

Northeast Power Coordinating Council Interregional Long Range Adequacy Overview

Approved by the RCC

November 30, 2010

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. Glenn Haringa, GE Energy, Andrew Ford, the PJM Interconnection, and Scott Brown, New Brunswick System Operator, 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 Region's plans to meet their Loss of Load Expectation (LOLE) planning criteria ¹ through a multi-area probabilistic assessment, in response to Goal #6a of "NPCC's 2010 Corporate Goals." ²

General Electric's (GE) Multi-Area Reliability Simulation (MARS) program ³ was selected for the analysis. GE Energy was retained by the Working Group to conduct the simulations.

The database developed by the NPCC CP-8 Working Group's "*NPCC Reliability Assessment for Summer 2010*", April 2010, 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 2011-2015 time period, consistent with the information reported for the *NERC 2010 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 is shown in Appendix A. Appendix B summarizes the Area Generation and Load assumptions used in the analysis.

¹ See: <http://www.npcc.org/documents/regStandards/Directories.aspx> , Directory No. 1, Section 5.2

² See: <http://www.npcc.org/documents/aboutus/BusPlanBylaws.aspx>

³ See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

⁴ See: <http://www.npcc.org/documents/reports/Seasonal.aspx> , Appendix VIII

⁵ See: <http://www.nerc.com/page.php?cid=4|61>

MODEL ASSUMPTIONS

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

Area Studies

New York

On May 19, 2009, the New York Independent System Operator (NYISO) issued its 2009 Comprehensive Reliability Plan (CRP),⁶ a study that recommends solutions to meet New York's future electric power needs and maintain the integrity of the state's bulk power grid. The 2009 CRP completed the NYISO's reliability planning cycle known as the Comprehensive Reliability Planning Process (CRPP).

The 2009 CRP was the starting point for the new economic planning process called the Congestion Assessment and Resource Integration Study (CARIS), starting in the summer of 2009. In response to its Order 890 compliance filing, the Federal Energy Regulatory Commission (FERC) conditionally approved on October 16, 2008 the NYISO's newly expanded planning process called the Comprehensive System Planning Process (CSPP), which integrates the existing CRPP, as well as the CARIS, into an extended two-year planning cycle.

The 2010 Reliability Needs Assessment (RNA)⁷ commences the fifth cycle of the NYISO's reliability planning processes provided for in its CSPP. The NYISO's CSPP encompasses the existing reliability planning processes with the new economic planning process called the Congestion Analysis and Resource Integration Study (CARIS). The RNA provides a long-range reliability assessment of both resource adequacy and transmission security of the New York bulk power system conducted over a 10-year planning horizon. This 2010 RNA builds upon the results and analyses contained in the NYISO's prior Comprehensive Reliability Plans (CRP) in 2005, 2007, 2008 and 2009 respectively. The first three CRPs responded to the Reliability Needs identified by their respective RNAs. The 2009 RNA, with the reduced forecast associated with energy efficiency peak load reductions, increased generation and increased demand response, identified no Reliability Needs. The fourth CRP indicated that the system was reliable and no solutions were necessary in response to the 2009 RNA.

The 2010 RNA identified no Reliability Need, assuming that all modeled transmission and generation facilities, including Indian Point, remain in service during the next 10 years from 2011 through 2020. The study of the Base Case indicates that the baseline system meets all applicable Reliability Criteria. However pending regulatory initiatives may affect Base Case facilities and could result in unanticipated retirement of capacity in

⁶ See: http://www.nyiso.com/public/webdocs/newsroom/planning_reports/CRP_FINAL_5-19-09.pdf

⁷ See:

http://www.nyiso.com/public/webdocs/newsroom/press_releases/2010/2010_Reliability_Needs_Assessment_Final_09212010.pdf

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New York. The NYISO will continue to monitor these developments and will conduct appropriate reliability studies as necessary.

New England

The New England Regional System Plan (RSP) is ISO-New England's annual planning report that identifies the resources and transmission facilities needed to maintain reliable and economic operation of New England's bulk electric power system over a ten-year horizon. A public meeting to discuss ISO-New England's Draft 2010 Regional System Plan (RSP) was held September 16, 2010. The New England RSP 2010⁸ was approved by ISO-New England's Board of Directors on October 28, 2010.

Ontario

The Independent Electricity System Operator of Ontario regularly assesses the adequacy and reliability of Ontario's power system. 18-Month Outlooks are issued on a quarterly basis. The latest Assessment of the Reliability and Operability of the Ontario Electricity System Update⁹ shows that with 3,400 megawatts (MW) of new generation expected to come online, and a transmission system adequate to meet expected demands, the period from September 2010 to February 2012 presents no unusual reliability or adequacy concerns.

Of the 3,400 MW of new generation, 1,900 MW consists of new gas-fired and renewable generation. The remaining 1,500 MW are from two refurbished nuclear units at the Bruce A Nuclear Station which are expected in the third and fourth quarters of 2011. This increase in capacity will provide additional supply options to the province, however, the Bruce complex will not be able to operate at full capacity until the completion of the Bruce to Milton transmission line expected in December 2012.

In light of Ontario's continuing positive supply conditions, the move towards the elimination of coal-fired generation by 2014 will continue as planned. Four coal-fired units amounting to about 2,000 MW deregistered on October 1, 2010.

Québec

The Québec assumptions used in this study are consistent with its most recent NPCC Review of Resource Adequacy.¹⁰ The 2009 Interim Review was the first update of the 2008 Comprehensive Review of Resource Adequacy approved in March 2009. The major assumptions of this 2009 Interim Review are consistent with the 2010 Interim Review and the second progress report of Hydro-Québec Distribution 2011-2020 Procurement Plan to be filed with the Québec Energy Board in November 2010.¹¹

⁸ See: <http://www.iso-ne.com/trans/rsp/index.html>

⁹ See: http://www.ieso.ca/imoweb/pubs/marketReports/18MonthOutlook_2010aug.pdf

¹⁰ See: <http://www.npcc.org/adequacy.cfm>

¹¹ See: http://www.regie-energie.qc.ca/EtatApproHQD/État%20d'avancement_2009.pdf

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Maritimes

The Maritimes Area is a winter peaking area with separate markets and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area. The Maritimes assumptions used in this study are consistent with its most recent NPCC Comprehensive Review of Resource Adequacy.¹²

The NPCC reliability criterion of less than or equal to 0.1 days of firm load disconnections per year is not exceeded by the Maritimes Area for all years covered by this review, and varies between 0.002 to 0.037 days/yr for the base load forecast with load forecast uncertainty. The Maritimes Area is also shown to adhere to its own 20% reserve planning criterion in all years for the base load forecast, with reserve levels varying between 24% and 36%.

PJM-RTO

The annual PJM Reserve Requirement Study (RRS)¹³ 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.

Load Representation

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

Load Shape

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

¹² See: <http://www.npcc.org/adequacy.cfm>

¹³ See: <http://www.pjm.com/~media/documents/reports/2010-pjm-reserve-requirement-study.ashx>

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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 from the 2003 and 2004 loads the load growth that had occurred from 2002, 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 2001, 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, reliability measures are reported for two load conditions: expected and extreme. The values for the expected load conditions are derived from computing the reliability at each of the seven load levels, and computing a weighted-average expected value based on the specified probabilities of occurrence. The indices for the extreme load conditions provide a measure of the reliability in the event of higher than expected loads, and were computed for the second-to-highest load level. These values are shaded in Table 1.

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Table 1
Per Unit Variation in Load Assumed (Month of January 2011)

Area	Per-Unit Variation in Load						
MT	1.1000	1.1000	1.0500	1.0000	0.9500	0.9000	0.9000
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	1.0569	1.0380	1.0190	1.0000	0.9810	0.9620	0.9431
QC	1.0853	1.0639	1.0426	1.0000	0.9573	0.9360	0.9146
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.¹⁴

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 2011-2015 period. Area peak load is shown against the initial area capacity, adjusted for purchases, retirements, and additions. More details can be found in Appendix B.

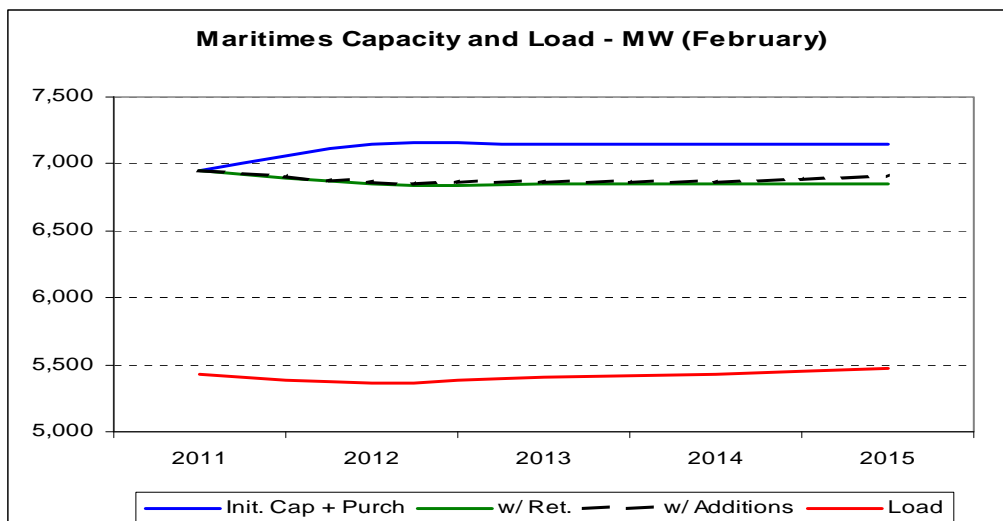


Figure 1 – Maritimes Area Capacity and Load

¹⁴ See: <http://www.npcc.org/adequacy.cfm>

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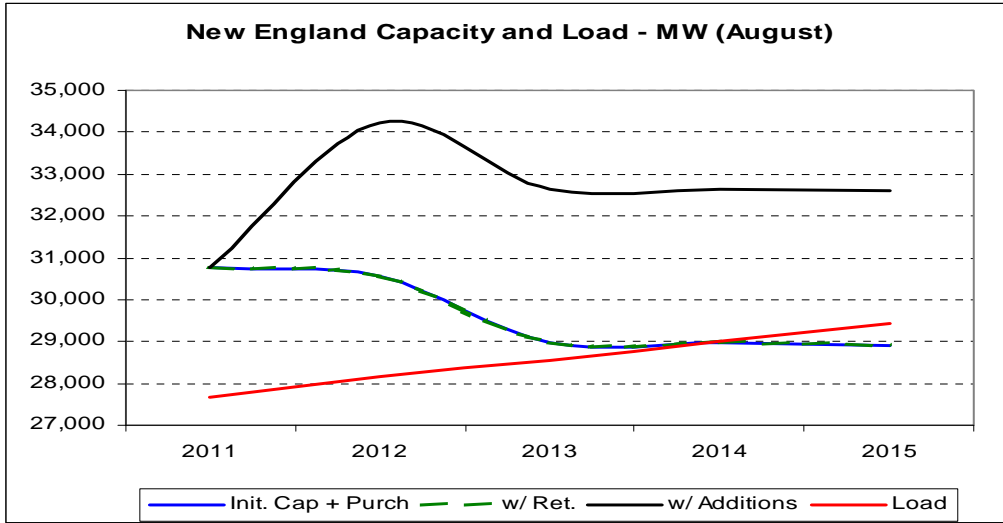


Figure 2 – New England Capacity and Load

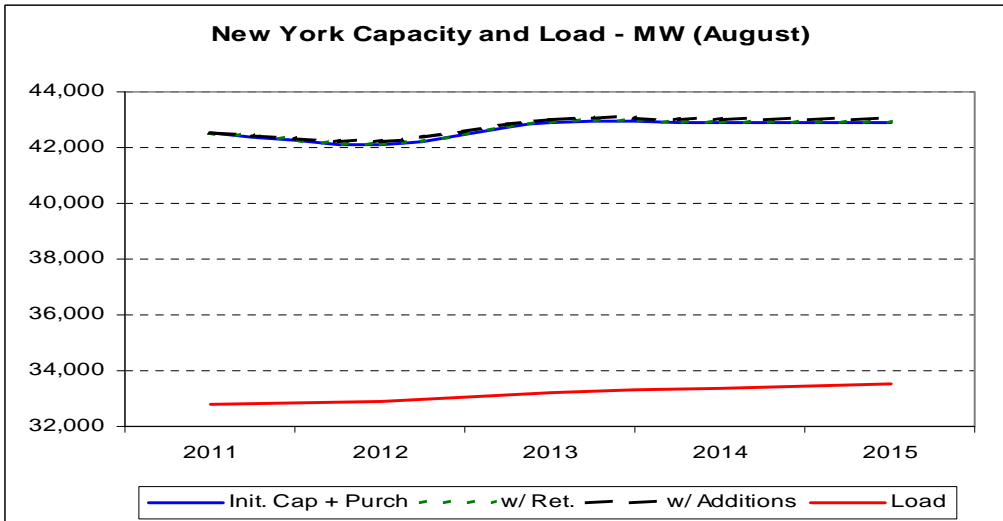


Figure 3 – New York Area Capacity and Load

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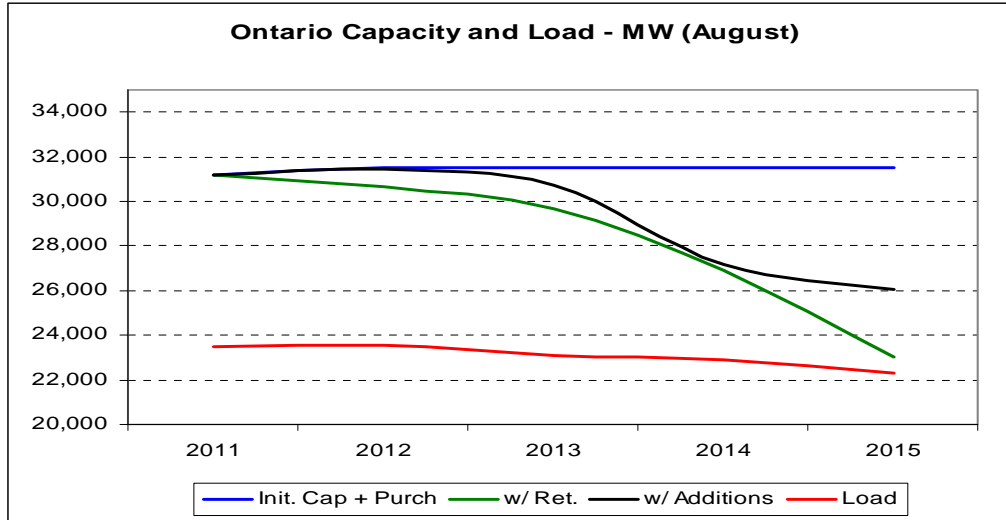


Figure 4 – Ontario Capacity and Load

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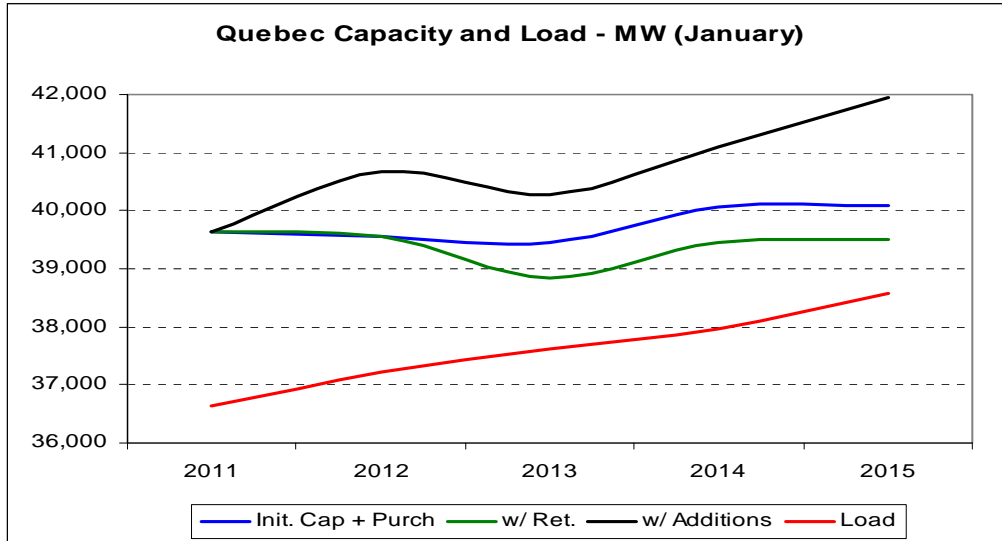


Figure 5 – Québec Capacity and Load

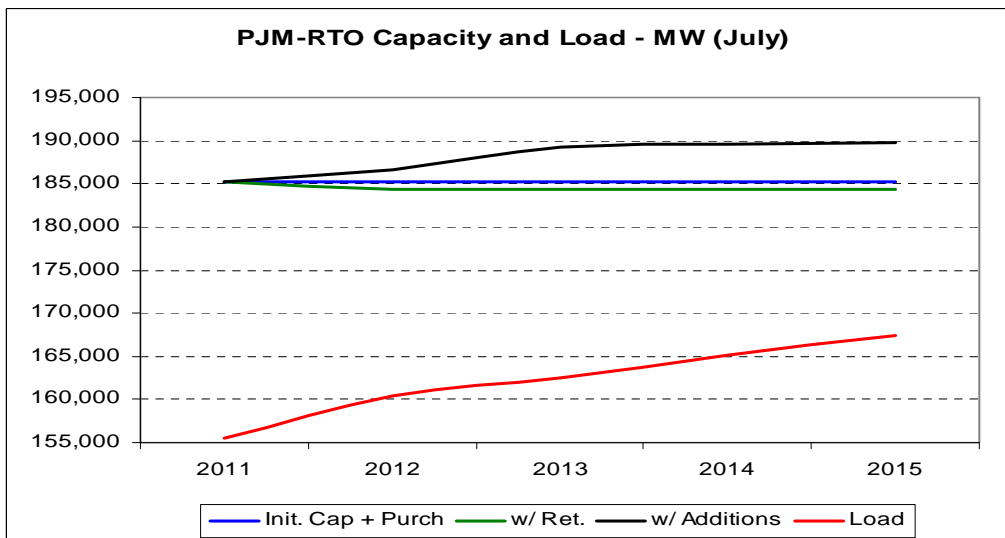


Figure 6 – PJM-RTO Capacity and Load

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Transfer Limits

Figure 7 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the 2011-2015 time period.

