Northeast Power Coordinating Council

2013 Long Range Adequacy Overview

Approved by the RCC

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Conducted by the

NPCC CP-8 Working Group
NPCC CP-8 WORKING GROUP

Philip Fedora (Chair)  Northeast Power Coordinating Council
Alan Adamson  New York State Reliability Council
Syed Ahmed  National Grid USA
Frank Ciani  New York Independent System Operator
Kevan Jefferies  Ontario Power Generation Inc.
Scott Leuthauser  Hydro-Québec Energy Services (US) Inc.
Dragan Pecuria  Nova Scotia Power Inc.
Kamala Rangaswamy  Nova Scotia Power Inc.
Abdelhakim Sennoun  Hydro-Québec Distribution
Rob Vance  NB Power/Énergie NB
Vithy Vithyananthan  Independent Electricity System Operator
Fei Zeng  ISO New England Inc.

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

This study evaluated, on a consistent basis, the long range adequacy of Northeast Power Coordinating Council’s (NPCC) and neighboring Regions’ plans to meet their Loss of Load Expectation (LOLE) planning criteria through a multi-area probabilistic assessment for the period from 2014 to 2018, based on the reported NERC 2013 Long Term Reliability Assessment data.

General Electric’s (GE) Multi-Area Reliability Simulation (MARS) program was selected by NPCC for its analysis. GE Energy Consulting was retained by the Working Group to conduct the simulations. MARS version 3.16 was used for the assessment.

The database developed by the NPCC CP-8 Working Group's "NPCC Reliability Assessment for Summer 2013", May 2013, 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 2014-2018 period, consistent with the information reported for the NERC 2013 Long-Term Reliability Assessment.

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

The Overview's Objective and Scope of Work are shown in Appendix A. Appendix B summarizes the Area Generation and Load assumptions used in the analysis. NERC’s 2013 Long-Term Reliability Assessment (LTRA) Narratives are provided (for reference) in Appendix C.
MODEL ASSUMPTIONS

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

**Area Studies**

**New York**
The Comprehensive Reliability Plan (CRP) is the reliability planning assessment portion of the New York Independent System Operator (NYISO) Comprehensive System Reliability Plan Planning Process (CSPP) \(^5\) conducted by the NYISO to provide a blueprint for meeting the reliability needs of the state’s bulk electricity grid over a 10-year planning horizon. The multi-phased process includes an assessment of reliability needs prior to the development of the reliability plan. The 2012 Comprehensive Reliability Plan (CRP) \(^6\) was published on March 19, 2013.

The 2012 CRP is the sixth CRP completed by the NYISO. The 2012 CRP determined that additional resources are needed over the last two years of the Study Period 2013-2022 in order for the New York Control Area (NYCA) to be in compliance with applicable reliability criteria.

Without these additional resources, the Reliability Needs first identified in the 2012 Reliability Needs Assessment \(^7\) (RNA), and subsequently confirmed in the 2012 CRP, would not be mitigated. Transmission security violations were identified starting in year 2013 and Resource Adequacy needs starting in 2021.

In order to mitigate these deficiencies, the NYISO requested market-based, regulated backstop, and alternative regulated solutions to the identified Reliability Needs. Market-based solutions are the preferred means to meet the future Reliability Needs, with regulated backstop and alternative regulated solutions available to be triggered, if needed.

The CRP reports that market-based, regulated backstop and alternative regulated solutions have been proposed to meet the reliability needs first identified in the 2012 RNA.

**New England**
The New England Regional System Plan (RSP) is the Independent System Operator of New England's (ISO-NE) annual planning report that identifies the resources and transmission facilities needed to maintain reliable and economic operation of New

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England’s bulk electric power system over a ten-year horizon. A public meeting to presenting an overview of the Draft 2013 RSP for stakeholder review and comment was held on September 12, 2013. The New England 2013 RSP was approved by ISO-New England’s Board of Directors on November 7, 2013.

The 2013 Regional System Plan (RSP13) provides information on system and project needs, system improvements, and the results of newly completed load, resource, and transmission analyses of the New England electric power system for reliably serving load throughout the region to 2022. It also discusses ongoing and new analyses based on the current and planned system and describes new and planned infrastructure for all areas of New England. The major factors influencing resource retirements and the development of the electric power system infrastructure for the 10-year planning period, such as existing and pending state and federal environmental and energy policies, also are addressed.

RSP13 and the system planning process throughout the year comply with all applicable sections of the ISO’s Transmission, Markets, and Services Tariff (ISO tariff), approved by FERC. The plan and planning process also satisfy the relevant criteria and requirements established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), participating transmission owners (PTOs), and ISO-NE.

Like the RSP12 forecast, the RSP13 regional forecast shows slow growth in the summer peak demand and annual energy use. The energy-efficiency forecast of demand-side resources also is similar to the RSP12 forecast and shows a further slowing of net load growth. Assuming no retirements, resources procured in the seventh Forward Capacity Auction (FCA #7) are sufficient to meet system wide needs through 2022, and the ISO-NE Generator Interconnection Queue indicates that additional resources are seeking to develop in the region. ISO-NE’s Generator Interconnection Queue includes the requests that generators submit to ISO New England to interconnect to the ISO-NE administered transmission system.

**Ontario**
The Independent Electricity System Operator of Ontario (IESO) regularly assesses the adequacy and reliability of Ontario’s power system. The latest Assessment of the Reliability and Operability of the Ontario Electricity System Update, dated December 12, 2013 provides Ontario's supply outlook over the next 18 months.

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NPCC 2013 LONG RANGE ADEQUACY OVERVIEW

Over the next 18 months of the assessment the IESO anticipates adequate supply levels and transmission resources to meet provincial demand under both normal and extreme weather conditions. Demand will remain relatively flat over this period.

Approximately 3,300 megawatts (MW) of transmission-connected renewable generation will account for most of the new supply that will come online over the 18-month timeframe covered by the assessment.

At the same time, the province will retire nearly 2,000 MW when the remaining units at Nanticoke Generating Station, a coal facility, officially cease operation in December 2013. A further 150 MW will be removed from service when the last unit at the Thunder Bay coal generating station begins conversion to biomass fuel in 2014.

