Northeast Power Coordinating Council

2014 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. Mark Walling, GE Energy Consulting, Patricio Rocha, the PJM Interconnection, and thanks them for their assistance in this analysis.

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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 2015 to 2019, based on the reported NERC *2014 Long Term Reliability Assessment* [2] 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 3.18 was used for the assessment.

The database developed by the NPCC CP-8 Working Group's "*NPCC Reliability Assessment for Summer 2014*", May 2014, [4] was used as the starting point for this Overview. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the 2015-2019 period, consistent with the information reported for the *NERC 2014 Long-Term Reliability Assessment*. [5]

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. NERC's 2014 Long-Term Reliability Assessment (LTRA) Narratives are provided (for reference) in Appendix C.

[1] See: https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf , Directory No. 1, Section 5.2
[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
[5] Available at: www.nerc.com.

MODEL ASSUMPTIONS

The assumptions used in NPCC's Long Range Adequacy Overview are consistent with the assumptions of the following recently completed Area studies and the *NERC 2014 Long-Term Reliability Assessment*:

Area Studies

New York

The Reliability Needs Assessment (RNA) is developed by the New York ISO (NYISO) in conjunction with Market Participants and all interested parties as its first step in the Comprehensive System Planning Process (CSPP). The RNA is the foundation study used in the development of the NYISO Comprehensive Reliability Plan (CRP). The RNA is performed to evaluate electric system reliability, for both transmission security and resource adequacy, over a 10-year study period. If the RNA identifies any violation of Reliability Criteria for Bulk Power Transmission Facilities (BPTF), the NYISO will report a Reliability Need quantified by an amount of compensatory megawatts (MW).

The 2014 RNA identifies transmission security violations beginning in 2015, some of which are similar to those found in the 2012 RNA. The 2014 RNA also identifies resource adequacy violations which begin in 2019 due to inadequate resource capacity located in Southeast New York (SENY) and increase through 2024.

The NYISO expects existing market rules and recent market rule changes to entice market participants to take actions that will help meet the resource adequacy needs in SENY, as identified by the 2012 RNA and the 2014 RNA. The resources needed downstream of the upstate New York to SENY interface is approximately 1,200 MW in 2024 (100 MW in 2019), which could be transmission or capacity resources. The new Zones G-J Locality will provide market signals for resources to provide service in this area. Capacity owners and developers are taking steps to return mothballed units to service, restore units to their full capability, or build new in the Zones G-J Locality. If some or all of these units return to service or are developed, the reliability need year would be postponed beyond 2019. In addition, other measures, such as demand response, energy efficiency and CHP projects approved by the New York Public Service Commission, could also postpone the reliability need year beyond 2019. The New York State Public Service Commission is also considering regulated transmission development to relieve the transmission constraints between upstate New York and southeastern New York, which could also defer the need for additional resources over the long term. Potential solutions will be submitted for evaluation during the solutions phase of the Reliability Planning Process (RPP) and included in the upcoming 2014 Comprehensive Reliability Plan (CRP) if appropriate.

As a backstop to market-based solutions, the NYISO employs a process to define responsibility should the market fail to provide an adequate solution to an identified reliability need. Since there are transmission security violations in Zones A, B, C, E, and F within the study period, the transmission owners (TOs) in those zones (i.e., National Grid, RGE, and NYSEG) are responsible and will be tasked to develop detailed regulated backstop solutions for evaluation in the 2014 CRP. Returning generation and updated transmission owner plans for their local systems could also mitigate the identified transmission security violations. Given the limited time between the identification of certain transmission security needs in the 2014 RNA report and their occurrence in 2015, the use of demand response and operating procedures, including those for emergency conditions, may be necessary to maintain reliability during peak load periods until permanent solutions can be put in place.

New England

The 2014 Regional System Plan (RSP14) is the annual report prepared by ISO New England (ISO-NE) on the planning efforts to identify the region's electricity needs and the plans for meeting these needs in order to maintain reliable and economic operation of New England's bulk power system over a ten-year horizon from 2014 to 2023. RSP14 and the ongoing system planning process comply with all applicable sections of the ISO's Transmission, Markets, and Services Tariff (ISO tariff), approved by FERC. The plan and planning process also satisfy the relevant standards, criteria, and other requirements established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), participating transmission owners (PTOs), and the ISO. The study proposals, scopes of work, assumptions, study results, findings and recommendations presented in this report have been reviewed and discussed through the regional stakeholder process. The report was approved by the ISO New England's Board of Directors on November 6, 2014.

The RSP14 builds on the results of previous regional system plans and analyses. It provides information on electric power system needs; system improvements; and the results of newly completed load, resource, and transmission studies for reliably meeting demand throughout the region to 2023. It discusses ongoing and new analyses based on the current and planned system and describes new and planned infrastructure for all areas of New England. The report also addresses many of the challenges the region is facing and how the ISO and its stakeholders are addressing key strategic issues. Notably, the report addresses the major factors influencing resource development, the requirements for fuel certainty, and the development of the electric power system infrastructure for the 10-year planning period, such as existing and pending state and federal environmental and energy policies. As part of its compliance with Attachment K of the ISO's Open Access Transmission Tariff (OATT), RSP14 specifically provides information on the timing of system needs and the quantity, general locations, and characteristics of the generation and demand resources that could resolve these needs and defer or eliminate the need for transmission projects.

Major findings and observations of the RSP14 include:

The ISO forecasts the 10-year growth rate to be 1.3% per year for the summer peak demand, 0.6% per year for the winter peak demand, and 1.0% per year for the annual use of electric energy. After allowing for energy efficiency forecast, the annual energy-use forecast shows essentially no net long-run growth; the summer peak is projected to increase at 0.7%; the winter peak demand is expected to slightly decline at a rate of 0.1% over the 10-year forecast.

The region's net Installed Capacity Requirement is expected to grow from 32,588 MW in 2014 to a representative value of 36,100 MW by 2023. This represents a growth of approximately 390 MW per year, which is equivalent to 1.14% per year.

Transmission projects placed in service have reduced congestion and decreased dependence on generating units located in load pockets. Several transmission projects to come on-line will further enhance the system or sub-area reliability. The major transmission projects under development include the Maine Power Reliability Program (MPRP) and New England East-West Solution (NEEWS). This infrastructure will improve the system reliability in the areas of Maine, New Hampshire, Springfield of Massachusetts and Rhode Island.

The ISO has taken a number of actions to address fuel-certainty issues resulted from the region's high dependence on natural gas-fired generation and other constrained-energy resources in the short and longer terms, including the implementation of FERC-approved special winter program to mitigate fuel constraints during the winter period, and enhancements to the energy and capacity markets.

Possible solutions for meeting the regional Renewable Portfolio Standards (RPSs) include developing the renewable resources already in the ISO generator interconnection queue; importing renewable resources from adjacent balancing authority areas; building new renewable resources in New England not yet in the queue; and using behind-the-meter projects and eligible renewable fuels, such as biomass, at existing generators.
Environmental compliance obligations for generators due to existing and pending state, regional, and federal environmental requirements are likely to impose operational limits on new and existing generators but pose only a limited retirement risk and lower reliability impacts compared to earlier assessments. The lowered retirement risk is due in large part to the flexibility that the EPA has provided in its cooling water rule and the Mercury & Air Toxics Standards (MATS), recognizing the reliability value that low capacity factor fossil steam generators provide in maintaining system fuel diversity.

Ontario
The Independent Electricity System Operator of Ontario (IESO) regularly assesses the adequacy and reliability of Ontario's power system. The latest Assessment of the Reliability and Operability of the Ontario Electricity System Update, dated September 4, 2014 [6] provides Ontario's supply outlook over the next 18 months.

The Outlook for the reliability of Ontario's electricity system remains positive for the coming fall – and throughout the next 18 months – with adequate supply and reliable transmission service forecasted.

During this Outlook period, two former coal stations that are being converted to biomass are expected to return to service. Atikokan Generating Station (GS) has completed commissioning and it is now the largest 100 per cent biomass facility in North America. Thunder Bay GS, the last coal facility to decommission in Ontario, will follow with their conversion to a biomass generation facility, and is anticipated in-service in early 2015.

Including Thunder Bay GS, more than 2,400 MW of new supply will be incorporated into the province's existing generation fleet during the Outlook period. This includes the province's first grid-connected solar projects which are presently commissioning and are expected to be in service in the next quarter, with facilities in northeast and western Ontario. By the end of the Outlook period, the amount of solar generation connected to the grid is expected to grow to 280 MW, complementing the 1,800 MW of embedded solar facilities located within distribution networks.

As part of its 2012 RFP for Alternative Technologies for Regulation Services, the IESO procured two projects, totaling six megawatts of storage capacity. Both came into service in summer 2014 and will help correct variations in power system frequency, and also support operational testing of storage

[6] See: http://www.ieso.ca/Documents/marketReports/18MonthOutlook_2014sep.pdf

capabilities. This procurement process also fed into the development of a framework for a subsequent storage RFP, which the IESO recently completed. This is expected deliver an additional 34 MW in storage capacity to provide additional benefits to both grid and market operations.

This report identifies nuclear outages scheduled in the spring of 2015. Demand response initiatives, increased reliance on the interties and restricted outage programs will be among the actions available to manage reserves in the event of extreme weather scenarios during the scheduled nuclear outages. The transmitters are requested to schedule preventive maintenance ahead of time to ensure reliable operation of their equipment such as voltage control facilities during the nuclear outages. Market participants are reminded to review their operational needs, such as fuel supply, to ensure their facilities are available to support the system during this period.

The IESO is also taking steps to strengthen the role of demand response in meeting the province's longer-term energy needs. In 2015, the IESO plans to hold a competitive capacity auction for new demand response resources to participate in the market beginning in 2016. This auction will contribute verifiable and reliable demand response that can be incorporated into forecasts.

The assumptions used in this study as well as in the 2014 NERC Long-Term Reliability Assessment are consistent with Ontario's Long-Term Energy Plan (LTEP). In its Interim Review [7] conducted in 2014, the IESO demonstrated that Ontario will be able to meet the NPCC resource adequacy criterion for years 2015 to 2017.

Québec

The Québec assumptions used in this study are consistent with the 2014 NERC Long-Term Reliability Assessment. [8]

The demand forecast average annual growth is 0.8 percent during the 5-year period. Energy efficiency and conservation programs are integrated in the demand forecasts and account for 1,550 MW toward the 2015–2016 winter peak demand. Energy efficiency will continue to grow throughout the assessment period and should account for 1900 MW toward the 2019-2020 winter peak demand. Demand forecasts also take into account 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 650 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 is also currently developing new DR programs, including Direct Control Load Management (DCLM) and others. Total DR expected to be available during the peak for the 2019–2020 winter period is projected to be approximately 2,000 MW.

About 1,700 MW of new available capacity (hydro, biomass and wind) is expected to be in service by 2019. There are no significant unit retirements planned during the assessment period.

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

[8] 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. Beginning October 1, 2013, the New Brunswick System Operator (NBSO) was amalgamated with NB Power, with NB Power taking over the role of the Reliability Coordinator for the Maritimes Area from NBSO. This does not affect resource adequacy in the Maritimes Area.

Load growth within the separate Maritimes Area subareas varies positively and negatively but on an aggregated basis is negligible during the period from 2015 to 2019.

Because of the relative size of the largest generating unit in the Maritimes Area, compared to its aggregated load, the area carries substantial reserve capacity. The required reserve margin for the Maritimes Area is 20 percent but typically exceeds 40%.

Generators use a diverse mix of fuel types with the result that the Maritimes Area is not overly reliant on any particular fuel to meet its load. The area assumes 300 MW of tie support in its resource mix for resource adequacy analysis but is not dependent on these this capacity to meet resource adequacy criterion. This value represents less than 25% of the interconnection benefits available to it from external areas in 2015.

The assumptions used in this study are consistent with the latest Maritimes Area Review of Resource Adequacy; [9] 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.

[9] See: https://www.npcc.org/Library/Resource%20Adequacy/RCC%20Approved%20%202013%20Maritimes%20Area%20Comprehensive%20Resource%20Adequacy%20report.pdf

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 were 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 2014, corresponding to the assumed occurrence of the NPCC system peak load (assuming the composite load shape). 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 2015)

Area	Per-Unit Variation in Load						
MT	1.1380	1.0920	1.0460	1.0000	0.9540	0.9080	0.8620
NE	1.0934	1.0383	0.9971	0.9635	0.9402	0.8500	0.8000
NY	1.0430	1.0310	1.0160	0.9980	0.9750	0.9440	0.9050
ON	1.0779	1.0519	1.0260	1.0000	0.9740	0.9481	0.9221
QC	1.0870	1.0860	1.0400	0.9991	0.9613	0.9230	0.9130
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 July 2015)

Area	Per-Unit Variation in Load						
MT	1.1380	1.0920	1.0460	1.0000	0.9540	0.9080	0.8620
NE	1.2480	1.1187	1.0047	0.9936	0.8970	0.8864	0.8513
NY	1.1172	1.0857	1.0459	0.9930	0.9370	0.8799	0.8281
ON	1.1769	1.1179	1.0590	1.0000	0.9410	0.8821	0.8231
QC	1.0542	1.0542	1.0247	1.0010	0.9753	0.9470	0.9458
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. [10]

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 2015 to 2019. 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.

