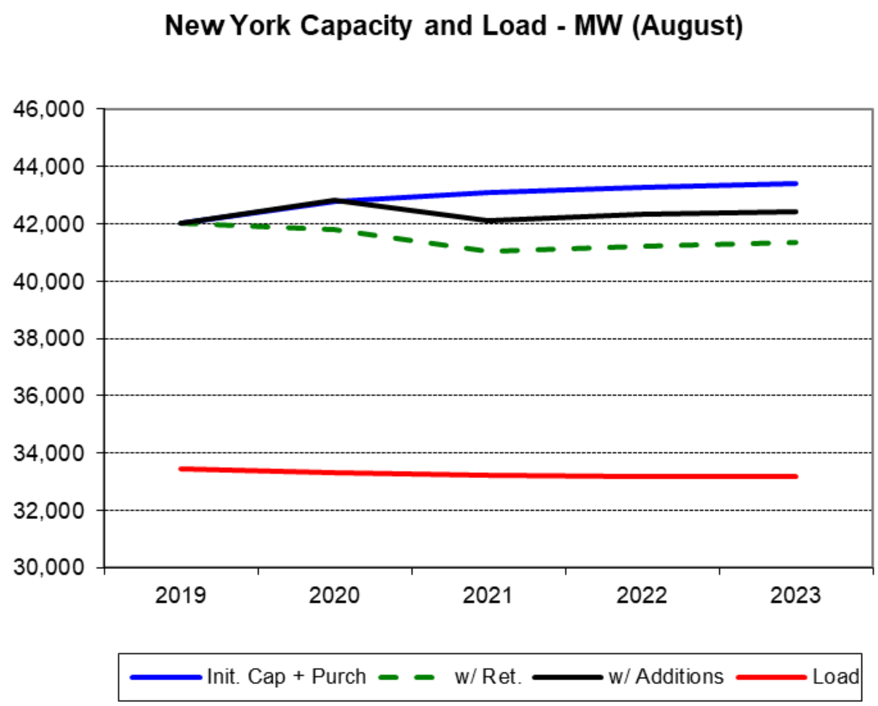


Figure 4 – New York Capacity and Load

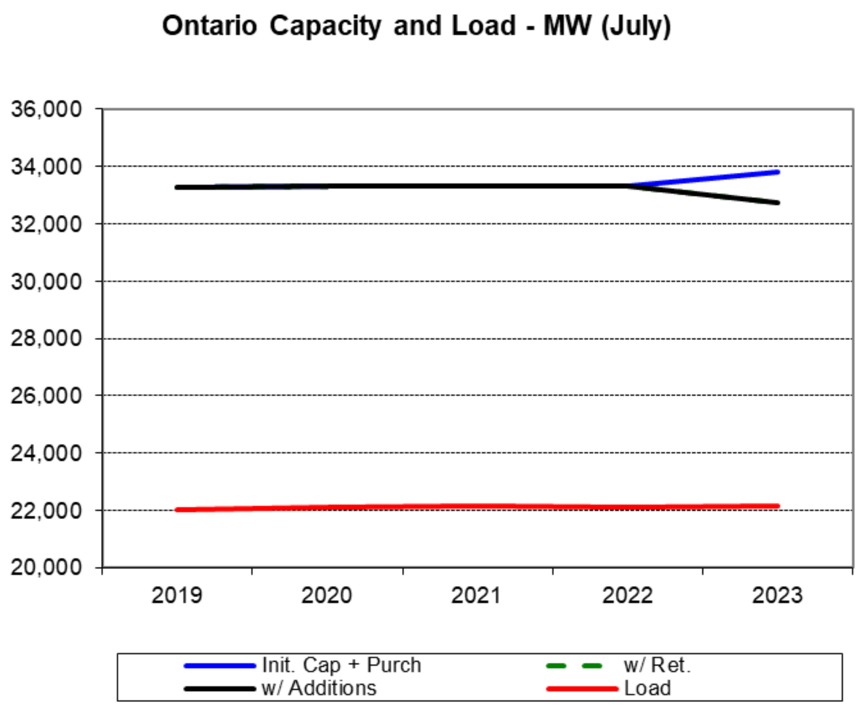


Figure 5 – Ontario Capacity and Load

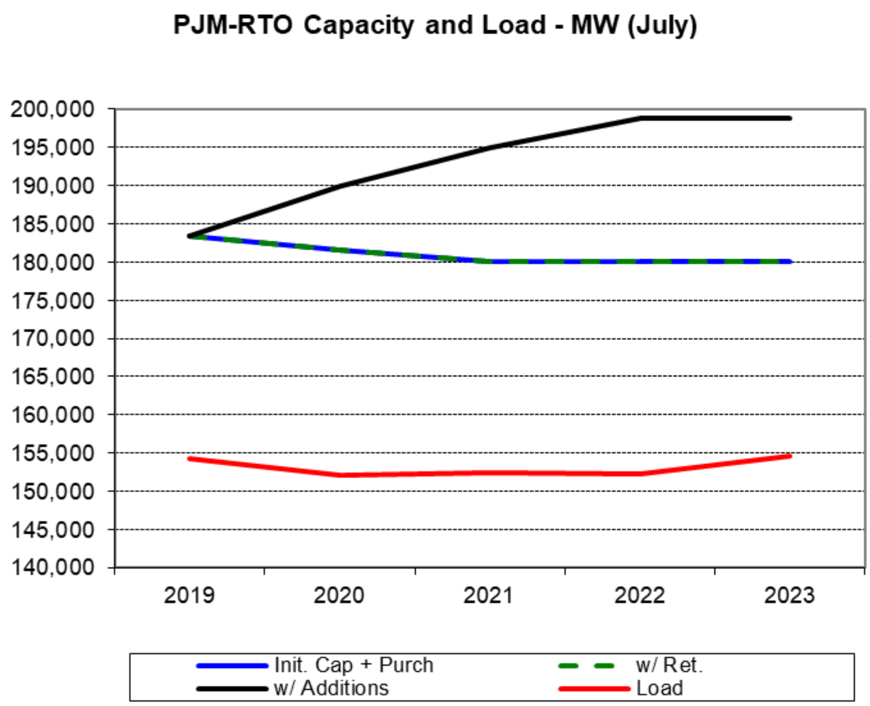
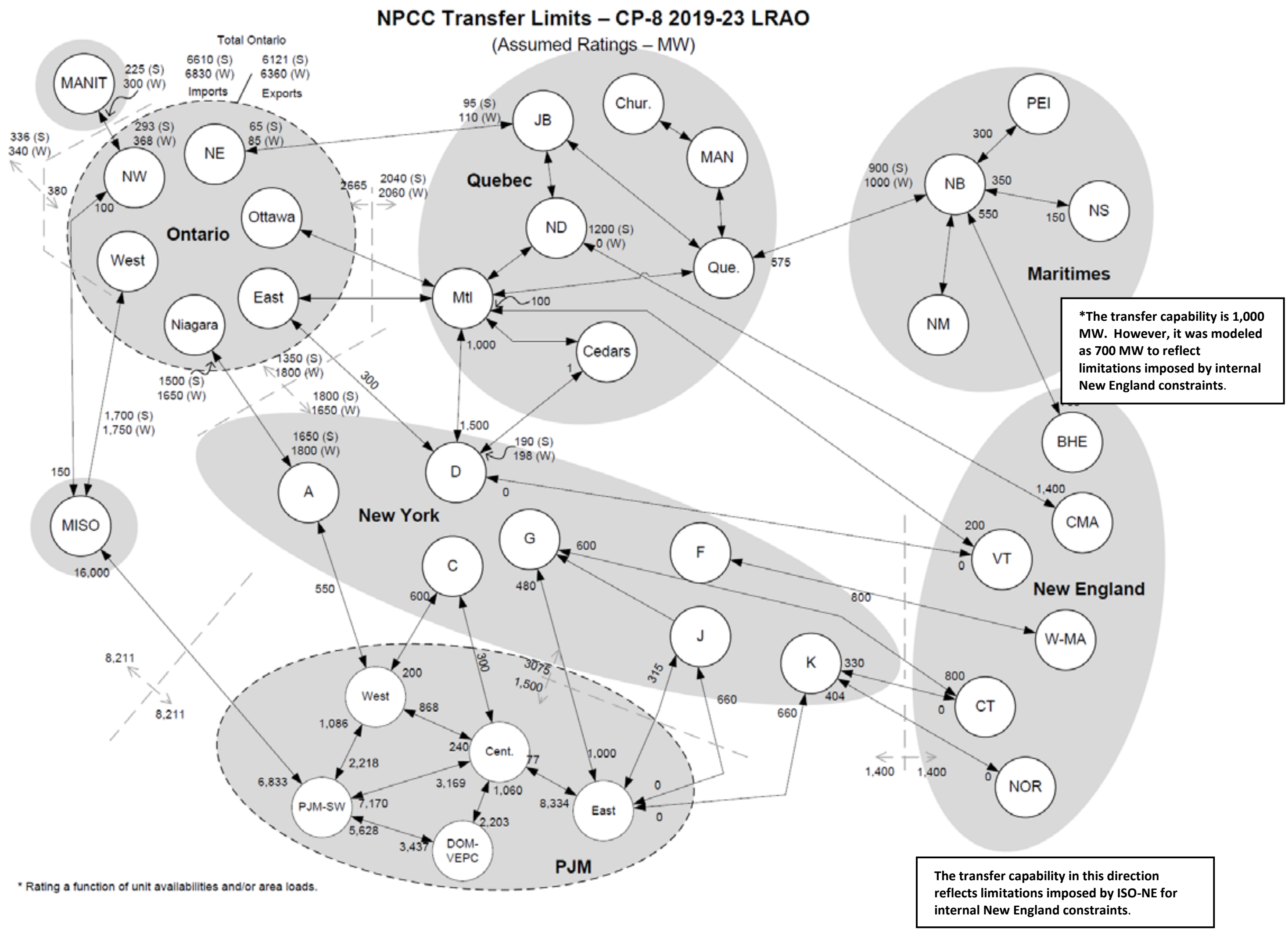