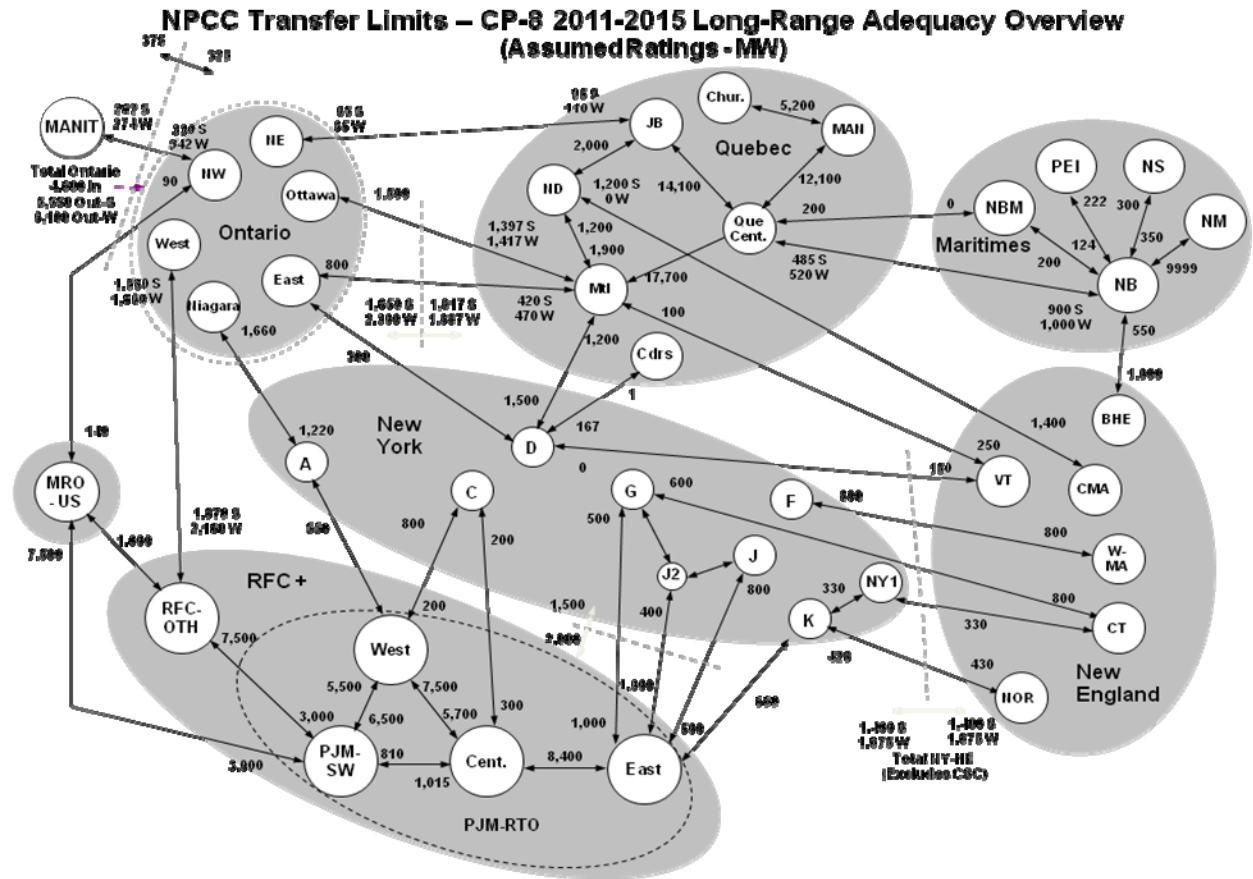


Figure 7 - Assumed Transfer Limits

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 - ReliabilityFirst Corp. |
| MRO - Midwest Reliability Organization | Que - Québec Centre | MT - Maritimes Area |

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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.

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.

Table 2 summarizes the load relief assumptions modeled for each NPCC area. 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.

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

Actions	MT (Feb)	NE (Aug)	NY (Aug)	ON (Aug)	QC (Jan)
1. Curtail Load / Utility Surplus Appeals	-	412	-	315	1,073
	-	-	-	1% of load	-
RT-DR/SCR/EDRP	-	682 ¹⁵	233	-	-
Manual Voltage Reduction	-	-	5.49% of load	-	-
2. No 30-min Reserves	229	744	600	473	500
3. Voltage Reduction or Interruptible Loads ¹⁶	380	-	1.53% of load	-	250
	-	-	-	-	-
RT-EG	-	-	488	-	-
4. No 10-min Reserves	660	-	-	1,080	750
Voltage Reduction	-	1.50% of load	-	-	-
General Public Appeals	-	-	188	-	-
5. 5% Voltage Reduction	-	-	-	2.60% of load	-
	-	-	-	-	-
No 10-min Reserves	-	1,079	1,200	-	-

¹⁵ Derated value shown accounts for assumed availability.

¹⁶ Interruptible Loads for the Maritimes area (implemented only for the Area), Voltage Reduction for all others.

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Assistance Priority

Table 3 indicates the priority order followed (valid through November 1, 2011) for allocating reserves and assistance to Control Areas with a resource deficiency. Except as shown, 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.

Table 3
Priority Order for Providing Emergency Assistance

Area Providing Assistance	Priority of Assistance	
	1 ST	2 ND
Millbank Units	QC	MT

AREA ASSUMPTIONS

Maritimes Area

The footprint of the Maritimes Area is comprised of the provinces of New Brunswick, Nova Scotia, Prince Edward Island and the Northern Maine Independent System Administrator, Inc (NMISA). NMISA serves approximately 40,000 customers in northern Maine and is radially connected to the New Brunswick power system. The Maritimes Area is a winter peaking region.

Forecast peak demand for the Maritimes Area in 2010/11 is 5,430 MW. Forecast average annual growth rate is 0.2%.

Existing capacity resources for 2010/11 total 7,147 MW, including 282 MW (derated) of wind generation. Due in part to the projection of a zero total load growth rate, there are no future plans to add more conventional generation capacity in the Maritimes Area within the next five years. For each year of the forecast, the reserve margin of the Maritimes Area exceeds 34% and thus meets the 20% reserve margin criterion used for planning purposes.

The only new bulk transmission forecast is a 2016 conceptual project to build a parallel circuit to the existing 200 miles of 345 kV transmission between Coleson Cove, New Brunswick and Onslow, Nova Scotia.

There are no significant generating unit outages, transmission additions or temporary operating measures that are anticipated to impact the reliability of the Maritimes during the next five years.

Demand

The 2010/11 peak demand forecast is 5,430 MW. This is 545 MW lower than reported in the *2006 NPCC Interregional Long Range Adequacy Overview*. The forecast average annual peak demand growth rate is 0.1% over the next five years, and this is lower than the 1.7% growth rate forecasted in 2006. Contributing significantly to this lower load forecast are significant industrial load decreases, slower customer load growth, and energy efficiency programs.

Separate demand and energy forecasts are prepared by each of the Maritimes Area jurisdictions, as there is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes Area. For Area studies, the individual forecasts are combined using the load shape of each jurisdiction.

The load forecast for New Brunswick is based on 30-year average temperatures (1971-2000) with the annual peak hour demand determined for a design temperature of -24°C over a sustained 8-hour period. It is prepared based on a cause and effect analysis of past loads, combined with data gathered through customer surveys, and an assessment of economic, demographic, technological and other factors that affect the utilization of electrical energy.

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The load forecast for Nova Scotia is based on the 10-year average temperatures measured in the Halifax area of the province, along with analyses of sales history, economic indicators, customer surveys, technological and demographic changes in the market, and the price and availability of other energy sources.

The load forecast for PEI uses an econometric model that factors in the historical relationship between electricity usage and economic factors such as gross domestic product, electricity prices, and personal disposable income.

The NMISA load forecast for northern Maine is based on historic average peak hour demand patterns inflated at a nominal rate and normalized to 30-year average historical weather patterns. Economic and other factors may also affect the forecast.

All jurisdictions in the Maritimes Area are winter peaking due to high electric heating load. Long term resource evaluations are based on a 20% reserve margin above the forecast firm winter peak load.

Current and projected energy efficiencies are incorporated directly into the load forecast. Nova Scotia Power Inc.'s (NSPI) energy efficiency programs are spread across various customer sectors - residential, commercial and industrial. They include programs for lighting, heating/cooling, refrigeration, water heating, motors and compressors. NSPI has developed a 2011 DSM Plan which has been approved by the Regulator. DSM is a relatively new initiative for the Utility and the program includes reporting mechanisms (independent evaluation by NSPI's Evaluation Consultant, and subsequent verification by the Regulator's Verification Consultant) to assess the demand and energy benefits particularly during the ramp-up period in the next few years. Going forward the new DSM Administrator, Efficiency Nova Scotia Corporation, will manage this function. This process is expected to be in operation by February 2011.

One of the demand response programs currently utilized in the Maritimes Area is interruptible demand. For 2010/11, the interruptible demand forecast for the peak month is 380 MW, which represents 7% of the peak demand forecast. In Nova Scotia, NSPI's demand response programs are primarily rate design-driven and along with interruptible pricing for large industrials, include time of day pricing for residential customers with electric thermal storage home heating equipment, and the Extra Large Industrial Interruptible Two Part Real Time Pricing rate for NSPI's two largest customers. Interruptible demand is reported separately; the other programs are incorporated directly into the load forecast. In Nova Scotia, future demand response programs are being contemplated but no specific measures have been identified.

In its NPCC Comprehensive Reviews of Resource Adequacy, the Maritimes Area uses a load forecast uncertainty representing the historical standard deviation of load forecast errors based upon the four year lead time required to add new resources.

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Capacity Transactions on Peak

The Maritimes Area does not forecast any capacity imports from other regions during the next ten years.

For the period 2010 through October 2011, there is a firm capacity sale of 200 MW from the Maritimes to Hydro-Québec. This sale is tied to two 100 MW oil combustion turbines at Millbank, NB and is backed up by a transmission reservation.

Transmission

The only new bulk transmission forecast is a 2016 conceptual project to build a parallel circuit to the existing 200 miles of 345 kV transmission between Coleson Cove, New Brunswick and Onslow, Nova Scotia.

There are no transmission constraints in the Maritimes Area affecting reliability.

No other significant substation equipment additions planned for the Maritimes Area within the next five years.

Generation

Figure 8 depicts the Maritimes area resource capacity mix by fuel type for the year 2010 on an capacity basis, representing 18.5% hydro, 9.2% nuclear, 23.8% coal, 31.1% oil, 7.1% gas, 4.5% oil/gas, 1.9% biomass, and 3.9% wind (derated) generation.

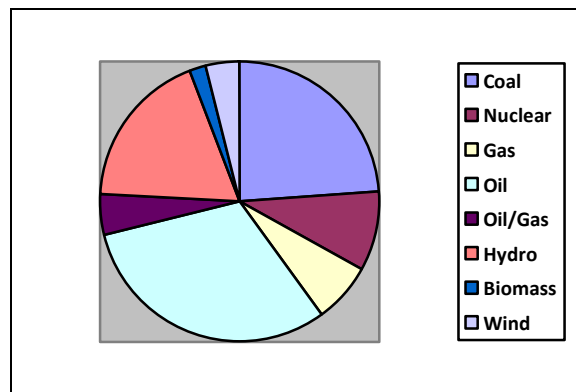


Figure 8 – Maritime Area Capacity Mix by Fuel Type for 2010

On-peak wind project capacity for the Maritimes (approx. 40% of nominal capacity) is equal to the three-year rolling average of actual winter capacity factor (combined with the forecasted capacity factor if in service less than three years). This deration of wind capacity for the Maritimes is consistent with the results from the September 2005 NBSO report “Maritimes Wind Integration Study.”¹⁷ This report showed that the effective capacity from wind projects, and their contribution to Loss of Load Expectation (LOLE) was equal to or better than their seasonal capacity factors. The coincidence of high winter wind generation with the peak winter loads results in the Maritimes Area receiving

¹⁷ See:

http://www.nbso.ca/Public/_private/2005%20Maritime%20Wind%20Integration%20Study%20_Final_.pdf

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a higher capacity benefit from wind projects versus that of a summer peaking area. The effective wind capacity calculation also assumes a good geographic dispersion of the wind projects in order to mitigate the occurrences of having zero wind production.

With relatively flat and even slightly negative load growth, there are no current plans for additional MW of conventional generation within the Maritimes Area during the study period. The majority of planned capacity for this period consists of new wind capacity driven by regional renewable energy targets as well as a small amount of hydro generation in Nova Scotia.

New England

ISO New England Inc. (ISO-NE) forecasts no major reliability issues with respect to fuel supply, availability of both supply or demand-side resources, or the capability of the regional transmission system to serve the projected seasonal peak demands and energy requirements of the six-state New England region.

New England, a sub region of NPCC, is a summer peaking system. The 2009 summer actual peak demand was 25,100 MW which was 2,775 lower than the *NERC 2009 Long-Term Reliability Assessment* projection for the 2009 summer peak demand of 27,875 MW. A non-typical, rainy summer season in 2009 in New England produced very few peak demand days. The Total Internal Demand projected for the 2010 summer is 27,190 MW and for the 2019 summer is 30,730 MW. This year's forecast of the ten-year (2010-2019) 50/50 summer peak demand compound annual growth rate (CAGR) is 1.4 percent. For the entire assessment period, the Net Internal Demand equals the Total Internal Demand.

For the 2010 summer, the Existing Capacity totals 32,567 MW which is 1,422 MW lower than the *NERC 2009 Long-Term Reliability Assessment* value of 33,989 MW. For the 2010 summer, the Existing, Certain capacity totals 32,251 MW which is 1,166 MW lower than last year's value of 33,417 MW. Approximately 3,010 MW of Future Capacity Additions are projected to be commercialized by the 2019 summer. Approximately one third (1,000 MW) of these overall capacity additions are new Demand Response Expected On-Peak and no major retirements of capacity is forecast through the end of the assessment period.

New England does not have a target reserve margin requirement. The NERC reference reserve margin for a thermal power system like New England is 15 percent. New England's 2010 summer reserve margin is 19.7 percent, which is 4.7 percent above the NERC reference reserve margin.

Transmission projects are developed to serve the entire New England region reliably and are fully coordinated with other regions. The following are significant additions projected to be placed in-service through the end of the assessment period:

1. The Maine Power Reliability Program (MPRP) establishes an additional 345 kV path through the state of Maine, beginning at Orrington. The new path continues

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south to Surowiec and ultimately ends at a new switching station at Three Rivers, near the Maine-New Hampshire border.

2. The New England East–West Solution (NEEWS) series of projects had been identified to improve system reliability. These projects include the addition of significant 345 kV transmission in Massachusetts, Rhode Island, and Connecticut. The continued need for all of the NEEWS projects is currently under review.
3. The Vermont Southern Loop Project installs a 51-mile 345 kV line between Vermont Yankee and Coolidge along with two 345/115 kV autotransformers at Newfane and Vernon.

Although recent improvements have been made, longer term studies of the southern New England system indicate possible future thermal, low-voltage, high-voltage, and short-circuit concerns under certain system conditions. The most significant concerns involve maintaining the reliability of supply to serve demand and developing the transmission infrastructure to integrate generation throughout this area. Similar to northern New England, many system upgrades, which are either in progress or have been recently completed, will address these concerns.

The New England 2010 Regional System Plan ¹⁸ identifies three issues that could possibly impact future system reliability. These are:

- 1) A potentially large influx in the amount of new, intermittent capacity resources namely wind generation.¹⁹ Currently, New England has very little existing wind capacity (less than 200 MW of nameplate), but concerns exist over the resultant impacts from compliance with state Renewable Portfolio Standards (RPS), and the corresponding build-out of these new supply-side resources in the near-term.
- 2) The unknowns associated with two upcoming nuclear plant (1,281 MW in total) relicensing processes that are scheduled to occur within a two year time frame.²⁰
- 3) The potential need to modify, refurbish or retire, both river and coastal, steam-generation power plants that currently use “*once-through*” cooling with “*closed-loop*” cooling systems.

The uncertainty and variability of new wind resources may pose operational challenges. The New England Wind Integration Study (NEWIS) is investigating the operational impacts of different penetration levels of wind resources. The study will also recommend changes in operating practices and procedures to accommodate a large-scale penetration of wind resources.

¹⁸ See: <http://www.iso-ne.com/trans/rsp/index.html>

¹⁹ Currently, ISO-NE has approximately 2,650 MW (total) of new onshore and offshore wind projects requesting study within its Generation Interconnection Queue.

²⁰ Within New England, approximately 1,281 MW of nuclear capacity has their current NRC Operating License expiring within a two-year timeframe and approximately 3,347 MW of nuclear capacity has their current NRC Operating License expiring within a fifteen-year timeframe.