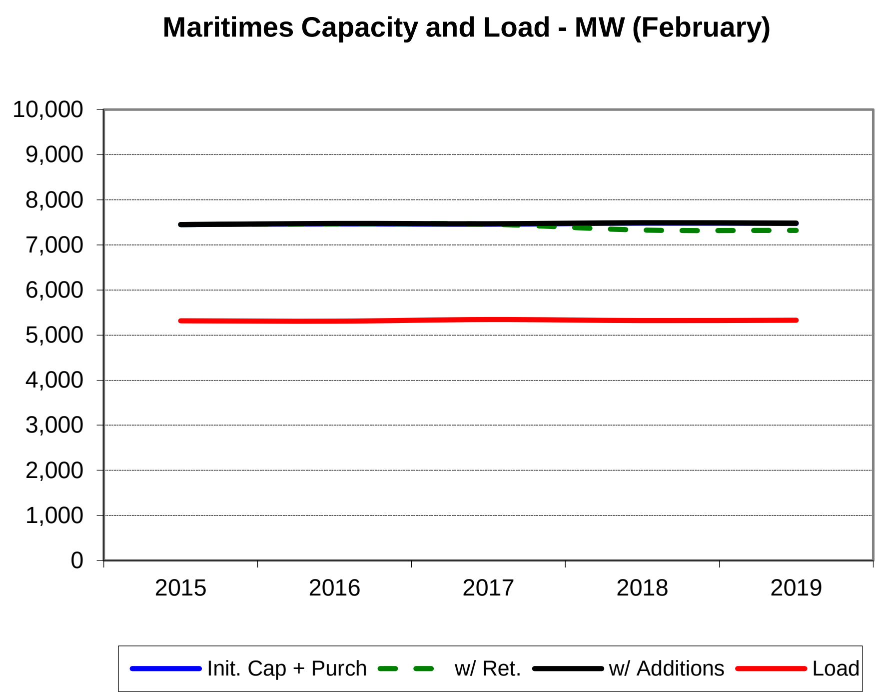


Figure 1 – Maritimes Area Capacity and Load

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

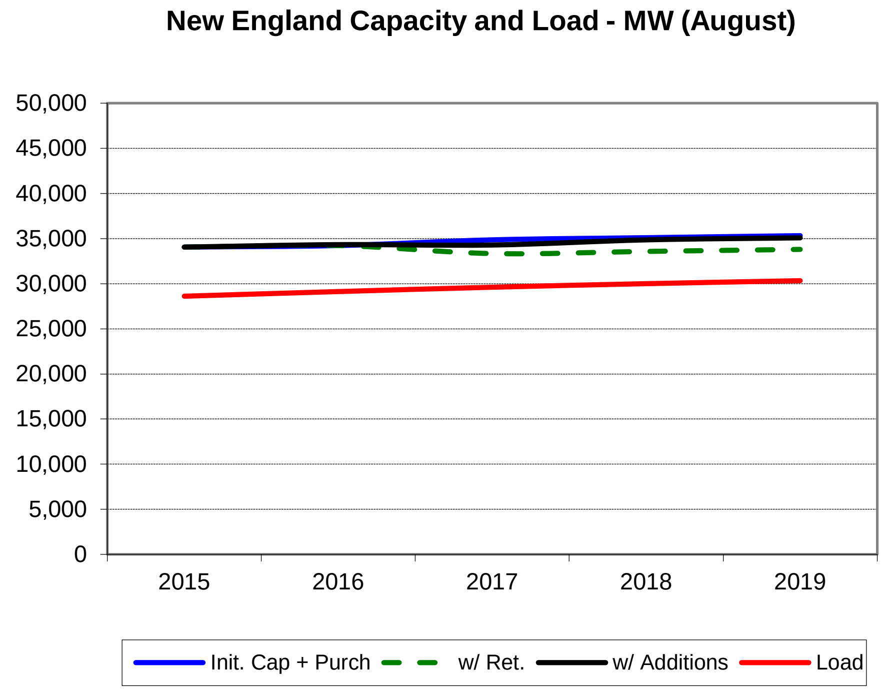


Figure 2 – New England Capacity and Load

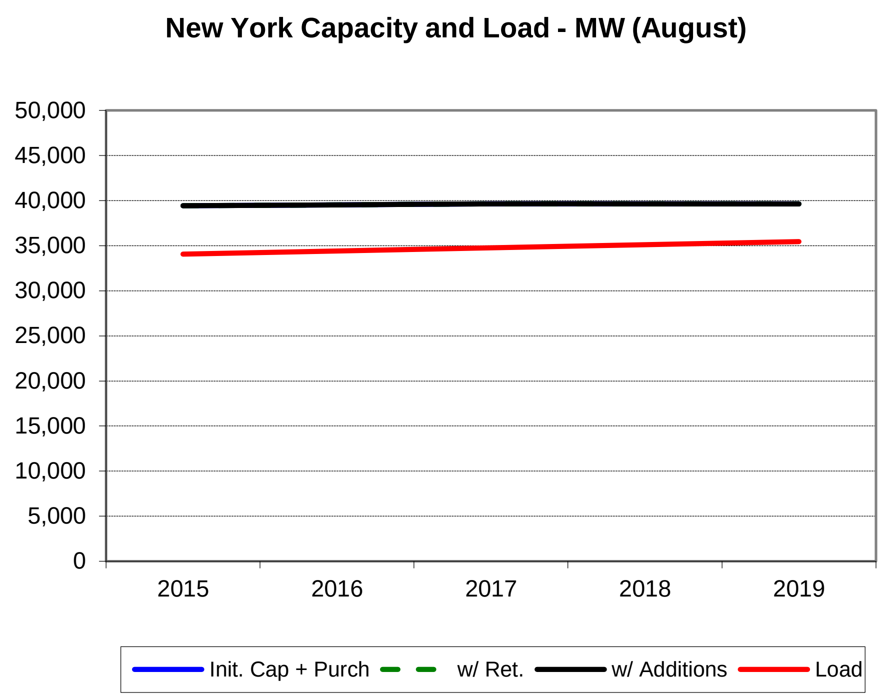


Figure 3 – New York Area Capacity and Load

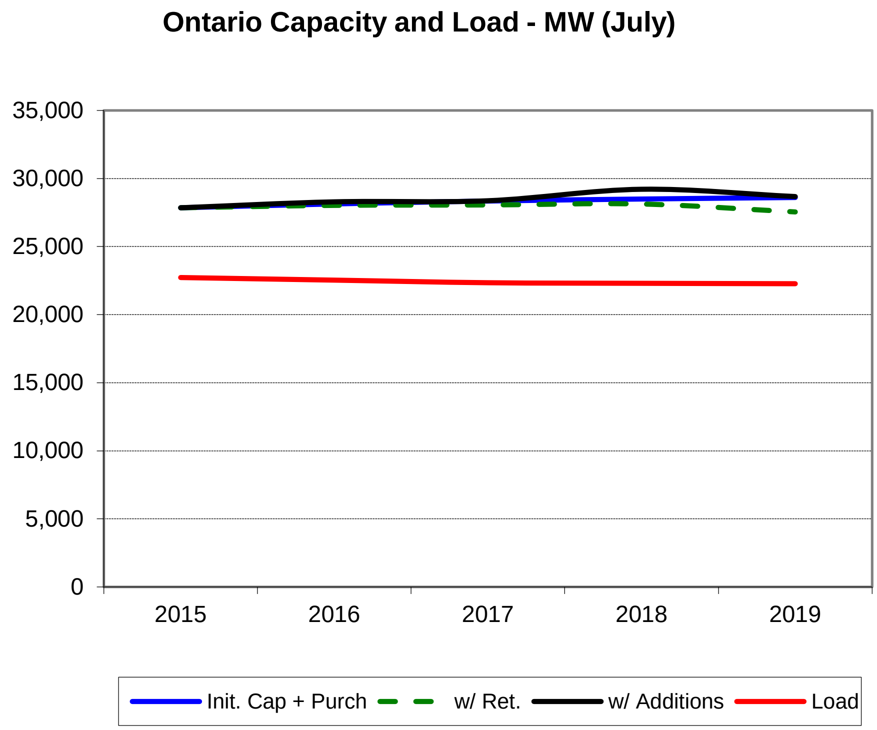


Figure 4 – Ontario Capacity and Load

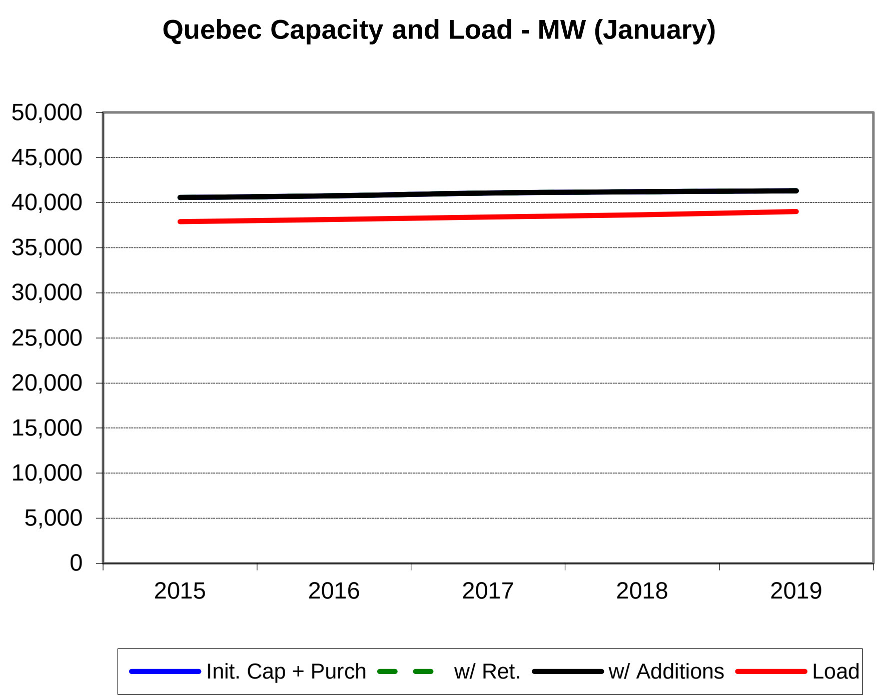


Figure 5 – Québec Capacity and Load

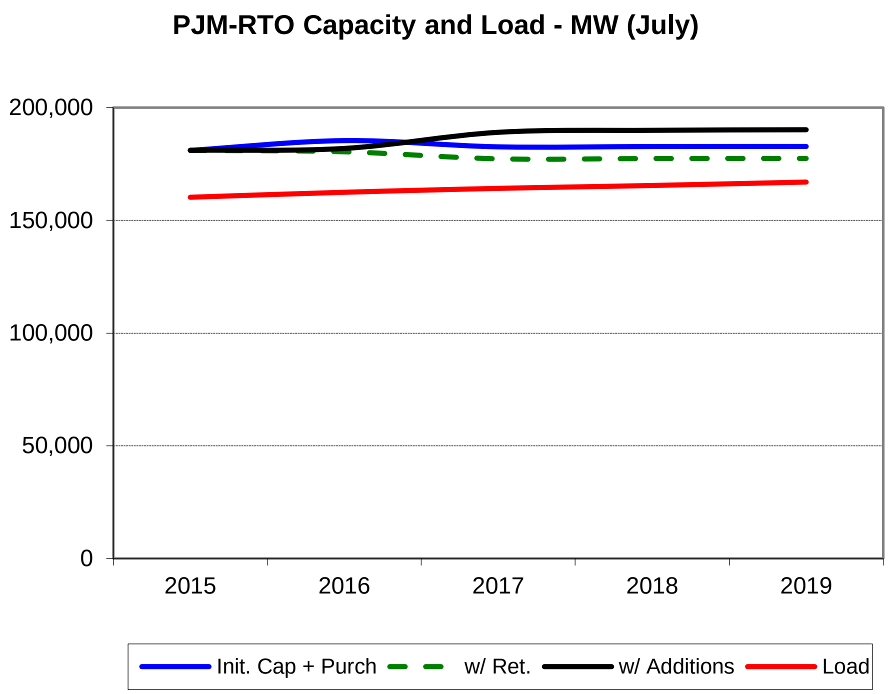


Figure 6 – PJM-RTO Capacity and Load

Transfer Limits

Figure 7 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the period 2015 to 2019.

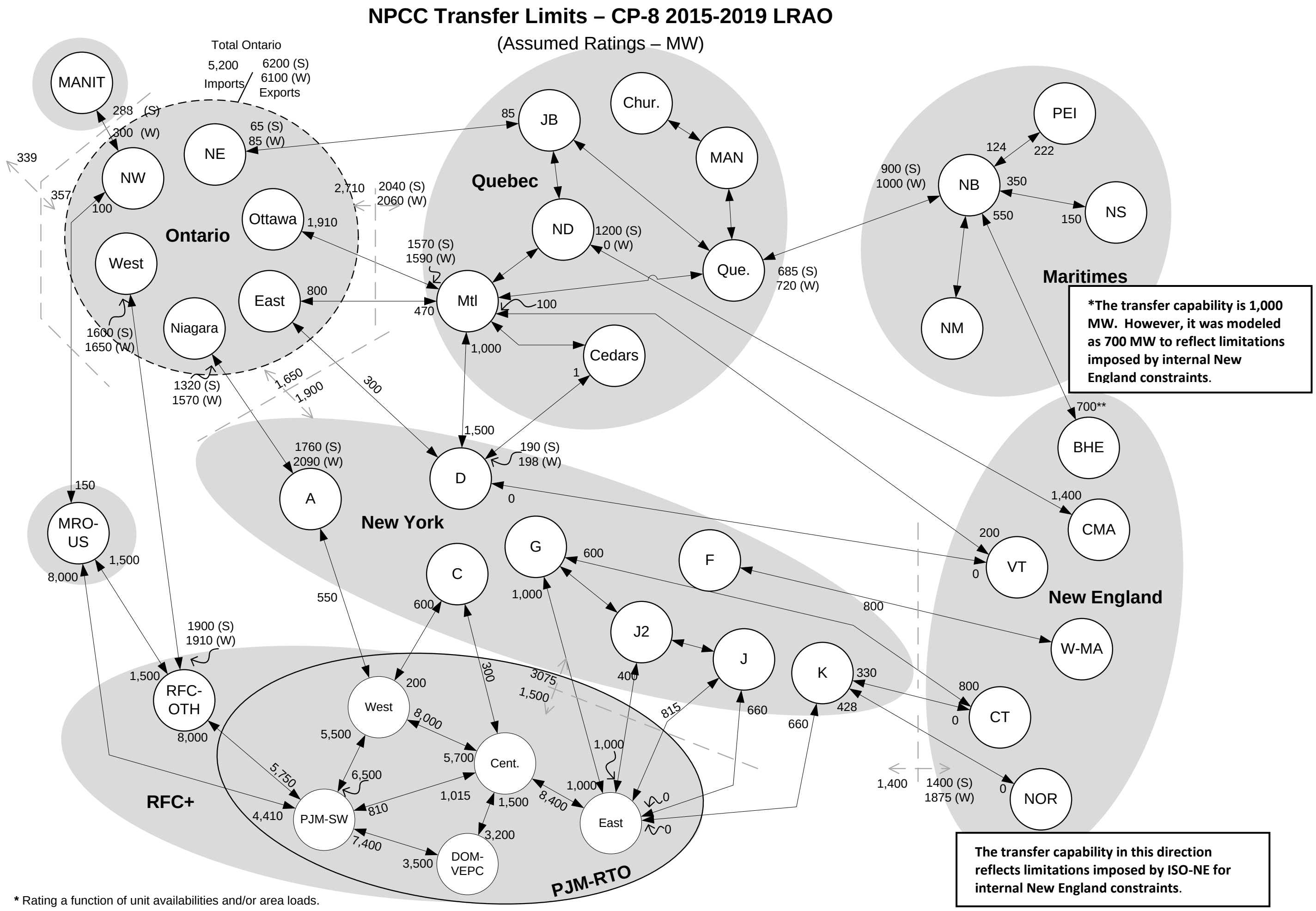


Figure 7 - Assumed Transfer Limits

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
MN	- Minnesota	W MA	- Western MA	NS	- Nova Scotia
MAN	- Manicouagan	NBM	- Millbank	NW	- Northwest (Ontario)
NE	- Northeast (Ontario)	VT	- Vermont	RFC	- Reliability*First* Corp.
MRO	- Midwest Reliability Organization	Que Centre	- Québec Centre	MT	- Maritimes Area

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 2015 Load Relief Assumptions - MW

Actions	MT (Feb)	NE (Aug)	NY (Aug)	ON (July)	QC (Jan)
1. Curtail Load / Utility Surplus	-	-	-	148	1,277
Appeals	-	-	-	1% of load	-
RT-DR/SCR/EDRP	-	738[11]	738[12]	-	-
SCR Load /Man. Volt. Red.	-		0.17% of load	-	-
2. No 30-min Reserves	233	625	655	473	500
3. Voltage Reduction	-	422	1.28% of load	1.40% of load-	250
Interruptible Loads	250	-	-	528	-
4. No 10-min Reserves	505	-	- -	945	750
RT-EG	-	294 [13]	-	-	-
General Public Appeals	-	-	204	-	-
5. 5% Voltage Reduction	-	-	-	0.70% of load	-
No 10-min Reserves	-	1,550	1,310	-	-
Appeals/Curtailments	-	-	-	40	-

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.

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.

[11] Derated value shown accounts for assumed availability.
[12] Derated value shown accounts for assumed availability.
[13] Derated value shown accounts for assumed availability.

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 RFC (Reliability*First* Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 3 and Figure 8.

Table 3
PJM, RFC-Other and MRO-US 2015 Assumptions [14]

	PJM	RFC-Other	MRO-US
Peak Load (MW)	160,257	44,209	32,221
Peak Month	July	July	July
Assumed Capacity (MW)	179,287	49,308	36,340
Purchase/Sale (MW)	3,263	-2,067	-1,589
Reserve (%)	23	15	16
Operating Reserves (MW)	3,400	2,206	1,700
Curtailable Load (MW)	14,815	3,694	2,692
No 30-min Reserves (MW)	2,765	1,470	1,200
Voltage Reduction (MW)	2,201	1,100	1,100
No 10-min Reserves (MW)	635	736	500
Appeals (MW)	400	200	200
Load Forecast Uncertainty	+/- 12.58%, 8.39%, 4.20%	+/- 11.77%, 7.85%, 3.92%	+/- 11.77%, 7.85%, 3.92%

The RFC-Other area modeled in this analysis was intended to represent the non-PJM-RTO region data within RFC. The modeling of the RFC region is in transition due to changes in the regional boundaries between RFC, MRO, and SERC. This model was based on publicly available data from the 2008 NERC Electricity Supply & Demand (ES&D), which reported the data according to the old boundary definitions. The modeling of RFC-Other is expected to evolve for future studies as data reflecting the new regional boundaries becomes available. For now, the RFC-Other area is the non-PJM-RTO region that was formerly in either MAIN or ECAR.

Unit data was from the publicly available NERC data. Each individual unit represented in the non-PJM RFC region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2014 RRS Report).

[14] 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/

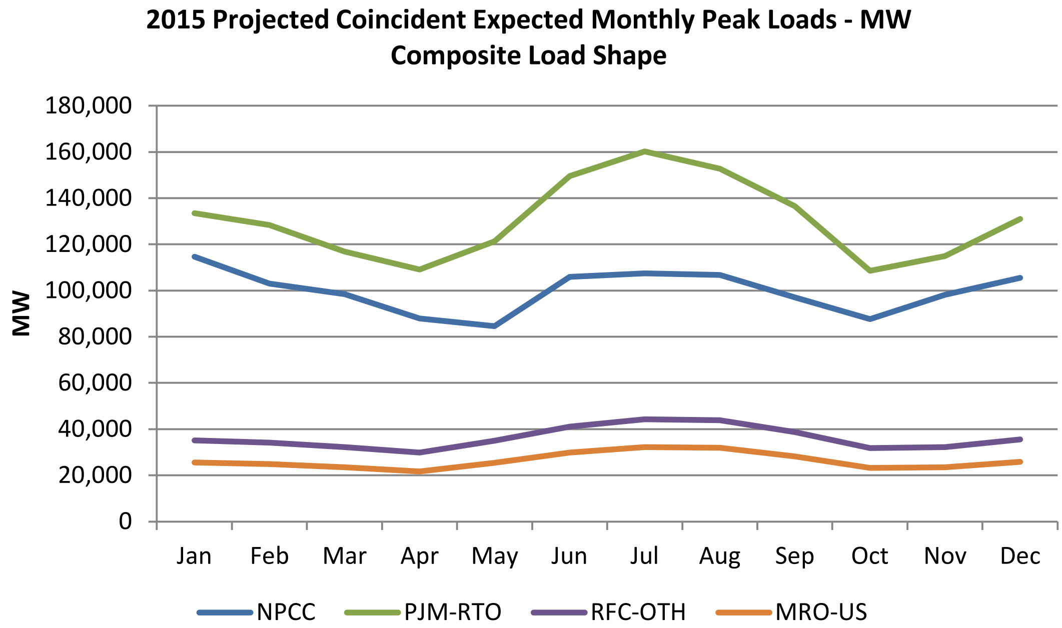


Figure 8 – 2014 Projected Monthly Expected Peak Loads for NPCC, RFC, PJM and the MRO

Reliability*First*

Reliability*First* is a not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. Reliability*First* was approved by the North American Electric Reliability Council (NERC) to become one of eight Regional Reliability Councils in North America and began operations on January 1, 2006.

Reliability*First* is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination (ECAR) Agreement, and the Mid-American Interconnected Network (MAIN) organizations. The year 2006 is a period of transition for the ECAR, MAAC and MAIN organizations, as their responsibilities were transferred to Reliability*First*.

MRO

The Midwest Reliability Organization (MRO) is a non-profit organization dedicated to ensuring the reliability of the bulk power system in the North Central part of North America. The primary focus of the MRO is ensuring compliance with regional and international reliability standards and criteria utilizing open, fair processes in the public interest.

Formation of the MRO was approved by the Mid-Continent Area Power Pool (MAPP) Executive Committee in November 2002. In 2005, this organization became operational and replaced the MAPP Regional Reliability Council of the North American Electric Reliability Council.

The U.S. portion of the MRO was modeled in this study, recognizing the strong transmission ties to the rest of the study system. Each individual unit represented in the MRO-US region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2014 RRS Report).

PJM-RTO

Load Model

PJM's Load Forecast issued in January 2014 [15] was used in this study. The methods and techniques used in the load forecasting process are documented in Manual 19 [16] (Load Forecasting and Analysis) and Manual 20 [17] (PJM Resource Adequacy Analysis.) The hourly load shape is based on observed 2002 calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the 2014 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 this year in which PJM West and PJM South were combined into one region (PJM Rest).This modeling change is 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 (2009-13) GADS data. This is consistent with modeling practices in the 2014 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 3 summer periods.

[15] Please see http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx
[16] http://www.pjm.com/~/media/documents/manuals/m19.ashx
[17] http://www.pjm.com/~/media/documents/manuals/m20.ashx

RESULTS

Figures 9(a) and 9(b) shows the estimated annual NPCC Area Loss of Load Expectation (LOLE) for the 2015-2019 period.

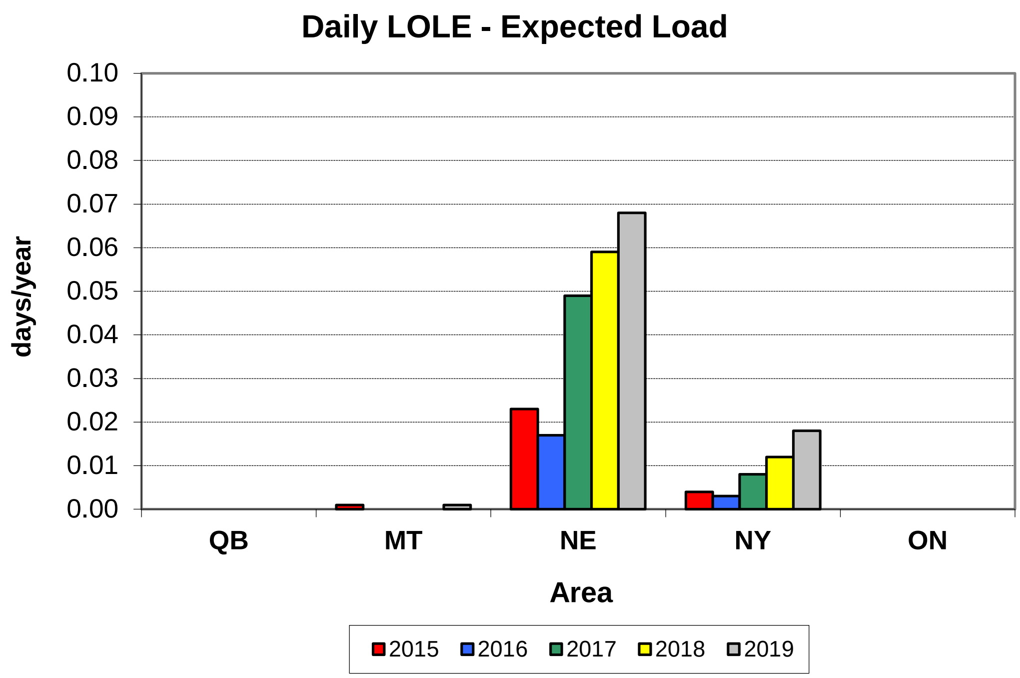


Figure 9(a) - Estimated Annual NPCC Area LOLE (2015 – 2019)

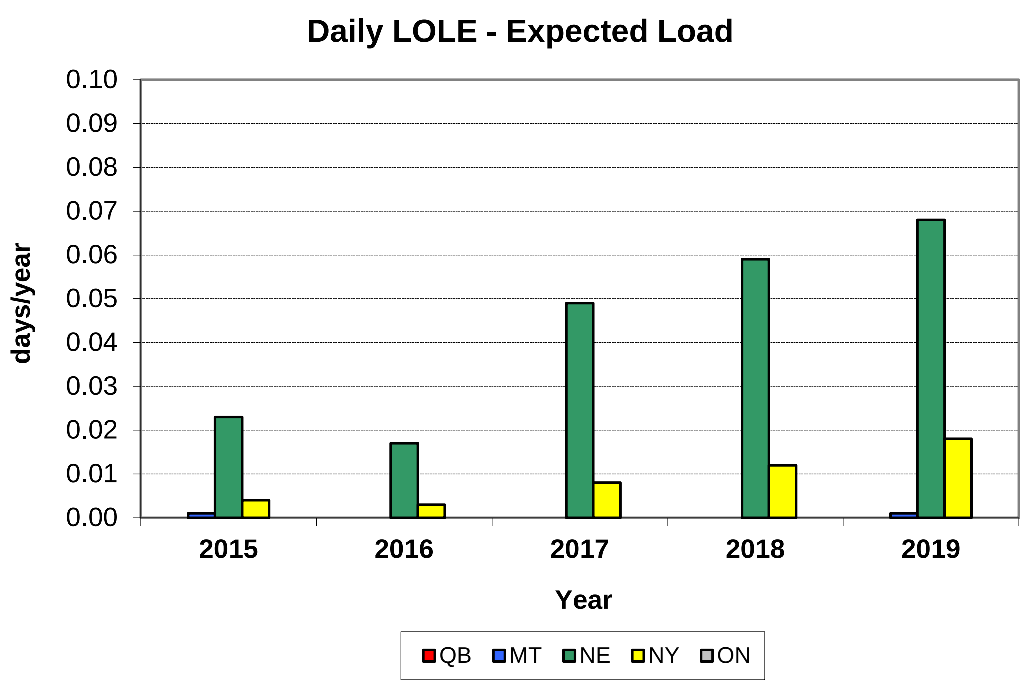


Figure 9(b) - Estimated Annual NPCC Area LOLE (2015– 2019)

Figures 9(c) and 9(d) shows the estimated annual NPCC Areas and Neighboring Region's Loss of Load Expectation (LOLE) for the 2015-2019 period.