Figure 6 – PJM-RTO Capacity and Load

Transfer Limits

Figure 7 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the period 2019 to 2023.



Note: With the Variable Frequency Transformer operational at Langlois (Cedars), Hydro-Québec can import up to 100 MW from New York. [16]

Figure 7 - Assumed Transfer Limits

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

Transfer limits between and within some areas are indicated in Figure 7 with seasonal ratings (S- summer, W- winter) where appropriate. The acronyms and notes used in Figure 7 are defined as follows:

Chur	- Churchill Falls	NOR	- Norwalk – Stamford	NM	- Northern Maine
MANIT	- Manitoba	BHE	- Bangor Hydro Electric	NB	- New Brunswick
ND	- Nicolet-Des Cantons	Mtl	- Montréal	PEI	- Prince Edward Island
BJ	- Bay James	C MA	- Central MA	CT	- Connecticut
W MA	- Western MA	NS	- Nova Scotia	Dom-VEPC	- Dominion Virginia Power
MAN	- Manicouagan	NBM	- Millbank	NW	- Northwest (Ontario)
NE	- Northeast (Ontario)	VT	- Vermont	MT	- Maritimes Area
MISO	- Mid-Continent Independent System Operator	Que	- Québec Centre		

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 or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves. Table 2 summarizes the load relief assumptions modeled for each NPCC area.

Table 2
NPCC Operating Procedures to Mitigate Resource Shortages
Peak Month 2019 Load Relief Assumptions - MW

Actions	HQ (Jan)	MT (Jan)	NE (Aug)	NY (Aug)	ON (Aug)
1. Curtail Load	1,460	-	-	-	-
Appeals	-	-	-	-	1% of load
RT-DR/SCR/EDRP	-	-	-	857[17]	-
SCR Load /Man. Volt. Red.	-	-	-	0.20% of load	-
2. No 30-min Reserves	500	233	625	655	473
3. Voltage Reduction	250	-	412	1.11% of load	-
Interruptible Loads	-	272	-	122	533
4. No 10-min Reserves	750	505	-	-	945
General Public Appeals	-	-	-	81	-
5. 5% Voltage Reduction	-	-	-	-	2.3% of load
No 10-min Reserves	-	-	980	1,310	-
Appeals/Curtailments	-	-	-	-	-

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

[17] Derated value shown accounts for assumed availability.

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 2 was a reasonable approximation for this analysis.

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.

Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of the neighboring regions of MISO (Midcontinent Independent System Operator) was assumed. The assumptions are summarized in Table 3 and Figure 8.

Table 3
PJM and MISO 2019 Assumptions [18]

	PJM	MISO
Peak Load (MW)	154,321	95,432
Peak Month	July	August
Assumed Capacity (MW)	189,433	111,772
Purchase/Sale (MW)	1,999	-3,134
Reserve (%)	30	18
Operating Reserves (MW)	3,400	3,906
Curtailable Load (MW)	9,113	4,272
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	+/- 13.5%, 9.0%, 4.5%	+/- 11.2%, 7.5%, 3.7%

For this study, the MISO region (minus the Entergy region) was included in the analysis replacing the RFC-OTH and MRO-US regions. In previous versions of the NPCC Long Range Adequacy Overview, 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), the Working Group 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.

[18] Load and capacity assumptions for RFC-Other and MRO-US based on NERC's Electricity, Supply and Demand Database (ES&D) available at: http://www.nerc.com/~esd/

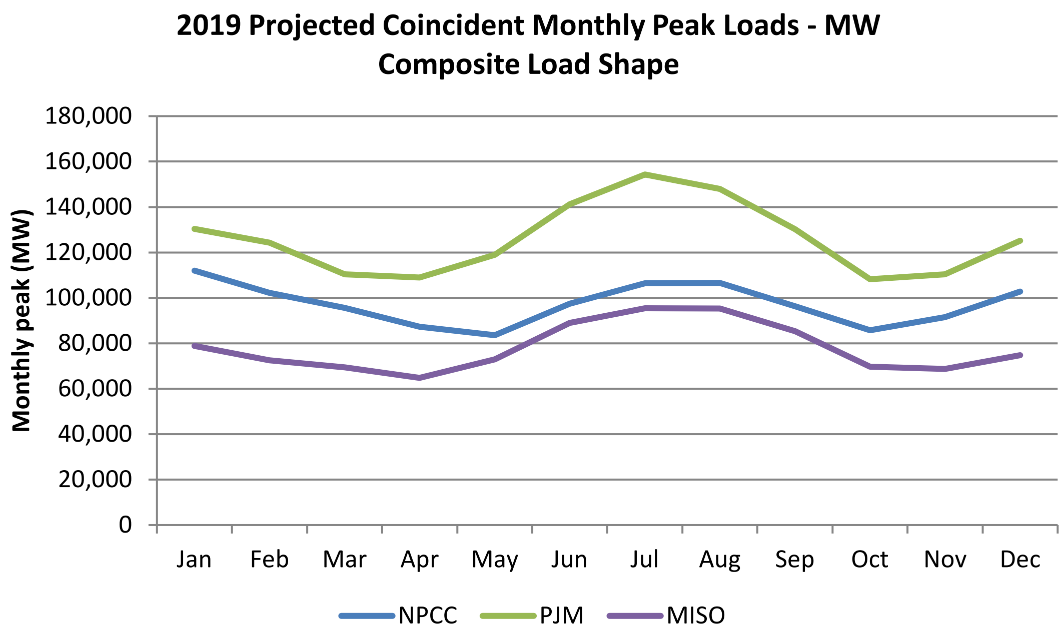


Figure 8 – 2018 Projected Monthly Expected Peak Loads for NPCC, PJM and MISO

MISO

The Mid-Continent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization administering wholesale electricity markets in all or parts of 15 states in the US.

MISO unit data was obtained from the publicly available NERC datasets. Each individual unit represented in MISO was then assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2018 RRS Report).