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Demand

A continuation of the economic downturn has lowered this year's forecast for summer peak demand and energy use when compared to last year's forecast. This year's forecast of the ten-year (2010-2019) 50/50 summer peak demand compound annual growth rate (CAGR) is 1.4 percent which has slightly increased from last year's ten-year (2009-2018) CAGR forecast of 1.2 percent for summer peak demand. However, this 2010 CAGR is somewhat misleading, as the demand level in the first year (2010) of the forecast is significantly lower due to the current economic downturn. This biases the overall compounded annual average growth rate in an upward fashion. The key factor leading to the lower summer peak demand forecast is that the economic downturn has significantly impacted the actual summer peak and energy demand within the New England region, which results in approximately a one to two year delay in achieving the same demand levels that had been previously predicted.

This year's forecast of the ten-year winter peak demand CAGR is 0.5 percent which has increased slightly from last year's ten-year CAGR forecast of 0.4 percent for winter peak demand. The forecast for winter peak demand is slightly higher than last year's forecast by the end of the forecast period based on updated historical demands and economic and price of electricity forecasts. The winter peak is less weather sensitive than the summer peak, closely linked to residential demand (the convergence of darkness and dinner), and less impacted by the recession.²¹

This year's forecast of the ten-year net annual energy CAGR is unchanged from last year's forecast of 0.9 percent. However, the overall forecast for net annual energy use is lower than last year's forecast due to the economic downturn.

ISO-NE's reference case demand forecast is the 50/50 forecast (50 percent chance of being exceeded), corresponding to a New England three-day weighted temperature-humidity index (WTHI) of 79.9, which is equivalent to a dry-bulb temperature of 90.2 degrees Fahrenheit and a dew point temperature of 70 degrees Fahrenheit. The reference case demand forecast is based on the most recent reference economic forecast, which reflects the economic conditions that "most likely" would occur.

ISO-NE develops an independent demand forecast for the Balancing Authority area as a whole and the six states within it. ISO-NE uses historical hourly demand data from individual member utilities, which is based upon Revenue Quality Metering (RQM), to develop historical demand data from which the regional peak demand and energy forecasts are based upon.²² From this historical data, ISO-NE develops a forecast of both state and monthly peak and energy demands. The peak demand forecast for the region and the states can be considered a coincident peak demand forecast.

²¹ The winter peak is also somewhat-dependent on electric heating demand, while the summer peak is directly-dependant on air conditioning demand. A much larger number of homes in New England have air conditioning versus electric heat.

²² RQM is submitted to the ISO-NE Settlements Department.

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Demand side resources are considered capacity resources in New England's FCM. Under FCM, there are passive demand resources (non-dispatchable/energy efficiency) and active demand resources (dispatchable/interruptible). The active demand resources can be triggered by ISO-NE in real-time under ISO-NE Operating Procedure No. 4 – *Action during a Capacity Deficiency* (OP4) to help mitigate a capacity deficiency, or dispatched day-ahead to mitigate a projected capacity deficiency.

As part of the qualification process to participate in a Forward Capacity Auction (FCA), any new demand resource must submit detailed information about the project, including location, project description, estimated demand reduction values, and projected commercial operation dates along with a project completion schedule. In addition, new demand resources must submit a Measurement and Verification (M&V) Plan, which must be approved by ISO-NE. The project sponsor is required to submit certification that the project complies with their ISO-approved M&V Plan. ISO-NE has the right to audit the records, data, and actual installations to ensure that the energy efficiency projects are providing the load reduction as contracted. ISO-NE tracks the project against their submitted schedules, thereby taking a proactive role in monitoring the progress of these resources to ensure they are ready to reduce demand by the start of the applicable FCM commitment period.

The demand resources that have cleared into the FCM through the first three auctions are: 1,898 MW of demand resources (572 of passive and 1,326 of active) will be available by August 2010, 2,388 MW by August 2011 (784 passive, 1,554 active), 2,898 MW by August 2012 (1,073 passive, 1,825 active), which are then held constant through the 2019 summer.

In addition to reliability-based DR programs, ISO-NE administers a price-response DR program where demand voluntarily interrupts based on the price of energy. As of May 2010, there were approximately 65 MW enrolled in the price response program. These programs are not counted as capacity resources since their interruption is voluntary.

Although several types of demand-side management resources can be used to satisfy state-mandated, renewable portfolio standards (RPS), ISO-NE does not require that information be submitted in order to participate in applicable demand-side markets.

ISO-NE addresses peak demand uncertainty in two ways:

1. **Weather** – Annual peak demand distribution forecasts are made based on 40 years of historical weather which includes the reference forecast (50 percent chance of being exceeded), and extreme forecast (10 percent chance of being exceeded),²³
2. **Economics** – Alternative forecasts are made using high and low economic scenarios.

²³ On an annual basis, the 50/50 reference peak has a 50 percent chance of being exceeded, and the 90/10 extreme peak has a 10 percent chance of being exceeded.

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ISO-NE also reviews projected summer and winter conditions of the assessment period using the annual extreme, 90/10 peak demand based on the reference economic forecast.

Generation

Figure 9 shows the aggregate capacity available at peak for the year 2010, representing 41.2% gas, 21.5% oil, 14.5% nuclear, 8.6% coal, 5.2% hydro (pumped storage), and 3.6% renewable generation.

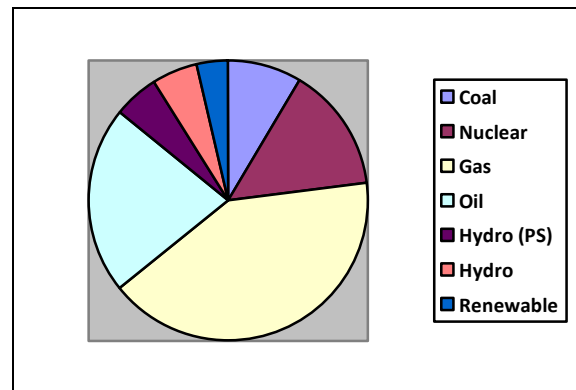


Figure 9 – New England Area Capacity Mix by Fuel Type for 2010

As of June 1, 2010, ISO-NE implemented its Forward Capacity Market (FCM) from which regional capacity is procured in advance to satisfy regional reliability requirements. June 1, 2010 marks the date by which regional capacity that now has Capacity Supply Obligations (CSO) under the FCM is reported within the *NERC 2010 Long-Term Reliability Assessment* as Existing, Certain capacity and all remaining non-CSO capacity is reported as Existing, Other capacity.²⁴ Since ISO-NE has already procured the CSO for the 2012/2013 Capability Period, regional capacity, through the time period 2010 through 2013, is identified within one of these two categories, depending on their CSOs. Beginning with the 2014 summer, those prior CSOs are then held constant throughout the assessment period.

For August 2010, ISO-NE reports 32,567 MW of Existing Capacity, which includes 32,251 MW of Existing, Certain capacity, 317 MW of Existing, Other capacity, and 0 MW of Existing, Inoperable capacity.

For August 2010, ISO-NE reports 111 MW of nameplate wind capacity, which includes 26 MW of Existing, Certain wind capacity expected on-peak along with an 85 MW on-peak derate of Existing, Other wind capacity.

²⁴ Derates for all resources other than wind and hydro are based on the difference between their CSO and their Qualified Capacity, or the maximum amount with which they could participate in the Forward Capacity Auctions. Qualified Capacity is similar to the generators' Seasonal Claimed Capability. For wind and hydro, the derates are the difference between the CSO (within Existing, Certain) and nameplate capacity. These derates, along with ISO New England capacity that did not participate in the Forward Capacity Market, are included in the Existing, Other category.

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ISO-NE's Reserve Margin calculations include Future Capacity Additions that are projected to begin commercial operation by the end of each year. If the new project's in-service date is prior to August 1st of that year that capacity is included within the Future, Planned capacity for the summer of the year, otherwise it is included within the Future, Planned capacity for the winter of the following year. This information is based on either the date specified in a signed Interconnection Agreement (IA) or discussions with ISO-NE indicating that the project is nearing completion and is preparing to become an ISO generator asset. Also included in the Future Capacity Additions are new projects that have contractual obligations within the ISO-NE FCM for the years 2010-2013. Conceptual capacity is subsequently identified as all the capacity remaining within the ISO-NE Generation Interconnection Queue that has not been designated as Future, Planned capacity, through the selection process identified above.

ISO-NE has a total of 8,809 MW of projects categorized as either Future, Planned capacity or Conceptual capacity within its Generator Interconnection Queue, with in-service dates ranging from 2011 to 2016.²⁵ Although some projects that reside within the ISO-NE Generator Interconnection Queue have declared in-service dates of 2010 or 2011, some of those projects have not demonstrated viable pre-commercial activities and have therefore been categorized as Conceptual capacity. The Queue projects were included in the Future, Planned category if they had an FCM obligation or were projected to be in service by 2010 summer. All other Queue projects were treated as Conceptual.

A 20 percent Confidence Factor has been applied to the amount of projected Conceptual capacity resources. This 20 percent Confidence Factor represents the amount of Conceptual capacity that may become commercialized within the region, starting in the year 2011. This 20 percent Confidence Factor is held constant going forward in time.

The ongoing transmission planning efforts associated with the New England Regional System Plan (RSP) support compliance with the NERC Transmission Planning requirements and assures that the transmission system is planned to sufficiently integrate generation with demand.

Capacity Transactions On-Peak

Firm summer capacity imports amount to approximately 388 MW in 2010, 2,150 MW in 2011, 1,920 MW for 2012, and 334 MW in 2013 and 2014. The capacity imports for 2010 through 2013 reflect the results of the appropriate Forward Capacity Auctions (FCAs). The 2013 FCA results were assumed to remain in place in 2014. Since the FCA imports are based on one-year contracts, beginning in 2015 the imports reflect only known, long-term Installed Capacity (ICAP) contracts. Firm summer capacity imports are 284 MW in 2015, 112 MW in 2016, and then level off at 6 MW for the 2017, 2018, and 2019 summers. If the imports that cleared in the 2013 summer do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or demand-side resources.

²⁵ As of the April 1, 2010 ISO-NE Generation Interconnection Queue publication.

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The entire amount of ICAP imports are backed by firm contracts for generation and the imports under the FCM are import capacity resources with an obligation for the 2010-2013 commitment periods. Although there is no requirement for those imports to have firm transmission service, it is specified that deliverability of firm imports must meet New England delivery requirements and should be consistent with the deliverability requirements of internal generators. The market participant is free to choose the type of transmission service it wishes to use for the delivery of firm energy, but the market participant bears the associated risk of market penalties if it chooses to use non-firm transmission services. Import assumptions are not based on partial path reservations.

For the 2010 summer, ISO-NE reports a firm capacity sale to New York (Long Island) of 100 MW, anticipated to be delivered via the Cross-Sound Cable (CSC). This firm capacity sale is held constant through the assessment period.

Transmission

ISO-NE's 2010 Regional System Plan ²⁶ identifies the region's needed transmission improvements for the ten-year period. The current plan builds on the results of previous RSPs and other regional activities. The transmission projects have been developed to coordinate major power transfers across the system, improve service to demand, and meet transfer requirements with neighboring balancing authority areas. Each RSP describes the transmission upgrades that are critical for maintaining the bulk transmission system. The New England region currently has over 200 transmission projects and components in various stages of planning, construction, and implementation.

Presently there are no significant concerns over meeting target in-service dates. However, if the implementation of much needed projects is delayed, interim measures will be taken, such as issuing gap *Requests-for-Proposals* (RFPs) to install temporary generation in a specific area of the system.

Currently, there are no transmission constraints which prevent the system from being operated in a manner which ensures the reliability of the New England-wide system.

New York

The compound annual demand forecast growth rate for the New York Control Area (NYCA) reported this year is 0.64 percent versus the 0.65 percent reported last year. The primary drivers are a recovery from the recession in the short term and additional energy efficiency impacts. Total Internal Demand in the 10th year is projected to be 34,986 MW while the Net Internal Demand is projected to be 34,792 MW.

Capacity classified as "Existing Certain" resources totals 39,260 MW. This includes 317 MW of new generation added since the prior reporting year and 982 MW of generation retirements. New capacity additions planned to be in-service over the assessment timeframe total 1,941 MW, of which 1,722 MW are combined cycle units. The current Installed Reserve Margin requirement, as determined by the New York State Reliability

²⁶ See: <http://www.iso-ne.com/trans/rsp/index.html>

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Council (NYSRC), for the New York Control Area for the Capability Year 2010 – 2011 is 18.0 percent. The projected reserve margins reported on the *NERC 2010 Long Term Reliability Assessment* exceed the current required reserve margin throughout the assessment period.

New York State is considering a number of environmental initiatives under the federal Clean Air Act, Clean Water Act and state law that could affect the availability of generation resources in New York or lead to retirements. The NYISO monitors those programs and analyzes their potential reliability impact through its Reliability Needs Assessment (RNA) and Comprehensive Reliability Plan (CRP). At this time there are no environmental or regulatory restrictions that adversely impact reliability during the 2010-2019 timeframe within the NYCA.

The NYISO's Reliability Planning Process is a long-range assessment of both resource adequacy and transmission reliability of the New York bulk power system conducted over five-year and ten-year planning horizons to ensure that the New York State bulk power system meets or exceeds the planned loss of load expectation (LOLE) that, at any given point in time, is less than or equal to an involuntary load disconnection that is not more frequent than once in every 10 years, or 0.1 days per year. Preliminary results of 2010 draft RNA demonstrate that the LOLE for the New York Control Area does not exceed 0.10 days per year in any year through 2020 under Base Case conditions.

Demand

Last year's compound annual growth rate reported in the *NERC 2009 Long-Term Reliability Assessment* for the NYCA was 0.65 percent from 2009 to 2018. This year's compound annual growth rate is 0.64 percent from 2010 to 2019. The primary differences between last year's forecast and this year's are a recovery from the recession in the short term and the impact of additional statewide energy efficiency programs.

The weather assumptions and economic assumptions for the 50-50 forecast confidence interval case are normal weather and an eventual recovery from the recession.

The NYISO develops independent forecasts for each of 11 zones in its control area; the total is based on the sum of the zones. Both coincident and non-coincident peak demands are forecast. The peak producing conditions are based upon the 50th percentile for most regions of the state. However, in certain regions in and around New York City, the peak-producing conditions are more conservative, based upon the 67th percentile. This provides additional reliability for this part of the control area.

Both the current and the previous forecasts have incorporated reductions in peak demand expected to be achieved by statewide energy efficiency programs. These programs are funded by the State of New York through system benefits charges applied to all retail rates. The programs are implemented by the New York State Energy and Research Development Agency (NYSERDA), the major investor-owned utilities in the state, and by state power authorities, such as the Long Island Power Authority and the New York Power Authority.

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The New York State Public Service Commission has ordered the creation of an Evaluation Advisory Group to develop statewide standards for the measurement and verification (M & V) of the impacts of the programs, after they are installed. This group is currently developing M & V protocols that will be followed by program implementers. Monthly program tracking results are provided to the Department of Public Service staff to determine whether program activities are meeting the goals set by the state.

The NYISO has two reliability-based Demand Response programs: the Emergency Demand Response Program (EDRP) and Installed Capacity (ICAP) Special Case Resources (SCR) program. Both programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid.

The Emergency Demand Response Program is designed to reduce power usage through the voluntary reduction in demand from businesses and large power users. Companies, mostly industrial and commercial, register with NYISO to take part in the EDRP. The companies are paid for reducing energy consumption when asked to do so. No activations, other than tests, which are required each Capability Period to demonstrate that the resource can achieve the demand reduction registered in the program, have occurred since August 3, 2006.

The Special Case Resources program also seeks to reduce power usage through the reduction of demand from businesses and large power users. Companies, mostly industrial and commercial, register to participate as SCRs. The companies must, as part of their agreement, curtail power usage, usually by shutting down when asked by the NYISO. In exchange, they are paid for their ICAP in advance for agreeing to cut power usage upon request and for the reduced power usage when actually called. No activations, other than tests, which are required each Capability Period to demonstrate that the resource can achieve the demand reduction registered in the program, have occurred since August 3, 2006.

Effective July 1, 2007, NYISO implemented the Targeted Demand Response Program (TDRP) to respond to requests for assistance from a Transmission Owner (TO) by activating EDRP and ICAP/SCR resources on a voluntary basis in one or more subzones. TDRP currently applies to Zone J, New York City, where nine subzones have been defined. No TDRP activations have occurred since August 3, 2007.

The NYISO has two economic programs; (1) the Day-Ahead Demand Response Program (DADRP), which allows energy users to bid their load reductions, into the NYISO's Day-Ahead energy market as generators do, and (2) the Demand-Side Ancillary Services Program (DSASP) that allows energy users to provide ancillary services such as Operating Reserve and Regulation. DADRP bidding and scheduling activity remains frequent, but is limited to only a handful of resources. There are no resources currently enrolled in DSASP.

The NYISO has used substantially the same methods for forecasting loads in 2009 and 2010. An econometric energy forecast is produced for each zone, based on economic and

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demographic forecasts provided by its economic consultant. A set of zonal load factors are applied to derive the zonal peak coincident demands. The system coincident peak demand is the sum over the zones. A set of zonal diversity factors are applied to derive the zonal non-coincident peak demands from the coincident peak demands. Finally, adjustments are made to each zone for the energy and demand impacts expected from energy efficiency programs.