Those changes are resulting in a transformed Ontario supply mix. In order to adapt to this evolving landscape, the IESO has introduced several new operating innovations with the help of its market participant partners. Flexibility, essential to the real-time balancing of supply and demand, is being addressed now through a variety of sources, including increased maneuverability of some nuclear units, demand response measures and new tools for managing wind and solar variability.

Québec
The Québec assumptions used in this study are consistent with its 2013 NPCC Interim Review of Resource Adequacy and the 2013 NERC Long-Term Reliability Assessment.

Energy efficiency and conservation programs and energy saving trends are accounted for directly in the assessment area’s demand forecasts and count for 2,150 MW toward the 2014–2015 winter peak demand. Energy efficiency and conservation programs are implemented throughout the year by Hydro-Québec Distribution and by the provincial government through its Ministry of Natural Resources. Energy efficiency will continue to grow throughout the assessment period.

Demand Response (DR) programs in the Québec Area—specifically designed for peak load reduction during winter operating periods—are interruptible demand programs (for large industrial customers), totaling 1,439 MW for the 2014–2015 winter period. DR is usually used in situations in which load is expected to reach high levels or when resources are not expected to be sufficient to meet load at peak periods. DR is considered as a resource and is relatively stable during the assessment period, with a maximum reached for the 2014–2015 winter peak period then settling down to 1,300 MW starting at the 2019–2020 winter period. The total on-peak DR and Energy Efficiency and conservation for the 2023–2024 winter period is projected to be approximately 4,900 MW.

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11 See: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
There are no significant unit retirements planned during the assessment period. A few small hydroelectric projects, totaling 80 MW, have been cancelled by the provincial government. TransCanada Energy’s 547 MW natural gas combined-cycle power plant in Bécancour is mothballed.

**Maritimes**
The Maritimes Area is a winter peaking area with separate markets and regulators in New Brunswick (NB), Nova Scotia, Prince Edward Island (PEI), and Northern Maine. Beginning October 1, 2013, the New Brunswick System Operator (NBSO) was amalgamated with NB Power, with NB Power taking over the role of the Reliability Coordinator for the Maritimes Area from NBSO. This will not affect resource adequacy in the Maritimes Area.

The assumptions used in this study are consistent with the *2013 NPCC Maritimes Area Comprehensive Review of Resource Adequacy*; the results indicate that the Maritimes Area will comply with the NPCC resource adequacy criterion.

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

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

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Load Representation

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

Load Shape

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

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

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

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

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

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

Load Forecast Uncertainty
Load forecast uncertainty was also modeled. The effects on reliability of uncertainties in the load forecast, due to weather and economic conditions, were captured through the load forecast uncertainty model in MARS. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

While the per unit variations in Area and sub-Area load can vary on a monthly and annual basis, Table 1 shows the values assumed for January 2014, corresponding to the assumed occurrence of the NPCC system peak load (assuming the composite load shape). Table 1 also shows the probability of occurrence assumed for each of the seven load levels modeled.

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

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

Table 1
Per Unit Variation in Load Assumed (Month of January 2014)

<table>
<thead>
<tr>
<th>Area</th>
<th>Per-Unit Variation in Load</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1.1380 1.0920 1.0460 1.0000 0.9540 0.9080 0.8620</td>
</tr>
<tr>
<td>NE</td>
<td>1.0934 1.0383 0.9971 0.9635 0.9402 0.8500 0.8000</td>
</tr>
<tr>
<td>NY</td>
<td>1.0430 1.0310 1.0160 0.9980 0.9750 0.9440 0.9050</td>
</tr>
<tr>
<td>ON</td>
<td>1.0779 1.0519 1.0260 1.0000 0.9740 0.9481 0.9221</td>
</tr>
<tr>
<td>QC</td>
<td>1.0860 1.0847 1.0378 0.9999 0.9622 0.9235 0.9140</td>
</tr>
<tr>
<td>Prob.</td>
<td>0.0062 0.0606 0.2417 0.3830 0.2417 0.0606 0.0062</td>
</tr>
</tbody>
</table>
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.  

Capacity and Load Summary
Figures 1 through 6 summarize area capacity and load assumed in this Overview at the time of area peak for the period 2014 to 2018. Area peak load is shown against the initial area generating capacity (includes demand resources modeled as resources), adjusted for purchases, retirements, and additions. New England generating capacity also includes active Demand Response, based on the Capacity Supply Obligations obtained through ISO-NE’s Forward Capacity Market three years in advance. More details can be found in Appendix B.

Figure 1 – Maritimes Area Capacity and Load - MW (February)

See: https://www.npcc.org/Library/Seasonal%20Assessment/Forms/Public%20List.aspx
NPCC 2013 LONG RANGE ADEQUACY OVERVIEW

New England Capacity and Load - MW (August)

Figure 2 – New England Capacity and Load

New York Capacity and Load - MW (August)

Figure 3 – New York Area Capacity and Load
Figure 6 – PJM-RTO Capacity and Load - MW (July)
Figure 7 stylistically illustrates the system that was represented in this Assessment, showing area and assumed transfer limits for the period 2014 to 2018.

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

The transfer capability is 1,000 MW. However, it was modeled as 700 MW to reflect limitations imposed by internal New England constraints.

*The transfer capability in this direction reflects limitations imposed by ISO-NE for internal New England constraints.
Operating Procedures to Mitigate Resource Shortages

Each area takes defined steps as their reserve levels approach critical levels. These steps consist of those load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves. Table 2 summarizes the load relief assumptions modeled for each NPCC area.