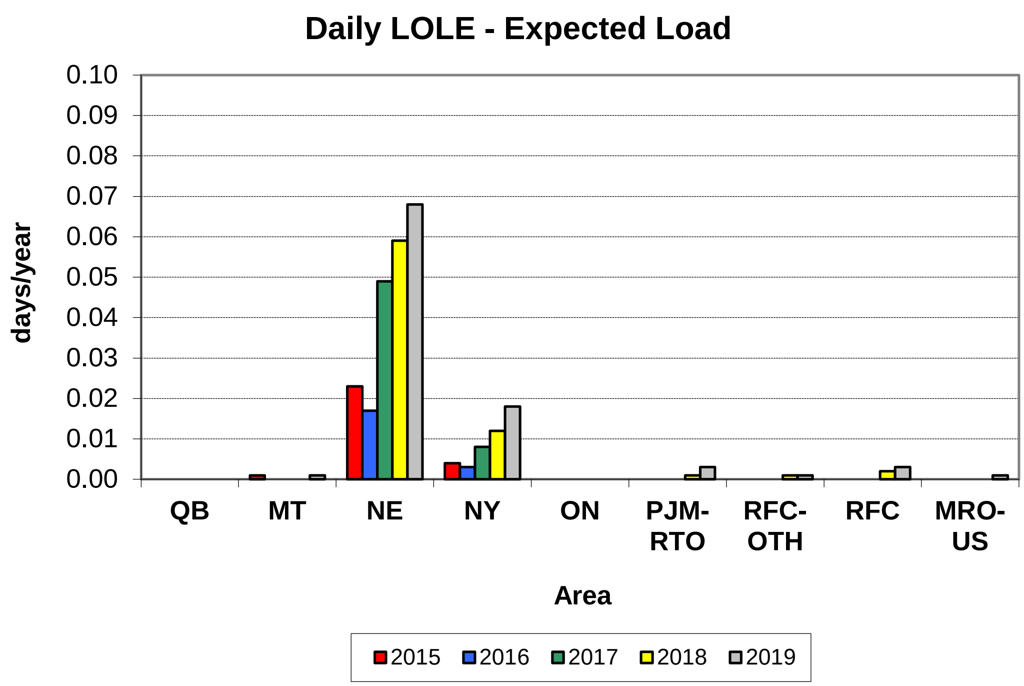


Figure 9(c) - Estimated Annual NPCC Areas and Neighboring Regions LOLE (2015 – 2019)

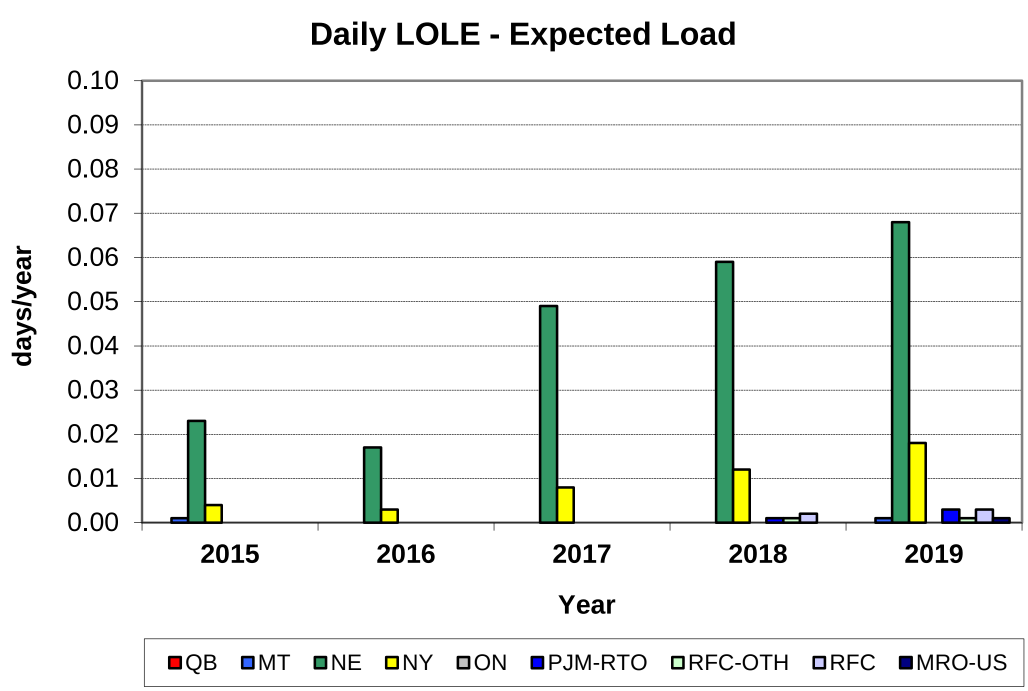


Figure 9(d) – Estimated Annual NPCC Areas and Neighboring Region's LOLE (2015 – 2019)

Figures 10(a) and 10(b) show the estimated annual NPCC Area Loss of Load Expectation (LOLH) estimated the 2015-2019 period.

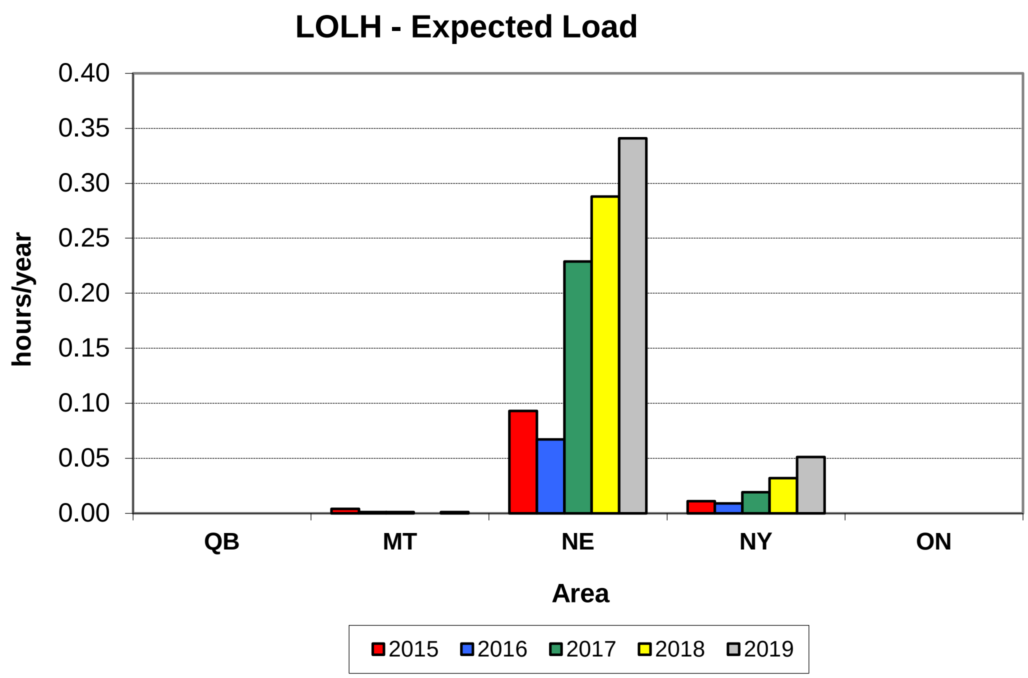


Figure 10(a) - Estimated Annual NPCC Area LOLH (2015 – 2019)

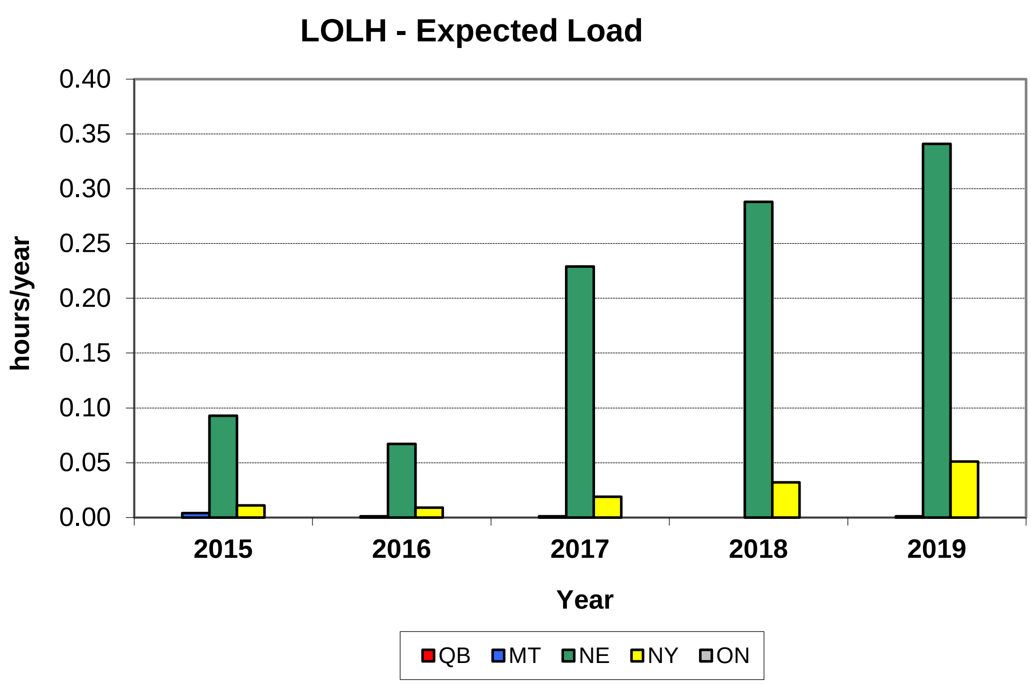


Figure 10(b) - Estimated Annual NPCC Area LOLH (2015 – 2019)

Figures 10(c) and 10(d) shows the estimated annual Loss of Load Expectation (LOLH) for NPCC Areas and neighboring Regions for the 2015-2019 period.

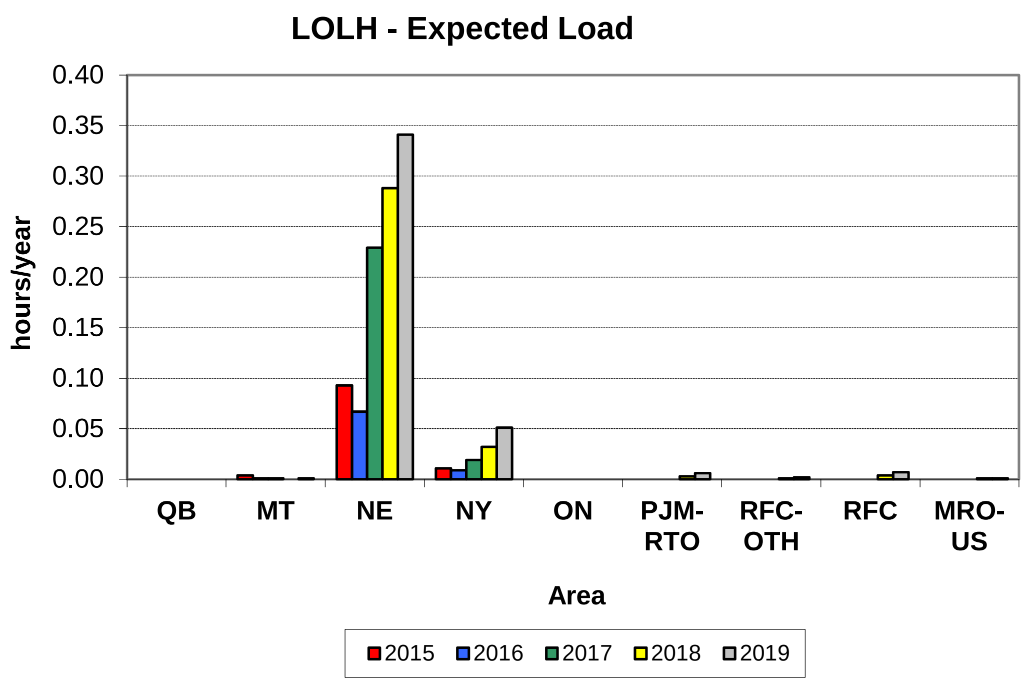


Figure 10(c) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2015 – 2019)

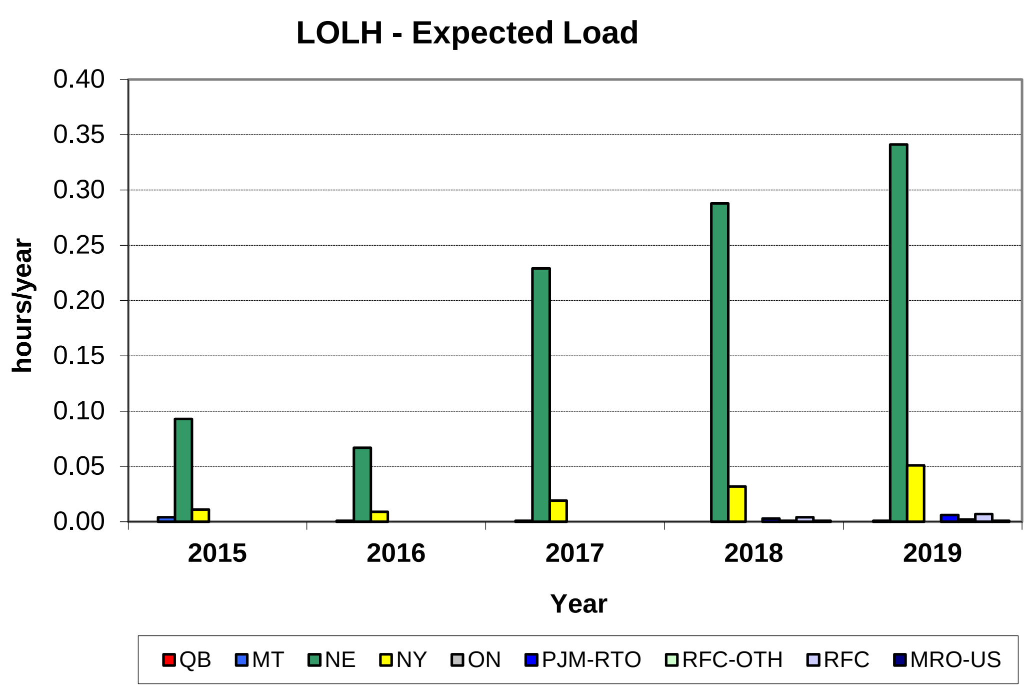


Figure 10(d) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2015 – 2019)

Figures 11(a) and 11(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2015-2019 period.

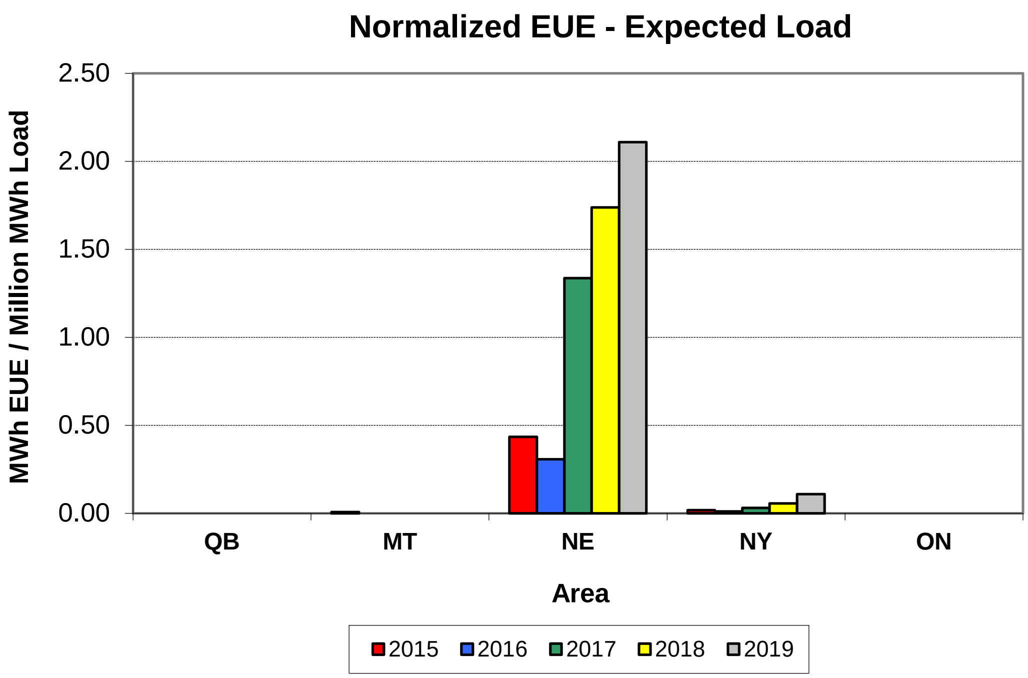


Figure 11(a) - Estimated Annual NPCC Area EUE (2015 – 2019)

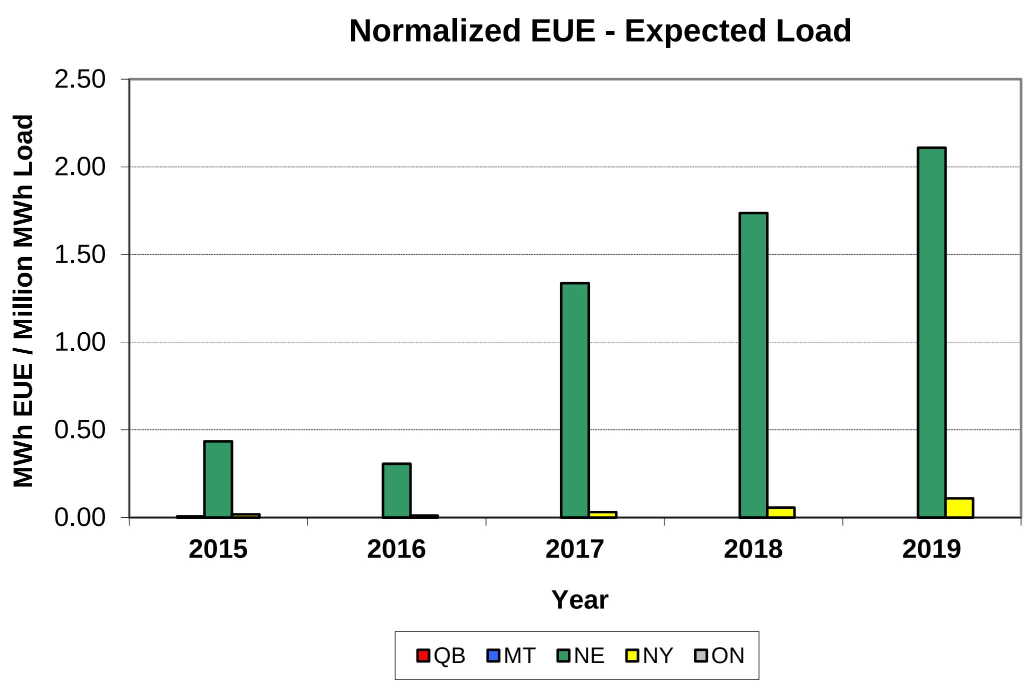


Figure 11(b) – Estimated Annual NPCC Area LOLH (2015 – 2019)

Figures 11(c) and 11(d) shows the estimated annual Expected Unserved Energy (EUE) for NPCC and the neighboring Regions for the 2015-2019 period.