The NYISO constructs a statistical estimate of the 90th percentile and 10th percentile bounds on the base case forecast due to the combined effects of variations in weather and the economy, by modeling the variation in the historic energy and peak data for the preceding 35 years.

Generation

Figure 10 represent the existing resources in the New York Control Area with a breakdown by fuel type and as published in the NYISO's 2010 Load and Data Report (Gold Book);²⁷ representing 18% gas, 9% oil, 36% gas & oil, 7% coal, 14% nuclear, 4% hydro (pumped storage), 11% hydro, <1% wind and 1% other (methane, refuse, solar, and wood) generation.

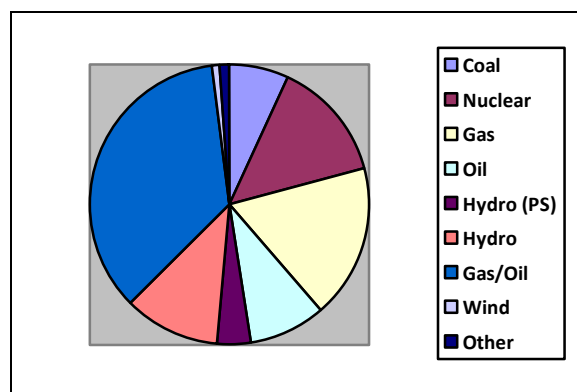


Figure 10 – New York Area Capacity Mix by Fuel Type for 2010

The NYISO maintains a list by Class Year of proposed²⁸ generation and transmission projects in the NYISO interconnection process. The interconnection process is a formal process defined by NYISO's tariffs by which the NYISO evaluates transmission and generation projects, submitted by Market Participants, developers, and other qualified organizations to determine their impact on system reliability.

Capacity Transactions on Peak

External capacity (ICAP) purchases and sales are administered by the NYISO. An annual study is performed to determine the maximum level of capacity imports from

²⁷ Load and Data Report:

http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

²⁸ The Class Year is the final step in the New York interconnection process where the system upgrade facilities, or "but for" facilities, are determined for proposed new interconnections and cost responsibility for those facilities is assigned.

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neighboring control areas allowed without violating the New York Control Area's (NYCA) Loss of Load Expectation (LOLE) criteria. For the Capability Year 2010, the amount is 2,645 MW. Except for Grandfathered Contracts, these Import Rights are allocated on a first-come, first-served basis with a monthly obligation. While capacity purchases are not required to have accompanying firm transmission, adequate external transmission rights must be available to assure delivery to the NYCA border when scheduled. All external ICAP suppliers must also meet the eligibility requirements as specified in the Installed Capacity Manual.

Unforced Capacity Deliverability Rights (UDRs) are rights associated with new incremental controllable transmission projects that provide a transmission interface to a NYCA locality where a minimum amount of Installed Capacity must be maintained. Three such projects are currently in service with a total transmission capability of 1,290 MW. Capacity transactions associated with a UDR are considered confidential market data.

NYCA resources that have sold capacity to an external control area are not qualified to participate in the NYISO ICAP Market, and are not counted as resources eligible to meet the NYCA's LOLE reliability criterion for the period the capacity is sold.

Transmission

Con Edison's M29 project consists of a 345 kV cable from Sprainbrook to Sherman Creek across the Dunwoodie South Interface. This project is planned to be in service in 2011. Con Edison is also increasing the rating of two 345 kV cable circuits between Farragut and East 13th St. by installing refrigerated cooling.

The interface into New York City and Long Island from Westchester, New York, namely Dunwoodie South, could become significantly limiting and impact reliability if there are unanticipated delays in new projects, unexpected retirements, or unanticipated load growth. These scenarios are monitored by the NYISO, and if any happen, the NYISO will determine whether there will be a significant reliability impact. If the impact is imminent, the NYISO will request that the New York Transmission Owners (TOs) implement a Gap Solution under the Comprehensive System Planning Process (CSPP). If there is a significant reliability impact to the system that will manifest itself during the next CSPP cycle, the NYISO will address the issue in the next Reliability Needs Assessment.

Ontario

The average annual demand growth rate for Ontario is revised upward by 0.5% compared to what was reported in the *NERC 2009 Long-Term Reliability Assessment*. The Reserve Margin is projected to be 27.7% in 2011, dropping to 20.0% in 2015 and then increasing to 27.8% in 2019, all above the target levels.

Demand

This year's demand forecast net of conservation has an average annual growth rate of -0.4% over the period 2010-2019 compared to last year's average growth of -0.9% for the

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2009-2018 timeframe. The average growth rate is higher this year as the recessionary year of 2009 is no longer part of the calculation. However, the negative demand growth continues as a result of increased conservation efforts, growth in embedded (distributed) generation and restructuring in the energy-intense industrial sector.

Ontario's forecast of demand is based on Monthly Normal (50/50) weather. The economic forecast is based on the most recent available information and predicts a slow economic recovery over the near term (2010-2011) before returning to its long-term growth trend based on demographic factors. Electricity demand is expected to lag the general economic recovery as structural changes take place in Ontario's economy. Conservation savings and the growth in embedded generation are expected to more than offset the growth in demand from increased population and economic expansion. Reliability analysis is based on this demand forecast.

The forecast of Ontario peak demand is the system peak demand and therefore represents the coincident peak demand of Ontario's ten main sub-areas. All analysis is done on the system peak demand.

The Ontario Power Authority ²⁹ (OPA) is responsible for coordinating conservation programs throughout the province. To date, there are a number of initiatives that will reduce electricity demand. These programs range from lighting and appliance replacement to building retrofits targeted towards the residential, commercial, and industrial sectors. Measurement and verification is the responsibility of the OPA as part of their mandate. Incremental conservation savings are expected to reach 3,300 MW over the forecast horizon.

Demand response within Ontario includes a number of different programs. Some wholesale customers within the province bid their load into the market and are responsive to price through IESO dispatch instructions. Other customers have been contracted by the OPA to provide demand response under tight supply conditions. The combined amount of these demand measures has been steadily increasing and currently amounts to slightly more than 1,250 MW in total, of which 56% is included for seasonal capacity planning purposes, with half of the included amount categorized as interruptible. This amount is expected to grow over time as more load is contracted to respond to tight supply conditions. By the end of the forecast, the interruptible component is expected to grow by more than 525 MW. The impacts of these initiatives are reflected in the reliability analysis.

The IESO quantifies the uncertainty in peak demand due to weather variation through the use of Load Forecast Uncertainty (LFU), which represents the impact on demand of one standard deviation in the underlying weather parameters. This is used with Monthly Normal weather demand to conduct probabilistic analysis. As well, the IESO uses an Extreme Weather scenario to study the impacts of adverse weather conditions on reliability of the IESO controlled grid. The IESO also reviews the reliability of the system prior to the impact of planned conservation savings. Although the IESO did not

²⁹ See: <http://www.powerauthority.on.ca/>

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explicitly look at alternate economic scenarios, the pre-conservation results are considered as a surrogate for the potential to return to previous growth rates.

Generation

As shown in Figure 11, Ontario's existing installed generation capacity represents nuclear (32%), coal (18%), oil/gas (25%), hydroelectric (22%), wind (3%), wood (biomass) and waste-fuelled (landfill gas) (0.3%) generation.

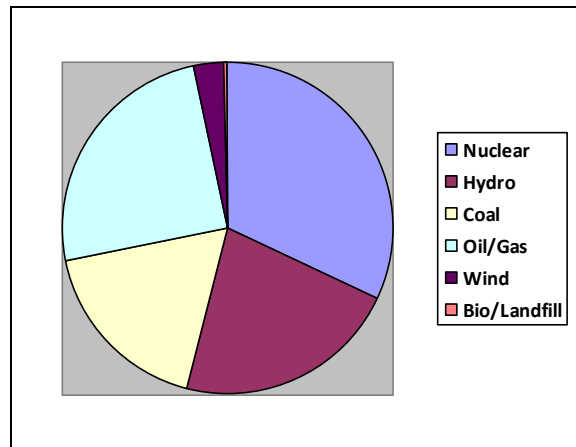


Figure 11 – Ontario Area Capacity Mix by Fuel Type for 2010

For summer 2010, the total existing Certain capacity resources connected to the IESO controlled grid is 32,115 MW. The existing Other capacity amounts to 4,849 MW which includes on-peak resource deratings, planned outages and transmission-limited resources. The Inoperable capacity is 28 MW. A net capacity increase of about 1,000 MW is recorded since last summer. Most of the increase was from gas-fired generation with smaller additions from hydroelectric and biomass generation

The installed capacity of the existing resources will decrease by about 2,000 MW in October 2010 with the de-registration of four coal-fired units at Lambton and Nanticoke. The remaining coal generation capacity, amounting to 4,400 MW, will cease burning coal by the end of 2014. Besides coal shutdown, additional decreases are attributed to the anticipated retirement or refurbishment of several nuclear units. Therefore, the existing capacity may decrease significantly at the end 2014 and onward to 2019. To manage the possible reduction in existing resources, 12,500 MW of future capacity resources, as well as 9,000 MW of conceptual capacity resources, are scheduled to be in service by 2019, depending on unit refurbishment or retirement plans. With the estimated contribution of conservation programs administered by the OPA, and forecast increases in distributed generation, the combination of Existing, Future and Conceptual resources are expected to satisfy target reserve margins, ranging from 17.0% to 18.9%, throughout the forecast period.

As of spring 2010, the existing installed capacity of wind generation resources on the IESO controlled grid was 1,084 MW. Thirteen percent of the installed wind capacity is

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assumed to be available at the time of summer peak, and thirty-two percent is assumed to be available at the time of winter peak. Monthly Wind Capacity Contribution (WCC) values are used to forecast the contribution from wind generators. WCC values (percent of installed capacity) are determined by picking the lower value between the actual historic median wind generator contribution and the simulated 10-year wind historic median contribution at the top five contiguous demand hours of the day for each winter and summer season, or shoulder period month. The process of picking the lower value between actual historic wind data, and the simulated 10-year historic wind data will continue until 10-years of actual wind data is accumulated; at which point the simulated wind data will be phased out of the WCC calculation. The WCC values are updated annually.

Ontario's solar capacity value is forecast to be forty percent of installed for the summer peak and five percent of installed for the winter peak. These values are based on historical modeled photovoltaic output data at the time of summer and winter peaks.

No derate is forecast for biomass generation. It is assumed that the full installed capacity will be available at the time of the peak.

Assumptions related to amounts and types of Conceptual capacity resources are from the Ontario Power Authority. Established in 2005, the OPA is the electricity system planner for the province of Ontario.

The OPA's statutory objects require it to, among other things, ensure adequate, reliable and secure electricity supply and resources in Ontario and to conduct independent planning for electricity conservation, demand management, renewable and other generation, and transmission.

In September 2009 the provincial government passed the Green Energy and Green Economy Act (GEGEA) providing a comprehensive framework for developing renewable energy generation. This framework includes a feed-in tariff (FIT) program and provisions that will facilitate the implementation of the necessary transmission and distribution infrastructure to support those renewable projects.

Approximately 3,300 MW of Conceptual renewable resources are expected to come on-line by 2019. This amount includes resources that are embedded and grid-connected. This is made up by about 2,400 MW of wind, 700 MW of solar, 80 MW of hydroelectric and 25 MW of biomass.

Generation resources identified for reliability analysis include (a) those which are currently in operation, (b) those which are not currently in operation but are anticipated to enter service in the future further to an executed financial contract with the Ontario Power Authority or further to an existing or anticipated government directive and (c) those conceptual sources identified in longer-term power system planning scenarios developed by the Ontario Power Authority. An adjustment or confidence factor was not applied to Conceptual resources for purposes of this assessment. Planning scenarios are

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developed by the Ontario Power Authority on an ongoing basis as part of its regular planning activities. Sensitivities and/or revisions to projections of conceptual resources take place within that ongoing planning process.

Conceptual resources have been identified and categorized consistent with the planning assumptions of the Ontario Power Authority. These planning assumptions reflect anticipated take-up of renewable energy procurement initiatives administered by the Ontario Power Authority, sequencing of associated transmission developments, projections around nuclear refurbishments and other projections.

Capacity Transactions on Peak

No Firm, Expected or Provisional imports into Ontario or exports to other regions are considered in the *NERC 2010 Long-Term Reliability Assessment*.

The IESO has agreements in place with neighbouring jurisdictions in NPCC, RFC and MRO for emergency imports and reserve sharing, should they be required in day-to-day operations.

Transmission

Construction of a new 176 km (110 mile) 500 kV double-circuit line from the Bruce Power complex to Milton Switching Station (SS) is in progress, with completion expected in 2012. This new line is required to accommodate the output of all eight generating units at the Bruce complex together with approximately 500 MW of existing wind- generating capacity, as well as a further 1,200 MW of new renewable generating capacity that is forecasted for development within the area. With the new generating facilities, the combined generation in the Bruce area is projected to total approximately 8,100 MW.

The existing Bruce special protection system (SPS) is also to be enhanced not only to accommodate the two new 500 kV circuits between the Bruce complex and Milton SS but also to address other contingency conditions not presently covered by the SPS. The intent of the expanded coverage is to limit the extent of restrictions imposed on the output from the Bruce units during transmission element outage conditions while also assisting with the re-preparation of the system following a permanent fault when subsequent contingency conditions may become more critical. This SPS will be a permanent feature to deal with contingencies and is not intended to avoid or delay the construction of bulk transmission facilities.

Since the current version of the Bruce SPS has now been in-service for over 16 years and some of the equipment has been superseded by more advanced technology, a project has been initiated by Hydro One Networks to replace the existing facilities. The replacement SPS is scheduled to be in-service by late-2012.

To coincide with the completion of the new Bruce to Milton 500 kV line, a 350 MVAR SVC is to be installed at Nanticoke SS, connected to the 500 kV bus bar, and another 350 MVAR SVC is to be installed at Detweiler TS, connected to the 230 kV bus bar. These

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SVCs are required to provide dynamic reactive support following a critical contingency involving either of the 500 kV circuits between the Bruce complex and Milton SS.

In 2010, approximately 1,500 MVAR of 230 kV-connected shunt capacitor banks are to be installed at Nanticoke SS and Middleport TS. Although these capacitor banks are required primarily to provide reactive support following the anticipated shut-down at the end of 2014 of the generating facilities at Nanticoke GS, they are also an integral component of the measures required during the interim period prior to the completion of the new Bruce to Milton 500 kV line. With Units 1 & 2 at the Bruce complex scheduled to return to service late 2011 or early 2012, there will be periods during 2011 and 2012 when either seven or eight Bruce units will be available for service. During these periods of high loading on the existing transmission circuits, reactive power management plays a significant role in reducing generation constraints. During the interim period, prior to the new line being completed, the new shunt capacitor banks will allow as much of the reactive capability from each of the operational units at Nanticoke SS to remain available for post-contingency voltage support. Once the new line is in service, the shunt capacitor banks together with new SVCs are required to support the post-contingency transfers without the need for generation rejection.

In late 2010, installation of series capacitors is to be completed at Nobel TS, the approximate mid-point of the two 500 kV circuits between Hanmer TS (Sudbury) and Essa TS (Barrie). To complement these series capacitors, the installation of a 300/-100 MVAR SVC will be completed at Porcupine TS (Timmins) and a 200/-100 MVAR SVC is to be installed at Kirkland Lake TS. Together, these facilities will increase the transfer capability of the Flow-South Interface from 1,300 MW to approximately 2,100 MW. This increase will be sufficient to relieve the existing congestion on this interface, while also accommodating the additional output from the proposed expansion of the four existing hydroelectric stations on the Lower Mattagami River (approximately 450 MW) together with other committed renewable energy developments in northern Ontario.

Phase angle regulators (PARs) are installed on the Ontario-Michigan interconnection at Lambton TS, representing two of the four interconnections with Michigan, but are not currently operational until completion of agreements between the IESO, the MISO, Hydro One and International Transmission Company. The expected in service date is not known at this time. The operation of these PARs along with the PAR on the Ontario-Michigan interconnection near Windsor will control flows to a limited extent, and assist in the control of Lake Erie Circulation.

The capability to control flows on the Ontario-Michigan interconnection between Scott TS and Bunce Creek is unavailable. The PAR installed at Bunce Creek in Michigan has failed and is scheduled for replacement. Without all four PARs in-service, there is no capability to control Lake Erie Circulation.

In October 2009, Ontario launched a feed-in tariff (FIT) program which generated interest in more than 9,000 MW of renewable generation – predominantly wind and solar generation - during the first two months of the program. Contracts for FIT program

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projects totaling 2,000 MW were executed based on existing transmission capability. This includes transmission and distribution connected projects. There are limitations to the existing transmission system that limits the amount and location of generation that can be connected. Some are regionally related while others are related to specific connection limitations associated with equipment capability or short circuit capability. These limitations vary over different parts of the system.

A number of major transmission reinforcement projects are being considered to enable greater renewable generation development across Ontario. The need and timing of these projects are driven by the uptake and location of the generation projects that have applied under the FIT program or that have been procured through other means.

The completion of new gas-fired generating facilities in the Sarnia and Windsor area has added approximately 1,900 MW of capacity in the area and resulted in constraints on the transmission system west of London. Two coal-fired units in this area, at Lambton, are planned to be deregistered in 2010 as part of Ontario's plan to phase-out coal-fired generation. Development of significant amounts of renewable generation west of London, driven by the FIT program, will require transmission reinforcement west of London. The FIT program received a significant number of applications for renewable generation in this area. Depending on the total amount of new generating capacity expected to be incorporated, these transmission facilities, including associated auto-transformers, would be designed for operation at either 230 kV or 500 kV.