MISO load data was obtained from publicly available sources, namely FERC Form 714 and the 2018-2019 MISO LOLE Study Report. [19]

PJM-RTO

Load Model

PJM's Load Forecast issued in January 2018 [20] was used in this study. The methods and techniques used in the load forecasting process are documented in Manual 19 [21] (Load Forecasting and Analysis) and Manual 20 [22] (PJM Resource Adequacy Analysis.) The hourly load shape is based on observed 2002

[19] https:// www.misoenergy.org/Library/Repository/Study/LOLE/2017%20LOLE%20Study%20Report.pdf
[20] https://www.pjm.com/-/media/library/reports-notices/load-forecast/2018-load-forecast-report.ashx
[21] http://www.pjm.com/~/media/documents/manuals/m19.ashx
[22] http://www.pjm.com/~/media/documents/manuals/m20.ashx

calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the 2018 PJM Load Forecast Report on a monthly basis. The load forecast uncertainty considered in this study is consistent with other recent probabilistic PJM models (the PJM Reserve Requirement Study, specifically). This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones or regions, and the forecast horizon.

Footprint Modeling

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

Generation Model

Performance statistics such as outage rates and planned outages for generation units considered in the study are based on 5-year (2013 -17) GADS data. This is consistent with modeling practices in the 2018 PJM Reserve Requirement Study. Wind and solar units are assigned a forced outage rate of 0 and a capacity credit factor computed based on generating output on peak hours (hours ending 3, 4, 5, and 6 PM Local Prevailing Time) during the past three summer periods.

RESULTS

Figures 9(a) and 9(b) shows the estimated annual NPCC Area Loss of Load Expectation (LOLE) for the 2019-2023 period.

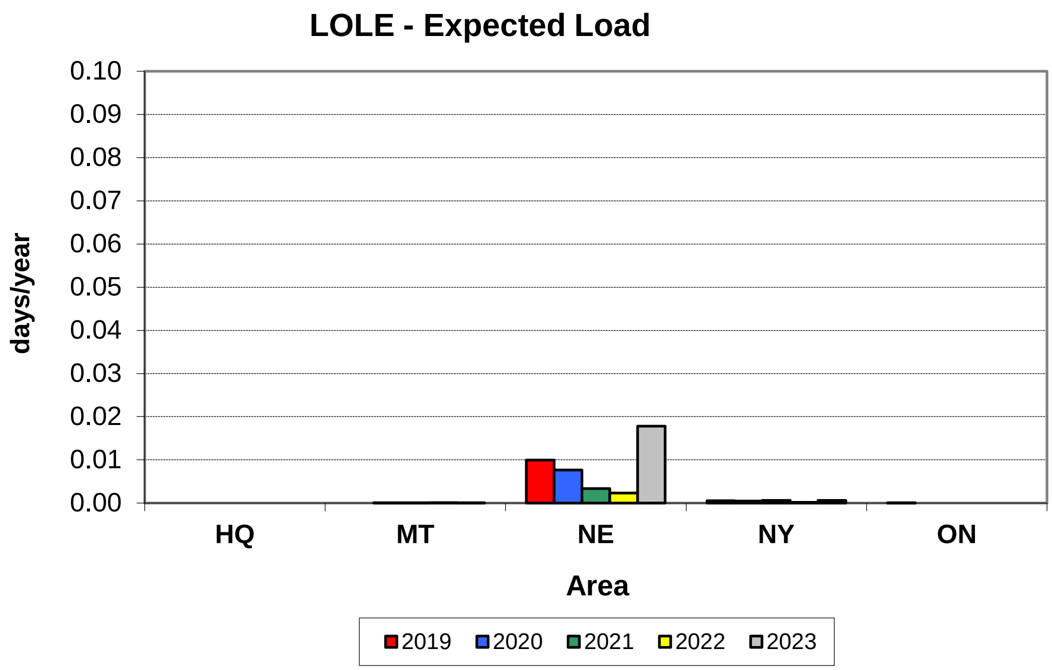


Figure 9(a) - Estimated Annual NPCC Area LOLE (2019 – 2023)

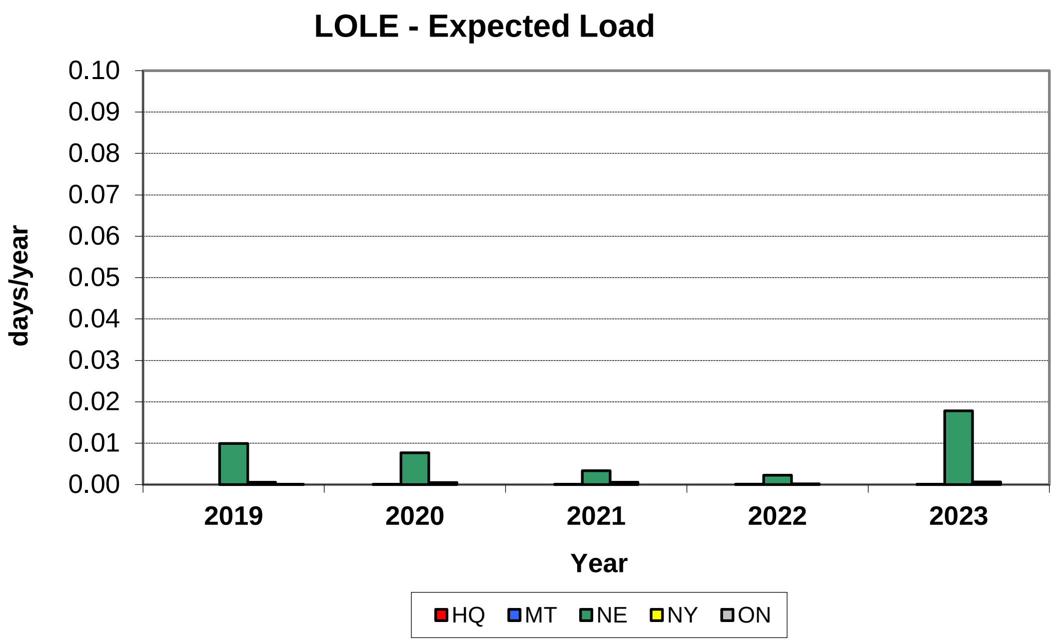


Figure 9(b) - Estimated Annual NPCC Area LOLE (2019– 2023)

Figures 9(c) and 9(d) shows the estimated annual NPCC Areas and Neighboring Region's Loss of Load Expectation (LOLE) for the 2019-2023 period.

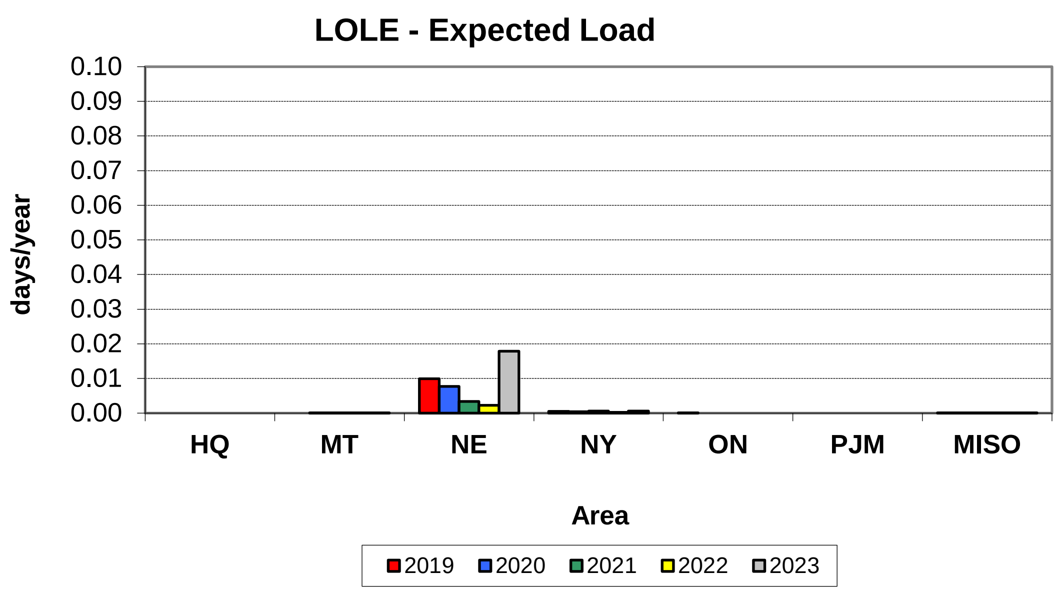


Figure 9(c) - Estimated Annual NPCC Areas and Neighboring Regions LOLE (2019 – 2023)