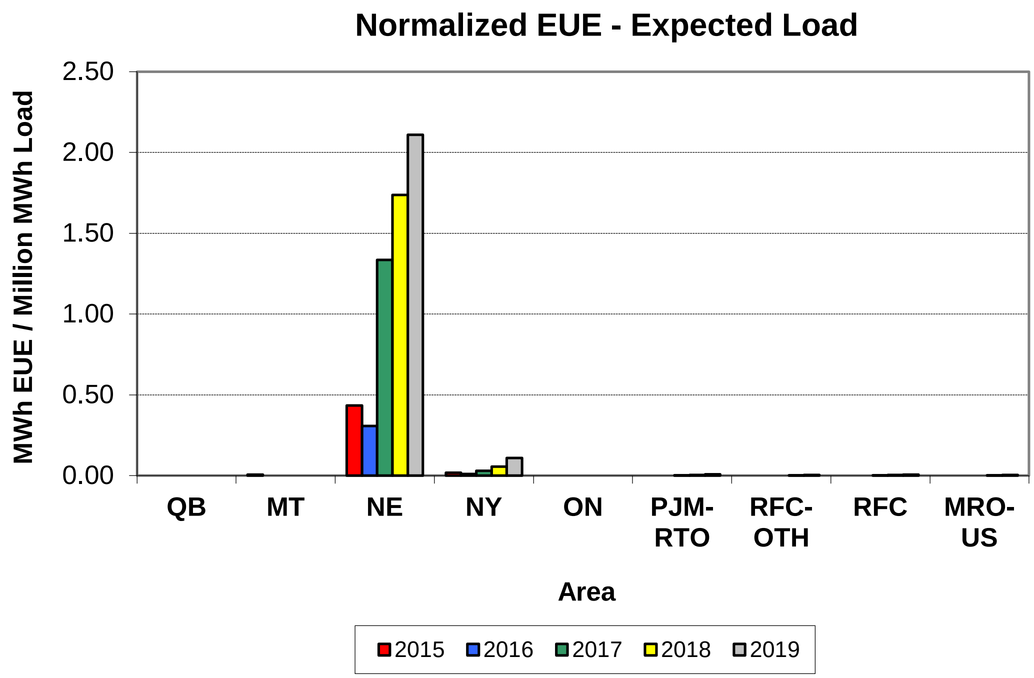


Figure 11(c) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2015 – 2019)

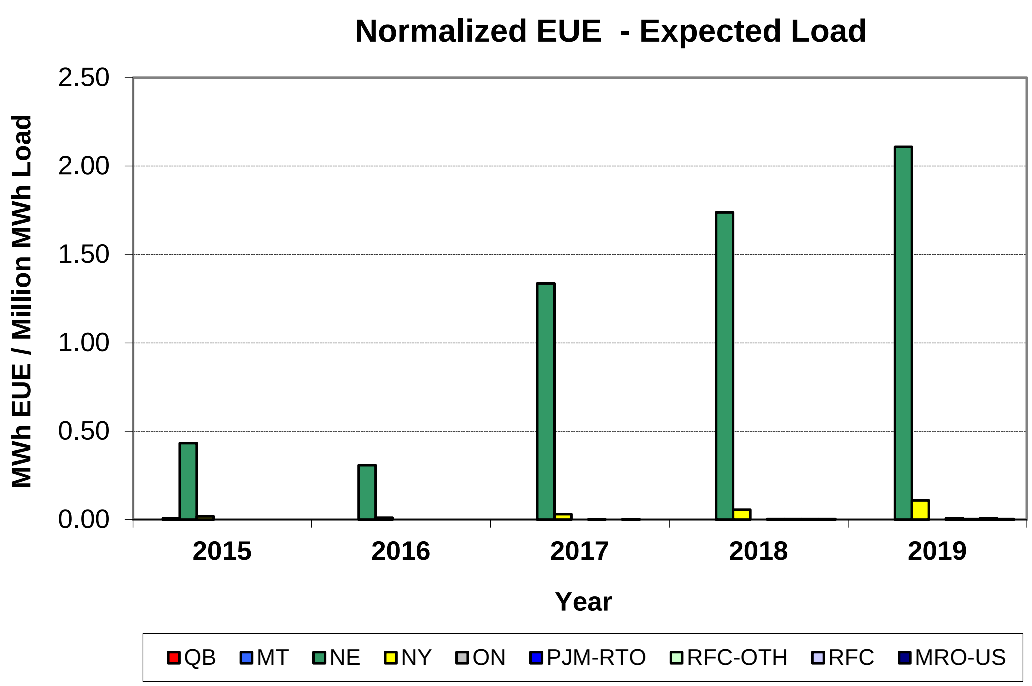


Figure 11(d) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2015 – 2019)

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 2014 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 approximately within one percent of the corresponding sum of the NPCC Areas annual energy forecasts.

Table 4 –Comparison of Energies Modeled (Annual MWhrs)

Year	2015	2016	2017	2018	2019
Québec					
MARS	191,764,560	191,407,632	190,277,792	192,575,584	191,735,104
2014 LTRA	186,841,612	188,769,965	189,421,327	190,067,433	191,379,790
MARS - LTRA	4,922,948	2,637,667	856,465	2,508,151	355,314
%(MARS-LTRA)/LTRA	2.63%	1.40%	0.45%	1.32%	0.19%
Maritimes					
MARS	27,697,488	27,682,142	27,583,488	27,653,688	27,741,594
2014 LTRA	27,371,000	27,474,836	27,519,414	27,624,243	28,008,934
MARS - LTRA	326,488	207,306	64,074	29,445	-267,340
%(MARS-LTRA)/LTRA	1.19%	0.75%	0.23%	0.11%	-0.95%
New England					
MARS	141,911,888	145,331,856	146,320,224	146,114,064	148,934,160
2014 LTRA	140,428,000	142,335,000	143,985,000	145,385,000	146,620,000
MARS - LTRA	1,483,888	2,996,856	2,335,224	729,064	2,314,160
%(MARS-LTRA)/LTRA	1.06%	2.11%	1.62%	0.50%	1.58%
New York					
MARS	163,214,000	163,907,008	163,604,000	163,753,008	164,305,008
2014 LTRA	163,214,000	163,907,000	163,604,000	163,753,000	164,305,000
MARS - LTRA	0	8	0	8	8
%(MARS-LTRA)/LTRA	0.00%	0.00%	0.00%	0.00%	0.00%
Ontario					
MARS	139,706,912	140,234,784	138,290,912	138,277,168	136,729,920
2014 LTRA	139,706,918	136,513,075	133,335,587	133,445,341	133,187,340
MARS - LTRA	-6	3,721,709	4,955,325	4,781,827	3,542,580
%(MARS-LTRA)/LTRA	0.00%	2.73%	3.72%	3.58%	2.66%

Year	2015	2016	2017	2018	2019
NPCC					
MARS	664,294,848	668,563,328	666,076,352	668,323,520	669,445,760
2014 LTRA	657,561,530	658,999,876	657,865,328	660,275,017	663,501,064
MARS - LTRA	6,733,318	9,563,452	8,211,024	8,048,503	5,944,696
%(MARS-LTRA)/LTRA	1.02%	1.45%	1.25%	1.22%	0.90%

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.

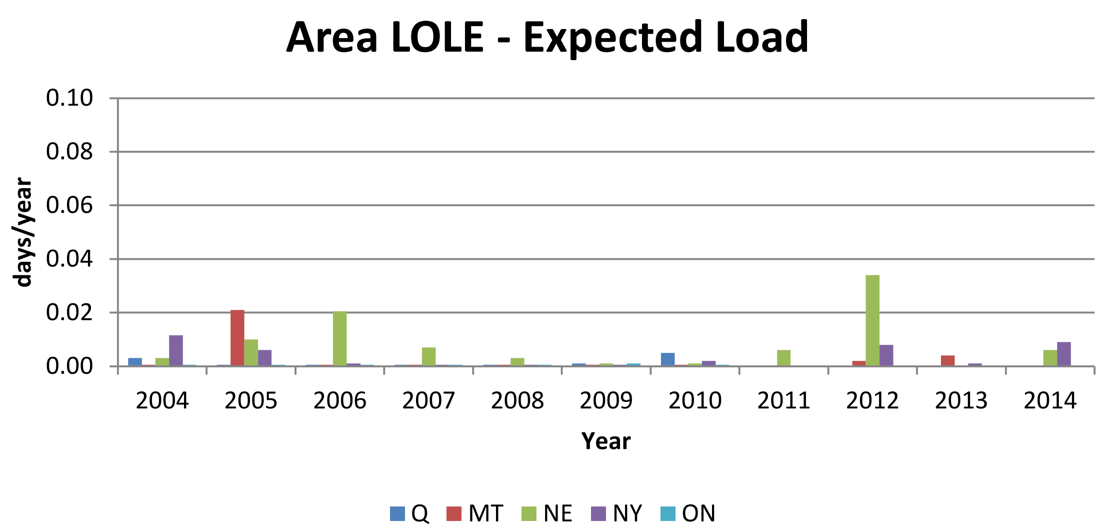


Figure 12(a) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

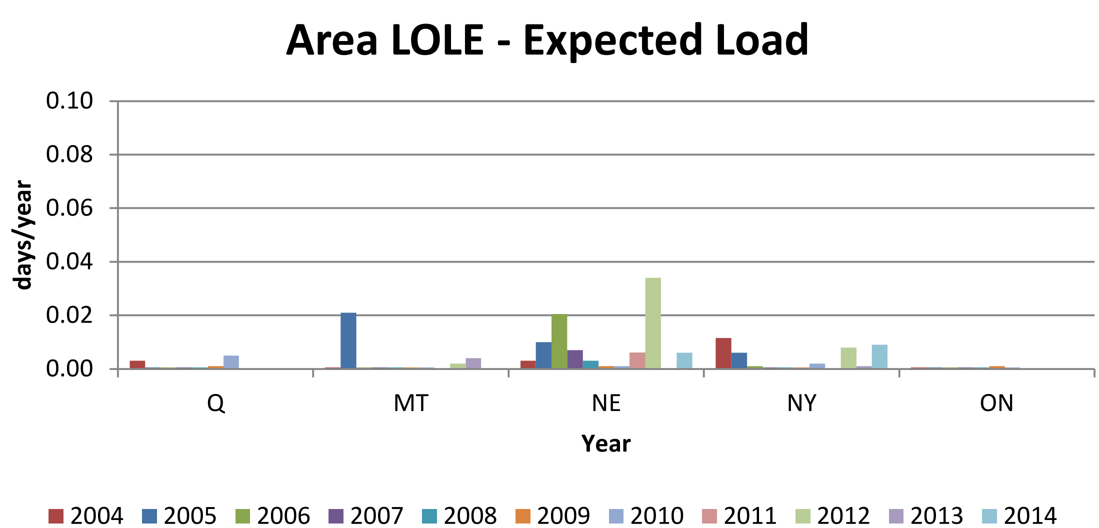


Figure 12(b) - Summary of Estimated Annual NPCC Area LOLE from previous NPCC Multi-Area Probabilistic Reliability Assessments (Base Case)

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 2015 – 2019.

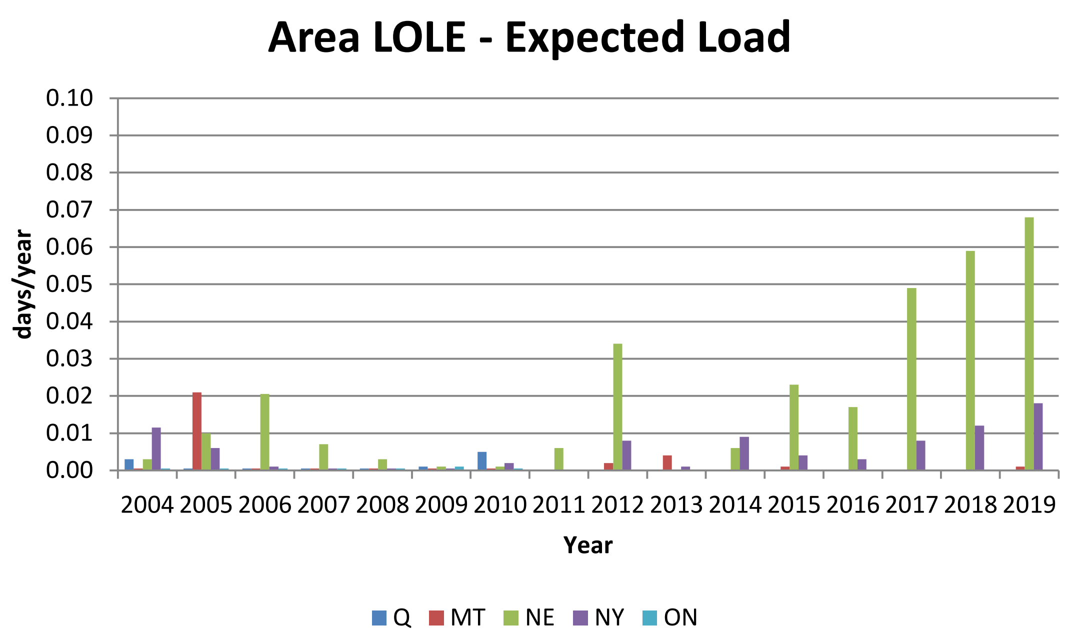


Figure 13(a) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

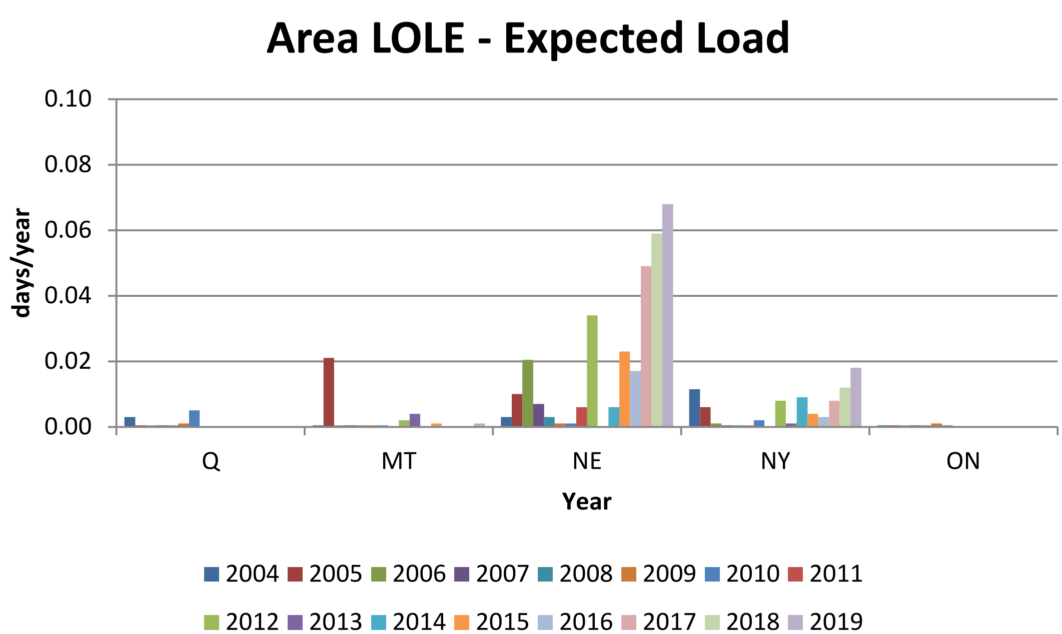


Figure 13(b) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

This summary illustrates that the NPCC Areas are estimated to have, on average, an annual LOLE less than 0.1 days/year through the 2015 – 2019 study period.

APPENDIX A

Objective and Scope of Work

1. Objective

On a consistent basis, evaluate the near term seasonal and long-range (five year) 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 2014 -2019 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 2014 - 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 2014 summer and November 2014 to March 2015 winter period, 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 (2014 - 2015) will be measured by estimating annual NPCC Area LOLE and 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 the 2015 - 2019 time period, 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 for the long-range (2015 – 2019) analysis will be measured by calculating 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.

3. Schedule

A report of the results of the summer assessment will be published no later than April 30, 2014.

A report of the results of the winter assessment will be approved no later than June 30, 2014.

A report summarizing the results of the NPCC Long Range Adequacy Overview will be published no later than December 31, 2014.

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	RFC-OTH	MRO-US
2015	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	40,587	7,618	30,626	37,820	28,237	179,287	49,308	36,340
Purchase/Sale (MW)	-15	0	1,542	1,635	0	3,263	-2,067	-1,589
Load (MW)	37,892	5,317	28,615	34,066	22,726	160,257	44,209	32,221
Nameplate Demand Response (MW)	1,277	250	2,385	1,132	715	14,815	3,694	2,692
Reserves (%)	10	48	21	19	27	23	15	16
Maintenance - Peak Week (MW)	**	10	0	373	425	0	0	0
Wind Output at time of Area Peak (MW)	834	645	158	82	793***	1,120	244	176
Wind Nameplate Capacity (MW)	2,779	1,101	1,081	1,457	3,987	1,120	244	176

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	RFC-OTH	MRO-US
2016	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	40,818	7,644	31,545	38,250	28,585	185,125	50,910	37,967
Purchase/Sale (MW)	-15	0	1,507	1,727	0	7,070	-3,305	-3,489
Load (MW)	38,137	5,308	29,130	34,412	22,535	162,465	44,522	32,449
Nameplate Demand Response (MW)	1,277	260	3,005	1,132	769	12,401	3,694	2,692
Reserves (%)	10	49	24	19	30	26	15	15
Maintenance - Peak Week (MW)	**	10	0	291	1,280	0	0	0
Wind Output at time of Area Peak (MW)	973	311	281	82	821***	1,141	264	176
Wind Nameplate Capacity (MW)	3,245	1,118	1,714	1,457	4,127	1,141	264	176

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	RFC-OTH	MRO-US
2017	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	41,141	7,669	30,362	37,947	28,679	185,558	50,034	38,265
Purchase/Sale (MW)	-58	0	1,167	1,825	0	4,249	-2,067	-2,360
Load (MW)	38,406	5,345	29,610	34,766	22,344	164,194	44,835	32,677
Nameplate Demand Response (MW)	1,240	260	3,033	1,132	1,212	12,401	3,694	2,692
Reserves (%)	10	48	17	18	32	23	15	18
Maintenance - Peak Week (MW)	**	48	0	291	1,642	0	0	0
Wind Output at time of Area Peak (MW)	973	668	287	123	921***	1,141	284	208
Wind Nameplate Capacity (MW)	3,245	1,143	1,734	1,457	4,626	1,141	284	208

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	RFC-OTH	MRO-US
2018	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	41,729	7,541	30,362	37,947	29,528	185,937	50,397	38,529
Purchase/Sale (MW)	188	-29	1,167	1,825	0	4,249	-2,067	-2,360
Load (MW)	38,658	5,322	30,005	35,111	22,301	165,478	45,149	32,905
Nameplate Demand Response (MW)	1,245	261	3,322	1,132	843	12,401	3,694	2,692
Reserves (%)	12	46	16	16	36	22	15	18
Maintenance - Peak Week (MW)	**	47	0	291	1,636	0	0	0
Wind Output at time of Area Peak (MW)	1,153	529	287	82	980***	1,218	304	208
Wind Nameplate Capacity (MW)	3,845	1,168	1,734	1,457	4,926	1,218	304	208

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	RFC-OTH	MRO-US
2019	(Jan)	(Feb)	(Aug)	(Aug)	(Jul)	(Jul)	(Jul)	(Jul)
Capacity (MW) *	41,765	7,541	73,362	37,947	28,997	185,961	50,760	38,793
Purchase/Sale (MW)	188	-29	1,167	1,825	0	4,249	-2,067	-2,360
Load (MW)	39,016	5,329	30,335	35,454	22,272	166,997	45,462	33,134
Nameplate Demand Response (MW)	1,245	268	3,546	1,132	843	12,401	3,694	2,692
Reserves (%)	11	46	16	15	34	21	15	18
Maintenance - Peak Week (MW)	**	47	0	291	2,390	0	0	0
Wind Output at time of Area Peak (MW)	1,154	455	287	82	1,035***	1,218	324	208
Wind Nameplate Capacity (MW)	3,848	1,168	1,734	1,457	5,201	1,218	324	208

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

** Capacity for Quebec reflects scheduled maintenance and restrictions

*** Random draws using a probability density function during the Monte Carlo simulation are used to simulate unit output. This value reflects an expected value of that function.

APPENDIX C

Maritimes

Assessment Area Overview

The Maritimes Assessment Area is a winter-peaking NPCC subregion that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million people.

Summary of Methods and Assumptions

Reference Margin Level

Load Forecast Methodology

Peak Season

Winter

Planning Considerations for Wind Resources

Planning Considerations for Solar Resources

Footprint Changes

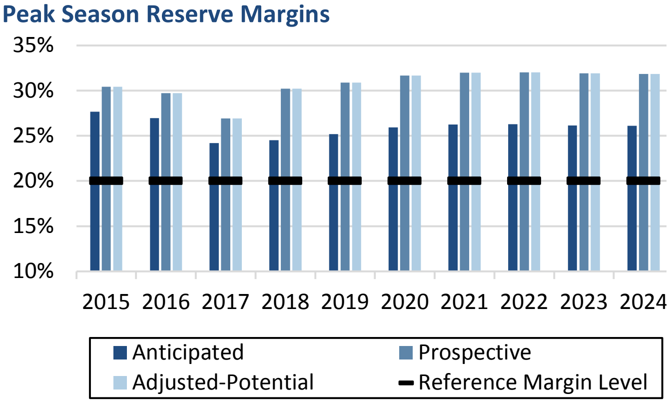
A conceptual tie line to the Canadian province of Newfoundland and Labrador could potentially impact the Maritimes footprint.

Assessment Area Footprint

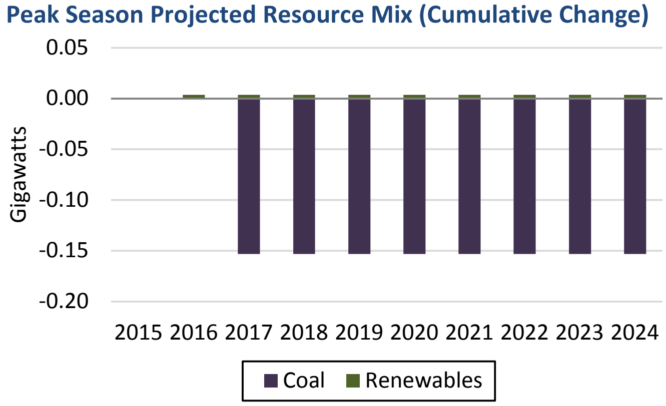
Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	5,477	5,513	5,508	5,493	5,466	5,434	5,421	5,420	5,425	5,427
Demand Response	247	252	252	252	251	251	251	251	251	251
Net Internal Demand	5,230	5,261	5,256	5,241	5,214	5,183	5,170	5,169	5,174	5,176
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	6,676	6,680	6,527	6,527	6,527	6,527	6,527	6,527	6,527	6,527
Prospective	6,820	6,824	6,671	6,824	6,824	6,824	6,824	6,824	6,824	6,824
Adjusted-Potential	6,820	6,824	6,671	6,824	6,824	6,824	6,824	6,824	6,824	6,824
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	27.66%	26.97%	24.19%	24.53%	25.18%	25.93%	26.25%	26.28%	26.16%	26.11%
Prospective	30.42%	29.71%	26.93%	30.20%	30.88%	31.67%	32.00%	32.03%	31.90%	31.85%
Adjusted-Potential	30.42%	29.71%	26.93%	30.20%	30.88%	31.67%	32.00%	32.03%	31.90%	31.85%
Reference Margin Level	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Ref. Margin Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	401	366	220	238	270	308	323	325	319	316
Prospective	545	511	364	535	567	605	620	622	616	613
Adjusted-Potential	545	511	364	535	567	605	620	622	616	613

Peak Season Reserve Margins



Peak Season Projected Resource Mix (Cumulative Change)



Demand, Resources, and Reserve Margins

The Reference Margin Level for the Maritimes Area is 20 percent and has not changed since the 2013LTRA. During summer and winter peak load periods, the Anticipated, Prospective, and Adjusted Potential Reserve Margins remain above the Reference Margin Level during the assessment period.