The northwest system is a sub-system connected to the rest of Ontario by the double circuit 230 kV East-West Tie. The region has significant amounts of hydroelectric generation and low water conditions can have a negative impact on the ability to serve the area load. A material portion of the coal phase-out program is occurring in this area, at Atikokan and Thunder Bay (a combined 500 MW). To maintain supply security in this area, over the wide range of possible system conditions, additional generation or increased westbound transfer capability into this region is required. This is one of the needs for this area. At other times, there can be periods of significant excess of supply over local demand. The FIT program has received significant renewable generation interest in this region. Additionally, demand in this area has reduced by 350 MW and 2.5 TWh over the past few years. However, there is limited transmission capability to transfer power eastbound out of this region, thus additional transfer capability is required. Solutions to meeting both needs are being assessed.

The transmission projects that are under various stages of construction and the planned projects will address the transmission constraints identified. The transmitters in Ontario together with the OPA proactively plan the transmission network in order to ensure timely system adjustments, upgrades, and expansions. Delays to the in-service of bulk transmission projects resulting from delays in obtaining required approvals or delays in construction may result in increased congestion or generation rejection in the interim. In the northwest, the supply security constraint may be addressed in the interim through imports, generation procurements, demand response, or post-contingency load rejection in the interim until the appropriate solutions are in service.

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In addition to the bulk transmission projects, there are plans, under various stages of development, to address the concerns identified in some of the large load centers regarding supply security and the ability to restore the supply following an interruption. In Windsor-Essex, a new transformer station and a new 230 kV line are being proposed to address inadequate supply capability and security. For the Kitchener-Waterloo-Cambridge-Guelph region the on-going needs would be addressed through a multi-staged solution that includes conservation, local generation and transmission. In the case of the Northern York Region, demand management and the addition of Holland TS in 2009 have helped to relieve some of the growing supply constraint in the region in the interim. New gas-fired generation is expected to be in service in 2012 to address inadequate supply to this area. The installation of generation capacity in the south-western portion of the Greater Toronto Area is required to maintain reliability at the local level, while providing for the required system level security as coal-fired generation is decommissioned in accordance with government policy by 2014.

Five units at Pickering Nuclear Generating Station (NGS) are anticipated to reach end of life by 2015 and all units are anticipated to reach end of life by 2016. Ontario Power Generation announced early this year its investment plan for continued safe and reliable performance of its Pickering B station for approximately 10 years. Currently, Pickering NGS connects directly to the 230 kV system at Cherrywood TS in the east GTA. The retirement of Pickering NGS would require a new 500 kV/230 kV transformer station in the Oshawa area to reliably supply loads in the region.

For area supply adequacy and security, the OPA's integrated planning approach addresses project delays. Integrated planning develops options for each need, not in isolation but in a coordinated manner. Integrated planning is guided by principles that maintain a long term view that anticipates uncertainties and maintains flexibility. Conservation, supply, and transmission plans are coordinated to deliver the options that are required. This includes regional balances of supply and demand as well.

Québec

The demand forecast growth for the *NERC 2010 Long Term Reliability Assessment* (LTRA) over the 2010-2019 period is revised downward compared to the *NERC 2009 Long Term Reliability Assessment*. The compound average growth is about 0.9 percent over the current assessment period, and this is 0.4 percent lower than in the 2009 LTRA. This downward revision of the demand forecast is explained by the introduction of a new and higher energy savings target and by a general economic slowdown affecting mostly the large industrial sector. The Total Internal Demand in the 10th year (2019/2020) of this assessment is 40,099 MW while the Net Internal Demand is 38,849 MW.

The Existing Capacity resources for the 2010/2011 period total 42,320 MW, of which 38,855 MW is categorized as Existing Certain. Wind power capacity contribution is accounted for in *NERC 2010 Long-Term Reliability Assessment*. A portion of wind power installed capacity is under contract with Hydro-Québec Production and is still de-rated by 100 percent as it was in earlier LTRA assessments. All other wind generation sites are under contract with Hydro-Québec Distribution and a capacity credit equivalent to 30 percent of nameplate capacity is retained for this portion. In 2011, the Gentilly-2 nuclear generating station (G.S.) (675 MW) is temporarily out of service for a complete refurbishment. Gentilly-2 will be back in service for Québec's 2012/2013 peak period with a 25 MW additional capacity for a total of 700 MW.³⁰

In the last Québec Balancing Area Interim Review of Resource Adequacy, which was approved by NPCC's Reliability Coordinating Committee on March 10, 2010, it was found that the Required Reserve Margin for reliability criterion compliance, expressed as a percentage of the Total Load Forecast should be 9.3 percent for the short term and around 12 percent in the long run. Over the current assessment period the reserve margin based on existing capacity and net firm transactions varies between 9.2 percent and 0.3 percent. The reserve margin based on deliverable resources varies between 9.4 percent in the first year and 10.6 percent in the last year of this assessment. This indicates that Québec Area meets its target reserve margin in the first year but needs additional resources to be above the region target reserve margin for the remaining period of this assessment. The reserve margin on prospective and potential resources varies between 15.2 percent in the first year and 15.8 percent in the last year of this assessment. This clearly shows that the Québec Area is above the target reserve margin throughout the current assessment period.

Over this assessment's time horizon, a total of 997 miles of new transmission lines are expected to be placed in-service. There is no transmission reliability concern identified for the Québec Balancing Authority area.

Demand

The *NERC 2010 Long-Term Reliability Assessment* compound annual growth rate is 0.9 percent. Compared to the 2009 LTRA annual growth rate, it is 0.3 percent lower. The load forecast used in this 2010 LTRA is the last revision issued in August 2010. The lower growth rate in the 2010 LTRA is mainly due to the general economic slowdown.

³⁰ Hydro-Québec has announced earlier in August that the refurbishing of Gentilly-2 will be delayed by one year.

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This difficult economic situation has affected all sectors of the economy and in particular, large industries. Moreover, the new demand forecast includes a new energy savings target which is higher than the previous.

Hydro-Québec Distribution (HQD) is the only Load Serving Entity (LSE) in the Québec sub-region. Thus, the load forecast is conducted for the Québec Balancing Authority Area represented as a single entity and there is no requirement for demand aggregating. Resource evaluations are based on coincident winter peak forecasts, with base case and high case scenarios.

Average weather conditions and uncertainties in demand are modeled by recreating each hour of a 36-year period (1971 through 2006) under the current load forecast conditions. Moreover, each year of historic data is shifted up to ± 3 days to gain information on conditions that occurred during a weekend. Such an exercise generates a set of 252 different demand scenarios. The base case scenario is the arithmetical average of peak hour in each of those 252 scenarios.

Load Forecast Uncertainty (LFU) includes weather and structural uncertainties. Demand variation modeling related to weather uncertainties was discussed previously. Structural uncertainty is caused by the evolution of economic and demographic parameters affecting demand (Prices, GDP, net family income, number of households, new residential developments, etc).

Global uncertainties are calculated as the independent combination of these two categories. Global uncertainty, expressed as a percentage of load is higher in this review than in the previous one. Higher structural uncertainties can be explained by the greater economic risks associated with the deployment of large industrial projects. No changes have been made to Hydro-Québec's demand forecast methodology since the *NERC 2009 Long Term Reliability Assessment*.

Energy Efficiency and demand response programs

Hydro-Québec Distribution's goal for 2010 is 4.5 TWh in recurring energy savings. The Energy Efficiency Plan (EEP) has set a new target of 17 TWh/year for 2021. The EPP focuses on energy conservation measures and includes programs tailored to residential customers, commercial and institutional markets, small and medium industrial customers, and large-power customers.

Hydro-Québec has two Demand Response Programs totalling 1,750 MW specifically design for peak shaving during winter cold periods:

- Interruptible demand programs — mainly addressed to large industrial customers — have an impact of 1,500 MW on peak demand.
- A voltage reduction scheme with 250 MW of demand reduction at peak has been set up by TransÉnergie.

In Québec, there are no Renewable Portfolio Standards (RPS) as in other Control Areas. However, some Demand Side Management targets are planned by the Québec

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Government and Hydro-Québec Distribution has to file monitoring reports to the “Régie de l’énergie du Québec” (Québec Energy Board) in relation to these targets.

The Energy Efficiency Program features can be found on Hydro-Québec’s Website.³¹

Generation

In Québec, all new expected resources are renewable such as wind power, biomass and hydroelectric power. As shown in Figure 12, Québec’s existing installed generation capacity 90.6% hydroelectric, 5.2% thermal, 1.9% nuclear, 1.8% wind, and 0.5% biomass generation.

Among existing capacities, the Gentilly-2 generation facility (currently rated 675 MW) is scheduled to be out of service for refurbishing from 2014 through 2015³². After returning in service, the total plant capacity will be upgrade to 700 MW, 25 MW over the actual. The 547 MW natural gas unit operated by TransCanada Energy (TCE) at Bécancour (under contract with HQD) is mothballed according to an agreement with HQD, approved by the Québec Energy Board. This generating facility is planned to be out of service until 2015/2016.

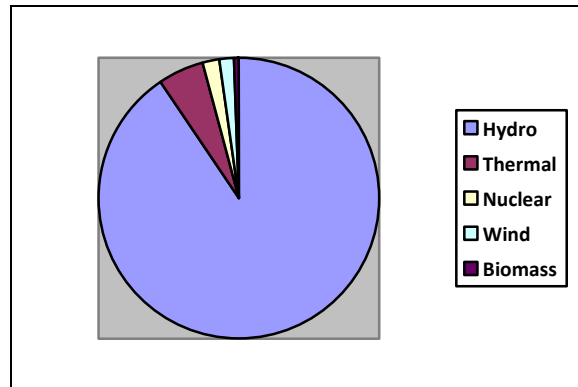


Figure 12 – Québec Area Capacity Mix by Fuel Type for 2010

Variable resources in the sub-region are mostly wind generating resources. Wind generation sites are owned and operated by Independent Power Producers (IPPs). Nameplate capacity is presently 642 MW of which 195 MW is under contract with Hydro-Québec Production (HQP) and is de-rated by 100 percent for this assessment. The rest (447 MW) is under contract with HQD and is derated by 70 percent for this assessment. Around 3,500 MW of wind projects are expected to be on-line through 2015. Capacity credit evaluation has shown that a 70 percent de-rate factor can be safely used for resource adequacy evaluations. Methods used for this assessment are discussed later in this document.

³¹ <http://www.hydroquebec.com/energywise/index.html>

³² Hydro-Québec has recently announced the refurbishing of Gentilly-2 will be 2013 through 2014.

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Moreover, approximately 180 MW of the sub-region's capacity is biomass. For the purpose of this evaluation another 125 MW of biomass was expected to be available for the 2012/2013 peak period.

There are no conceptual capacity resources in the Québec Area for this assessment period. However, several projects are under construction or consideration. These projects when completed will provide a significant increase in capacity over the next few years.

The projects are:

Eastmain-1 A / La Sarcelle Project

The project consists in building two generating stations (Eastmain-1 A - 768 MW, 2.3 TWh/year and La Sarcelle - 150 MW, 0.9 TWh/year) in the James Bay area, near the existing Eastmain-1 G.S. The project, scheduled for commissioning in 2011/2012, will provide Hydro-Québec's generating fleet with an additional capacity of 918 MW and an additional output of 3.2 TWh per year.

Romaine Complex Project

Hydro-Québec has obtained the necessary approvals to build a 1,550 MW hydroelectric complex on the Rivière Romaine, on the north shore of the St. Lawrence Gulf. The complex will consist of four hydro generating stations with an annual output of 8.0 TWh. Construction has begun in March 2009 and is scheduled to be completed in 2020. The first power station commissioning is planned for 2014.

SM-3 PA Project

The project consists in adding a 440 MW unit to the existing SM-3 generation station on the Sainte Marguerite River. The project is scheduled to be completed in 2014/2015.

Wind Generation Projects

Table 4 summarizes all wind generation projects, near 2,500 MW, that are expected to be in service over the next few years through HQD's first and second calls for tenders.

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Table 4 – Quebec Wind Generation Projects

Supplier Name	Project Location	Nameplate Capacity (MW)	In Service Date
Northland Power Inc.	St-Ulric-St-Léandre	22.5	December 1, 2011 ³³
Northland Power Inc.	Mont-Louis	100.5	December 1, 2011
Cartier-Énergie Éolienne INC	Les Méchins	150	December 1, 2011
Cartier-Énergie Éolienne INC	Montagne Sèche	58.5	December 1, 2011
Cartier-Énergie Éolienne INC	Gros Mornes	100.5	December 1, 2011
		111	December 1, 2012
3Ci	Des Moulins	156	December 1, 2011
Enerfin	De L'Érable	100	December 1, 2011
Invenergy	Le Plateau	138.6	December 1, 2011
St-Laurent Énergies	Saint Robert Ballarmin	80	December 1, 2011
Kruger	St-Rémi	100	December 1, 2012
St-Laurent Énergies	Lac Alfred	150	December 1, 2012
		150	December 1, 2013
St-Laurent Énergies	Massif du Sud	150	December 1, 2012
Venterre	New Richmond	66	December 1, 2012
Venterre	St-Valentin	50	December 1, 2012
Borex/SEC	Seigneurie de Beaupré #2	132.6	December 1, 2013
Borex/SEC	Seigneurie de Beaupré #3	139.3	December 1, 2013
B&B VDK	MRC La Matapédia	100	December 1, 2014
St-Laurent Énergies	Rivière du Moulin	150	December 1, 2014
		200	December 1, 2015
St-Laurent Énergies	Clermont	74	December 1, 2015

Other generation from biomass, small hydro and wind are expected to be in service in the next few years. These include the following:

- A call for tenders launched in January 2009 for 125 MW of biomass cogeneration.
- A Power Purchase Program for small hydropower projects of 50 MW or less for a total of 150 MW

³³ For the time being, the project consisting in an addition of 22.5 MW to St-Ulric wind farm is delayed.

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- A call for tenders launched in April 2009 for 500 MW of new wind-generated capacity developed by communities.

When performing resource assessments Hydro-Québec considers all facilities that are available at peak period. Capacities are adjusted for scheduled maintenance and restrictions. Detailed information in relation with expected forced outages is used as input data for reliability assessment evaluations in the control area.

Capacity Transactions on Peak

The Québec Area has secured a 200 MW firm purchase contract with New Brunswick until October 2011. This contract is backed by dedicated generation and firm transmission rights.

The Québec Area also has two firm export contracts for this assessment period:

- 145 MW with Ontario (Cornwall).
- 310 MW with New England until the end of 2011.

This last contract with New England is expected to be renewed for the upcoming years covering this assessment.

Transmission

In June 2010, a new double-circuit 315 kV transmission line from Chénier to Outaouais has been commissioned which now permits full use of the new 1,250 MW interconnection's capacity with Ontario's Independent Electricity System Operator (IESO). A fourth 1,650 MVA 735/315 kV transformer at Chénier has been commissioned in July. A third 345 MVAR capacitor bank has also been installed at Chénier.

Another sizable 315 kV project under construction is the new Anne-Hébert 315/25 kV transformer station near Québec City. A new 8.2 mile 315 kV line tapped from an existing circuit is also being built to feed this station.

On the longer term, to accommodate load growth, a number of new transformer stations are now in the planning or conceptual phases, and 120 to 315 kV transmission lines will be built to integrate these stations with rest of the existing system.

Different calls for tenders for wind generation have been issued by Hydro-Québec Distribution in the past years. A total of approximately 3,500 MW (Including wind generation already in service) is forecasted to be on line in 2015. A number of wind transmission projects with voltages ranging from 120 kV to 315 kV are either under construction or in planning stages to integrate this wind generation. These wind generation projects are distributed in many areas of the Province of Québec, but most are near the shores of the Gaspésia Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

A System Reinforcement Project submitted to and approved by the Québec Energy Board (*Régie de l'énergie du Québec*) is still ongoing. Mainly, this includes two Static Var Compensators to be installed at Chénier 735-kV substation and series compensation on a number of 735-kV lines. Moreover, the *Régie* has also approved the addition of two -200 Mvar inductive branches on the future SVCs to be installed at Chénier substation. This is

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to account for the filing of the 2 X 1,200 MW firm point to point transmission service by Hydro-Québec Production on the HQT-MASS and HQT-NE ties using the Châteauguay and Phase II interconnections. The project also includes the addition of an SVC at Bout-de-l'Île substation in 2013 along with the addition of a 735 kV section at Bout-de-l'Île and Bergeronnes series compensation nominal current-carrying capacity upgrade in 2014.

Hydro-Québec Production has now started construction of the Romaine River Complex on the Lower North Shore of the St. Lawrence River. TransÉnergie is now in the planning stage for the integration of this project to the system. Four Generating Stations will be integrated on a 735 kV infrastructure initially operated at 315 kV. The first G.S. to be commissioned, Romaine-2 (645 MW), will be integrated in 2014 at Arnaud 735/315 kV substation. The other Generating Stations will be integrated through 2020.³⁴ TransÉnergie is also planning the addition of a 735 kV section at Bout-de-l'Île substation in Montréal for the 2013-2014 peak period. This will permit the redistribution of load around Montréal and a new 735 kV source in Montréal's east area.

Moreover, a new 735 kV switching station named Aux Outardes is presently being considered near the actual Micoua substation. It is needed to alleviate capacity problems at Micoua and to reduce the impact from certain loss-of-two-line events at Micoua after 2015.

No potential reliability impacts are expected from not meeting in-service target dates for wind generation integration projects. Most projects are 100 MW or less, and a delay in any one of them, when taken individually, has practically no effect on the overall system reliability within Québec.