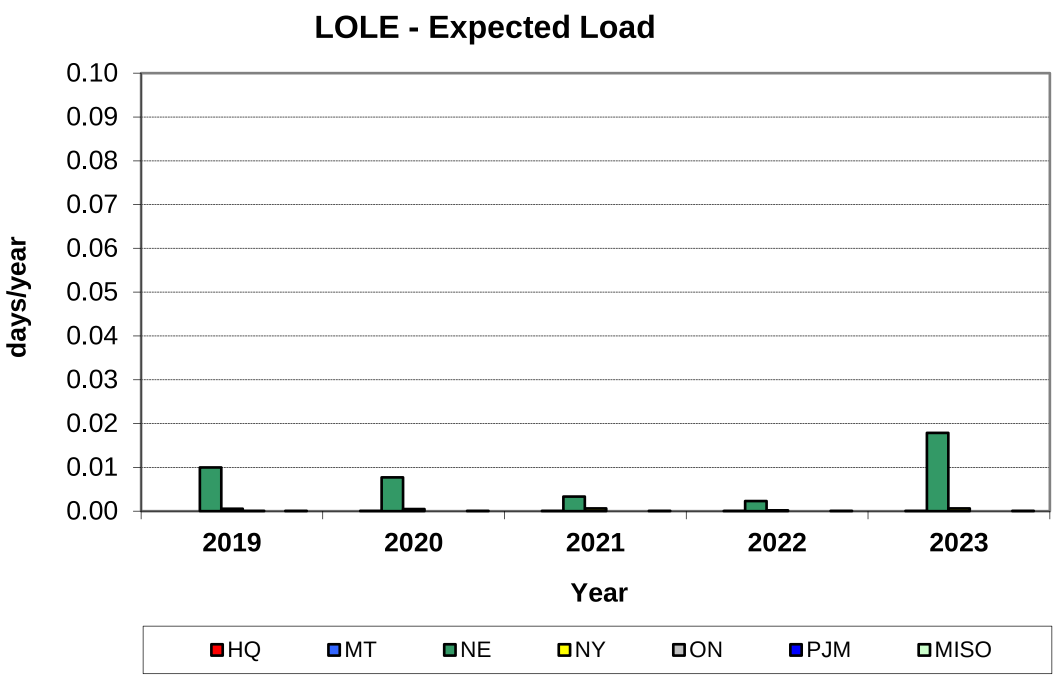


Figure 9(d) – Estimated Annual NPCC Areas and Neighboring Region's LOLE (2019 – 2023)

Figures 10(a) and 10(b) show the estimated annual NPCC Area Loss of Load Expectation (LOLH) estimated the 2019-2023 period.

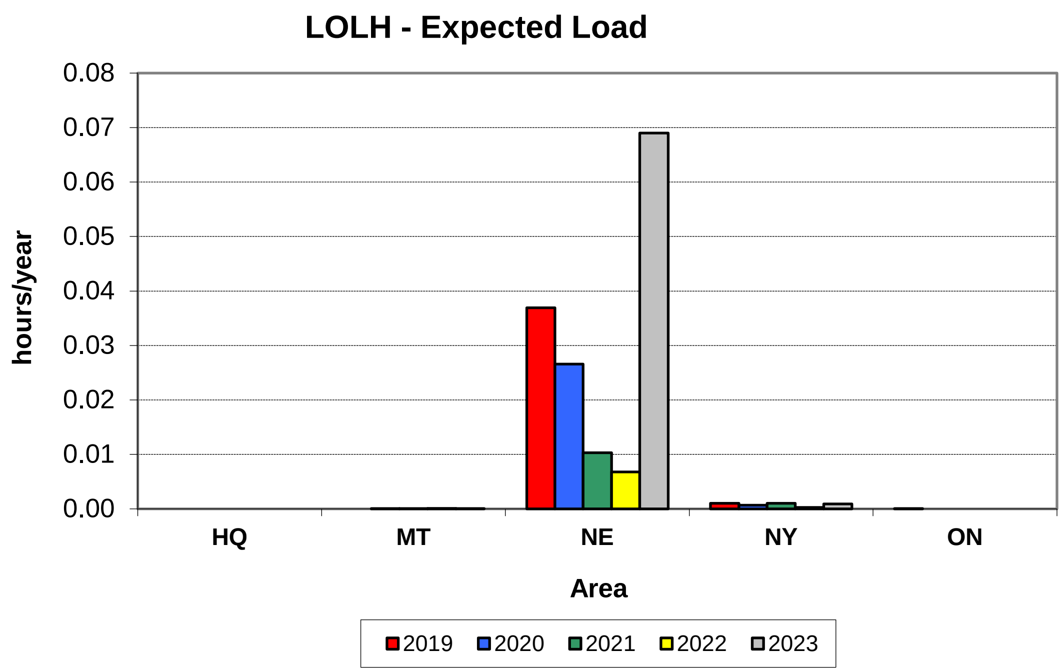


Figure 10(a) - Estimated Annual NPCC Area LOLH (2019 – 2023)

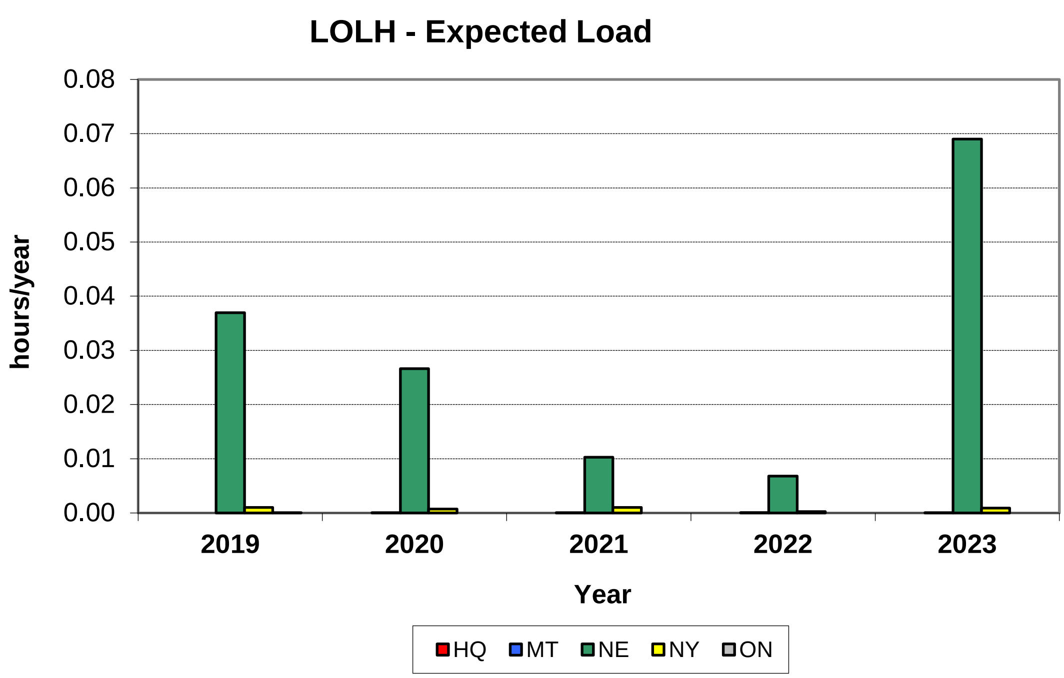


Figure 10(b) - Estimated Annual NPCC Area LOLH (2019 – 2023)

Figures 10(c) and 10(d) shows the estimated annual Loss of Load Expectation (LOLH) for NPCC Areas and neighboring Regions for the 2019-2023 period.