Table 2
NPCC Operating Procedures to Mitigate Resource Shortages
Peak Month 2014 Load Relief Assumptions - MW

<table>
<thead>
<tr>
<th>Actions</th>
<th>MT (Feb)</th>
<th>NE (Aug)</th>
<th>NY (Aug)</th>
<th>ON (July)</th>
<th>QC (Jan)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Curtail Load / Utility Surplus Appeals</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>228</td>
<td>1,339</td>
</tr>
<tr>
<td>RT-DR/SCR/EDRP</td>
<td>-</td>
<td>1,038</td>
<td>773</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>SCR Load /Man. Volt. Red.</td>
<td>-</td>
<td>-</td>
<td>0.21%</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2. No 30-min Reserves</td>
<td>234</td>
<td>625</td>
<td>655</td>
<td>473</td>
<td>500</td>
</tr>
<tr>
<td>3. Voltage Reduction</td>
<td>-</td>
<td>414</td>
<td>1.35%</td>
<td>1.40%</td>
<td>250</td>
</tr>
<tr>
<td>Interruptible Loads</td>
<td>245</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>4. No 10-min Reserves</td>
<td>660</td>
<td>-</td>
<td>-</td>
<td>945</td>
<td>750</td>
</tr>
<tr>
<td>RT-EG</td>
<td>-</td>
<td>432</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>General Public Appeals</td>
<td>-</td>
<td>-</td>
<td>204</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>5. 5% Voltage Reduction</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.70%</td>
<td>-</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>-</td>
<td>1,550</td>
<td>1,310</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

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.

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16 Derated value shown accounts for assumed availability.
17 Derated value shown accounts for assumed availability.
18 Derated value shown accounts for assumed availability.
The Working Group recognizes that Areas may invoke these actions in any order, depending on the situation faced at the time; however, it was agreed that modeling the actions as in the order indicated in Table 2 was a reasonable approximation for this analysis.

**Assistance Priority**

All Areas received assistance on a shared basis in proportion to their deficiency. In this analysis, each step was initiated simultaneously in all Areas and sub-Areas.
Modeling of Neighboring Regions

For the scenarios studied, a detailed representation of the neighboring regions of RFC (ReliabilityFirst Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 3 and Figure 8.

Table 3
PJM, RFC-Other and MRO-US 2014 Assumptions

<table>
<thead>
<tr>
<th></th>
<th>PJM</th>
<th>RFC-Other</th>
<th>MRO-US</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load (MW)</td>
<td>159,712</td>
<td>43,023</td>
<td>31,356</td>
</tr>
<tr>
<td>Peak Month</td>
<td>July</td>
<td>July</td>
<td>July</td>
</tr>
<tr>
<td>Assumed Capacity (MW)</td>
<td>184,623</td>
<td>49,713</td>
<td>36,232</td>
</tr>
<tr>
<td>Purchase/Sale (MW)</td>
<td>-817</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>25</td>
<td>21</td>
<td>21</td>
</tr>
<tr>
<td>Operating Reserves (MW)</td>
<td>3,400</td>
<td>2,206</td>
<td>1,700</td>
</tr>
<tr>
<td>Curtailable Load (MW)</td>
<td>15,146</td>
<td>2,264</td>
<td>1,650</td>
</tr>
<tr>
<td>No 30-min Reserves (MW)</td>
<td>2,765</td>
<td>1,470</td>
<td>1,200</td>
</tr>
<tr>
<td>Voltage Reduction (MW)</td>
<td>2,201</td>
<td>1,100</td>
<td>1,100</td>
</tr>
<tr>
<td>No 10-min Reserves (MW)</td>
<td>635</td>
<td>736</td>
<td>500</td>
</tr>
<tr>
<td>Appeals (MW)</td>
<td>400</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Load Forecast Uncertainty</td>
<td>+/- 12.55%, 8.37%, 4.18%</td>
<td>+/- 12.34%, 8.22%, 4.11%</td>
<td>+/- 12.34%, 8.22%, 4.11%</td>
</tr>
</tbody>
</table>

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

Unit data was from the publicly available NERC data. Each individual unit represented in the non-PJM RFC region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2012 RRS Report).

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

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

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

The U.S. portion of the MRO was modeled in this study, recognizing the strong transmission ties to the rest of the study system. Each individual unit represented in the MRO-US region was assigned unit performance characteristics based on PJM RTO fleet class averages (consistent with PJM 2012 RRS Report).

**PJM-RTO Load Model**

The forecast contained in the January 2013 PJM Load Forecast was used, consistent with the 2013 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.) 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 2013, 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 is forecast.

**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 2013 reserve requirement study.

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RESULTS

Figures 9(a) and 9(b) shows the estimated annual NPCC Area Loss of Load Expectation (LOLE) for the 2014-2018 period.

Figure 9(a) - Estimated Annual NPCC Area LOLE (2014 – 2018)

Figure 9(b) - Estimated Annual NPCC Area LOLE (2014– 2018)
Figures 9(c) and 9(d) shows the estimated annual NPCC Areas and Neighboring Region’s Loss of Load Expectation (LOLE) for the 2014-2018 period.

Figure 9(c) - Estimated Annual NPCC Areas and Neighboring Regions LOLE (2014 – 2018)
Figures 10(a) and 10(b) show the estimated annual NPCC Area Loss of Load Expectation (LOLE) estimated the 2014-2018 period.
Figure 10(a) - Estimated Annual NPCC Area LOLH (2014 – 2018)

Figure 10(b) - Estimated Annual NPCC Area LOLH (2014 – 2018)
Figures 10(c) and 10(d) shows the estimated annual Loss of Load Expectation (LOLH) for NPCC Areas and neighboring Regions for the 2014-2018 period.

Figure 10(c) - Estimated Annual LOLH for NPCC Areas and Neighboring Regions (2014 – 2018)
Figures 11(a) and 11(b) shows the estimated annual Expected Unserved Energy (EUE) for NPCC Areas for the 2014-2018 period.
Figure 11(a) - Estimated Annual NPCC Area EUE (2014 – 2018)

Figure 11(b) – Estimated Annual NPCC Area LOLH (2014 – 2018)
Figures 11(c) and 11(d) shows the estimated annual Expected Unserved Energy (EUE) for NPCC and the neighboring Regions for the 2014-2018 period.
Table 4 shows the percentage difference between the amount of annual energy estimated by the GE MARS program and the amount reported in the *NERC 2013 Long Term Reliability Assessment*. This is primarily due to the differences in the NPCC Area assumptions used for their respective energy forecasts. The GE MARS calculation for the total estimated NPCC annual energy is approximately 3 – 5 percent higher than the corresponding sum of the NPCC Areas annual energy forecasts.
### Table 4 – Comparison of Energies Modeled (Annual MWhrs)