Compared to the 2013LTRA, the aggregated load growth rate for the combined sub-areas is practically unchanged for both the summer and winter seasonal peak load periods. Overall, the Maritimes Area's 3,500 MW summer peak and 5,500 MW winter peak loads are both expected to decline slightly during the 10-year assessment period. Current and projected effects of energy efficiency are incorporated directly into the load forecast for each of the areas. Direct Control Load Management (DCLM) in New Brunswick (NB) is intended to shift peak load into lower load periods and this program is directly embedded in the load forecast (reported as energy efficiency).[18] DCLM in NB is expected to rise from approximately 20 MW in 2015 to about 240 MW by the end of the assessment period. The amount of Interruptible Load in 2015 will be approximately 335 MW during the summer and 240 MW during the winter, increasing by about 10 MW/year over the assessment period.

Planned capacity additions include 231 MW (28 MW during the peak) of wind capacity, along with a 10 MW biomass plant, both in Nova Scotia (NS). These additions will have virtually no reliability impacts, due to their smaller size. A 153 MW generator in NS is expected to be retired in October 2017. This retirement depends on the planned construction of an undersea HVDC cable between NS and the Canadian Province of Newfoundland and Labrador as part of the Muskrat Falls hydro-electric generation development. NS plans to offset the retirement of the thermal unit with a 153 MW import of hydro capacity from Muskrat Falls.

Currently there are no Firm capacity contracts between the Maritimes Area and neighboring areas. While the Maritimes Area includes 300 MW of tie benefits in its resource adequacy analyses, it is not dependent on these capacity transactions or emergency imports from neighboring areas to meet its Reference Margin Level. Any such transactions are coordinated through NPCC working groups, which include members from all neighboring areas.

Transmission Outlook and System Enhancements

One major new transmission line addition in the Maritimes Area is planned for 2017. Development of the aforementioned Muskrat Falls Generation Project in the Canadian Province of Newfoundland and Labrador in 2017 will see the installation of a High-Voltage Direct Current (HVdc) undersea cable link (Maritime Link) between that province and NS.

The Eel River, NB HVdc interconnection with the Canadian Province of Québec will be refurbished during 2014. This interface provides import and export capability up to 350 MW with the Province of Québec and contributes to frequency response in the Maritimes Area. An additional 230 kV breaker installation will allow the separation of supplies to two 230/138 kV transformers in the substation at Eel River.

The construction periods for the planned projects mentioned above are all short and can be scheduled during times that will not significantly affect the reliability of the area. Capacity imports associated with the Maritime Link Project and the retirement of a comparable-sized unit will be timed to coincide so that the project will not have an impact on overall reliability.

Long-Term Reliability Issues

The hydroelectric power supply system in the Maritimes Area with a capacity of approximately 1,330 MW is predominantly run-of-the-river as opposed to storage based. Large quantities of energy cannot be held in reserve to stave off drought conditions. If such conditions occur, the hydro system would still be used to follow load in the area and respond to sudden

[18] DCLM for the Maritimes area is not counted as controllable and dispatchable DR. System operators do not currently have the ability to control or dispatch this program.

short-term capacity requirements. Thermal units would be used to keep the small storage capability of the hydro systems usable only for load following and/or peak supply. The Maritimes Area is not overly reliant on wind capacity to meet resource adequacy requirements. Neither (1) the lack of wind during peaks, (2) very high wind speeds, nor (3) icing conditions that would cause wind farms to suddenly shut down should affect the dependability of supply to the area, as ample spinning reserve is available to cover the loss of the largest baseload generator in the area. The latter situation is mitigated further by wide geographic dispersal of wind resources across the area.

RPSs have led to the development of substantially more wind generation capacity than any other type of renewable generation. Reduced frequency response associated with wind generation may, with increasing levels of wind generation in the future, require displacement with conventional generation during light load periods. With the significant amount of large- scale wind energy currently being balanced on the NB system, the next phase of renewable energy development in NB will focus on smaller-scale projects with a particular emphasis on non-variable forms of generation, such as wood-based biomass. In NS, the Maritimes Link project will displace several conceptual wind farm installations with renewable hydro resources and should help mitigate potential and related frequency response issues.

The Maritimes Area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (derated), dual-fuel oil/gas, tie benefits, and biomass, with no one type feeding more than 26 percent of the total capacity in the area. There is not a high degree of reliance upon any one type or source of fuel. Resource planners in the Maritimes Area do not anticipate that fuel disruptions will pose significant challenges to resource adequacy during the assessment period. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to GHG emissions.

Load growth in the southeastern corner of the NB sub-area, though not specifically identified in the load projections, has outpaced the rest of that sub-area. Planners are monitoring transmission loads and voltages in the area to ensure reliability is not affected. No reinforcements have been planned at this time. Demand-Side Management programs aimed at reducing and shifting peak demands and any future potential imports to NB from NS could reduce transmission loads in the southeastern NB area. On the whole, the NB sub-area expects a slight decline in load during the assessment period. The impact on the resource adequacy LOLE value is captured by modeling a reduction in tie transfer capabilities between sub-areas. The *NPCC - 2013 Maritimes Area Comprehensive Review of Resource Adequacy*[19] showed that after transfer levels were reduced from 300 MW to 150 MW, LOLE values do not exceed the NPCC target limit of 0.1 days per year of resource inadequacy. The Reference Margin Levels will not be affected by this issue.

The addition of renewable resources, particularly in NS, is an emerging issue in the Maritimes Area within the assessment period. Nova Scotia's Renewable Electricity Standard (RES) is seeking to displace significant amounts of fossil-fired generation with renewable resources. By 2015, 25 percent of the province's electricity sales (energy) will be supplied by renewable energy sources, and by 2020 this number increases to 40 percent. Increasing amounts of renewable resources could affect BPS reliability if variable or low-mass slow speed units are added without considering the reduction of frequency response after system contingencies or transmission enhancements to prevent voltage or overload problems. The process of completing system impact studies prior to interconnecting new generation should identify whether the emergence of any of these issues could limit the operation of or amount of new renewable generation added to the system on a case-by-case basis.

Because of the relative size of the largest generating unit in the Maritimes Area compared to its aggregated load, the area carries substantial reserve capacity. Generators use a diverse mix of fuel types with the result that the Maritimes Area is not overly reliant on any particular fuel to meet its load. The area is strongly interconnected with neighboring areas via high-

[19] NPCC - 2013 Maritimes Area Comprehensive Review of Resource Adequacy.

capacity transmission lines but is not dependent on these areas to supply area load. As a result, LOLE analysis suggests that even with reasonable foreseeable contingencies—including load forecast uncertainty, extreme weather, fuel disruptions, and generator and transmission interruptions—the Maritimes Area load will be reliably supplied for the 10 years covered in this report.

NPCC 2014 LONG RANGE ADEQUACY OVERVIEW

New England

Assessment Area Overview

ISO New England (ISO-NE) Inc. is a regional transmission organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system and also administers the Region's wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles.

Summary of Methods and Assumptions

Reference Margin Level

The Installed Capacity Requirement (ICR), results in a Reference Margin Level of 15.7 percent in 2015, declining to 14.3 percent in 2017 and remaining at that level for the remainder of the period.

Load Forecast Methodology

Peak Season

Summer

Planning Considerations for Wind Resources

Planning Considerations for Solar Resources

Footprint Changes

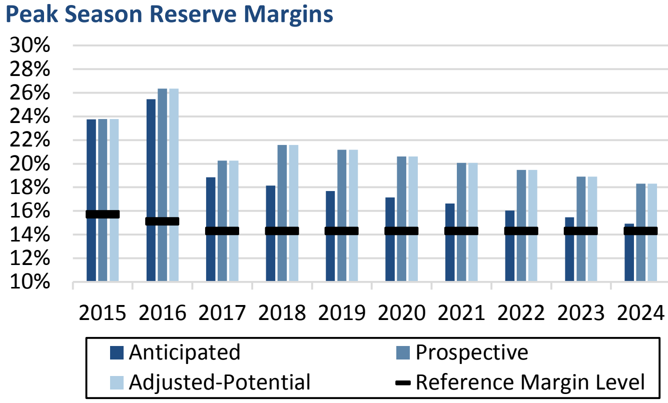
N/A

Assessment Area Footprint

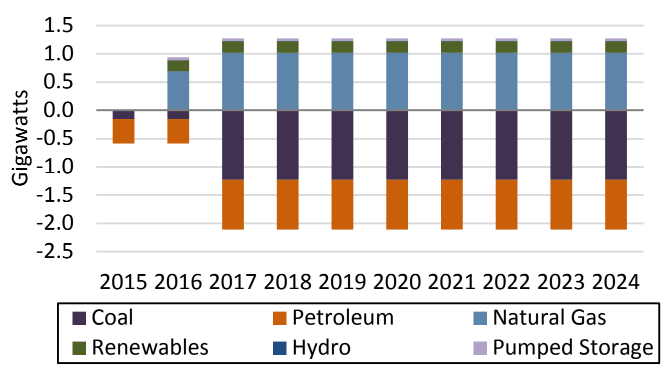
Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	26,930	27,291	27,521	27,677	27,782	27,911	28,028	28,167	28,298	28,430
Demand Response	1,167	944	994	994	994	994	994	994	994	994
Net Internal Demand	25,763	26,347	26,527	26,683	26,788	26,917	27,034	27,173	27,304	27,436
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	31,880	33,052	31,529	31,529	31,529	31,529	31,529	31,529	31,529	31,529
Prospective	31,887	33,286	31,904	32,446	32,463	32,463	32,463	32,463	32,463	32,463
Adjusted-Potential	31,887	33,286	31,904	32,446	32,463	32,463	32,463	32,463	32,463	32,463
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	23.75%	25.45%	18.85%	18.16%	17.70%	17.13%	16.63%	16.03%	15.47%	14.92%
Prospective	23.77%	26.34%	20.27%	21.60%	21.18%	20.60%	20.08%	19.47%	18.89%	18.32%
Adjusted-Potential	23.77%	26.34%	20.27%	21.60%	21.18%	20.60%	20.08%	19.47%	18.89%	18.32%
Reference Margin Level	15.70%	15.10%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%	14.30%
Ref. Margin Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	2,073	2,727	1,208	1,030	910	762	629	470	320	169
Prospective	2,080	2,961	1,583	1,947	1,844	1,697	1,563	1,404	1,254	1,103
Adjusted-Potential	2,080	2,961	1,583	1,947	1,844	1,697	1,563	1,404	1,254	1,103

Peak Season Reserve Margins



Peak Season Projected Resource Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

New England's (ISO-NE) Reference Margin Level is based on the capacity needed to meet the NPCC one-day-in-10-years LOLE resource planning reliability criterion. The amount of capacity needed—referred to as the Installed Capacity Requirement (ICR)—varies from year to year depending on expected system conditions. The ICR, which is calculated three years in advance for each Forward Capacity Market (FCM) auction, results in a Reference Margin Level of 15.7 percent in 2015, 15.1 percent in 2016, and 14.3 percent in 2017. In this assessment, the last calculated Reference Margin Level (14.3 percent) is applied for the remaining years.

ISO-NE's Anticipated Reserve Margin during the annual peak reflects the Seasonal Claimed Capability of all ISO-NE generators, as well as demand resources and imports that have Capacity Supply Obligations (CSOs) as a result of the FCM auctions. In the 2015 summer, ISO-NE's Anticipated Resources amount to 31,880 MW, which results in an Anticipated Reserve Margin of 23.8 percent of the Net Internal Demand of 25,763 MW. The Anticipated Reserve Margin remains above the 14.3 percent Reference Margin Level through the entire assessment period.

The 2015 summer peak Total Internal Demand (TID), which takes into account 1,685 MW of passive demand resources, or energy efficiency, is 26,930 MW. There has been no substantial change in the forecast since last year.

Demand-Side Management (DSM) in the ISO-NE BPS includes both active and passive demand resources. Active demand resources consist of real-time DR and real-time emergency generation, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP-4). Active demand resources are based on the CSOs obtained through ISO-NE's FCM three years in advance. The CSOs decrease slightly from 1,167 MW in 2015 to 944 MW in 2016 and then increase to 994 MW in 2017. Since there are no further auction results, the CSOs are assumed to remain at the same level through the end of the reporting period.

Passive demand resources (i.e., energy efficiency and conservation) include installed measures (e.g., products, equipment, systems, services, practices, and strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. Passive DR is also secured by means of the FCM. However, ISO-NE has developed an EE forecasting method that takes into account the potential impact of growing EE and conservation initiatives in the region to project the amount of EE beyond the years when the FCM CSOs have already been procured. EE has generally been increasing and is projected to continue growing throughout the study period. The amount of EE in 2015 is 1,685 MW and is projected to increase to nearly 3,500 MW by 2024.

Active demand resources are treated like generating resources in ISO New England and are dispatched by ISO operators when they are needed to meet load and operating reserve requirements. A number of retirements are expected to take place in the region within the next three years. Salem Harbor Units 3 and 4, which are coal- and oil-fired units with a combined capacity of 587 MW, were scheduled to retire by June 1, 2014. Salem Harbor Units 1 and 2, which were coal-fired units with a total capacity of 158 MW, were previously retired in December 2011. As a result of these retirements, upgrades to five transmission lines in the North Shore area (northwest of Boston) were identified as being needed to address immediate reliability concerns. Those transmission upgrades have been placed in service. The capacity lost with the retirement of Salem Harbor is expected to be replaced by the new Footprint Power 674 MW generating plant, which is to be located at the Salem Harbor site.

In August 2013, the Vermont Yankee nuclear plant (619 MW) announced that it would be shutting down by the end of 2014. Later in 2013, ISO-NE was notified that an additional 1,877 MW planned to retire on June 1, 2017. This total consisted of five coal- and oil-fired resources representing 1,535 MW from the Brayton Point Station and three oil-fired resources representing 342 MW from Norwalk Harbor Station.

Even with these retirements, the reserve margin is not expected to fall below the 14.3 percent Reference Margin Level during the assessment period. However, since new environmental requirements may result in the retirement of additional resources, the ISO is working with stakeholders to identify issues and find the means of meeting future capacity needs. Approximately 6,900 MW of proposed generation is in the ISO Generator Interconnection Queue. Market incentives are under development to increase resource development where and when needed.

By design, the level of the ICR specified for New England could necessitate the use of specific OP-4 actions because the ICR calculation includes capacity and accounts for the load relief these actions provide. Operable capacity study results show that the need for load and capacity relief by OP-4 actions will be approximately 2,600 MW during extremely hot and humid summer peak load conditions. This amount is likely achievable through OP-4 actions by depleting operating reserves, scheduling emergency transactions with neighboring systems, operating real-time emergency generators, and implementing five percent voltage reductions.

Preserving the reliable operation of the system will become increasingly challenging with potential retirements and the need for operating flexibility, particularly in light of the reliance on natural gas resources. These factors are expected to increase the need for reliable resources, especially those able to provide operating reserves and ramping capabilities. To begin addressing this need, the ISO has procured additional 10-minute reserves and replacement operating reserves.

These challenges will be addressed over the long term through the Strategic Planning Initiative. As part of this initiative, the ISO has been actively collaborating with stakeholders on comprehensive near- and long-term rule changes across the region’s suite of energy, reserve, and capacity markets. Proposed enhancements to the FCM include modification of the zonal structure used in the capacity market, flexibility in Energy Market offers, and a “pay-for-performance” mechanism in the FCM that will create stronger financial incentives for capacity suppliers to perform when called on during periods of system stress.

New England has witnessed significant growth in the development of solar photovoltaic (PV) resources over the past few years, and continued growth of PV is expected. Solar PV resources installed in New England are predominantly BTMG, not visible to ISO Operations in real time. An estimated one-third of these projects are registered in ISO’s energy market as Settlement-Only Resources. ISO-NE is not directly involved in the interconnection of most of these resources and has therefore not traditionally been aware of when and where they are installed. ISO-NE recently formed a stakeholder working group to increase its understanding of development trends of PV and other distributed generation resources, and to develop a forecast of PV over the next 10 years. At the end of 2013, 500 MWac of PV was installed in New England, and projections indicate that over 1,800 MWac will be added by 2023.

In January 2014, ISO-NE began incorporating wind forecasting into its processes, scheduling, and dispatch services. With wind forecast integration complete, the ISO will be working toward the full economic dispatch of wind resources in phase 2 of this project. The ISO will continue to analyze wind integration issues and work with stakeholders to address the issues challenging the wind interconnection process and the performance of the system with wind resources in locally constrained areas. New England is applying advanced technologies, including FACTS and HVdc, phasor measurement units (PMUs), and smart meters, which may be used to provide the regulation and reserve services required to reliably integrate variable renewable resources. Currently there is only 101 MW of on-peak wind capacity in New England, and only 185 MW (on-peak capacity) of future planned wind additions during the study period.

Given the embedded nature of most PV development in New England—projects are interconnected to the distribution system and can neither be directly observed nor dispatched by the regional system operator—the influence of increased amounts of PV will introduce increased variability and uncertainty to the system and eventually will have an impact on system operations (e.g., result in the need for increased reserve, regulation, and ramping). As such, new forecasting techniques eventually will be required to account for PV generation appropriately. To prepare for this, ISO-NE is actively tracking the growth of PV in the region, monitoring its impact on operational load forecasting performance, and researching forecasting options that may serve as short- and/or long-term solutions.

Firm summer capacity imports are based on FCM CSOs, which amount to 1,642 MW in 2015 and decrease to 1,267 MW in 2017. Firm transactions beyond 2017 are held constant at the value in 2017. Only firm imports are reported in this assessment. However, in addition to capacity imports that have CSOs, external transactions can participate in the Day-Ahead and Real-time Energy Markets. In past years, actual imports during the peak have been significantly higher than the CSOs. For example, in 2013 the imports to New England from New York, New Brunswick, and Quebec at the time of the peak demand totaled 3,172 MW, or 1,969 MW more than the CSO of 1,203 MW. During the assessment period, there is a firm capacity sale to New York (Long Island) of 100 MW anticipated to be delivered via the Cross-Sound Cable.

In the case of inadequate 10-minute operating reserves, ISO-NE can implement an OP-4 action to arrange for the purchase of up to 1,000 MW of available emergency capacity and energy, or energy only (if capacity backing is not available), from Market Participants or neighboring Control Areas. ISO-NE coordinates with other assessment areas to evaluate changes to the transmission system that would have an impact on import and export capabilities, and to determine a safe and reliable transfer limit if changes are needed. For long-term studies, ISO-NE confirms imports and exports through NPCC working group studies.

Transmission Outlook and System Enhancements

Several future transmission projects coming on-line during the assessment period are important to the continuation of, or enhancement to, system or sub-area reliability. The major projects under development in New England include the Maine Power Reliability Program (MPRP) and the New England East–West Solution (NEEWS). The new paths that are part of MPRP (many components of which are under construction) will provide the basic infrastructure necessary to increase the ability to move power from New Hampshire into Maine and improve the ability of Maine’s transmission system to move power into the local load pockets as necessary. NEEWS consists of a series of projects that will improve system reliability in areas including Springfield, Massachusetts, and Rhode Island, and increase total transfer capability across the New England east-to-west and west-to-east interfaces.

New smart grid technologies such as FACTS are being used in New England to improve the electric power system’s performance and operating flexibility. In addition, several investor-owned and municipal utilities in New England are conducting smart grid pilot programs or projects ranging from smart meter deployments to full-scale direct load control and distribution automation projects. ISO-NE anticipates that these projects may lead to more significant smart grid assets becoming available for potential utilization during the assessment period.

Long-Term Reliability Issues

If New England experiences extreme summer weather that results in 90/10 peak demands or greater, ISO-NE still should have enough operable capacity available to reliably manage the BPS. However, if supply-side outages diminish New England’s operable capacity to serve these 90/10 peak demands, ISO-NE will be able to invoke OP-4 to meet the demand and maintain the operating reserve requirement.