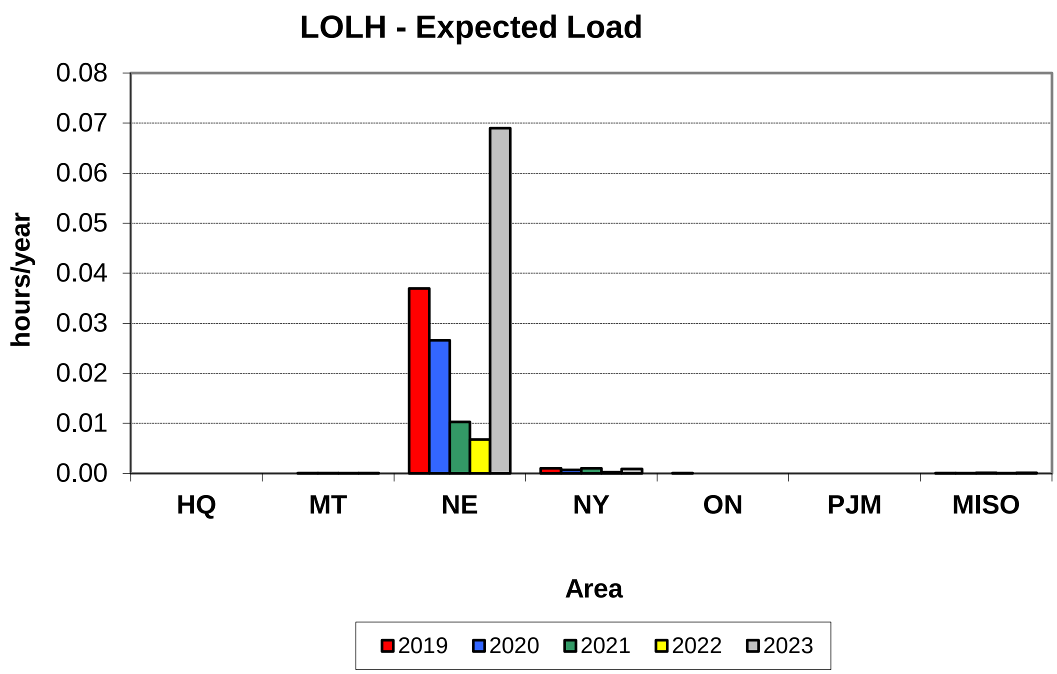


Figure 10(c) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2019 – 2023)

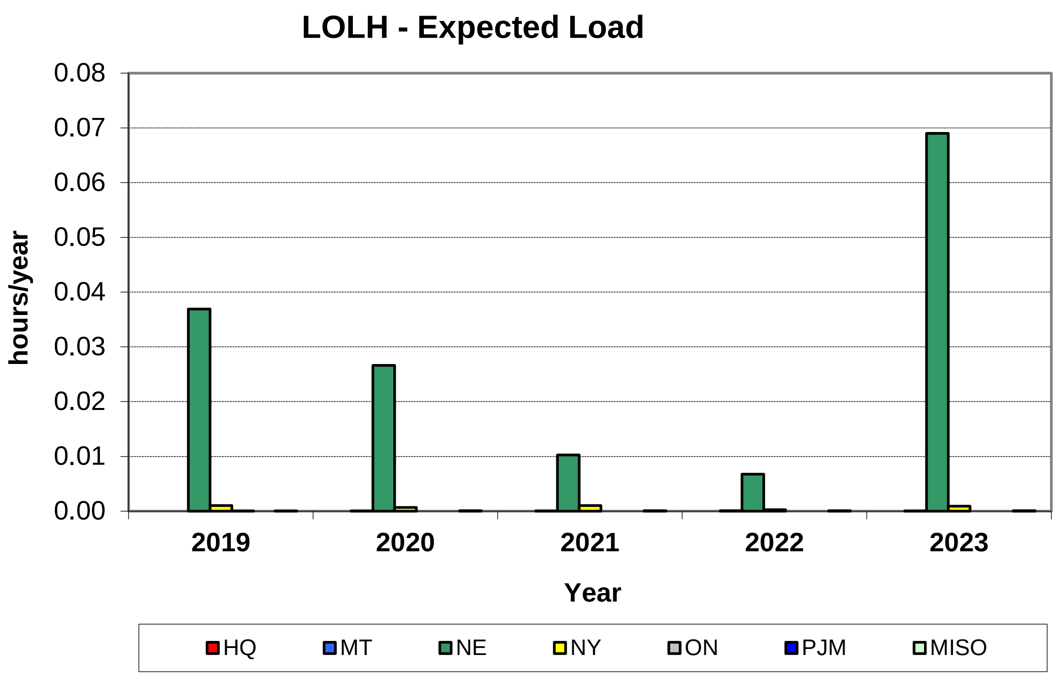


Figure 10(d) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2019 – 2023)

Figures 11(a) and 11(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2019-2023 period.

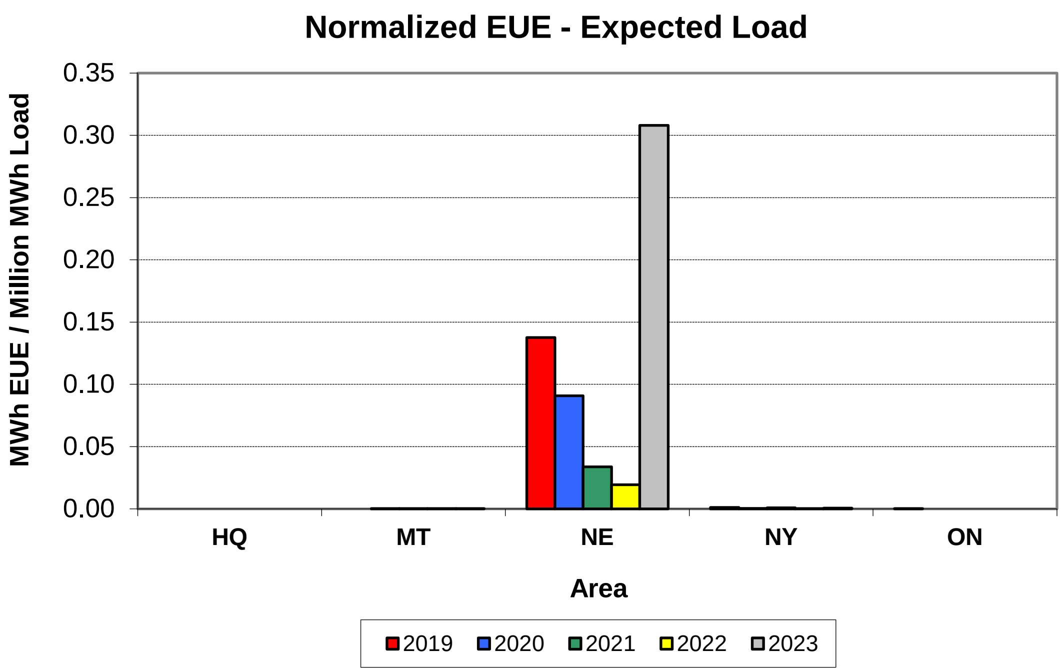


Figure 11(a) - Estimated Annual NPCC Area EUE (2019 – 2023)