<table>
<thead>
<tr>
<th>Region</th>
<th>Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
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<tr>
<td>Quebec</td>
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<tr>
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<td>2014</td>
<td>189,666,944</td>
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<tr>
<td>2013 LTRA</td>
<td></td>
<td>184,657,255</td>
<td>184,139,419</td>
<td>186,215,000</td>
<td>187,109,684</td>
<td>188,669,341</td>
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<td>(MARS-LTRA)</td>
<td>5,358,857</td>
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<td>4,097,640</td>
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<tr>
<td>% (MARS-LTRA)/LTRA</td>
<td>2.9%</td>
<td>3.3%</td>
<td>2.2%</td>
<td>1.3%</td>
<td>3.3%</td>
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<tr>
<td>Maritimes</td>
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<tr>
<td>MARS</td>
<td>2014</td>
<td>27,269,334</td>
<td>27,461,594</td>
<td>27,448,072</td>
<td>27,446,702</td>
<td>27,474,180</td>
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<td>27,268,000</td>
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<td>27,385,000</td>
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<tr>
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<td>66,594</td>
<td>63,072</td>
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<tr>
<td>% (MARS-LTRA)/LTRA</td>
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<td>0.2</td>
<td>0.2</td>
<td>0.2</td>
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<tr>
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<td>143,757,472</td>
<td>146,375,472</td>
<td>149,448,416</td>
<td>151,278,512</td>
<td>153,289,536</td>
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<td>131,037,000</td>
<td>131,831,000</td>
<td>133,274,000</td>
<td>133,420,000</td>
<td>133,454,000</td>
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<tr>
<td>(MARS-LTRA)</td>
<td>12,720,472</td>
<td>14,544,472</td>
<td>16,174,416</td>
<td>17,858,512</td>
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<tr>
<td>% (MARS-LTRA)/LTRA</td>
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<td>11.0</td>
<td>12.1</td>
<td>13.4</td>
<td>14.9</td>
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<td>New York</td>
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<tr>
<td>MARS</td>
<td>2014</td>
<td>172,192,144</td>
<td>174,193,488</td>
<td>176,807,168</td>
<td>177,703,056</td>
<td>179,282,480</td>
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<td>165,571,000</td>
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<td>167,054,000</td>
<td>167,703,000</td>
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<tr>
<td>(MARS-LTRA)</td>
<td>7,540,144</td>
<td>8,622,488</td>
<td>10,003,168</td>
<td>10,649,056</td>
<td>11,579,480</td>
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<tr>
<td>% (MARS-LTRA)/LTRA</td>
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<td>5.2</td>
<td>6.0</td>
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<tr>
<td>MARS</td>
<td>2014</td>
<td>137,849,920</td>
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<td>134,748,368</td>
<td>132,376,136</td>
<td>131,774,464</td>
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<td>141,053,400</td>
<td>137,322,300</td>
<td>134,381,600</td>
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<tr>
<td>(MARS-LTRA)</td>
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<td>366,768</td>
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<tr>
<td>% (MARS-LTRA)/LTRA</td>
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<td>-0.4</td>
<td>0.3</td>
<td>0.5</td>
<td>-0.1</td>
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<tr>
<td>Year</td>
<td>2014</td>
<td>2015</td>
<td>2016</td>
<td>2017</td>
<td>2018</td>
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<tr>
<td>NPCC</td>
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<tr>
<td>MARS</td>
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<td>675,732,608</td>
<td>682,576,256</td>
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<td>646,258,719</td>
<td>648,059,600</td>
<td>646,675,084</td>
<td>649,110,941</td>
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<tr>
<td>(MARS-LTRA)</td>
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<td>26,068,449</td>
<td>27,876,336</td>
<td>29,057,524</td>
<td>33,465,315</td>
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<tr>
<td>% (MARS-LTRA)/LTRA</td>
<td>3.4%</td>
<td>4.0%</td>
<td>4.3%</td>
<td>4.5%</td>
<td>5.2%</td>
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</table>
Figures 12(a) and 12(b) summarize the estimated annual NPCC Area Loss of Load Expectation (LOLE) from previous NPCC Multi-Area Probabilistic Reliability Assessments under Base Case assumptions for the expected load level.
This retrospective summary illustrates the NPCC Areas have generally demonstrated, on average, an annual LOLE significantly less than 0.1 days/year.

Figures 13(a) and 13(b) adds the estimated annual NPCC Area Loss of Load Expectation (LOLE) estimated for 2014 – 2018.
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 2013 -2018 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 2013 - 2014 time
NPCC 2013 LONG RANGE ADEQUACY OVERVIEW

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 2013 summer and November 2012 to March 2014 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 (2013 - 2014) 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 2014 - 2018 time period, to consistently review the resource adequacy of NPCC Areas and neighboring Regions under Base Case (likely available resources and transmission) assumptions, recognizing the above considerations.

Reliability for the long-range (2014 – 2018) analysis will be measured by calculating the annual Loss of Load Expectation (LOLE) for each NPCC Area and neighboring Regions for each calendar year. In addition, Loss of Load Hours (LOLH) and Expected Unserved Energy will also be similarly estimated for the NPCC Areas.

3. Schedule

A report of the results of the summer assessment will be published no later than April 30, 2013.

A report of the results of the winter assessment will be published no later than June 28, 2013.