RPSs mandate that by 2023, energy efficiency and renewable resources such as wind and solar must supply approximately one-third of the projected electric energy in New England. Possible solutions for meeting the regional RPSs include developing the renewable resources already in the ISO generator interconnection queue; importing renewable resources from adjacent balancing authority areas; building new renewable resources in New England not yet in the queue; and using BTMG projects and eligible renewable fuels, such as biomass, at existing generators.

Concerns exist over the resultant impacts from compliance with state RPSs and the potential build-out of these new renewable resources. Because of concerns over the increasing amounts of wind capacity, ISO-NE completed a major wind integration study that identified the detailed operational issues of integrating large amounts of wind resources into the

New England power grid. The New England Wind Integration Study (NEWIS) found that the large-scale integration of wind resources is feasible, but resource planners will need to continue addressing a number of issues, including the development of an accurate means of forecasting wind generation outputs. As a result of that recommendation, ISO-NE implemented a centralized wind power forecasting service. The addition of variable energy resources, particularly wind and solar, will likely grow with time, hence increasing the need for flexible resources to provide operating reserves as well as other ancillary services, such as regulation and ramping.

Since ISO-NE's Demand Response resources are treated as capacity and are procured three years in advance in its Forward Capacity Auctions, approximately 1,000 MW of active DR are expected to be available. As previously noted, active DR can be triggered by ISO-NE in real time under OP-4 to help mitigate a capacity deficiency by reducing the peak demand. Over the past three years, the actual performance of these resources during summer peak period OP-4 events has ranged from 95 to 100 percent, and winter response rates have ranged from 75 to 100 percent.

PV resources (and to a lesser extent other types of DG resources) are rapidly developing in New England and predominantly are not directly observable or controllable by ISO-NE. Because of the differences between the state-jurisdictional interconnection standards that apply to most PV resources and the FERC-jurisdictional standards that apply to larger conventional generators, PV exhibits different electrical characteristics during system conditions typical of grid disturbances. ISO-NE is working with the New England states, distribution utilities, IEEE, and various international experts to ensure that the future interconnection standards for PV (and other inverter-interfaced DG resources) better coordinate with broader system reliability requirements.

Environmental compliance obligations for generators due to existing and pending state, regional, and federal environmental requirements are likely to impose operational limits on new and existing generators but pose only a limited retirement risk and lower reliability impacts compared to earlier assessments. The lowered retirement risk is due in large part to the flexibility that the EPA has provided in its cooling water rule and MATS, recognizing the reliability value that low-capacity-factor fossil steam generators provide in maintaining system fuel diversity.

Up to 12.1 GW of generating capacity in New England that currently utilizes once-through cooling, including a subset of units with larger withdrawal capacities, may potentially need to convert closed-cycle cooling systems.

Approximately 7.9 GW of existing coal- or oil-fired capacity in New England is subject to MATS. Most affected generators in New England are equipped with required air toxics control devices due to earlier compliance with state air toxics regulations in New England. No retirements have been announced or are expected in New England due to MATS. However, a one-year compliance extension request has been sought by a generator for less than 100 MW of affected coal-fired capacity. Recent revisions to air quality standards limit ambient concentrations of ozone, and its precursors (fine particulate matter and sulfur dioxide) are expected to require additional emissions reductions from fossil-fired generators.

New England faces a number of concerns for ensuring the reliability of the fuel supply, particularly the supply of natural gas and oil. Operating experience has exposed some vulnerabilities associated with the strategic risks of resource performance and flexibility and the increased reliance on natural-gas-fired capacity. During severe winter weather, such as that experienced in winter 2013–2014, system operators faced challenges due to the combination of high winter loads resulting from cold weather, and limited natural gas and oil used to fuel generating units. In such situations, gas pipelines are often operating at their maximum levels to supply local distribution companies (LDCs) that supply retail natural gas customers. Although oil-fired generators could compensate for the reduced availability of gas-fired generation, they may be limited by inadequate oil inventory at the beginning of winter, and securing midwinter replenishment of oil can be difficult due to challenges with oil transportation and availability.

ISO-NE had implemented a winter reliability program in 2013–2014 and will initiate a modified program for the winter of 2014–2015, along with scheduled market improvements. The major components of the planned winter reliability program include annual audits of dual-fuel resources; additional compensation to offset testing costs associated with restoring or commissioning dual-fuel capability; additional winter period Demand Response; and additional compensation for unused oil inventory at the end of the winter period.

Recent and planned improvements to the regional and interregional natural gas infrastructure provide initial steps for expanding the access to natural gas supply sources to meet New England's increasing demand for natural gas for power generation. More expansion is required, however. Although natural gas production volumes in the northeast region are forecast to rise, New England cannot access the full benefit of production because of existing pipeline capacity constraints.

The natural gas pipelines serving the region are at or near capacity, but they will not expand until customers commit to Firm service. A study performed by ICF International found that if one assumes the same weather conditions as winter 2013–2014, winter peak-day gas supplies will be barely adequate or slightly in deficit through 2020. Outages of capacity that is not fueled by natural gas, such as a disruption to a nuclear unit, or unforeseen outages of natural gas infrastructure, would result in a serious gas supply deficit.

An emerging reliability issue currently being addressed by ISO-NE is the significant growth of DG resources in New England. Because PV resources constitute the largest segment of DG resources throughout New England, the ISO's analysis of DG focuses exclusively on the impact of additional distributed PV. To help address the interrelated questions of exactly how much additional PV is projected in the ISO's 10-year planning horizon and what impact this future PV could have on the regional power grid, the ISO, in conjunction with stakeholders, endeavored to create a forecast of all future PV resources. In September 2013, the ISO established the Distributed Generation Forecast Working Group (DGFWG) to assist its development of a DG forecast and provide a forum to discuss DG integration issues.

Due to the complexities associated with creating a PV forecast, the ISO began with an interim PV forecast that was limited to PV that results from state policies. The PV estimates are based on state-by-state policy initiatives, with discounts to account for the uncertainty of existing and future policies. The ISO is working with the DGFWG to find ways to improve on the forecast in future years.

Results of the forecast will inform various ISO system planning functions. For example, the ISO intends to use data from the DG forecast in transmission studies, new generator interconnection studies, and economic studies. The ISO will work with stakeholders to explore how the DG forecast may potentially be used in these planning analyses and other market-related assessments. These may include such tasks as the development of the ICR.

The growth in DG presents some challenges for grid operators and planners. Challenges for the ISO include: (1) a limited amount of data concerning DG resources, including their size, location, and operational characteristics; (2) a current inability to observe and control DG resources in real time; (3) a need to better understand the impacts of growing DG on system operations, including ramping, reserve, and regulation requirements; and (4) potential reliability impacts to the regional power system posed by future amounts of DG resulting from existing state interconnection standards.

Ongoing work between ISO-NE and the DGFWG will help position New England to best integrate rapidly growing DG resources in a way that maintains reliability and allows the states to realize the public policy benefits they have identified as the basis for their DG programs.

NPCC 2014 LONG RANGE ADEQUACY OVERVIEW

New York

Assessment Area Overview

The New York Independent System Operator (NYISO) is the only BA within the state of New York (NYBA) The NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. The NYISO manages the New York State transmission grid, encompassing approximately 11,000 miles of transmission lines over 47,000 square miles and serving the electric needs of 19.5 million New Yorkers. New York experienced its all-time peak load of 33,956 MW in the summer of 2013.

Summary of Methods and Assumptions

Reference Margin Level
The NYSRC Installed Reserve Margin (IRM) of 17 percent extends from to April 2015. Because this margin will be reassigned in 2015, NYISO will use the default Reference Margin Level of 15 percent.

Load Forecast Methodology
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Modeled with a 17 percent capacity factor

Planning Considerations for Solar Resources
Modeled with a 65 percent capacity factor

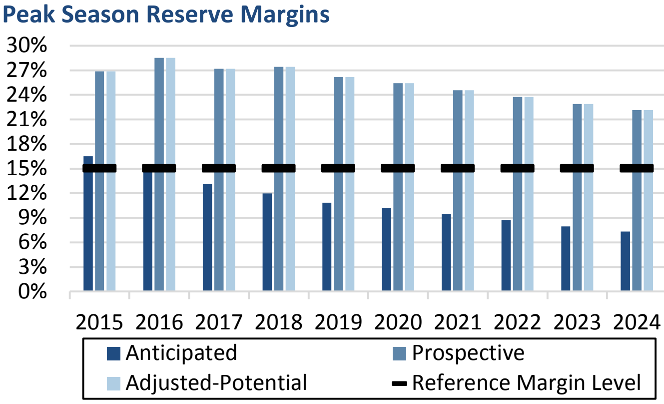
Footprint Changes
N/A

Assessment Area Footprint

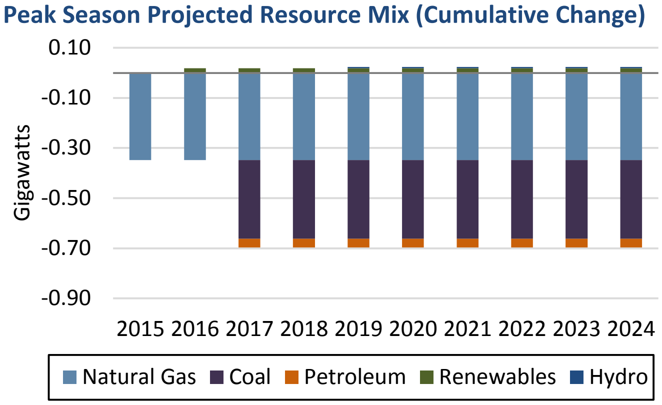
Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	34,066	34,412	34,766	35,111	35,454	35,656	35,890	36,127	36,369	36,580
Demand Response	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189	1,189
Net Internal Demand	32,877	33,223	33,577	33,922	34,265	34,467	34,701	34,938	35,180	35,391
Resources (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	38,311	38,330	37,980	37,980	37,985	37,985	37,985	37,985	37,985	37,985
Prospective	41,715	42,691	42,702	43,217	43,228	43,228	43,228	43,228	43,228	43,228
Adjusted-Potential	41,715	42,691	42,702	43,217	43,228	43,228	43,228	43,228	43,228	43,228
Reserve Margins (%)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	16.53%	15.37%	13.11%	11.96%	10.86%	10.21%	9.46%	8.72%	7.97%	7.33%
Prospective	26.88%	28.50%	27.18%	27.40%	26.16%	25.42%	24.57%	23.73%	22.88%	22.14%
Adjusted-Potential	26.88%	28.50%	27.18%	27.40%	26.16%	25.42%	24.57%	23.73%	22.88%	22.14%
Reference Margin Level	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ref. Margin Excess/Shortfall (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	502	123	(633)	(1,030)	(1,420)	(1,652)	(1,921)	(2,194)	(2,472)	(2,715)
Prospective	3,907	4,485	4,088	4,207	3,823	3,591	3,322	3,049	2,771	2,528
Adjusted-Potential	3,907	4,485	4,088	4,207	3,823	3,591	3,322	3,049	2,771	2,528

Peak Season Reserve Margins



Peak Season Projected Resource Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

The current Installed Reserve Margin (IRM) requirement for the NYBA that covers the period from May 2014 to April 2015 (2014 Capability Year) is 17 percent. The New York State Reliability Council (NYSRC) sets this requirement annually based upon an annual study conducted by its Installed Capacity Subcommittee (ICS). Because the IRM will be reassigned after April 2015, a 15 percent Reference Margin Level has been used for this long-term assessment. While the Anticipated Reserve Margin falls below the 15 percent Reference Margin Level in 2017, the Prospective Reserve Margin remains above for all seasons and years of the assessment period.

The energy forecast for the downstate area is lower than that of last year due to a change in the expected relationship of energy growth with the economy. Whereas economic growth (based on either employment or metro area GDP) is expected to increase, some of the zones in the downstate area are projected to have negative energy growth, but continue to expect positive summer and winter peak demand growth. This decline in year-over-year energy usage is attributed to the continued impact of energy efficiency programs and is reflective of a recent history of negative energy usage on a weather-adjusted basis.

FERC approved changes to the ICAP/SCR program (Docket No. ER14-39) that became effective on March 15, 2014. These changes went through an extensive discussion and review process through the NYISO committees prior to filing a tariff change with FERC. The process to determine the ICAP value of SCR resources was modified as a result of these changes.

New York State has recently announced new initiatives in DER, BTMG, and customer-sited solar photo-voltaic power. The impact of solar PV has been incorporated in this year's energy efficiency projections. It is still too early to determine the impact of DER on energy and summer peak, as the new policy has not yet been translated into specific targets or goals.

NYBA's existing generation, Special Case Resources (SCR), and net imports total 41,307 MW for 2015. There are 4,579 MW of proposed generation included in the 2014 Load and Capacity Data Report. Of this total, 3,461 MW are fossil fuel projects,

1,044 MW are wind turbine projects, and 22 MW are non-wind renewable energy projects. Additionally, based on publicly available information, 806 MW of summer capacity may be retired or mothballed by 2017.

Capacity transactions modeled in NYBA reliability studies are part of the NYBA's resource mix to meet LOLE criteria. These transactions would be expected to perform on peak or any other time as needed to meet the demand. Capacity transactions modeled in NYBA's assessments have met the requirements as defined in the NYBA's tariffs. Both the NYBA and the respective neighboring assessment areas have agreed upon the terms of the capacity transaction. The NYBA does not rely on emergency imports to meet the assessment area's Reference Margin Level. However, transfer capability is reserved on the ties with neighboring areas in NYBA's planning studies to allow for emergency imports as one potential emergency operating procedure step in the event of a system emergency.

Transmission Outlook and System Enhancements

The Transmission Owner Transmission Solutions (TOTS) consist of three transmission projects in central New York, downstate New York, and New York City. TOTS is part of the Con Edison and the New York Power Authority (NYPA) filing in response to a November 2012 Order from the New York Public Service Commission (PSC) which recognized the significant reliability needs which would occur if the Indian Point Energy Center (IPEC) were retired upon the expiration of IPEC's existing licenses.

Long-Term Reliability Issues

The 2012 RNA identified new environmental regulatory programs. These state and federal regulatory initiatives cumulatively will require considerable investment by the owners of New York's existing thermal power plants in order to comply. The NYBA has determined that as much as 33,200 MW in the existing fleet will have some level of exposure to the new regulations.

Since the publication of the RNA the U.S. Supreme Court has consented to hear an appeal of the Cross State Air Pollution Rule (CSAPR).In July 2011, the EPA replaced the Clean Air Transport Rule (CATR) proposal with the finalized CSAPR. The rule requires significant additional reductions of SO_2 and NOx emissions beyond those previously identified. The CSAPR establishes a new allowance system for units larger than 25 MW of nameplate capacity. Affected generators will need one allowance for each ton emitted in a year. In New York, CSAPR will affect 154 units that represent 25,900 MW of capacity. The EPA has estimated New York's annual allowance costs for 2012 at $65 million. There are multiple scenarios which show that New York's generation fleet can operate in compliance with the program in the first phase. Compliance actions for the second phase may include emission control retrofits, fuel switching, and new clean efficient generation. If the EPA appeal is successful, it may be reasonable to expect reasonable delay in the implementation of the rule until 2016, which would place it on a schedule that is nearly concurrent with MATS.

The EPA finalized a regulation in February 2012 to establish emission rate standards for MATS that will limit emissions through the use of Maximum Achievable Control Technology (MACT) for hazardous air pollutants (HAP) from coal- and oil-fueled steam generators with a nameplate capacity greater than 25 MW. The majority of the New York coal fleet has installed emission control equipment that may place compliance within reach. The heavy oil-fired units will need to either make significant investments in emission control technology or switch to (or maintain) a cleaner mix of fuels in order to comply with the proposed standards. Given the current outlook for the continued attractiveness of natural gas compared to heavy oil, it is anticipated that compliance will be achieved by dual-fuel units through the use of natural gas to maintain fuel ratios such that the effective capacity factor on oil is less than 8. Compliance requirements begin in March 2015.

The EPA has proposed a Section 316(b) rule providing standards for the design and operation of power plant cooling systems. This rule will be implemented by the New York State Department of Environmental Conservation (NYSDEC), which has finalized a policy for the implementation of this rule is known as Best Available Technology (BAT) for plant cooling water intake structures. This policy is activated upon renewal of a plant's water withdrawal and discharge permit. Based upon a review of current information available from NYSDEC, NYISO has estimated that between 4,400 and 7,300 MW of capacity could be required to retrofit closed-cycle cooling systems.

The class of steam electric units constructed between 1963 and 1977 is subject to continuing emission reductions required by the Clean Air Act. In New York, 16 units with 8,400 MW of capacity are affected. The owners of these units have submitted their plans for Best Available Retrofit Technology (BART) and have received modified Title V air permits incorporating the final plans. The oil-fired units are proposing alternatives that include maintaining the status quo, lower sulfur fuels, and low NOx combustion systems. Two smaller coal plant owners have chosen to retire small boilers. The new permit limitations became effective January 1, 2014. No additional capacity losses are anticipated as a direct result of the implementation of BART.

The NYSDEC has promulgated revised regulations for the control of NOx emissions from fossil-fueled electric generating units. These regulations are known as NOx RACT (Reasonably Available Control Technology) for oxides of nitrogen. In New York, 254 units with 27,800 MW of capacity are affected. Emission reductions required by these revised regulations must be in place by July 2014.

The Regional Greenhouse Gas Initiative (RGGI) established a cap over CO2 emissions from most fossil-fueled power plants with more than 25 MW in 2009. In 2012, the RGGI states undertook a program review, which concluded in February 2013. The program review called for reducing the cap by 45,000,000 to 91,000,000 tons for 2014 and then applying annual reductions of 2.5 percent until 2020. A key provision to keeping the allowance and electricity markets functioning is the

Cost Containment Reserve (CCR). If demand exceeds supply at predetermined trigger prices, an additional 10,000,000 in allowances would be added to the market.

The EPA has released a revised rule for final comments that is designed to limit CO_2 emissions from new fossil-fueled steam generators and combined-cycle units. The rules are generally less stringent than the NYSDEC's Part 251 that is applicable in NY. This EPA rule does not apply to simple-cycle turbines that limit their sales to the grid to less than one-third of their potential output.

NPCC 2014 LONG RANGE ADEQUACY OVERVIEW

Ontario

Assessment Area Overview

Ontario's electrical power system is geographically one of the largest in North America covering an area of 415,000 square miles and serving the power needs of more than 13 million people. Ontario is interconnected electrically with Québec, MRO-Manitoba, and states in MISO (Minnesota and Michigan), NPCC-New York.

Summary of Methods and Assumptions

Reference Margin Level
The IESO-established Reserve Margin Requirement is applied as the Reference Margin Level.[20]

Load Forecast Methodology
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
Modeled, based on historic performance

Planning Considerations for Solar Resources
Modeled, based on historic performance; 30 percent for summer.

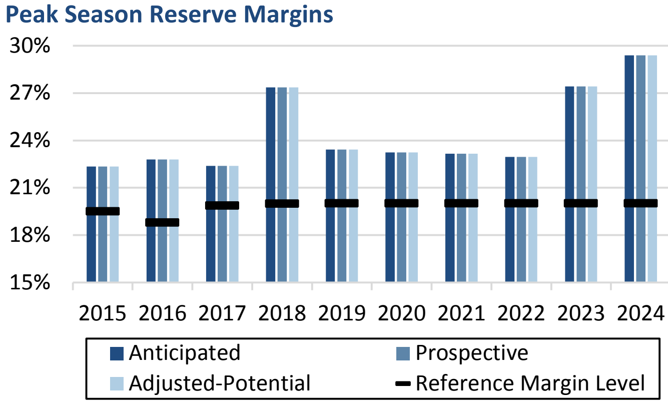
Footprint Changes
N/A

Assessment Area Footprint

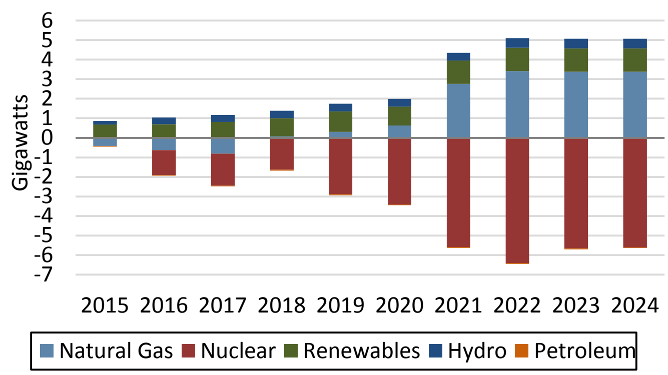
Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	22,158	21,914	21,649	21,606	21,576	21,375	21,534	21,514	21,321	21,046
Demand Response	567	621	695	695	695	795	945	1,095	1,295	1,495
Net Internal Demand	22,158	21,914	21,649	21,606	21,576	21,375	21,534	21,514	21,321	21,046
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	27,112	26,910	26,497	27,519	26,630	26,345	26,520	26,455	27,169	27,232
Prospective	27,112	26,910	26,497	27,519	26,630	26,345	26,520	26,455	27,169	27,232
Adjusted-Potential	27,112	26,910	26,497	27,519	26,630	26,345	26,520	26,455	27,169	27,232
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	22.36%	22.80%	22.39%	27.36%	23.42%	23.25%	23.16%	22.96%	27.43%	29.39%
Prospective	22.36%	22.80%	22.39%	27.36%	23.42%	23.25%	23.16%	22.96%	27.43%	29.39%
Adjusted-Potential	22.36%	22.80%	22.39%	27.36%	23.42%	23.25%	23.16%	22.96%	27.43%	29.39%
Reference Margin Level	19.50%	18.78%	19.86%	19.99%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Ref. Margin Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	633	880	549	1,593	738	695	680	638	1,583	1,977
Prospective	633	880	549	1,593	738	695	680	638	1,583	1,977
Adjusted-Potential	633	880	549	1,593	738	695	680	638	1,583	1,977

Peak Season Reserve Margins



Peak Season Projected Resource Mix (Cumulative Change)



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[20] Ontario IESO, for its own assessments, treats Demand Response as a resource instead of a load-modifier. As a consequence, the Net Internal Demand, Planning Reserve margins and the Target Reserve Margin numbers differ in the IESO reports when compared to NERC reports. The Ontario reports would report lower reserve margins.