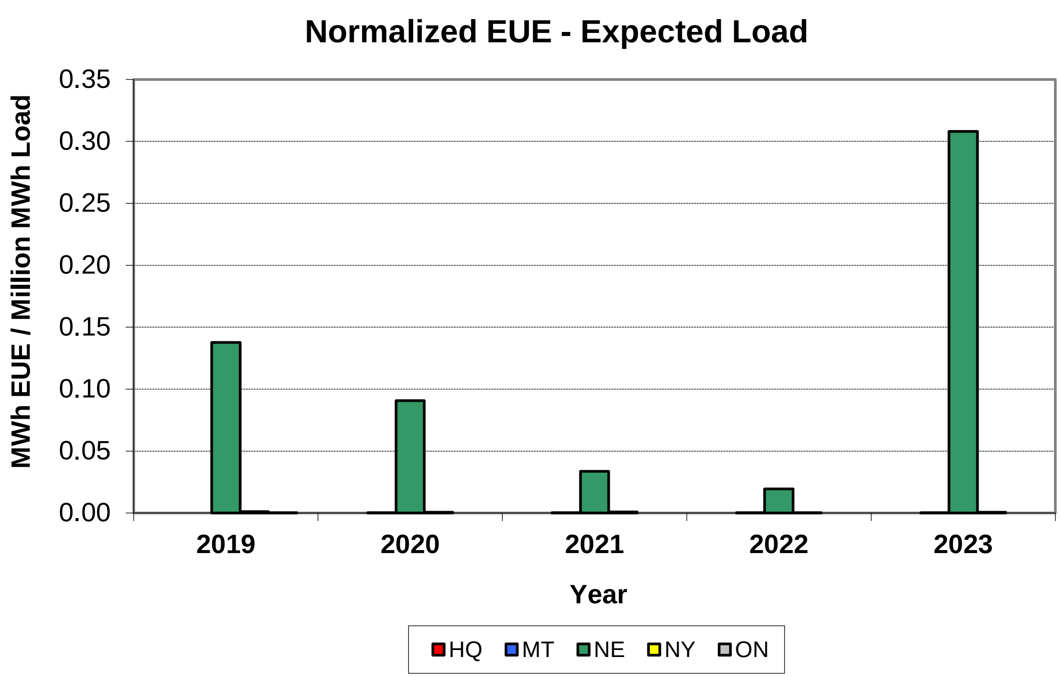


Figure 11(b) – Estimated Annual NPCC Area LOLH (2019 – 2023)

Figures 11(c) and 11(d) shows the estimated annual Expected Unserved Energy (EUE) for NPCC and the neighboring Regions for the 2019-2023 period.

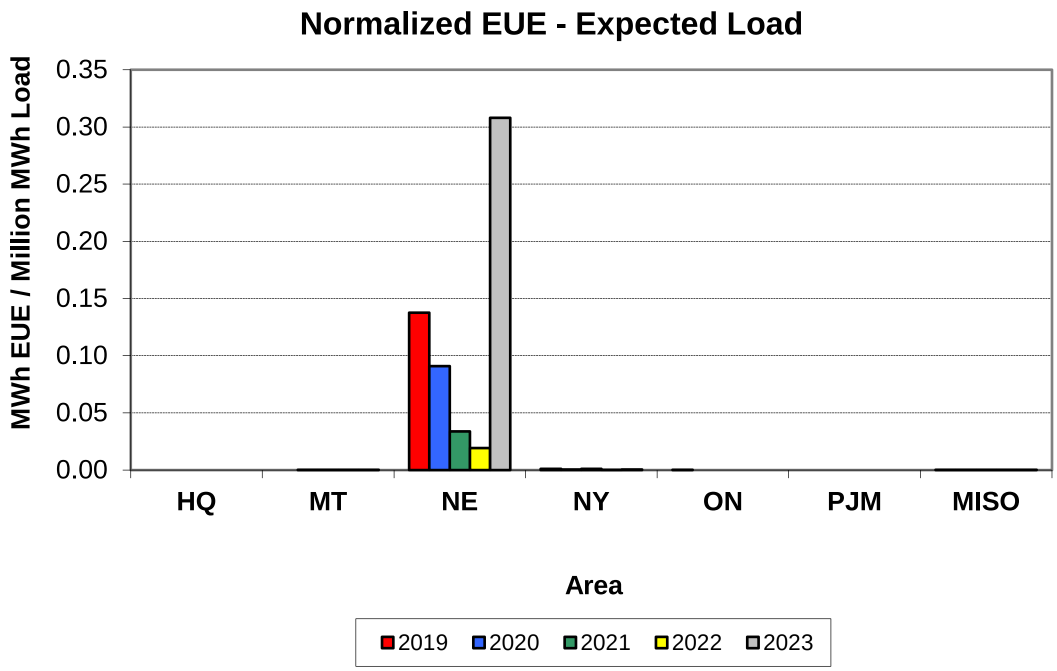


Figure 11(c) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2019 – 2023)

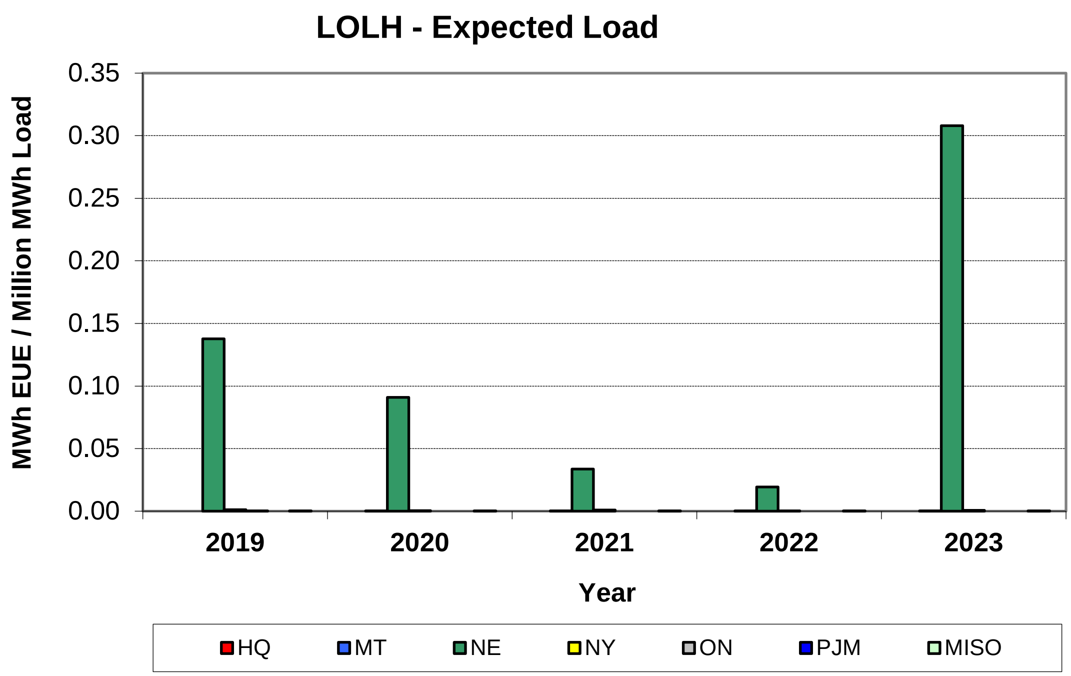


Figure 11(d) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2019 – 2023)

Table 4 shows the percentage difference between the amount of annual energy estimated by the GE MARS program and the amount reported in the *NERC 2018 Long Term Reliability Assessment*. This is primarily due to the differences in the NPCC Area assumptions used for their respective energy forecasts. The GE MARS calculation for the total estimated NPCC annual energy is within 2% of the corresponding sum of the NPCC Areas annual energy forecasts.

Table 4 –Comparison of Energies Modeled (Annual GWh)

Year	2019	2020	2021	2022	2023
Québec					
MARS	192,577	192,928	189,731	189,157	189,249
2018 LTRA	186,436	188,485	189,334	190,694	191,567
MARS - LTRA	6,141	4,443	398	-1,537	-2,318
%(MARS-LTRA)/LTRA	3.29%	2.36%	0.21%	-0.81%	-1.21%
Maritimes					
MARS	27,062	27,354	27,254	27,168	27,118
2018 LTRA	27,062	27,353	27,253	27,185	27,106
MARS - LTRA	0	1	1	-17	13
%(MARS-LTRA)/LTRA	0.00%	0.00%	0.00%	-0.06%	0.05%
New England					
MARS	115,337	113,696	111,626	110,070	108,709
2018 LTRA	122,497	120,395	118,949	117,870	117,039
MARS - LTRA	-7,161	-6,699	-7,323	-7,800	-8,330
%(MARS-LTRA)/LTRA	-5.85%	-5.56%	-6.16%	-6.62%	-7.12%
New York					
MARS	155,416	154,344	153,351	152,686	152,383
2018 LTRA	156,649	155,567	154,567	153,898	153,593
MARS - LTRA	-1,233	-1,223	-1,216	-1,212	-1,210
%(MARS-LTRA)/LTRA	-0.79%	-0.79%	-0.79%	-0.79%	-0.79%
Ontario					
MARS	133,576	133,003	132,516	132,435	132,424
2018 LTRA	134,045	133,687	133,330	133,245	133,215
MARS - LTRA	-468	-684	-814	-809	-791
%(MARS-LTRA)/LTRA	-0.35%	-0.51%	-0.61%	-0.61%	-0.59%

Year	2019	2020	2021	2022	2023
NPCC					
MARS	623,969	621,325	614,478	611,518	609,883
2018 LTRA	626,689	625,487	623,433	622,892	622,520
MARS - LTRA	-2,720	-4,162	-8,955	-11,374	-12,636
%(MARS-LTRA)/LTRA	-0.43%	-0.67%	-1.44%	-1.83%	-2.03%

OBSERVATIONS

Figures 12(a) and 12(b) summarize the estimated annual NPCC Area Loss of Load Expectation (LOLE) from previous NPCC Multi-Area Probabilistic Reliability Assessments under Base Case assumptions for the expected load level.