A report summarizing the results of the NPCC Long Range Adequacy Overview will be published no later than December 31, 2013.
APPENDIX B
Modeled Capacity and Load at time of Area’s Annual Peak,
Based on Composite Load Shape

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<td>Capacity (MW) *</td>
<td>41,190</td>
<td>6,968</td>
<td>31,887</td>
<td>38,405</td>
<td>30,208</td>
<td>191,554</td>
<td>50,998</td>
<td>37,196</td>
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<td>1,251</td>
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<td>-817</td>
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<td>Load (MW)</td>
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<td>28,290</td>
<td>33,725</td>
<td>22,937</td>
<td>159,712</td>
<td>43,023</td>
<td>31,356</td>
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<td>15,146</td>
<td>2,264</td>
<td>1,650</td>
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<td>Response (MW)</td>
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</tr>
<tr>
<td>Reserves (%)</td>
<td>11</td>
<td>33</td>
<td>28</td>
<td>18</td>
<td>35</td>
<td>25</td>
<td>21</td>
<td>21</td>
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<td>Maintenance -</td>
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<td>48</td>
<td>0</td>
<td>58</td>
<td>106</td>
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<td>0</td>
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<td>Peak Week (MW)</td>
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<tr>
<td>Wind Output at</td>
<td>694</td>
<td>572</td>
<td>96</td>
<td>62</td>
<td>460</td>
<td>1,227</td>
<td>192</td>
<td>144</td>
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<tr>
<td>time of Area Peak</td>
<td></td>
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<td></td>
<td></td>
<td>***</td>
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<tr>
<td>Wind Nameplate</td>
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<td>889</td>
<td>684</td>
<td>1,367</td>
<td>2,498</td>
<td>8,158</td>
<td>1,477</td>
<td>1,108</td>
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<td>Capacity (MW)</td>
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### NPCC 2013 LONG RANGE ADEQUACY OVERVIEW

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<td>31,651</td>
<td>187,712</td>
<td>51,423</td>
<td>37,506</td>
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<tr>
<td><strong>Purchase/Sale (MW)</strong></td>
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<td>0</td>
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<td>1,237</td>
<td>0</td>
<td>-817</td>
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<td>0</td>
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<td><strong>Load (MW)</strong></td>
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<td>34,138</td>
<td>22,852</td>
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<td>43,867</td>
<td>31,971</td>
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<td>245</td>
<td>3,156</td>
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<td>905</td>
<td>15,197</td>
<td>2,474</td>
<td>1,803</td>
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<td>23</td>
<td>15</td>
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<td>19</td>
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<td>144</td>
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<td>1,108</td>
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<td>22,801</td>
<td>166,147</td>
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<td>32,237</td>
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<td>36</td>
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<tr>
<td><strong>Wind Output at time of Area Peak (MW)</strong></td>
<td>973</td>
<td>659</td>
<td>231</td>
<td>62</td>
<td>775</td>
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<td>4,212</td>
<td>10,597</td>
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## NPCC 2013 LONG RANGE ADEQUACY OVERVIEW

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<td>168,232</td>
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<td>905</td>
<td>15,197</td>
<td>2,854</td>
<td>2,080</td>
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<td>35</td>
<td>15</td>
<td>15</td>
<td>39</td>
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<td>21</td>
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<tr>
<td>Maintenance - Peak Week (MW)</td>
<td>**</td>
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<td>0</td>
<td>0</td>
<td>516</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wind Output at time of Area Peak (MW)</td>
<td>973</td>
<td>674</td>
<td>231</td>
<td>62</td>
<td>775</td>
<td>**</td>
<td>1,544</td>
<td>192</td>
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<tr>
<td>Wind Nameplate Capacity (MW)</td>
<td>3,244</td>
<td>1,412</td>
<td>1,197</td>
<td>1,367</td>
<td>4,212</td>
<td>10,897</td>
<td>1,477</td>
<td>1,108</td>
</tr>
</tbody>
</table>
## NPCC 2013 LONG RANGE ADEQUACY OVERVIEW

<table>
<thead>
<tr>
<th>Year</th>
<th>Quebec</th>
<th>Maritime Area</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
<th>PJM-RTO</th>
<th>RFC-OTH</th>
<th>MRO-US</th>
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<tbody>
<tr>
<td>2018</td>
<td>(Jan)</td>
<td>(Feb)</td>
<td>(Aug)</td>
<td>(Aug)</td>
<td>(Jul)</td>
<td>(Jul)</td>
<td>(Jul)</td>
<td>(Jul)</td>
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<tr>
<td>Capacity (MW)</td>
<td>42,552</td>
<td>7,441</td>
<td>32,476</td>
<td>38,405</td>
<td>30,547</td>
<td>194,776</td>
<td>52,841</td>
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<tr>
<td>Purchase/Sale (MW)</td>
<td>1,068</td>
<td>153</td>
<td>-6</td>
<td>1,905</td>
<td>0</td>
<td>-817</td>
<td>0</td>
<td>0</td>
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<tr>
<td>Load (MW)</td>
<td>38,254</td>
<td>5,232</td>
<td>30,155</td>
<td>35,103</td>
<td>22,610</td>
<td>168,011</td>
<td>45,053</td>
<td>32,836</td>
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<tr>
<td>Nameplate Demand Response (MW)</td>
<td>1,132</td>
<td>246</td>
<td>2,986</td>
<td>1,289</td>
<td>905</td>
<td>15,197</td>
<td>3,061</td>
<td>2,231</td>
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<tr>
<td>Reserves (%)</td>
<td>11</td>
<td>36</td>
<td>14</td>
<td>15</td>
<td>39</td>
<td>19</td>
<td>21</td>
<td>21</td>
</tr>
<tr>
<td>Maintenance - Peak Week (MW)</td>
<td>**</td>
<td>17</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wind Output at time of Area Peak (MW)</td>
<td>973</td>
<td>688</td>
<td>231</td>
<td>62</td>
<td>959 ***</td>
<td>1,583</td>
<td>192</td>
<td>144</td>
</tr>
<tr>
<td>Wind Nameplate Capacity (MW)</td>
<td>3,244</td>
<td>1,437</td>
<td>1,197</td>
<td>1,367</td>
<td>5,211</td>
<td>10,897</td>
<td>1,477</td>
<td>1,108</td>
</tr>
</tbody>
</table>

* Wind capacity included at nameplate rating; demand response not included in capacity
** Capacity for Quebec reflects scheduled maintenance and restrictions
*** Random draws using a probability density function during the Monte Carlo simulation are used to simulate unit output. This value reflects an expected value of that function.
APPENDIX C

2013 NERC Long-Term Reliability Assessment (LTRA) Narratives

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

Beginning October 1, 2013, the New Brunswick System Operator (NBSO) was amalgamated with NB Power, with NB Power taking over the role of the Reliability Coordinator for the Maritimes Area from the NBSO as well as becoming the Balancing Authority for the NB, PEI, and northern Maine sub areas. Nova Scotia Power Inc. (NSPI) is the Balancing Authority for Nova Scotia.