Demand, Resources, and Planning Reserve Margins

Ontario has invested heavily in electricity infrastructure over the past decade. Investments have enabled the phase-out of coal-fired generation in the province and have reduced the carbon intensity of Ontario's electricity supply mix. Ontario's electricity demand growth has been low to moderate during this period. Growing net supply additions and moderate demand have resulted in substantial capacity margins. Capacity margins have been reduced to more normal levels with the recent phase-out of coal-fired generation in the province. Ontario's evolving supply mix features increasing and significant penetrations of renewable sources.

The Reference Margin Levels for the first four years of the assessment period vary between 18.78 and 20 percent through 2020, then remain at 20 percent through 2024. This variance is necessary to reflect the changes in outages, demand forecast, and available resources. However, the Reference Margin Levels published in this report have been modified to reflect NERC's reserve margin calculation. Previously, Demand Response (DR) was treated as a resource, but now it must be accounted for in the margin calculation as a load modifier for all Assessment Areas. This approach results in a higher percent for both the Reference Margin Level and the projected Reserve Margins.

Between 2020 and 2024, Ontario will rely on new planned resources of up to 3,640 MW, as per Ontario's Long-Term Energy Plan (LTEP), to meet the Reference Margin Level. Ontario possesses a range of options to address these needs, including market-based mechanisms. Additional planning activities to meet future resource adequacy needs are currently underway.

This year's forecast of Net Energy for Load (NEL) has an average annual growth rate of -0.4 percent during the 10-year period, similar to the 2013LTRA forecast of -0.2 percent average growth for 2013–2023. Although there is increased demand for electricity driven by modest economic expansion and population growth, these increases are being more than offset by three key factors:

1. The growth in embedded generation and BTMG capacity, which has a significant downward impact on grid-supplied electricity, which is the demand value being considered (rather than total consumption).
2. Conservation impacts that reduce the overall need for both end-use and grid-supplied electricity.
3. The increasing impact of price-sensitive demand through the implementation of time-of-use rates, as well as the Industrial Conservation Initiative.

In general, distributed (embedded) generation (DG) is having the largest impact on grid-supplied energy demand. Summer peaks are particularly affected by the increased penetration of solar-powered DG. The summer peaks are also being influenced by efficiency changes to air conditioners.

The winter peaks are not significantly impacted by DG, because in Ontario, most is comprised of solar facilities, and the peak occurs after sunset, when solar DG is no longer generating power. However, the winter peak is seeing downward pressure from conservation savings due primarily to lighting efficiencies as end users move to compact fluorescent and LED technology.

While overall demand is expected to decline, there will be some variation within Ontario. The Greater Toronto area (GTA) has the largest share of the Ontario population and economy. The Essa zone, which lies just north of the GTA, will see positive growth resulting from ongoing expansion of the GTA. Primarily due to expected mining growth associated with vast untapped natural resources in the northern portions of the province, a rebound is expected during the later years of the forecast. The Net Internal Demand forecast in the 2014LTRA reference case is reduced by the amount of DR programs, previously counted as resources in Ontario. For its own provincial assessments, DR programs will continue to be treated as resources.

Over the course of the forecast, the DR program impacts during the summer are expected to increase from just over 500 MW, at present, to less than 1,500 MW by the end of the forecast period. Starting in 2020, the increased DR is expected to show significant growth. In the IESO, DR is comprised of three programs: Demand Response 3 (DR3), Peaksaver PLUS® (primarily driven by air-conditioning load), and dispatchable loads. Participation in dispatchable load programs drops during the peak period.

Conservation is expected to yield incremental peak savings of more than 3,000 MW by 2024. The Ontario government's Long-Term Energy Plan (LTEP) established a provincial conservation and demand management target of 30 TWh/year of cumulative savings by 2032. The reference year for the savings is 2005, with projected milestones of 11 TWh/year by 2015 and 21 TWh/year by the end of 2024. Those savings will be achieved through improved building codes, equipment standards, and conservation programs.

LTEP 2013 has also set a goal to use DR to be able to meet 10 percent of net peak demand by 2025, equivalent to approximately 2,400 MW under forecast condition. This includes all DR programs, such as Time-of-Use rates, Industrial Conservation Initiative, market dispatchable load, DR3, and Peaksaver PLUS®. The responsibility for existing and newly introduced DR initiatives has been transferred from the Ontario Power Authority (OPA) to the IESO.

In June 2014, the IESO implemented a redesigned framework for activation of the DR3 program through integration into the electricity market. DR3 is a contractual peak load reduction program that encourages businesses to reduce their electricity use during periods of peak demand. The redesigned framework will model DR3 as aggregated resources within IESO market and system tools. In place of activations that are based on a combination of supply cushion and price-based triggers, DR3 resources are activated when they represent a competitively priced energy resource in the pre-dispatch time frame (i.e., activated on a price trigger only).

All coal units in Ontario have been phased out as of April 2014, in accordance with Ontario government policy. In the years following the coal phase-out, the province's next reliability challenge will be to carefully manage the renewal of its nuclear fleet. Nuclear units at Pickering Generating Station will not be refurbished, and current plans are to operate these units through approximately 2020.

Supply options for maintaining resource adequacy over this time period are being considered. These options include conservation, re-contracting Non-Utility Generator (NUG) facilities as their contracts reach maturity, new gas-fired generation, and conversion of some or all of the Lambton and Nanticoke coal-fired units to natural gas, imports, and energy storage. About 1,400 MW of NUG contracts have the opportunity to be renegotiated as the contracts are expiring within the next decade. The OPA is in the process of renegotiating the NUG contracts.

Over the assessment period, the capacity of embedded generation, such as DERs and BTMG, is expected to increase significantly. The Feed-in Tariff (FIT) and microFIT programs drive this growth with renewable generation. Over the forecast period, about 2,500 MW of wind and solar DG is projected to be added—most of which is solar. By 2024 there will be over 4,000 MW of DG in Ontario.

In 2014, the IESO issued a request for proposals to procure up to 35 MW of energy storage to explore how new technologies can provide additional flexibility to carry out grid operations. The IESO storage procurement process supports the LTEP, which calls for 50 MW of energy storage in Ontario. Subsequent to the IESO's procurement process, the OPA will issue a request for proposals for the remaining 15 MW. These procurements are structured to maximize learning about energy storage services and how they can best serve Ontario's needs. Contracts were planned to be executed during the summer of 2014 and become operational sometime in 2017.

About 14 percent of the installed wind capacity is assumed to be available at the time of summer peak, and 33 percent is assumed to be available at the time of winter peak. Ontario's solar capacity value is forecast to be 30 percent of installed capacity for the summer peak and 4 percent for the winter peak. The assumed capacity contribution for hydroelectric is 71 percent for the summer peak and 76 percent for the winter peak.

To meet the challenge of rapid deployment of renewables across the province and help capture the benefits of Ontario's investment in variable generation, the IESO has adapted power system planning and operations, as well as the IESO-administered markets to accommodate the influx of renewables. The IESO implemented the Renewables Integration Initiative (RII) in 2013 to effectively integrate up to 10,700 MW of renewable generation by 2021. RII has already yielded results, including the integration of the hourly centralized forecast into IESO scheduling tools, and enhanced visibility of renewable output of distributed-connected variable generation facilities 5 MW or greater. This was accomplished by providing system operators with greater levels of awareness of system conditions. Improved variable generation forecasting and greater visibility is expected to bring measurable benefits to the maintenance of system reliability and market efficiency. The dispatch of grid-connected renewable resources provides increased flexibility from available variable generation resources and will allow IESO to operate the system reliably by providing the needed tools to manage issues such as ramp needs and surplus baseload generation (SBG) situations.

Frequency response, short-term inertial response, voltage ride-through capability, and voltage support are some of the performance requirements clearly identified during the connection process and validated through tests before the new grid-connected resources complete their facility registration with the IESO. Frequency response and voltage ride-through capability requirements also apply to distribution-connected resources larger than 10 MW. To capture the effects of all DG on the performance of the grid, including those smaller than 10 MW, the IESO periodically conducts system studies. If needed, mitigating measures such as grid-connected SVCs will be developed and requested to be implemented.

Capacity transfers are not considered in this assessment, as Ontario does not have any Firm contracts with other areas. Emergency imports are not considered in this assessment. However, for use during daily operation, operating agreements between IESO and neighboring jurisdictions in NPCC, RF, and MRO include contractual provisions for emergency imports into IESO. IESO also participates in a shared activation of reserve groups, including IESO, ISO-NE, Maritimes, NYISO, and PJM.

Transmission Outlook and System Enhancements

Northwestern Ontario is connected to the rest of the province by the double-circuit, 230 kV East–West Tie. The primary source of generation within the northwest is hydroelectric. In addition, strong local load growth is forecasted as mentioned above. Additional capacity is required to maintain reliable supply to this area under the wide range of possible system and water conditions. The expansion of the East–West Tie with the addition of a new double circuit 230 kV transmission line is expected to be in-service by 2018 and will provide reliable and cost-effective long-term supply to the northwest.

Long Term Reliability Issues

The renewable resources target for wind, solar, and bioenergy is 10,700 MW by 2021, which is accommodated through transmission expansion and maximized use of the existing system. Ontario will add a few hundred MW of hydroelectric capacity to reach a target of 9,300 MW by 2025. A substantial amount of renewable generation is embedded and included in the demand forecast. This level of variable generation will be incorporated into the system through the development of new facilities and significant investments to upgrade existing facilities in Ontario. The operational and adequacy concerns of integrating of new variable generation are addressed through RII and the connection requirements imposed by the IESO on grid-connected resources, and on resources larger than 10 MW connecting to the distribution system.

A reduction of SBG events is expected after the nuclear refurbishment programs begin. The vast majority of SBG is currently managed through normal market mechanisms, including export scheduling and nuclear maneuvering. The IESO's variable generation dispatch tools have provided additional flexibility to alleviate most SBG events.

In light of environmental and other concerns, coal-fired generation has been replaced in Ontario by sources that emit less carbon. In the years ahead, natural gas-fired generation will play an important role in Ontario's supply mix balance, providing the flexibility to cushion the electricity system when demand and intermittent resources rise or fall.

Almost all of Ontario's oil and natural gas comes from outside the province. In addition to the use of these fuels for electricity generation, Ontario relies on oil and natural gas to support basic needs such as heat and transportation. In particular, reliance on natural-gas-fired generation will grow as this form of generation represents an essential element in the sustainability of a responsive and flexible electricity system. Supply to Ontario's gas fleet is supported by significant Firm supply and transportation contracts. The IESO is an active participant in the Eastern Interconnection Planning Collaborative effort in the ongoing development of Gas-Electric System Interface Study[21] that evaluates the capability of natural gas systems to satisfy the future needs of the electric system across most of the Eastern Interconnection.

With the growth in conservation savings and DG, demand forecasting has become more complex. The introduction of smart meters and higher on-peak electricity prices has introduced consumer price response previously not seen in Ontario. Traditionally, demand was a function of weather conditions, economic cycles, and population growth. With multiple factors influencing demand, determining the causality of demand changes has become increasingly nuanced and requires greater data and analysis.

[21] EIPC: Gas-Electric System Interface Study.

Québec

Assessment Area Overview

The Québec Assessment Area (Province of Québec) is a winter-peaking NPCC subregion that covers 595,391 square miles with a population of eight million. Québec is one of the four NERC Interconnections in North America, with ties to Ontario, New York, New England, and the Maritimes, consisting either of HVdc ties or radial generation or load to and from neighboring systems.

Summary of Methods and Assumptions

Reference Margin Level
Reference Reserve Margin Levels are drawn from the Québec Area 2013 Interim Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee in December 2013

Load Forecast Methodology
Coincident; normal weather (50/50)

Peak Season
Winter

Planning Considerations for Wind Resources
On-peak contribution is approximately 30 percent of the total.

Planning Considerations for Solar Resources
N/A

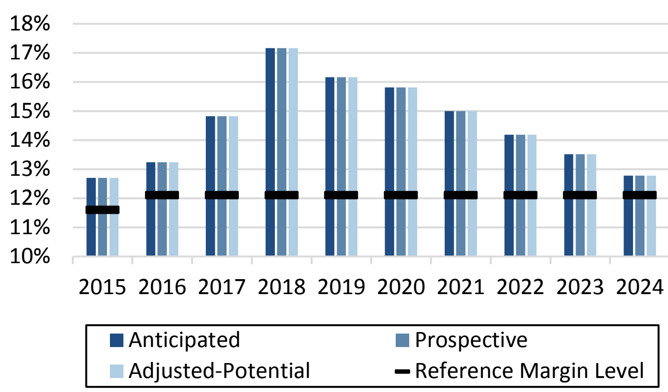
Footprint Changes
N/A

Assessment Area Footprint

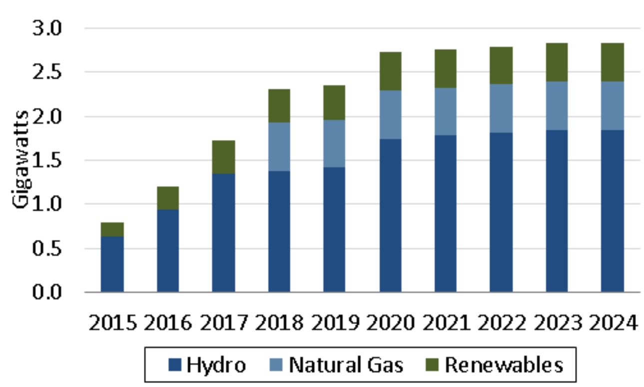
Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	38,316	38,612	38,847	39,168	39,567	40,218	40,558	40,862	41,120	41,373
Demand Response	1,708	1,852	1,902	1,952	2,002	2,202	2,252	2,252	2,252	2,252
Net Internal Demand	36,608	36,760	36,945	37,216	37,565	38,016	38,306	38,610	38,868	39,121
Resources (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	41,257	41,628	42,421	43,602	43,637	44,028	44,051	44,086	44,121	44,121
Prospective	41,257	41,628	42,421	43,602	43,637	44,028	44,051	44,086	44,121	44,121
Adjusted-Potential	41,257	41,628	42,421	43,602	43,637	44,028	44,051	44,086	44,121	44,121
Reserve Margins (%)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	12.70%	13.24%	14.82%	17.16%	16.16%	15.81%	15.00%	14.18%	13.51%	12.78%
Prospective	12.70%	13.24%	14.82%	17.16%	16.16%	15.81%	15.00%	14.18%	13.51%	12.78%
Adjusted-Potential	12.70%	13.24%	14.82%	17.16%	16.16%	15.81%	15.00%	14.18%	13.51%	12.78%
Reference Margin Level	11.60%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%	12.10%
Excess/Shortfall (MW)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Anticipated	476	384	968	1,845	1,489	1,374	1,071	765	511	226
Prospective	476	384	968	1,845	1,489	1,374	1,071	765	511	226
Adjusted-Potential	476	384	968	1,845	1,489	1,374	1,071	765	511	226

Peak Season Reserve Margins



Peak Season Projected Resource Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

The Reference Margin Levels are drawn from the Québec Area 2013 Interim Review of Resource Adequacy[22] and varies between 10 and 12 percent. The Anticipated Reserve Margin also varies between 12.8 and 17.2 percent, remaining above the Reference Margin Level for all seasons and years during the assessment period.

The Québec Area demand forecast has increased compared to the 2013LTRA report, mainly due to industrial sector growth. The demand forecast average annual growth is 0.9 percent during the 10-year period, similar to the 1.0 percent forecast in the 2013LTRA.

EE and conservation programs are integrated in the demand forecasts and account for 1,550 MW for the 2015–2016 winter peak. These programs are implemented throughout the year by Hydro-Québec Distribution (HQD) and by the provincial government, through its Ministry of Natural Resources. EE will continue to grow during the entire assessment period.

Demand forecasts also take into account the load shaving that results from the residential dual-energy space-heating program. The impact of this program on peak load demand is estimated to be around 650 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), totaling 1,458 MW for the 2015–2016 winter period. DR is usually used in situations when load is expected to reach high levels, or when resources are not expected to be sufficient to meet load during peak periods. DR remains relatively stable during the assessment period, with a maximum of 2,252 MW reached during 2021–2022 winter season.

The Québec Area is currently developing new DR programs, including Direct Control Load Management (DCLM), which could provide an additional 300 MW of DR by 2021–2022. Total on-peak DSM (including EE and conservation programs) for the 2024–2025 winter period is projected to be approximately 5,250 MW.

A total of 1,560 MW of new hydro generation is expected to be in service by 2021. Additional updates to existing hydro generation will add an additional 400 MW of capacity during the assessment period. With regard to other renewable resources (biomass and wind), a total of 1,900 MW is expected to be in service by 2021. At this time, all projects are expected to be on time and there are no cancellations or deferments.

Biomass and wind resources are owned by Independent Power Producers (IPPs). These IPPs have signed contractual agreements with Hydro-Québec. Therefore, for biomass resources, maximum capacity and expected on-peak capacity are equal to contractual capacity, representing almost 100 percent of nameplate capacity. For wind resources, capacity contribution at peak is estimated at 30 percent of contractual capacity, representing 970 MW and 1,220 MW, respectively, for the 2015–2016 and 2024–2025 winter periods. Maximum wind capacity is set equal to contractual capacity, which generally equals nameplate capacity. For summer peak period calculations, the expected on-peak wind capacity is set to zero as wind resources are derated by 100 percent. BTMG is negligible and is embedded in the load forecast.

Expected capacity purchases are planned by Hydro-Québec Distribution as needed to meet the Québec internal demand. These purchases are set at 1,100 MW throughout the assessment period and may be supplied by resources located in Québec or in neighboring markets. In this regard, Hydro-Québec Distribution has designated the Massena–Châteauguay (1,000 MW) and Dennison–Langlois (100 MW) interconnections' transfer capacity to meet its resource requirements during winter peak periods. These purchases are not backed by firm long-term contracts. However, on a yearly basis, Hydro-Québec Distribution proceeds with short-term capacity purchases of Unforced Capacity ("UCAP") as needed in order to meet its capacity requirements for the upcoming winter. The Québec Area does not rely on any emergency capacity imports to meet its Reserve Margin Reference Level. The Québec Area will support firm capacity sales totaling 974 MW to

[22] Québec Area 2013 Interim Review of Resource Adequacy, approved by NPCC's Reliability Coordinating Committee on December 3, 2013.

New England and Ontario (Cornwall) during the 2015–2016 winter peak period, backed by firm contracts for both generation and transmission, declining to 145 MW in 2020.

Transmission Outlook and System Enhancements

TransÉnergie's system consists of an extensive 735 kV network underlain with 315 kV, 230 kV, 120 kV and 69 kV subsystems totaling to 20,886 line miles (33,613 km). The system uses telecommunications and advanced protection and control applications to ensure its reliability and improve its performance. This will continue into the future. The system is planned according to NPCC and NERC Planning Standards, but with additional criteria that consider system topology and substation characteristics particular to TransÉnergie's system (complementary contingencies) and address voltage sensitivity to load variation and interconnection ramping.

Romaine River Hydro Complex Integration

Construction of the first phase of transmission for the Romaine River Hydro Complex project is presently underway. The total capacity will be 1,550 MW. The generating stations will be integrated on a 735 kV infrastructure initially operated at 315 kV. Romaine-2 (640 MW) and Romaine-1 (270 MW) will be integrated in 2014–2016 at Arnaud 735/315/161 kV substation. One 315/161 kV, 500-MVA transformer is required at Arnaud for this project. Romaine-3 (395 MW) and Romaine-4 (245 MW) will be integrated between 2017 and 2020 at Montagnais 735/315 kV substation.