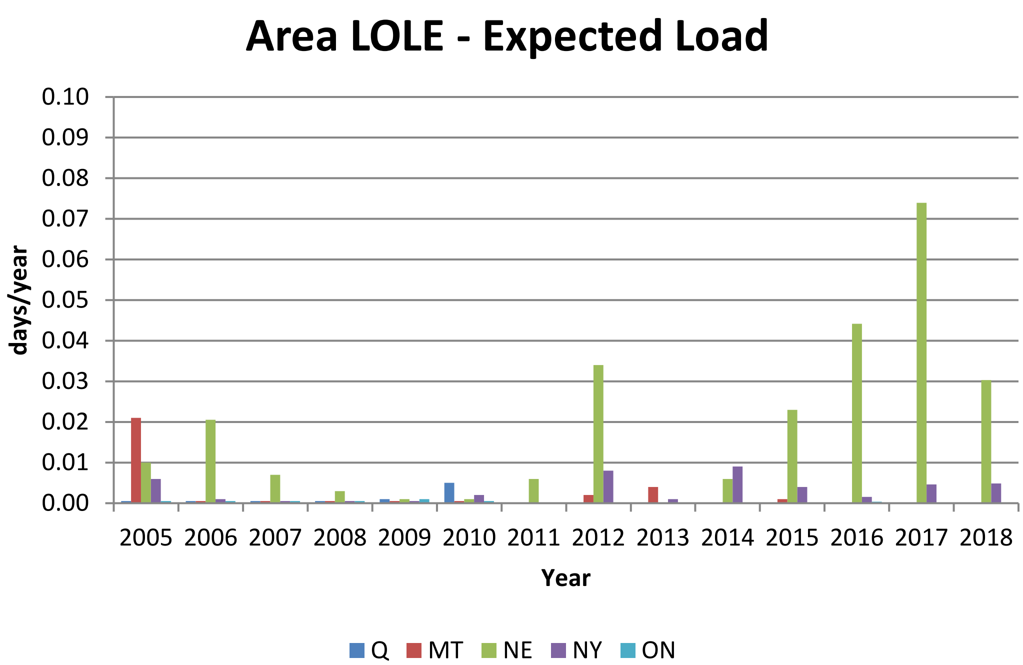


Figure 12(a) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

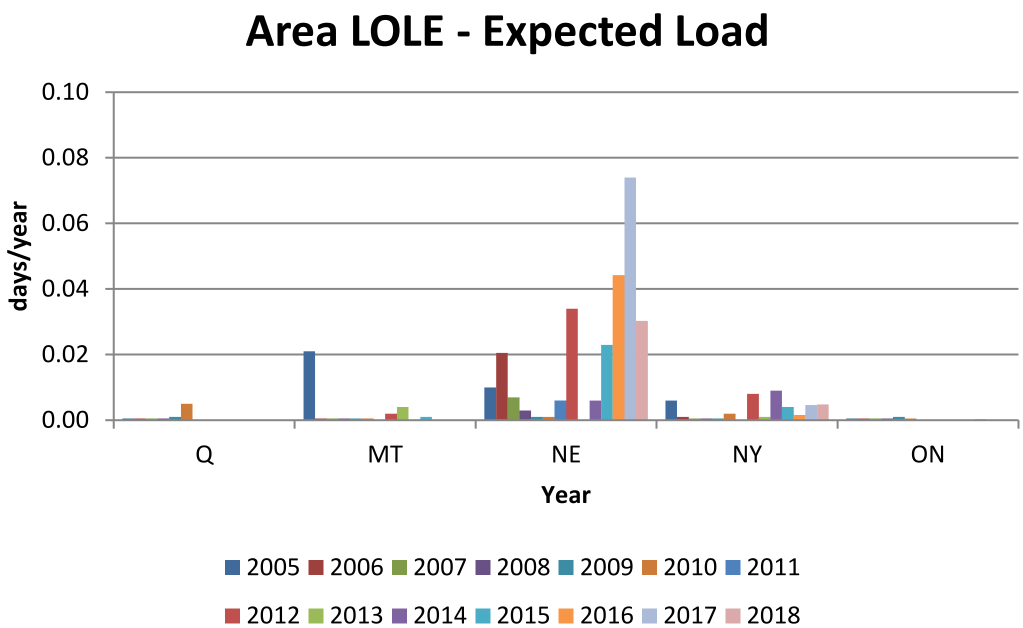


Figure 12(b) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

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

Figures 13(a) and 13(b) adds the estimated annual NPCC Area Loss of Load Expectation (LOLE) estimated for 2019 – 2023.