Generation
As shown in Table 5, the primary sources of fuel in the Maritimes Area are oil and coal, followed by hydro, natural gas, and nuclear. Other capacity sources include wind and biomass.

<table>
<thead>
<tr>
<th>Maritimes</th>
<th>2013 Existing Capacity (MW)</th>
<th>Share (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1,709</td>
<td>25.1%</td>
</tr>
<tr>
<td>Petroleum</td>
<td>1,857</td>
<td>27.3%</td>
</tr>
<tr>
<td>Gas</td>
<td>848</td>
<td>12.5%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>660</td>
<td>9.7%</td>
</tr>
<tr>
<td>Hydro</td>
<td>1,333</td>
<td>19.6%</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Geothermal</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Wind</td>
<td>252</td>
<td>3.7%</td>
</tr>
<tr>
<td>Biomass</td>
<td>141</td>
<td>2.1%</td>
</tr>
<tr>
<td>Solar</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>6,800</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Demand, Resources, and Planning Reserve Margins
During summer and winter peak load periods, all Planning Reserve Margins for the Maritimes Area exceed 26 percent during the LTRA assessment time frame.

With fiscal restraint, challenging economic conditions, and anticipated gain and loss-of-loads, the aggregated growth rate for the combined subareas increases slightly and then turns marginally negative for both the summer and winter seasonal peak load periods.
over the 10-year LTRA assessment period. This indicates that any aggregated growth will be effectively offset by the sum of any DSM projections or load losses included in the subarea forecasts.

Though not specifically identified in the load projections, the load growth in the southeastern corner of New Brunswick has outpaced the rest of that subarea. Planning studies to propose transmission solutions that will reliably supply load in the southeastern area, which includes the Prince Edward Island and Nova Scotia Interconnections, are ongoing. Nova Scotia is expected to experience modest load reductions. The declines in these two subareas more than offset the modest growth forecast for the much smaller Prince Edward Island area, where an increase in electric heating is driving an average annual increase of 1.7 percent for the LTRA assessment period, and the northern Maine region, where a practically flat annual growth rate of 0.5 percent was projected for all assessment years.

Current and projected Energy Efficiency effects are incorporated directly into the load forecast for each of the areas. DR is specifically identified. Winter DR is projected at levels approximating 250 MW until 2019; after 2019, it drops to about 185 MW. DR in the Maritimes Area is uniformly load-modifying and is not used for peak shaving. It is used to reduce demand during emergencies and is not backed by capacity reserves.

Jurisdictions within the Maritimes Area have established Energy Efficiency corporations or government agencies whose mandates are to provide sustainable Energy Efficiency and conservation solutions to customers. Policy drivers include maintaining affordable electricity prices for customers and lessening the impact of energy use on the environment.

Additionally, a pilot program called PowerShift Atlantic is developing the capability to use load control for Ancillary Services. Launched in 2010 as part of the Clean Energy Fund, PowerShift Atlantic is a collaborative research project led in partnership by New Brunswick Power, Saint John Energy, Maritime Electric, Nova Scotia Power, New Brunswick Power – System Operator, the University of New Brunswick, Natural Resources Canada, the government of New Brunswick, and the government of Prince Edward Island. This four-year innovative program will run until 2014, piloting technology that shifts energy supply to specific appliances in homes and commercial buildings in order to optimize wind generation with minimal or no disruption to participating electric utility customers.

There is one planned retirement over the LTRA assessment period, located in Nova Scotia. A 153-MW generator is expected to be retired in January 2018 and is tied to the conceptual construction of an undersea HVdc cable between Nova Scotia and the Canadian Province of Newfoundland and Labrador as part of the Muskrat Falls hydroelectric generation development. Unit retirements in Nova Scotia are reviewed and re-evaluated based on system requirements and regulatory compliance. The 33-MW
Burnside 4 generator in Nova Scotia unit is out of service and is expected to be back in
service in 2015. Because of its small size, it does not have a significant effect on
resource adequacy measures.

In an effort to retain large industrial customers that own renewable energy sources in
New Brunswick and promote renewable energy, New Brunswick Power, the government-
owned utility in New Brunswick, purchases surplus renewable energy from them. The
energy produced never enters the New Brunswick system and is netted out against the
customers’ load. Current load forecasts assume no further uptake of this program. The
impact of this program on resource adequacy is minimal since the major sources are
already included in area capacity totals. There are no other significant increases in
distributed generation identified in the Maritimes Area except in Nova Scotia. Existing
distributed resources are netted against load and not counted as capacity. In Nova Scotia,
increased amounts of renewable generation will be connected to the distribution system
through the Community Feed-in-Tariff as outlined in the province’s Renewable
Electricity Plan in April 2010. Further study will be required to fully understand the cost
and technical implications related to possible transmission upgrades and new operational
demands on existing infrastructure. Nova Scotia Power has commissioned a renewables
integration study with General Electric. The results of the study will be available this
year and should provide insight into the resource adequacy and operational issues related
to increased renewables.

The PowerShift Atlantic pilot project is an example of a potential “nontraditional”
Demand-Side resource that could be developed in the Maritimes Area. The program
attempts to balance variable wind generation against loads that contain some degree of
energy storage, such as water heaters to make more effective use of wind resources. Any
impact on resource adequacy would be positive since it allows wind to be dispatched with
less variability.

With the exception of minimal summer derates in northern Maine, biomass facilities in
the Maritimes are not derated during peak load periods. Hydro facilities contain enough
storage at the sites to allow them to be dispatched at their full ratings during peak load
periods. Currently in New Brunswick, Prince Edward Island, and Northern Maine, wind
generators are accredited with on-peak capacity based on their observed or expected
seasonally adjusted capacity factors. In Nova Scotia, the firm capacity of wind projects is
assumed to be 20 percent of the installed capacity if the project has the necessary
transmission capacity available. The Maritimes Area is reviewing and assessing
previously used methods for attributing on-peak wind capacity. To this end, for
probabilistic resource adequacy analysis at the NPCC regional level, the Maritimes Area
supplies an hourly wind profile rather than a derated capacity value during peak load
periods.