The main system upgrades for this project requires construction for 2014 of a new 735 kV switching station to be named "Aux Outardes" and located between the existing Micoua and Manicouagan Transformer substations. Two 735 kV lines will be redirected into the new station and one new 3 miles (5 km) 735 kV will be built between Aux Outardes and Micoua.

Bout-de-l'Île 735 kV Section

In 2013, TransÉnergie added a new 735 kV section at Bout-de-l'Île substation located at the east end of Montréal Island. The Boucherville – Duvernay line (Line 7009) has been looped into this substation and the first of two -±300 -Mvar Static Var Compensators (SVC) has been be added to the 735 kV section.

The second SVC will be added in 2014, as well as two 735/315 kV, 1,650-MVA transformers banks. This new 735 kV source will allow redistribution of load around the Greater Montréal area and will accommodate load growth in the eastern part of Montréal. This project will enable future major modifications to the Montréal area regional sub-system. Many of the present 120 kV distribution substations will be rebuilt into 315 kV substations and the Montréal regional network will be converted to 315 kV.

Chamouchouane – Montréal 735 kV Line

Planning studies have shown the need to reinforce the transmission system with a new 735 kV line in the near future. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to a substation in Montréal (255 miles (410 km)). It will reduce transfers on other parallel lines on the 735 kV Southern Interface, thus optimizing operation flexibility and reducing losses.

Planning, permitting and construction delays are such that the line is scheduled for the 2018–2019 winter peak period. Public information meetings have begun on this project. The final line route has not completely been determined, yet and authorization processes are ongoing.

The Northern Pass Transmission Project

This project to increase transfer capability between Québec and New England by 1,200 MW is currently under study. It involves construction of a ±300 kV DC transmission line about 75 km (47 miles) long from Des Cantons 735/230 kV substation to the Canada – United States border. This line will be extended into the United States to a substation to be built in Franklin, New Hampshire.

The project in Québec also includes the construction of two 600-MW converters at Des Cantons and a 300 kV DC switchyard. The planned in-service date has been re-evaluated to winter 2018-2019.

The Champlain-Hudson Power Express Project

This project to increase transfer capability between Québec and New York by 1,000 MW is currently under study.[23] The project involves the construction of a ±320 kV dc underground transmission line about 50 km (31 miles) long from the Hertel 735/315 kV substation just south of Montréal to the Canada–United States border. This line will be extended underground and underwater (Lake Champlain and Hudson River) to Astoria station in New York City. The project in Québec also includes the construction of one 1,000 MW converter at Hertel. The planned in-service date is fall 2017.

Other regional substation and line projects are in the planning or permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City areas and another dozen in other areas with in-service dates from 2014 to 2020, consisting mostly of 315/25 kV and 230/25 kV distribution substations to replace 120 kV and 69 kV infrastructures.

Long Term Reliability Issues

Given the importance of hydroelectric resources within the Québec Area, an energy criterion has been developed to assess energy reliability. The criterion states that sufficient resources should be available to go through sequences of two or four consecutive years of low water inflows totaling 64 TWh and 98 TWh, respectively, with a 2 percent probability of occurrence. These assessments are presented three times a year to the Régie de l'énergie du Québec (Québec Energy Board). Normal hydro conditions are projected during the assessment period, and reservoir levels are expected to be sufficient to meet both peak demands and daily energy demand.

However, while technical developments in recent years have contributed to creating a more reliable system, sustainable system reliability may be challenged by several issues. For example, wind generation integration has not significantly impacted day-to-day operation of the system, and the actual level of wind generation does not require particular operating procedures. However, with the increasing amount of wind on the system, there is a potential for impacts on system management. Accordingly, the following issues are currently under study:

- Wind generation variability on system load and interconnection ramping
- Frequency and voltage regulation
- Increase of start-ups/shutdowns of hydroelectric units due to load following coupled with wind variability
- Efficiency losses in generating units and/or reduction of low-load operation flexibility due to the low inertia response of wind generation coupled with must-run hydroelectric generation

In addition to these issues, there are occasions during recent summers when several 735 kV lines in the southern part of the system became heavily loaded due to the hot temperatures in southern Québec. Although this is a new issue for the Québec Area, it is expected to occur again with increased air conditioning loads and growing exports to other summer-peaking systems. More recently, studies have been performed and thermal limits have been optimized with other mitigating measures to address the potential for future line overloads following a contingency during periods of hot temperatures.

[23] Federal Register Notice – October 1, 2014.

NPCC 2014 LONG RANGE ADEQUACY OVERVIEW

PJM

Assessment Area Overview

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM companies serve 61 million people and cover 243,417 square miles. PJM is a Balancing Authority, Planning Coordinator, Transmission Planner, Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider and Reliability Coordinator.

Summary of Methods and Assumptions

Reference Margin Level
The PJM RTO Reserve Requirement is applied as the Reference Margin Level for this assessment.

Load Forecast Methodology
Coincident; normal weather (50/50)

Peak Season
Summer

Planning Considerations for Wind Resources
On-peak contribution of 13 percent of installed capacity.

Planning Considerations for Solar Resources
38 percent of nameplate capacity.

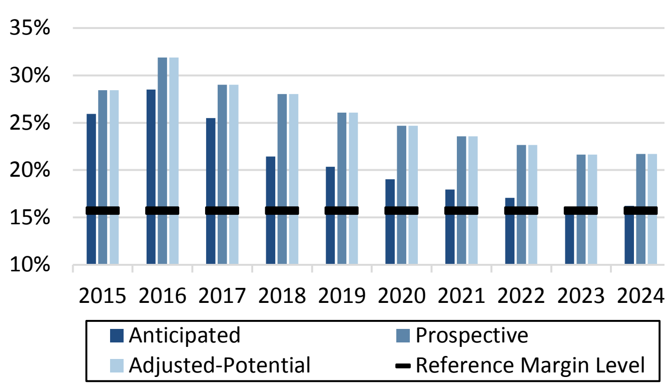
Footprint Changes
The East Kentucky Power Cooperative (EKPC), which integrated into the PJM RTO on June 1, 2013, is now part of PJM's load and generation data.

Assessment Area Footprint

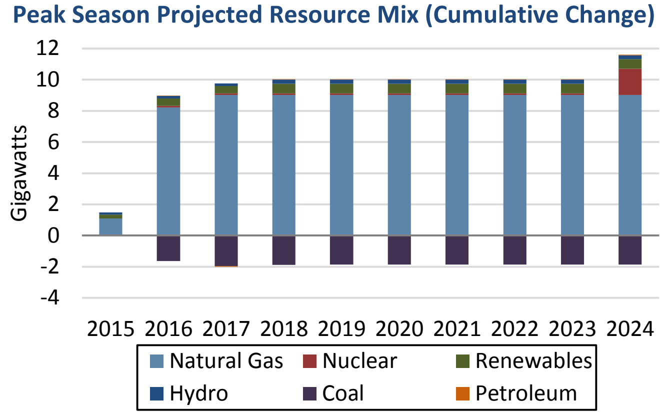
Peak Season Demand, Resources and Reserve Margins

Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total Internal Demand	160,259	162,470	164,195	165,479	166,900	168,593	170,027	171,217	172,542	173,729
Demand Response	14,812	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402	12,402
Net Internal Demand	145,447	150,068	151,793	153,077	154,498	156,191	157,625	158,815	160,140	161,327
Resources (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	183,163	192,850	190,497	185,904	185,928	185,928	185,928	185,928	185,928	187,498
Prospective	186,787	197,909	195,818	195,962	194,767	194,768	194,768	194,768	194,768	196,338
Adjusted-Potential	186,787	197,909	195,818	195,962	194,767	194,768	194,768	194,768	194,768	196,338
Reserve Margins (%)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	25.93%	28.51%	25.50%	21.44%	20.34%	19.04%	17.96%	17.07%	16.10%	16.22%
Prospective	28.42%	31.88%	29.00%	28.02%	26.06%	24.70%	23.56%	22.64%	21.62%	21.70%
Adjusted-Potential	28.42%	31.88%	29.00%	28.02%	26.06%	24.70%	23.56%	22.64%	21.62%	21.70%
Reference Margin Level	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%	15.70%
Excess/Shortfall (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Anticipated	14,880	19,221	14,873	8,793	7,173	5,215	3,555	2,179	646	842
Prospective	18,504	24,280	20,193	18,852	16,013	14,055	12,395	11,019	9,486	9,682
Adjusted-Potential	18,504	24,280	20,193	18,852	16,013	14,055	12,395	11,019	9,486	9,682

Peak Season Reserve Margins



Peak Season Projected Resource Mix (Cumulative Change)



Demand, Resources, and Planning Reserve Margins

The PJM RTO Reserve Requirement as calculated by PJM is 15.7 percent for the 2015–2016 planning period, which runs from June 1, 2015, through May 31, 2016. The PJM RTO Reserve Requirement is 0.5 percentage points lower this year compared to the 2014–2015 value due to the retirement of coal units with high forced outage rates. The 15.7 percent PJM RTO Reserve Requirement (applied as the Reference Margin Level) is applicable for the entire assessment period. PJM RTO will have an adequate Anticipated Reserve Margin though the entire assessment period. The Prospective and Adjusted-Potential Reserve Margins are also above the Reference Margin Level for the entire assessment period.

Use of more granular historical economic data and the addition of another year of load experience to the load forecasting model resulted in generally lower (approximately 0.5 percent) peak and energy forecasts this year compared to the forecast done last year. Annualized 10-year growth rates for individual zones range from 0.4 percent (Rockland Electric) to 1.8 percent (Dominion Virginia Power).

PJM has filed tariff changes with FERC that will require more robust reporting of the DR operational capability in real time for Curtailment Service Providers. PJM does not have reliability concerns with DR expansion, but the additional operational information will help avoid the dispatch of DR that may not be necessary to meet the need of the emergency conditions. PJM has created three different DR products to address the issue of availability: Limited DR (10 days for 6 hours per day during the summer peak period), Extended Summer DR (unlimited days during the summer peak period for 10 hours per day) and Annual DR (unlimited days for 10 hours per day any time of the year). These programs require necessary amounts of annual capacity to fulfill the PJM reliability requirements.

The PJM reported transactions are the aggregate of generator-specific transactions. These transactions include the Firm reservation rights for the generation and Firm transmission rights to transfer the power across the PJM border. Long-term Firm capacity transfer contacts exist, but they are not accepted into PJM installed capacity until the PJM Reliability Planning Model (RPM) three-year planning window. The impact of transactions is minimal in PJM since they only amount to about two percent of the forecast peak load. PJM previously forecast transactions using the Firm capacity contracts but has recently decided to only show capacity transactions through a three-year planning window to coordinate with neighboring entities.

Energy efficiency programs included in the 2015–2017 load forecast are approved for use in the RPM and total 685 MW for the 2015 summer. This value increases to 918 MW in 2016 and remains constant through the end of the assessment period.

Transmission Outlook and System Enhancements

Northeast New Jersey Transmission Enhancement

PJM 2013 RTEP process results have validated the need for a solution to identified short circuit duty violations at the Essex, Kearney and New Jersey Transit Meadowlands (NJT Meadows) 230 kV substations. Notably, 2013 short circuit analyses revealed that the two 345 kV tie lines connecting PSE&G's Hudson substation to ConEd's Farragut substation contribute to short circuit duties at Hudson, Kearney and Essex. As a result, the Hudson/Farragut HVDC alternative was originally recommended in large part for its ability to block this fault current pass-through to the northern New Jersey PSE&G system. However, circuit breaker short circuit over duties were not the only NERC criteria violations identified. Generator deliverability tests identified thermal violations on lines in northern New Jersey which have required reconsideration of PJM's initial HVDC solution proposal and the subsequent development of a more comprehensive solution.

In collaboration with PSE&G planning staff, PJM evaluated two northern New Jersey double-circuit upgrade solutions: one at 230 kV and one at 345 kV. Additionally, the double circuit 345 kV solution also solves the identified thermal criteria violations in northern New Jersey.

In parallel with the analytical work performed to compare the double circuit 345 kV and HVDC alternatives, PJM also retained an independent engineering consultant to review each project, validate cost estimates and assess the project constructability. From that perspective, the consultant's findings did not identify any "fatal flaws" that would prevent either project from being implemented. Based on the performance of each of the alternatives, the cost of each and the findings of the independent consultant regarding constructability, PJM recommended the double circuit 345 kV alternative to address the short circuit and thermal problems in northern New Jersey. The PJM Board approved the recommendation in December 2013.[24]

Need for Byron - Wayne Confirmed

PJM reviewed – as it does every year – transmission plans developed in earlier years. By doing so PJM can determine whether, as a result of changing assumptions, previously approved transmission upgrades are still required. And, if so, determine whether they are still required in the year originally identified, as with the Byron - Wayne 345 kV Transmission Line (Grand Prairie Gateway). As part of its 2012 RTEP process, PJM conducted its annual simultaneous feasibility analysis to assess the transmission system's ability to accommodate all transmission rights for the next 10-year period. PJM's 2012 transmission rights analysis identified 16 thermal constraints in ComEd and nine PJM-MISO Market-to-Market constraints. RTEP analysis in 2013 also identified a number of thermal constraints similar to those identified in 2012, confirming the need for the Byron - Wayne 345 kV in 2017.

Artificial Island Order 1000 Proposal Window

PJM sought proposals from April 29, 2013, through June 28, 2013, to improve operational performance on Bulk Electric System (BES) facilities in the southern New Jersey Artificial Island area, the site of PSE&G's Salem 1 and 2 and Hope Creek 1 nuclear generating plants. Under certain system conditions, this area's complexity has presented PJM and PSE&G system operators with limited solutions, potentially forcing them in some circumstances to remove an Artificial Island unit from service in order to stay within operating limitations to maintain reliability. PJM specified that RTEP proposals improve limited stability margins, minimum Artificial Island MVar output requirements, and previously identified high-voltage reliability issues.

Seven different sponsors submitted 26 separate proposals. Proposals reflected a diverse range of technologies at both 500 kV and 230 kV—new transformation, substations and associated equipment, additional circuit breakers, system reconfiguration, dynamic reactive devices, dynamic series compensation and DC technology—spanning a range of project risk exposure levels and lead-time requirements. In parallel with analytical evaluation, PJM enlisted engineering consultants in 2013 to evaluate project proposal constructability in terms of physical characteristics, feasibility, cost, design commonalities, and other challenges associated with line and river crossings. Additionally, the consultants

[24] 2013 Regional Transmission Expansion Plan Report (See page 7).

examined the ability to expand or reconfigure existing substations and determine required transmission and generation outages.

Market Efficiency Order 1000 Proposal Window

During this window, PJM sought proposals to identify transmission projects to relieve internal PJM transmission congestion. The scope of the request encompassed the top 25 congestion events observed in 2013 Market Efficiency Analysis for study years 2017, 2020, and 2023 and for which no reliability based RTEP upgrades have been already identified. Proposed enhancements must provide a benefit/cost ratio of at least 1.25 and must not introduce any reliability criteria violations. Six different sponsors submitted 17 separate proposals during the window to meet the stated requirements. Analysis identified three proposals for further evaluation. All three addressed, either in whole or part, congestion on the Hunterstown 230/115 kV transformer. PJM expects to make a recommendation to the Board in 2014 that comprises adding a second Hunterstown 230/115 kV transformer and reconductoring the existing Hunterstown - Oxford 115 kV line.

AEP / Dominion Transmission Rebuilds

PJM's RTEP includes 500 kV transmission line rebuild projects over the next eight years by AEP and Dominion as listed below. The towers of all six lines, built in the 1960s, are nearing the end of their useful lives and will soon require rebuild. Now the Cloverdale - Lexington and Lexington - Dooms 500 kV line rebuilds have been identified to solve PJM baseline reliability criteria violations.

AEP/Dominion Line Rebuilds

Line Rebuild	Driver	In-Service Month, Year
Cloverdale - Lexington 500 kV	NERC Category C3 "N-1-1" Criteria	December 2016
Lexington - Dooms 500 kV	Dominion Reliability Criteria Violation	June 2016
Dooms - Cunningham 500 kV	Dominion Supplemental Project	December 2018
Cunningham - Elmont 500 kV	Dominion Supplemental Project	May 2018
Mt. Storm - Valley 500 kV	Dominion Supplemental Project	June 2021
Valley - Dooms 500 kV	Dominion Supplemental Project	December 2021

Cloverdale - Lexington 500 kV Line

RTEP analysis conducted in 2013 identified reliability criteria violations under PJM light load criteria tests on the AEP portion of the Cloverdale - Lexington 500 kV line. In October 2013, the Board approved PJM's upgrade recommendation to rebuild the AEP portion of the Cloverdale- Lexington 500 kV line, including replacement of eleven tower structures. This follows December 2011 PJM Board approval to reconductor the Dominion portion of the Cloverdale-Lexington 500 kV circuit to solve NERC criteria Category C violations. Jointly owned by Dominion and AEP, coordinated plans are underway to rebuild and/or reconductor their respective portions of the 44 mile line in order to increase the operational limit of that line to meet PJM's minimum summer emergency requirement of 3,992 MVA.

Dooms – Lexington 500 kV Line

PJM 2012 RTEP analysis identified a Dominion reliability criteria violation in 2016 in which the Dooms - Lexington line would be overloaded for several N-1-1 contingencies. In May 2012, the PJM Board approved the recommended solution to reconductor the line, increasing its rating from 2,913 MVA to 4,340 MVA. The project is expected to be completed by December 2016.

State RPS laws require entities that serve load do so using various eligible renewable resources including wind, solar and other technologies. States in the PJM region have a variety of RPS definitions and targets. Overall, approximately 38 GW of renewable energy would be required from renewable resources to meet aggregate RPS targets by 2028 in states in which PJM operates. And, while NERC Reliability Standard violations remain PJM's principal basis under the RTEP Protocol for justifying transmission expansion, construction of major transmission infrastructure will likely be necessary to support the achievement of RPS public policy goals.

Wind and solar powered facilities – now an expanding percentage of interconnection requests – constitute a growing driver of regional transmission expansion. The emergence of state RPS standards has prompted PJM to examine further the potentially more far-reaching impacts that the extensive penetration of wind resources driven by those standards will have on reliability and market efficiency. During 2013, both internal scenario studies and interregional studies examined the penetration of renewable-powered generation to meet state RPS targets. Those studies confirm that significant build-out of transmission will be needed for PJM to deliver the aggregate wind generation required to meet states' aggregate RPS goals.

Behind-the-meter-generation (BTMG) is not counted as PJM capacity and has no effect on the PJM Reserve Margin. During a hot weather event in September 2013, [25] PJM called on BTMG to operate to alleviate specific transmission related operating concerns. PJM will establish and document an approach for representing known BTMG in the PJM's Energy Management Systems and the related operating criteria for dispatchers. Working with the States and the Transmission Owners, PJM will better incorporate BTMG into emergency operations.

[25] PJM Report: Technical Analysis of Operational Events and Market Impacts.

Long-Term Reliability Issues

Light load system conditions, as low as 30 percent of summer peak for some transmission owners, present system dispatchers with operational performance issues. Generation dispatch under such conditions differs markedly from that under peak load conditions, particularly for units powered by renewable sources such as wind. PJM has begun to experience thermal overloads and high voltage events driven by low demand dispatch patterns and the capacitive effects of lightly loaded transmission lines. From a 15-year planning perspective, these light load concerns gave rise to the approval of new reliability criteria analysis procedures in 2010, first implemented and benchmarked in 2011, for both baseline analysis and queued interconnection request studies. Light load reliability analysis ensures that the system transmission is capable of delivering generating capacity under such conditions.

As part of its 2013 cycle of RTEP studies, PJM identified six light-load criteria violations, five of which represented normal and N-1 thermal overloads. The most significant of these is a project to rebuild the AEP portion of the Cloverdale – Lexington 500 kV line in Virginia that will require $40 million, expected by June 2015. The remaining four thermal criteria violations will require 138 kV upgrades in AEP and ComEd; they are much lower in scope and estimated cost and are expected by June of 2017. The sixth criteria violation, voltage in nature, requires an upgrade to the 765 kV Cloverdale substation, also in Virginia, and construction of a new 500 kV bus with an estimated project cost of $85 million projected to be in service by the end of 2016.

PJM planning staff has initiated efforts with operations staff and individual TOs to examine real-time high voltage events across the RTO. Based on additive power flow studies completed in 2013, PJM collaborated with TOs to develop solutions approved by the PJM Board that ultimately included shunt reactors, SVCs, Reactor breakers, and Modifications to, and optimization of existing facilities, generator voltage schedule adjustments, transformer tap settings and switched shunt capacitor settings.

Planning study results were reviewed with TOs in order to determine optimal reactor sizes and locations across PJM to maximize their effectiveness at mitigating high voltages, subsequently confirmed by additional power flow analysis. In-service dates begin by June 1, 2015.