The same is true for in-service delays for future transformer stations. Delays may have local impacts such as delaying load transfers from other substations and may affect local load pockets, but will have no effect on the overall bulk system reliability within Quebec.

Hydro-Québec TransÉnergie does not foresee any transmission constraints during this assessment's horizon that could significantly impact reliability. TransÉnergie's transmission planning studies and generation/load integration studies are conducted according to NPCC Regional Reliability Reference Directory No. 1 "Design and Operation of the Bulk Power System", and according to NERC TPL standards. Due to TransÉnergie's particular system configuration and to the fact that the system is a separate Interconnection in North America, system planning is conducted such that no transmission constraints or congestion are forecasted to appear on the system.

The following summarizes the significant substation equipment (other than load or transformer stations) planned to be commissioned during the next years:

2010-2011

- 345 MVAR 315-kV shunt capacitor at Chénier 735/315 kV substation (Done)
- Fourth 1,650 MVA 735/315 kV transformer at Chénier substation (Done)
- Double-circuit 315 kV line from Chénier to Outaouais (Done)
- Wind Integration (Ongoing)

³⁴ Information on the project is available at: <http://www.hydroquebec.com/romaine/index.html>

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- 735 kV breaker addition at Duvernay 735/315 kV substation (Ongoing)

2011-2012

- 345 MVAR 315-kV shunt capacitor at Duvernay 735/315 kV substation
- Two -300/300 MVAR SVCs at Chénier 735/315 kV substation (Including -200 MVAR extra reactive branches for each SVC)
- Series compensation at Jacques-Cartier 735-kV (35 percent compensation on two 735-kV lines, #7024 and #7025)
- 315-kV integration of Eastmain-1A and La Sarcelle Hydro
- Wind integration

2012-2013

- Wind integration

2013-2014

- Wind integration
- New 735-kV section at Bout-de-l'Île substation and integration into Line 7009
- New -100/300 MVAR SVC at Bout-de-l'Île 735/315 kV substation in Montréal
- Biomass integration

2014-2015

- Wind integration
- Two 1,650 MVA 735/315 kV transformers at Bout-de-l'Île 735/315 kV substation
- 315 kV integration of Romaine-2 Hydro (Lower North shore of St. Lawrence River)
- 2 X 180 MVAR 315 kV shunt capacitors at Arnaud 735/315 kV substation
- 2 X 180 MVAR 161 kV shunt capacitors at Saguenay 735/161 kV substation
- New 735 kV switching station ("Aux Outardes") near existing Micoua substation

Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of the neighboring regions of RFC (ReliabilityFirst Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 5 and Figure 13.

Table 5
PJM, RFC-Other and MRO-US 2011 Assumptions³⁵

	PJM	RFC-Other	MRO-US
Peak Load (MW)	155,477	94,410	35,135
Peak Month	July	July	July
Assumed Capacity (MW)	186,998	104,220	38,752
Purchase/Sale (MW)	-1,844	0	0
Reserve (%)	19	10	10
Weighted Unit Availability (%)	87.50	86.58	87.58
Operating Reserves (MW)	3,400	2,206	1,700
Curtailed Load (MW)	3,257	2,000	1,666
No 30-min Reserves (MW)	2,765	1,470	1,200
Voltage Reduction (MW)	2,201	0	1,100
No 10-min Reserves (MW)	635	736	500
Appeals (MW)	400	0	200
Load Forecast Uncertainty	94.13 +/- 5.05, 10.10, 15.15	94.01 +/- 5.15, 10.30, 15.44	94.30 +/- 4.90, 9.81, 14.71

³⁵ 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/>

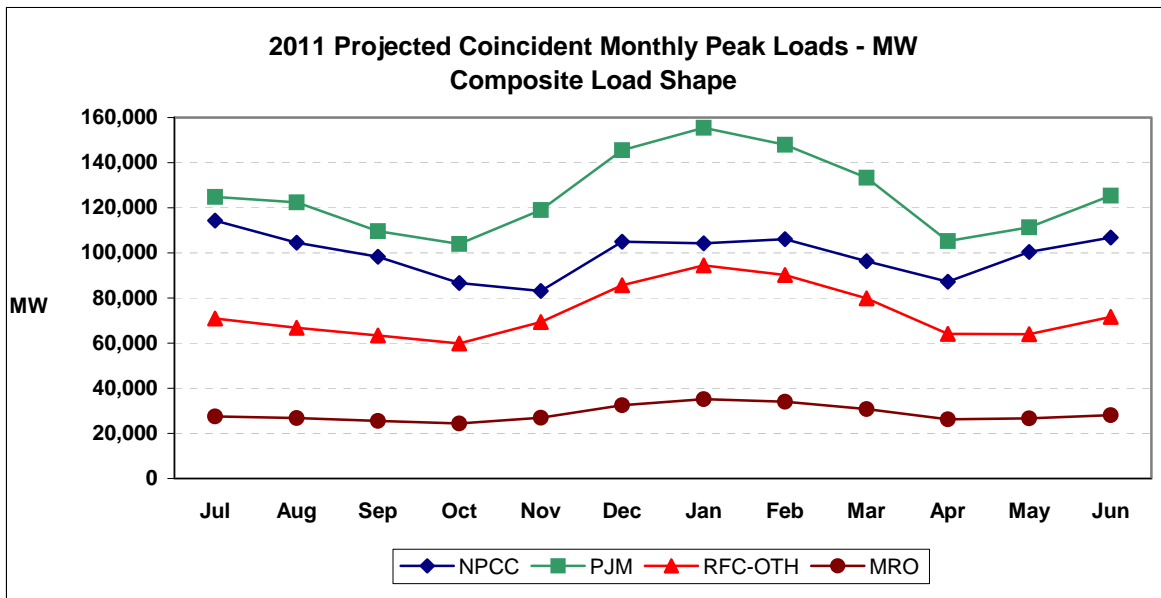


Figure 13 - 2011 Projected Monthly Expected Peak Loads for NPCC, RFC, PJM and the MRO

ReliabilityFirst

ReliabilityFirst is a newly formed not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. ReliabilityFirst 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.

ReliabilityFirst 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 are identified and transferred to ReliabilityFirst.

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.

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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.

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.

PJM-RTO

Load Model

The forecast contained in the January 2009 PJM Load Forecast ³⁶ was used, consistent with the 2009 RRS. The methods and techniques used in the load forecasting process are documented in Manual 19 (Load Forecasting and Analysis) and Manual 20 (PJM Resource Adequacy Analysis.) ³⁷ 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 PJM Load Forecast Report, January 2009, for the forecast monthly loads. This study modeled load forecast uncertainty consistent with that used in recent probabilistic PJM models, per the above references, which reflects uncertainty for loads at a predetermined probability of occurrence. This load uncertainty typically reflects factors such as weather, economics, diversity (timing) of peak periods among internal PJM zones or regions, the period years the model is based on, sampling size, and how many years ahead in the future the load forecast.

Expected Resources

All generators that have been demonstrated to be deliverable were modeled as PJM capacity resources in the PJM-RTO study area. Active generation projects in the PJM interconnection queues were modeled in the PJM-RTO study area after applying a suitable commercial probability.

³⁶ See: <http://www.pjm.com/~media/documents/reports/2010-load-forecast-report.ashx>

³⁷ Please refer to PJM Manual 19 <http://pjm.com/~media/documents/manuals/m19.ashx> and PJM Manual 20, <http://ftp.pjm.com/~media/documents/manuals/m20.ashx> for technical specifics.

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

Expected Transmission Projects

The transfer values shown in the study are reflective of peak load flow model conditions. PJM is a summer peaking area. The studies performed to determine these transfer values are in line with the Regional Transmission Planning Process employed at PJM, of which the Transmission Expansion Advisory Committee (TEAC) reviews these activities. All activities of the TEAC can be found at the pjm.com web site. All transmission projects are treated in aggregate, with the appropriate timing and transfer values changing in the model, consistent with PJM's Regional Transmission Expansion Plan (RTEP.)³⁸

Market programs

The Reliability Pricing Model (RPM)³⁹ is PJM's capacity-market model. Implemented in 2007, the RPM, based on making capacity commitments three years ahead, is designed to create long-term price signals to attract needed investments in reliability in the PJM region.

The long-term RPM approach, in contrast to PJM's previous short-term capacity market, includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – resources that include not just generating plants, but demand response and transmission facilities.

The RPM model works in conjunction with PJM's Regional Transmission Expansion Planning (RTEP) process to ensure the reliability of the PJM region for future years.

The RPM includes the continued use of self-supply and bilateral contracts by load-serving entities (LSEs) to meet their capacity obligations. The capacity auctions under the RPM obtain the remaining capacity that is needed after market participants have committed the resources they will supply themselves or provide through contracts.

The RPM provides:

- Procurement of capacity three years before it is needed through a competitive auction;
- Locational pricing for capacity that reflects limitations on the transmission system's ability to deliver electricity into an area and to account for the differing need for capacity in various areas of PJM;
- A variable resource requirement to help set the price for capacity;
- A backstop mechanism to ensure that sufficient resources will be available to preserve system reliability.

The technical modeling requirements for the PJM Reliability Pricing Model are consistent with the existing modeling and methods used at PJM, per the above modeling summaries used in this study.

³⁸ See: <http://pjm.com/planning.aspx>

³⁹ See: <http://pjm.com/markets-and-operations/rpm.aspx>

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

Modeling

The modeling of PJM-RTO breaks the PJM region into four distinct areas: Eastern Mid-Atlantic Central Mid-Atlantic, Western Mid-Atlantic, and the PJM Western areas combined with PJM South. This modeling follows known operational models and constraints while recognizing that areas with high reserves have few events invoking emergency operating procedures. The model in this study used many of the same modeling assumptions used in the PJM 2009 reserve requirement study.⁴⁰

Fuel

Figure 14 shows PJM-RTO's resource capacity mix by fuel type for the year 2010 on an installed capacity basis at the end of March 31, 2010;⁴¹ representing 40.7% coal; 29.3% natural gas; 18.2% nuclear; 6.4% oil; 4.7% hydroelectric; 0.4% solid waste, and 0.2% wind generation.

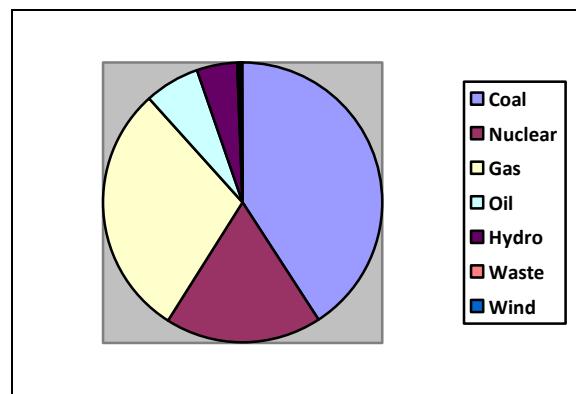


Figure 14 – PJM-RTO Capacity Mix by Fuel Type for 2010

⁴⁰ See: <http://www.pjm.com/committees/planning/downloads/20051130-item8-pjm-irm-letter.pdf>

⁴¹ See: <http://www.pjm.com/~media/documents/reports/state-of-market/2010/2010q1-som-pjm.ashx>

RESULTS

Figures 15 (a) and 15(b) shows the estimated annual NPCC Area Loss of Load Expectation (LOLE) for the 2011-2015 period.

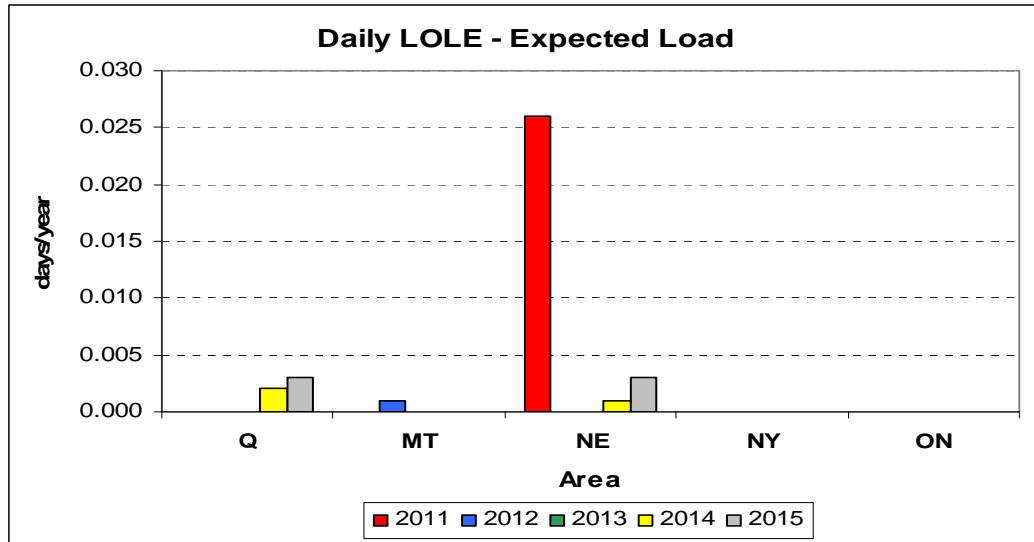


Figure 15(a) - Estimated Annual NPCC Area LOLE (2011 – 2015)

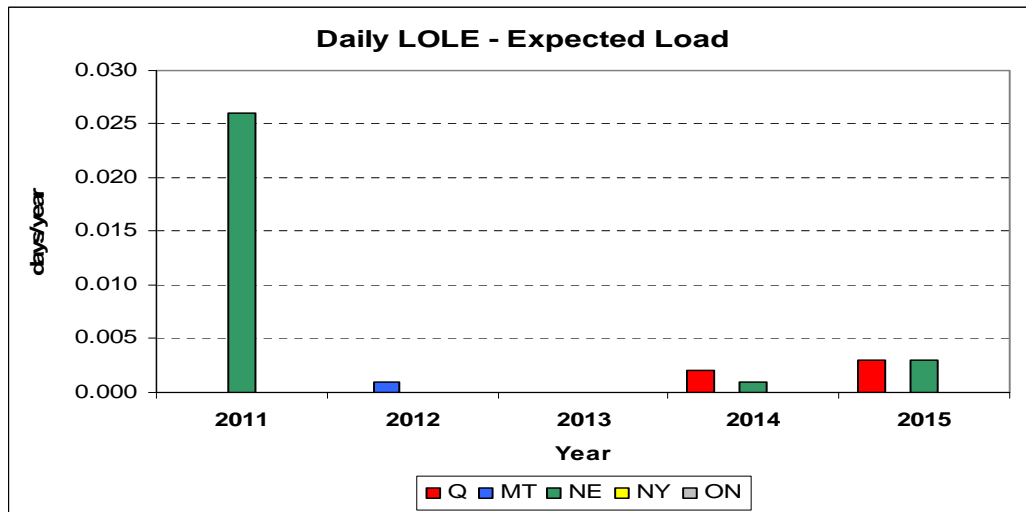


Figure 15(b) - Estimated Annual NPCC Area LOLE (2011 – 2015)

Figures 15(c) and 15(d) shows the estimated annual NPCC Areas and Neighboring Region’s Loss of Load Expectation (LOLE) for the 2011-2015 period.

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

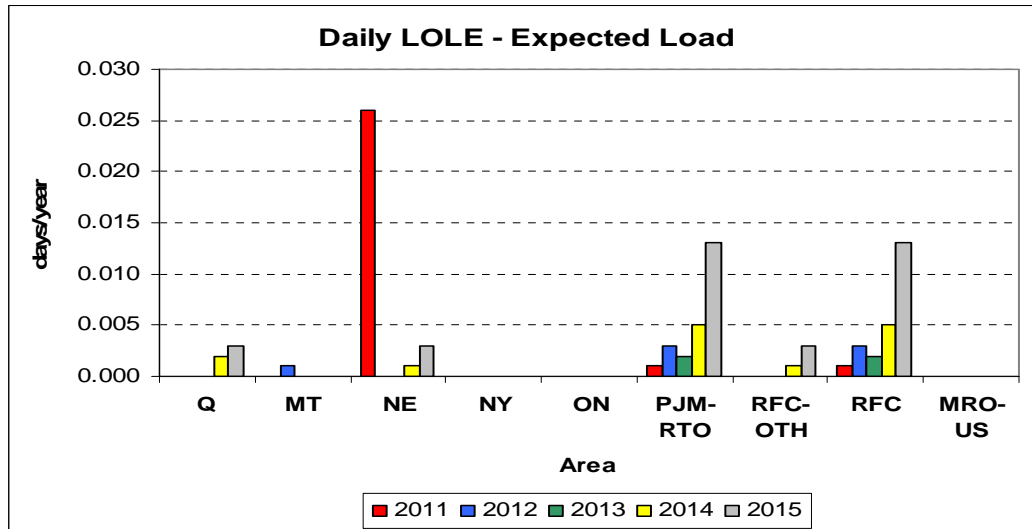


Figure 15(c) - Estimated Annual NPCC Areas and Neighboring Regions LOLE (2011 – 2015)

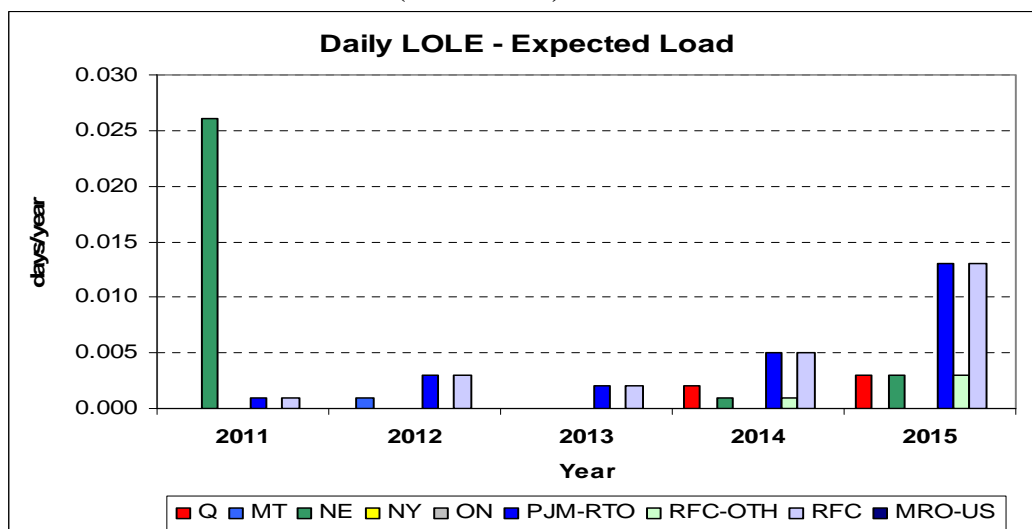


Figure 15(d) – Estimated Annual NPCC Areas and Neighboring Region’s LOLE (2011 – 2015)

At the December 2008 NERC Planning Committee (PC) meeting, the PC approved the formation of a Generation & Transmission Reliability Planning Models Task Force (G&TRPMTF) with two main deliverables in the scope:

- ✓ To evaluate approaches and models for composite generation and transmission (G&T) reliability assessment. (The term “generation” was taken to include all resources including demand-side management.)
- ✓ To provide a common set of probabilistic reliability indices and recommend probabilistic-based work products that could be used to supplement the NERC’s long term reliability assessments.