Plans are underway for the individual jurisdictions within the Maritimes Area to
coordinate the sharing of wind data and possibly wind forecasting information and
services. With the integration of more variable resources, it may become necessary to curtail these generation levels at light load periods to ensure adequate levels of Spinning Reserves and inertia for frequency control. The grid codes in the area require the ability to curtail to be designed into the control systems for large-scale variable resources and to be available for system operators to dispatch accordingly.

The Maritimes Area is not dependent on capacity transactions with neighboring areas to meet its Reserve Margin requirements. Beginning in 2018 and continuing well beyond the assessment period, the Maritimes Area has included 153 MW of firm imports from the Newfoundland utility, Nalcor, but this is completely offset by the corresponding retirement of a coal-fired generator in Nova Scotia with no significant impacts on resource adequacy.

Transmission and System Enhancements
During the review period, one major new transmission line addition is categorized as Conceptual. In 2018, development of the Muskrat Falls hydroelectric project would see the installation of an HVdc undersea cable link (Maritime Link) between Newfoundland and Labrador and Nova Scotia.

In recent years, the load growth in southeastern New Brunswick has exceeded growth in other areas of the province. This has resulted in increased reliance on the Dedicated Path Logic (DPL) SPS as well as the eastern UVLS schemes for loss of 345-kV lines feeding the Southeast. Planning studies are ongoing to propose transmission solutions that will reliably supply load in the southeastern area, which includes the Prince Edward Islands and Nova Scotia Interconnections.

In 2014, a 345-kV breaker installation will complete a ring bus at the tap point to which the 467-MW Belledune plant in New Brunswick is connected, increasing the reliability supply from the second-largest generator in the Maritimes Area. Additionally, the Eel River HVdc Interconnection with the Canadian province of Québec will be refurbished during 2014. This interface provides import and export capability up to 350 MW with Quebec and contributes to frequency response in the Maritimes Area. An additional 240-kV breaker will be installed to allow the separation of supplies to two 240/138-kV transformers in the substation at Eel River.

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

Regarding system enhancements, a new 75-Mvar reactor will be installed during 2014 at the Belledune Terminal and will provide additional voltage control in the area during times of light load. Undervoltage Loadshedding (UVLS) is used throughout the Maritimes Area to maintain adequate voltages during contingencies to major transmission...
facilities. In particular, this is the case in southeastern New Brunswick where, driven by a lack of generating facilities, UVLS and Special Protection Systems (SPS) facilities are critical to maintain voltages during loss of major transmission facilities feeding that sector. In that region, up to 475 MW (as estimated at peak load) can be interrupted using UVLS. This is not expected to change during the LTRA assessment period; however, studies are underway to identify specific enhancements that may increase transfer capabilities and reliability and reduce exposure to events that may trigger UVLS operation.

There are currently no specific plans to install more SPS in the Maritimes Area, but this does not rule out the possibility during the LTRA assessment period. SPS are considered when it is in the best interests of the customer to provide an efficient and reliable electric system. The ongoing studies to enhance the capabilities of the southeastern transmission supply lines will assess the use of such technology. Current SPS are expected to remain in service for the LTRA assessment period.

As previously mentioned, while still in pilot study mode, PowerShift Atlantic seeks to take control of loads with some inherent energy storage capability (such as water heaters), dispatching their reduction as variable wind resources drop in output and reintroducing them when the wind generation picks back up. This levels the output from these variable resources and frees up traditional resources from this balancing duty, allowing them to be used to supply the remaining loads.

The main utility in New Brunswick (New Brunswick Power) is investing heavily in smart grid technology, which includes capabilities to control loads in its jurisdiction. To the extent that this leads to a reduction in peak loads, it will enhance reliability.

**Long-Term Reliability Issues**

With a capacity of approximately 1,330 MW, the hydroelectric power supply system in the Maritimes Area is predominantly run-of-the-river (as opposed to storage-based) and is not able to be held in reserve to stave off drought conditions. If such conditions were to exist in the Maritimes Area, operation of the system would be relatively unchanged. The hydro system would still be used to follow load in the area and respond to sudden short-term capacity requirements. Thermal units would be used to keep the small storage capability of the hydro systems usable for load following and peak supply.

Renewable Portfolio Standards (RPS) have led to the development of substantially more wind generation capacity than any other renewable generation type. Reduced frequency response is associated with wind generation and, with increasing levels in the future, may require displacement with conventional generation during light load periods.

Because of the relative size of the area’s largest generating units compared to its aggregated load, the area carries substantial reserve capacity. For this reason, a lack of response from some of the loads expected to be shed during an interruption request will
not significantly affect resource adequacy. For the same reason, and because the area
peaks in winter as opposed to neighboring jurisdictions that peak in summer, long-term
outages to individual units do not cause undue stress from a technical perspective. It is
expected that any capacity or energy shortfalls due to long-term unit outages could be
offset by purchases from New England during their off-peak season, or from Québec.

There are no significant increases in distributed generation identified in the Maritimes
Area except in Nova Scotia, where increased amounts of renewable generation will be
connected to the distribution system through the Community Feed-in-Tariff outlined in
the province’s Renewable Electricity Plan in April 2010. Further study will be required
to fully understand the cost and technical implications related to possible transmission
upgrades and new operational demands on existing infrastructure.

The government has acknowledged the need to develop less intermittent sources of
renewable energy in the New Brunswick subarea. With the significant amount of large-
scale wind energy currently being balanced on New Brunswick’s system, the next phase
of renewable energy development will focus on smaller scale projects, with a particular
emphasis on nonintermittent forms of generation, such as wood-based biomass. Wind
ergy will continue to be integrated in the New Brunswick balancing area, but in
measured and manageable stages. In Nova Scotia, approximately 216 MW of wind
generation, including distributed resources, is planned for installation during the
assessment period. Additional RPS energy is expected to be sourced from the
Conceptual tie Maritime Link HVdc connection to the Muskrat Falls hydroelectric power
project in the Canadian province of Newfoundland and Labrador. The Maritimes Area
examines cases where a complete absence of wind in the area occurs due to weather
conditions and has concluded that the area is not overly reliant on wind generation to
meet its 20 percent reserve criterion, the level at which the area meets the NPCC resource
adequacy reliability criterion.