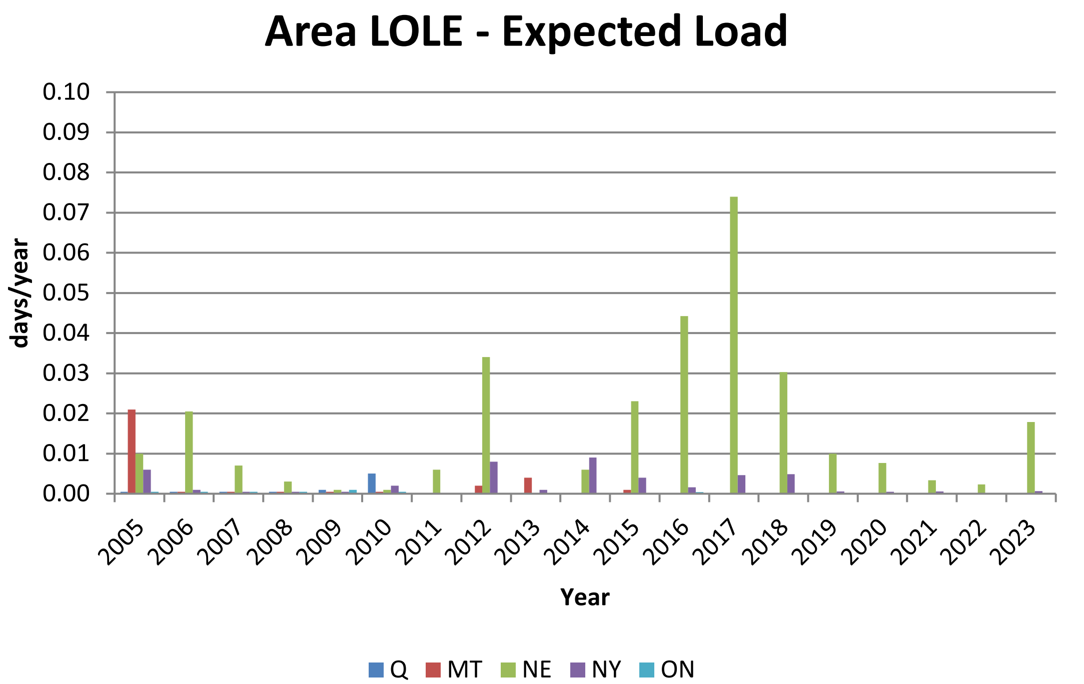


Figure 13(a) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

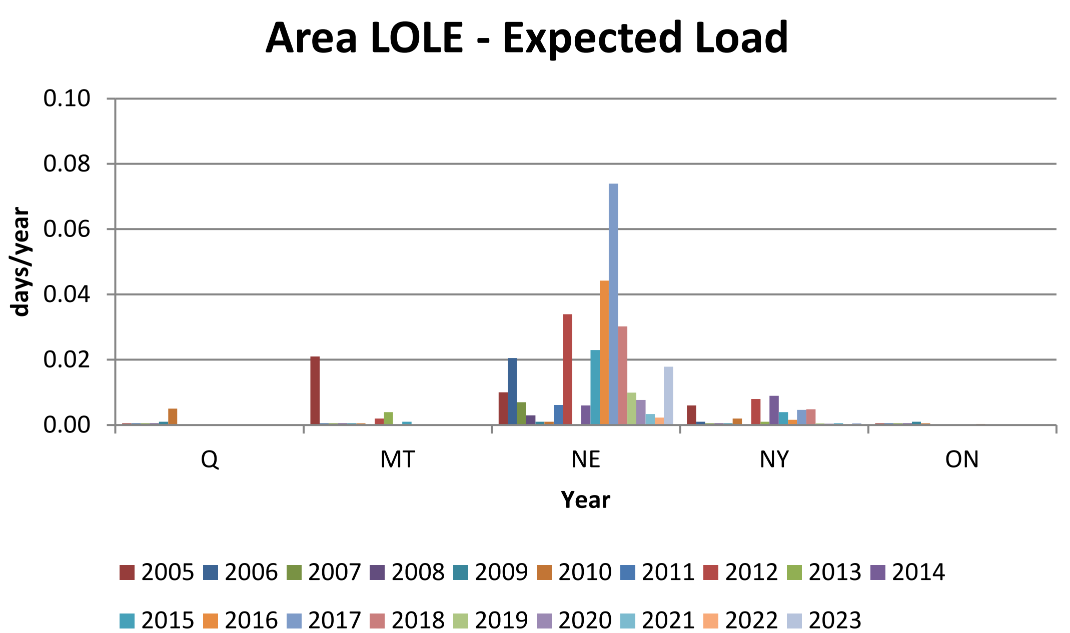


Figure 13(b) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case

APPENDIX A

Objective and Scope of Work

1. **Objective**
   On a consistent basis, evaluate the near term seasonal and long-range adequacy of NPCC Areas' and reflecting neighboring regional plans proposed to meet their respective resource adequacy planning criteria through multi-area probabilistic assessments. Monitor and include the potential effects of proposed market mechanisms in NPCC and neighboring regions expected to provide for future adequacy in the overview.

   In meeting this objective, the CP-8 Working Group 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 2018 - 2023 time period.

2. **Scope**
   The near-term seasonal analyses will use the current CP-8 Working Group's G.E. MARS database to develop a model suitable for the 2018 - 2019 time period to consistently review the resource adequacy of NPCC Areas and reflecting neighboring Regions' assumptions under Base Case (likely available resources and transmission) and Severe Case assumptions for the May to September 2018 summer and November 2018 to March 2019 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 (2018 - 2019) will be measured by estimating the use of NPCC Area operating procedures used to mitigate resource shortages.

   The long-range analysis will extend the CP-8 Working Group's G.E. MARS database to develop a model suitable for each 2019 - 2023 calendar year, to consistently review the resource adequacy of NPCC Areas and neighboring Regions under Base Case (likely available resources and transmission) assumptions, recognizing the above considerations.

Reliability of the long-range (2019 - 2023) will be measured by estimating the annual Loss of Load Expectation (LOLE) for each NPCC Area and neighboring Regions for each calendar year. In addition, Loss of Load Hours (LOLH) and Expected Unserved Energy will also be similarly estimated for the NPCC Areas, consistent with related NERC Reliability Assessment Subcommittee probabilistic analyses.

3. Schedule

A report of the results of the summer assessment will be approved no later than April 28, 2018.

A report of the results of the winter assessment will be approved no later than September 29, 2018.

A report summarizing the results of the Long-Range Adequacy Overview will be approved no later than December 29, 2018.

APPENDIX B

Modeled Capacity and Load at time of Area's Annual Peak, Based on Composite Load Shape

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2019	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	42,061	7,473	31,016	40,244	28,329	189,433	111,772
Purchase/Sale (MW)	-113	-191	1,391	1,278	0	2,319	-3,134
Load (MW)	38,387	5,316	28,577	32,857	22,017	154,321	95,432
Nameplate Demand Response (MW)	1,460	272	3,530	857	533	9,113	4,272
Reserves (%)	13	42	26	29	31	30	18
Maintenance - Peak Week (MW)	**	37	0	50	1,128	0	0
Wind Output at time of Area Peak (MW) ***	1,132	390	189	433	952	1,330	1,430
Wind Nameplate Capacity (MW)	3,775	974	1,081	1,898	4,786	1,330	1,430

* Wind capacity included at nameplate rating; demand response not included in capacity

** Capacity for Quebec reflects scheduled maintenance and restrictions

*** This value reflects the expected value during peak, although the modeling varies across areas: Quebec, New England, PJM and MISO model wind units as equivalent thermal units; the Maritimes and New York use historical hourly profiles; [23] Ontario utilizes random draws using a probability density function during the Monte Carlo simulation.

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

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2020	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	42,117	7,471	31,119	40,574	27,415	193,789	112,647
Purchase/Sale (MW)	-216	-131	1,265	1,784	0	2,565	-3,380
Load (MW)	38,714	5,317	28,714	32,629	22,085	152,033	96,173
Nameplate Demand Response (MW)	1,519	272	3,837	1,132	533	7,675	4,272
Reserves (%)	12	43	26	33	27	34	18
Maintenance - Peak Week (MW)	**	10	0	50	1,947	0	0
Wind Output at time of Area Peak (MW) ***	1,140	390	189	433	984	1,742	1,474
Wind Nameplate Capacity (MW)	3,801	974	1,714	2,024	4,946	1,742	1,474

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2021	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	42,458	7,314	31,218	39,967	24,093	196,333	113,076
Purchase/Sale (MW)	-959	-200	953	1,800	0	2,565	-3,380
Load (MW)	38,920	5,293	28,893	32,451	22,156	152,432	96,537
Nameplate Demand Response (MW)	1,544	272	4,383	1,132	533	7,691	4,429
Reserves (%)	11	40	27	32	11	36	18
Maintenance - Peak Week (MW)	**	10	0	50	5,269	0	0
Wind Output at time of Area Peak (MW) ***	1,146	431	189	123	984	1,849	1,497
Wind Nameplate Capacity (MW)	3,819	974	1,734	2,024	4,946	1,849	1,497

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2022	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	42,457	7,294	31,282	39,779	25,905	196,333	113,633
Purchase/Sale (MW)	-817	-166	247	1,844	0	2,565	-3,380
Load (MW)	39,290	5,257	29,093	32,339	22,098	152,210	97,011
Nameplate Demand Response (MW)	1,585	266	4,696	1,132	533	7,721	4,429
Reserves (%)	10	41	25	32	20	36	18
Maintenance - Peak Week (MW)	**	0	0	50	3,457	0	0
Wind Output at time of Area Peak (MW) ***	1,146	431	189	82	984	1,849	1,519
Wind Nameplate Capacity (MW)	3,819	974	1,734	2,024	4,946	1,849	1,519

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	MISO
2023	(Jan)	(Jan)	(Aug)	(Aug)	(Jul)	(Jul)	(Aug)
Capacity (MW) *	42,457	7,293	31,282	39,965	24,910	196,333	114,209
Purchase/Sale (MW)	-33	-166	247	1,844	500	2,565	-3,380
Load (MW)	39,600	5,203	29,300	32,284	22,139	154,656	97,498
Nameplate Demand Response (MW)	1,610	266	4,981	1,132	533	7,747	4,272
Reserves (%)	11	42	25	33	17	34	18
Maintenance - Peak Week (MW)	**	0	0	50	3,350	0	0
Wind Output at time of Area Peak (MW) ***	1,146	431	189	82	984	1,849	1,563