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

At the September 2010 PC meeting, the G&TRPMTF Final Report on Methodology and Metrics was approved.⁴²

The metric results described in the Final Report included the : (i) annual Loss-of Load Hours (LOLH), (ii) Expected Unserved Energy (EUE), and (iii) Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE) for two common forecasted years – year 2 and year 5.

Pursuant to those recommended metrics, Figures 16 (a) and 16(b) show the estimated annual NPCC Area Loss of Load Expectation (LOLH) estimated the 2011-2015 period.

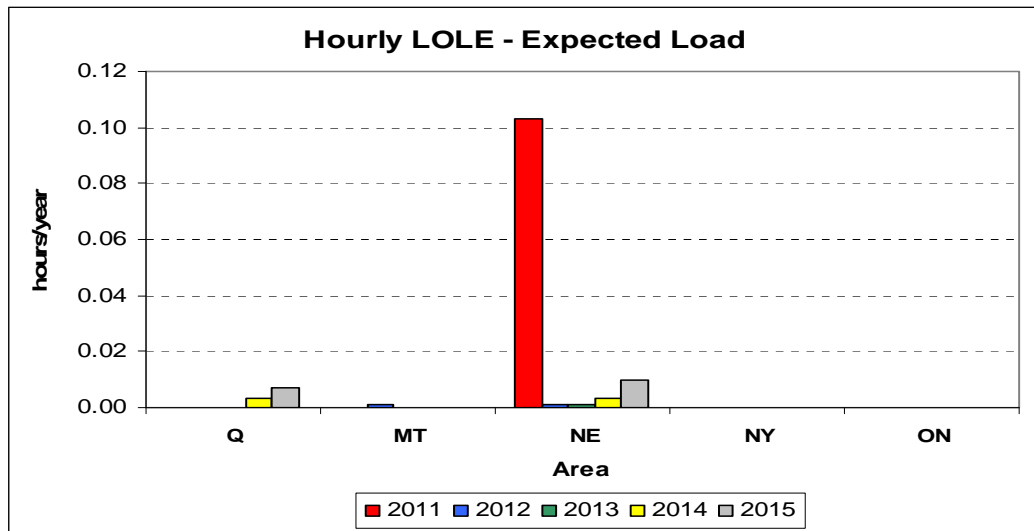


Figure 16(a) - Estimated Annual NPCC Area LOLH (2011 – 2015)

⁴² See:

<http://www.nerc.com/docs/pc/gtrpmtf/GTRPMTF%20Meth%20&%20Metrics%20Report%20final%20w.%20PC%20approvals,%20revisions.pdf>

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

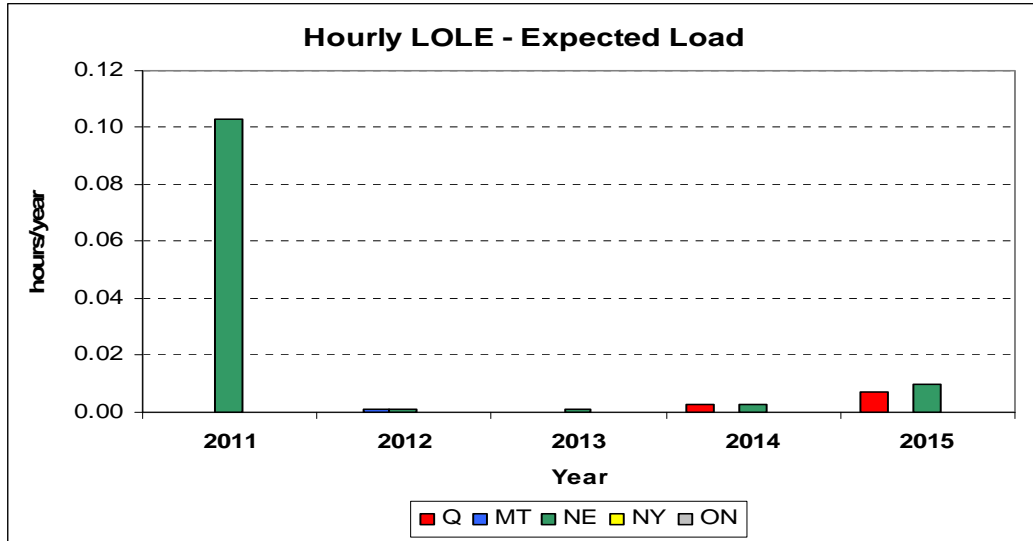


Figure 16(b) - Estimated Annual NPCC Area LOLH (2011 – 2015)

Figures 16(c) and 16(d) shows the estimated annual Loss of Load Expectation (LOLE) for NPCC Areas and neighboring Regions for the 2011-2015 period.

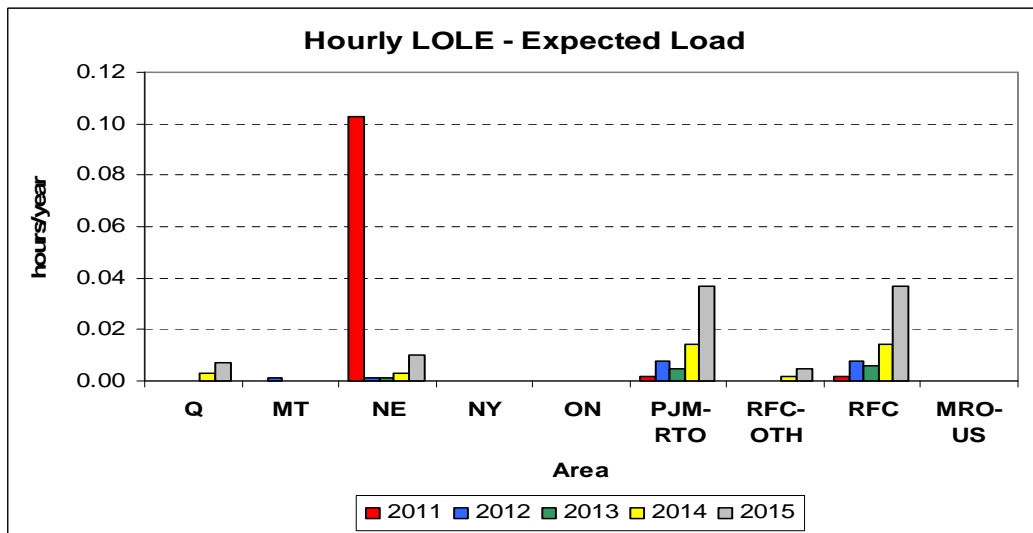


Figure 16(c) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2011 – 2015)

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

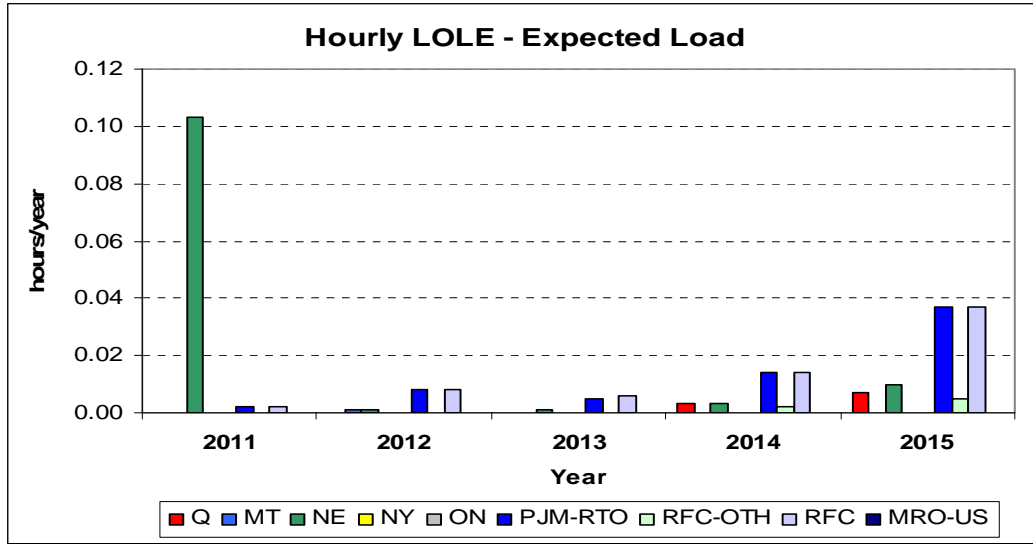


Figure 16(d) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2011 – 2015)

Figures 17(a) and 17(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2011-2015 period.

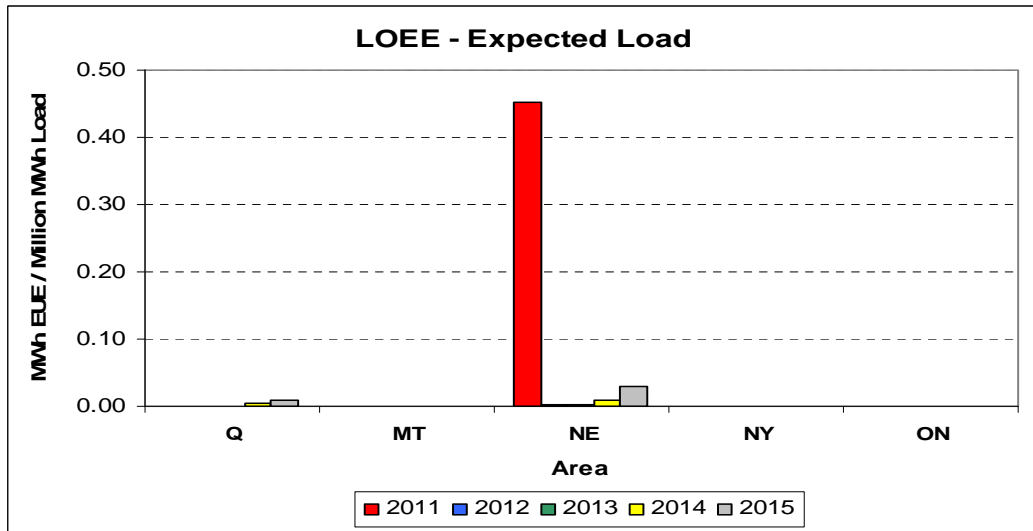


Figure 17(a) - Estimated Annual NPCC Area EUE (2011 – 2015)

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

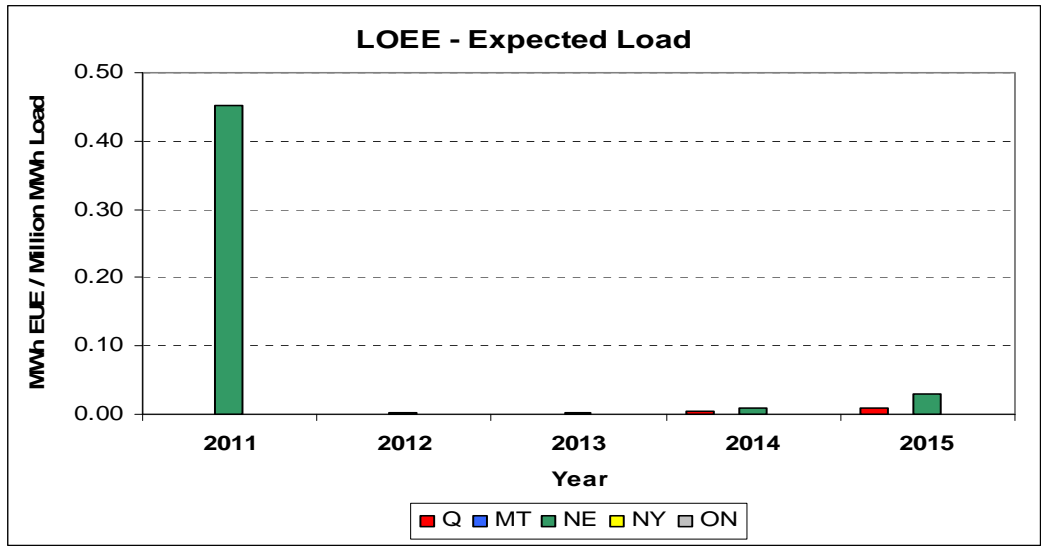


Figure 17(b) – Estimated Annual NPCC Area LOLH (2011 – 2015)

Figures 17(c) and 17(d) shows the estimated annual Expected Unserved Energy (EUE) for NPCC and the neighboring Regions for the 2011-2015 period.

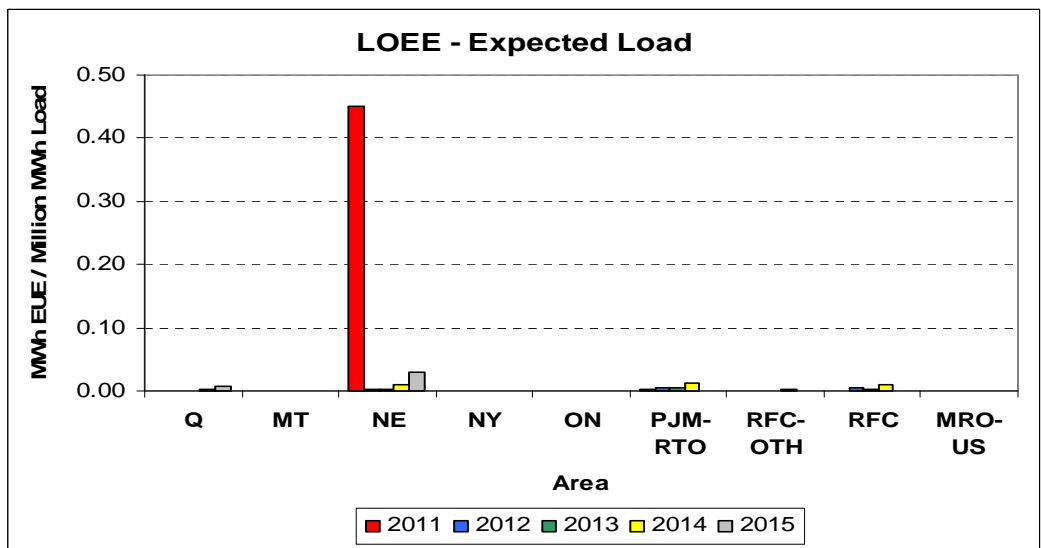


Figure 17(c) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2011 – 2015)

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

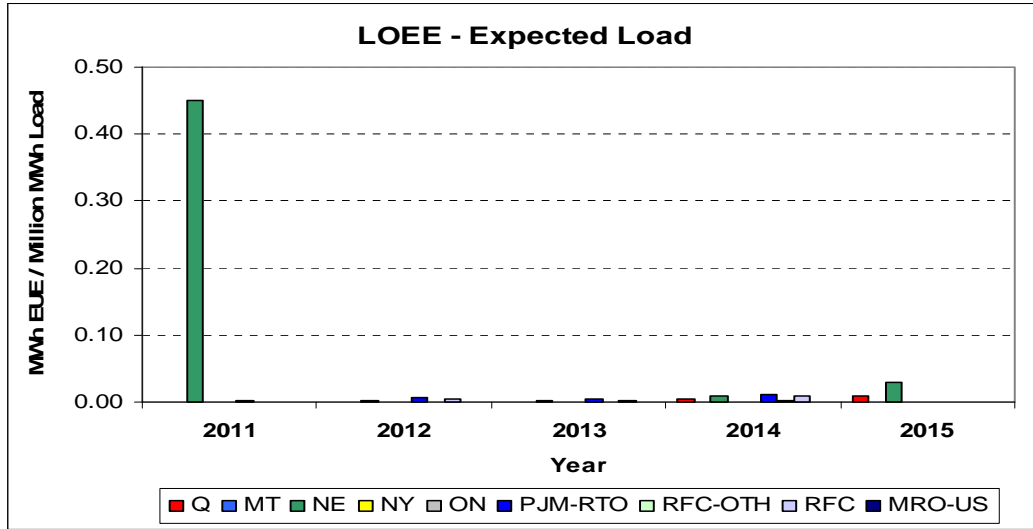


Figure 17(d) - Estimated Annual EUE for NPCC Areas and Neighboring Regions (2011 – 2015)

Table 6 shows the percentage difference between the amount of annual energy estimated by the GE MARS program and the *NERC 2010 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 estimate for the total estimated NPCC annual energy is approximately 2% higher than the corresponding sum of the NPCC Areas annual energy forecasts.

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

Table 6 –Comparison of Energies Modeled

Year	2011	2012	2013	2014	2015
Quebec					
MARS	188,037,504	187,020,128	188,873,632	189,618,448	193,478,048
2010 LTRA	185,599,000	189,048,361	189,982,471	191,542,856	196,113,797
(MARS-LTRA)	2,438,504	-2,028,233	-1,108,839	-1,924,408	-2,635,749
% (MARS-LTRA)/LTRA	1.3	-1.1	-0.6	-1.0	-1.3
Maritimes					
MARS	28,414,514	28,557,300	28,661,444	28,687,762	28,770,718
2010 LTRA	28,415,000	28,817,000	29,103,000	29,356,000	29,649,000
(MARS-LTRA)	-486	-259,700	-441,556	-668,238	-878,282
% (MARS-LTRA)/LTRA	0.0	-0.9	-1.5	-2.3	-3.0
New England					
MARS	140,488,032	143,392,576	145,230,720	147,522,288	149,554,032
2010 LTRA	132,370,000	134,005,000	134,655,000	136,060,000	137,280,000
(MARS-LTRA)	8,118,032	9,387,576	10,575,720	11,462,288	12,274,032
% (MARS-LTRA)/LTRA	6.1	7.0	7.9	8.4	8.9
New York					
MARS	168,076,688	167,660,944	169,276,608	170,078,928	170,585,120
2010 LTRA	160,446,000	161,618,000	163,594,000	164,556,000	165,372,000
(MARS-LTRA)	7,630,688	6,042,944	5,682,608	5,522,928	5,213,120
% (MARS-LTRA)/LTRA	5	3.7	3.5	3.4	3.2
Ontario					
MARS	143,482,624	140,242,816	138,523,392	137,872,320	136,606,224
2010 LTRA	143,611,000	140,373,975	138,653,130	138,003,963	136,743,289
(MARS-LTRA)	-128,376	-131,159	-129,738	-131,643	-137,065
% (MARS-LTRA)/LTRA	-0.1	-0.1	-0.1	-0.1	-0.1
NPCC					
MARS	668,499,392	666,873,728	670,565,760	673,779,776	678,994,112
2010 LTRA	650,441,000	653,862,336	655,987,601	659,518,819	665,158,086
(MARS-LTRA)	18,058,392	13,011,392	14,578,159	14,260,957	13,836,026
% (MARS-LTRA)/LTRA	2.8	2.0	2.2	2.2	2.1

OBSERVATIONS

Figures 18(a) and 18(b) summarize the estimated annual NPCC Area Loss of Load Expectation (LOLE) from the 2001 – 2010 NPCC Summer Multi-Area Probabilistic Reliability Assessments under Base Case assumptions for the expected load level.

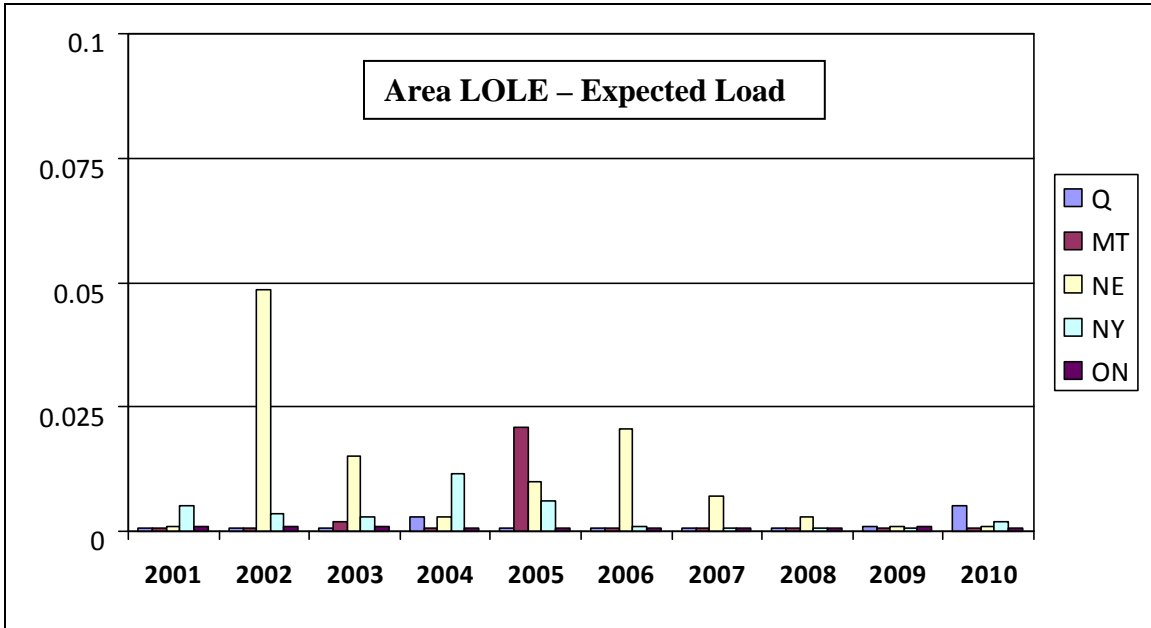


Figure 18(a) - Summary of Estimated Annual NPCC Area LOLE from the NPCC Summer Multi-Area Probabilistic Reliability Assessments (Base Case)

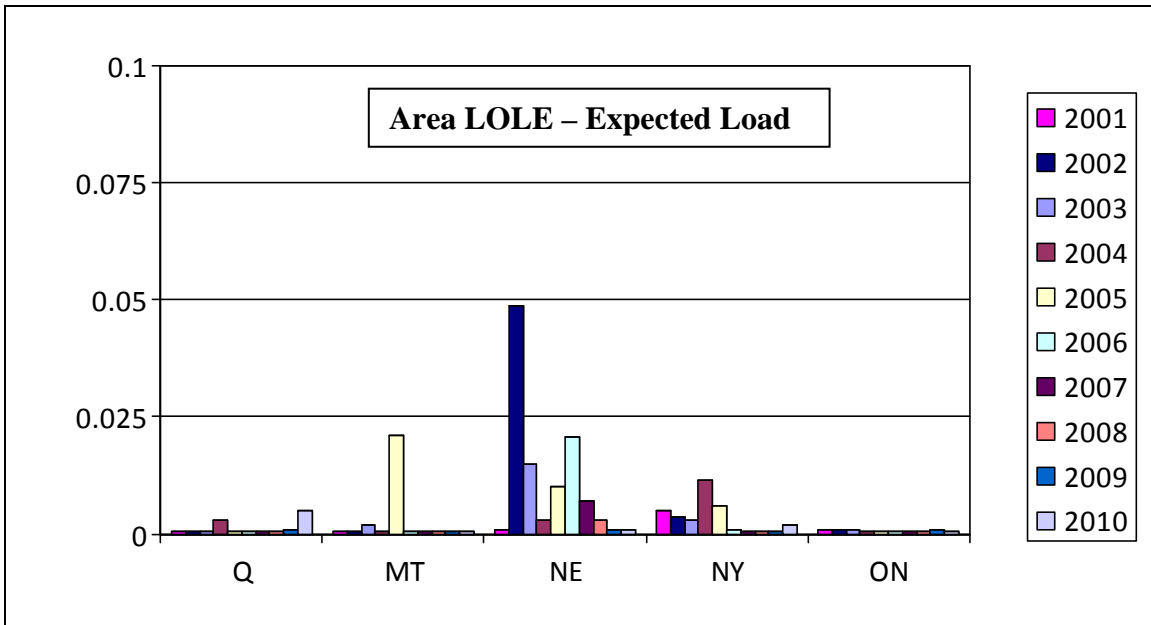


Figure 18(b) - Summary of Estimated Annual NPCC Area LOLE from the NPCC Summer Multi-Area Probabilistic Reliability Assessments (Base Case)

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

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

Figures 19(a) and 19(b) adds the estimated annual NPCC Area Loss of Load Expectation (LOLE) estimated for 2011 – 2015.

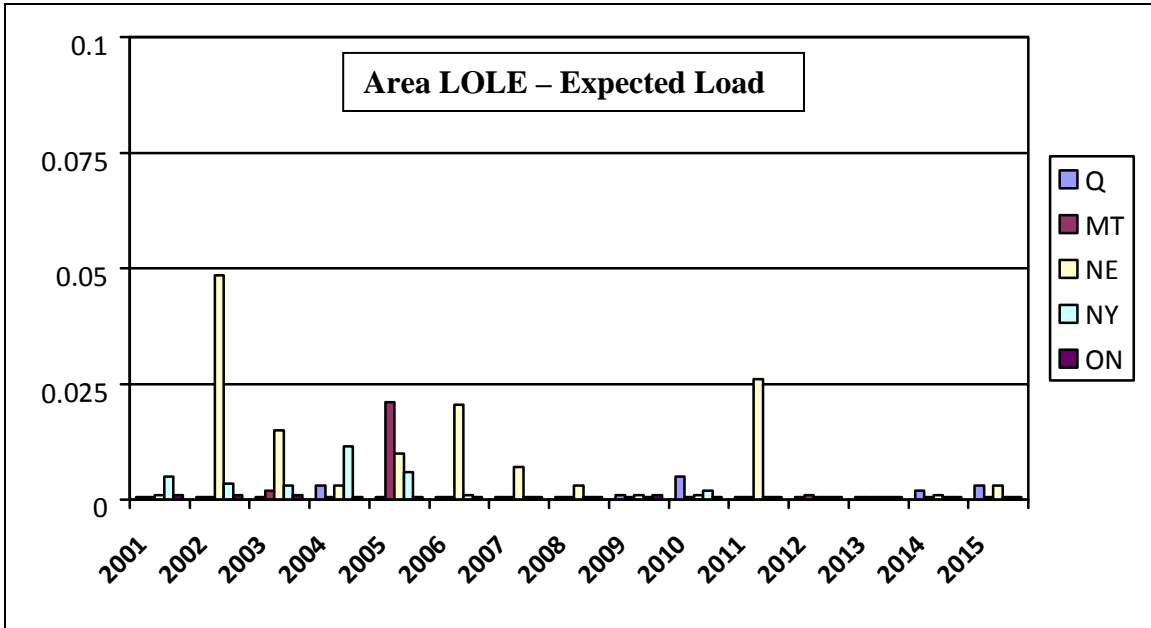


Figure 19(a) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

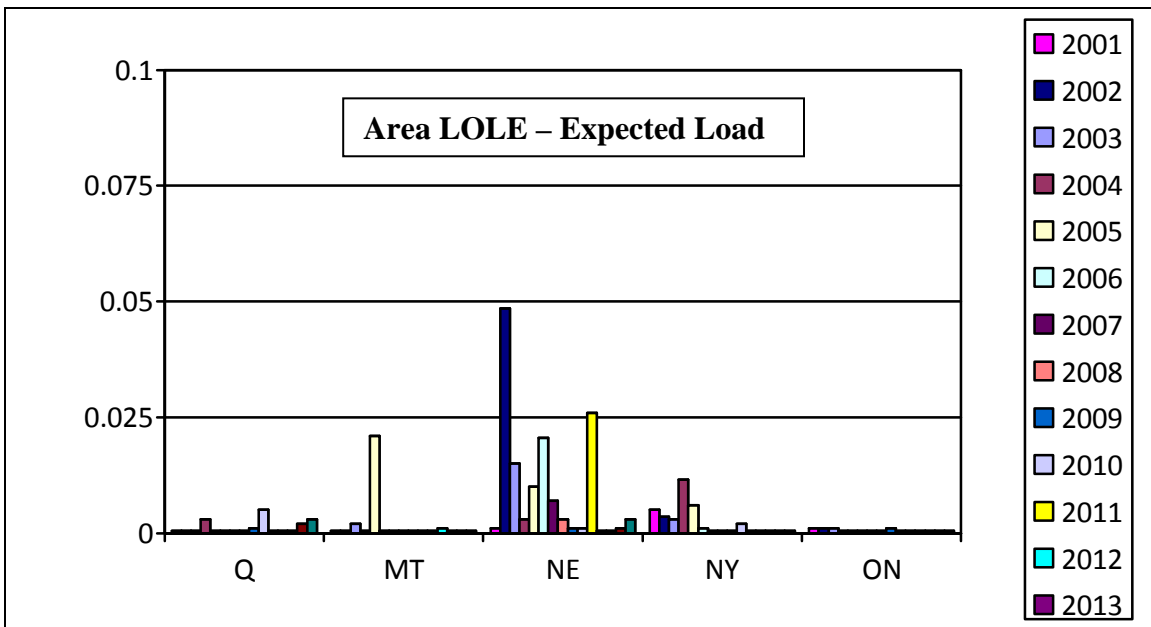


Figure 19(b) – Combined Summary of Estimated Annual NPCC Area LOLE (Base Case)

APPENDIX A

Objective and Scope of Work

1. Objective

On a consistent basis, evaluate the near term seasonal and long-range (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 2010 -2014 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 2010 - 2011 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 2010 summer and November 2010 to March 2011 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 (2010 -2011) 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 2012 - 2014 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.

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

Reliability for the long-range (2010 – 2014) analysis will be measured by calculating the annual Loss of Load Expectation (LOLE) for each NPCC Area and neighboring Regions.

3. Schedule

A report of the results of the summer assessment will be published no later than April 30, 2010.

A report of the results of the winter assessment will be published no later than June 30, 2010.

A report summarizing the results of the long-range overview will be published no later than December 31, 2010.

NPCC INTERREGIONAL LONG RANGE ADEQUACY OVERVIEW

APPENDIX B

Capacity and Load at Time of Area Peak Base Case with Composite Load Shape

	Quebec	Maritime Area	New England	New York	Ontario	PJM-RTO	RFC-OTH	MRO-US
2011								
	Jan	Feb	Aug	Aug	Aug	Jul	Jul	Jul
Capacity (MW) *	37,857	7,147	28,728	39,934	31,532	186,998	104,220	38,752
Purchase/Sale (MW)	1,768	-200	2,050	2,600	-325	-1,844	0	0
Load (MW)	36,625	5,430	27,658	32,790	23,497	155,447	94,410	35,135
Demand Response (MW)	0	0	1,953	0	1,175	0	0	0
Reserves (%)	8	28	20	30	40	19	10	10
Maintenance - Peak Week (MW)	**	806	0	609	788	90	0	0
Max. Wind Capacity (MW) *	134	288	0	1,319	173	888	595	1,440
2012								
	Jan	Jan	Aug	Aug	Aug	Jul	Jul	Jul
Capacity (MW) *	38,962	6,856	32,408	40,030	31,448	188,528	103,782	39,663
Purchase/Sale (MW)	1,709	0	1,820	2,162	0	-1,844	0	0
Load (MW)	37,232	5,362	28,152	32,906	23,526	160,428	94,045	35,760
Demand Response (MW)	0	0	2,445	0	1,262	0	0	0
Reserves (%)	9	28	33	28	41	16	10	11
Maintenance - Peak Week (MW)	**	660	0	597	750	90	0	0
Max. Wind Capacity (MW) *	337	291	0	1,319	313	1,138	605	1,465
2013								
	Jan	Feb	Aug	Aug	Aug	Jul	Jul	Jul
Capacity (MW) *	38,688	6,861	32,408	40,030	30,729	191,134	104,971	40,263
Purchase/Sale (MW)	1,583	0	234	2,948	0	-1,844	0	0
Load (MW)	37,613	5,403	28,562	33,226	23,120	162,543	94,755	36,346
Demand Response (MW)	0	0	2,445	0	1,342	0	0	0
Reserves (%)	7	27	25	29	41	16	11	11
Maintenance - Peak Week (MW)	**	129	0	627	755	90	0	0
Max. Wind Capacity (MW) *	549	297	0	1,319	560	1,183	650	1,465
2014								
	Jan	Feb	Aug	Aug	Aug	Jul	Jul	Jul
Capacity (MW) *	38,913	6,861	32,408	40,030	27,149	191,396	106,358	41,174
Purchase/Sale (MW)	2,192	0	234	2,948	0	-1,844	0	0
Load (MW)	37,976	5,434	29,016	33,384	22,880	165,081	96,060	36,962
Demand Response (MW)	0	0	2,445	0	1,344	0	0	0
Reserves (%)	8	26	23	29	26	15	11	11
Maintenance - Peak Week (MW)	**	132	0	626	0	90	0	0
Max. Wind Capacity (MW) *	706	297	0	1,319	603	1,253	710	1,490
2015								
	Jan	Feb	Aug	Aug	Aug	Jul	Jul	Jul
Capacity (MW) *	39,728	6,904	32,408	40,030	26,042	191,645	107,756	42,080
Purchase/Sale (MW)	2,222	0	184	2,948	0	-1,844	0	0
Load (MW)	38,566	5,469	29,436	33,506	22,334	167,477	97,264	37,554
Demand Response (MW)	0	0	2,445	0	1,346	0	0	0
Reserves (%)	9	26	21	28	24	13	11	12
Maintenance - Peak Week (MW)	**	135	0	625	88	90	0	0
Max. Wind Capacity (MW) *	841	339	0	1,318	647	1,469	775	1,510

* Wind capacity included at maximum output for the month, not nameplate rating; demand response not included in capacity

** Capacity for Quebec reflects scheduled maintenance and restrictions