To reduce emissions associated with energy production, governments in the Maritimes
Area introduced RPSs that led to a large-scale development of wind energy resources.
Current emissions limits in the Maritimes Area are specified as annual system volumes
rather than generator-specific volumes, providing flexibility in the operation of the fleet.
Future regulations limiting GHG emissions are expected and could limit the future
utilization of fossil-fuelled generation. System Operators in the Maritimes Area are
tracking such developing standards and conducting analyses regarding their impact on
future resource adequacy.

Currently, the increasing load in southeastern New Brunswick and additional renewable
resources throughout the area are being examined in the Maritimes Area as two emerging
reliability issues. Load growth in the southeastern area of New Brunswick has been more
rapid than in other areas in the province. Voltages and thermal loading on lines are
approaching unacceptable levels during 345-kV contingencies for various operating
scenarios. This issue may require transmission reinforcements four to eight years from
With recent reductions in load forecasts, emphasis on peak load reduction in DSM programs, and a potential conceptual tie to Newfoundland that may provide a new source in the area, New Brunswick Power is studying transmission enhancements and SPS solutions to the overload and undervoltage issues that currently do not include 345-kV line construction within the LTRA assessment period.

If enhancements are not made and load continues to grow, this issue could affect system reliability by threatening voltage instability and potentially overloading circuits for 345-kV outages feeding that area. Though the load growth and potential voltage issues are localized to southeastern New Brunswick, the circuit overloads occur on parallel 138-kV circuits leading from sources in southwestern New Brunswick to the high load areas in the Southeast. The localized low voltages and overloads of parallel circuits during contingencies would be moderate and unlikely to create reliability problems in neighboring Regions.

Generation levels are unaffected and with lower expected loads, the issue is purely transmission-related—predominately affecting transfer capabilities from New Brunswick to Prince Edward Island and Nova Scotia. The impact on the resource adequacy LOLE value is captured by modeling a reduction in tie transfer capabilities between subareas.

The 2012 NPCC Interim Review of Resource Adequacy showed that after transfer levels were reduced from 300 MW to 150 MW, LOLE values did not exceed the NPCC criteria of one day in 10 years of resource inadequacy.

In southeastern New Brunswick, interconnection of any new resources would likely help mitigate this emerging issue. New Transmission circuits (if required) would be feasible, since New Brunswick Power has already secured right-of-way corridors for the circuits needed to address the issue.

The issue is most problematic for 345-kV contingencies when New Brunswick loads are at near peak levels during particularly high southern or northern New Brunswick generation dispatches with high exports to Prince Edward Island and/or Nova Scotia.

Nova Scotia’s Renewable Electricity Standard (RES) would displace significant amounts of fossil-fuelled generation with renewable resources. By 2015, 25 percent of the province’s electricity sales will be supplied by renewable energy sources. This increases to 40 percent by 2020.

The addition of renewable resources—particularly in Nova Scotia—is an emerging concern in the Maritimes area. Nova Scotia has commissioned a renewables integration study with General Electric. The results of the study will be available by the end of 2013 and will provide insight into the resource adequacy and operational issues related to increased renewables. The impacts on LTRA Reserve Margin Reference levels are positive as the addition of new resources actually enhances resource adequacy (provided
that existing traditional resources are not prematurely retired as a result of the new capacity).

Increasing the amount of renewable resources could affect system reliability if variable or low-mass, slow-speed units are added without considering the reduction of frequency response after system contingencies or transmission enhancements to prevent voltage or overload problems. Completing system impact studies prior to interconnecting new generation should identify whether the emergence of any of these issues could limit operation of—or the amount of—new renewable generation added to the system on a case-by-case basis.

Many of the sites chosen for new renewable generation facilities are located near the energy sources or existing transmission infrastructure. There is potential for such additions across the entire Maritimes area. While the added generation may relieve congestion in some cases, the lack of adequate transmission facilities could delay or limit the development of new renewable resources. The variable output and intermittent nature of many renewable resources is a major daily consideration for generation dispatchers. The low inertia effects on system frequency response will be felt mostly during off-peak, light load periods when high-mass units have been displaced by low-mass new renewable resources.

Several new resources being considered have short installation timelines, which makes long-term capacity projections used in the 2013 LTRA reference case less reliable as projects come and go in response to changing government incentive policies.
New England
ISO New England (ISO-NE) Inc. is a regional transmission organization (RTO), serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. It is responsible for the reliable day-to-day operation of New England’s bulk power generation and transmission system and also administers the Region’s wholesale electricity markets and manages the comprehensive planning of the regional BPS. The New England regional electric power system serves approximately 14.5 million people over 68,000 square miles. New England is a summer-peaking electric system.

Generation
As shown in Table 6, the primary source of fuel in the New England Area is natural gas, followed by oil and nuclear. Other capacity major sources include coal and hydro.

<table>
<thead>
<tr>
<th>New England</th>
<th>2013 Existing Capacity (MW)</th>
<th>Share (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>2,289</td>
<td>7.2%</td>
</tr>
<tr>
<td>Petroleum</td>
<td>7,083</td>
<td>22.3%</td>
</tr>
<tr>
<td>Gas</td>
<td>13,598</td>
<td>42.8%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>4,624</td>
<td>14.6%</td>
</tr>
<tr>
<td>Hydro</td>
<td>1,374</td>
<td>4.3%</td>
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<tr>
<td>Pumped Storage</td>
<td>1,720</td>
<td>5.4%</td>
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<tr>
<td>Geothermal</td>
<td>0</td>
<td>0.0%</td>
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<tr>
<td>Wind</td>
<td>97</td>
<td>0.3%</td>
</tr>
<tr>
<td>Biomass</td>
<td>932</td>
<td>2.9%</td>
</tr>
<tr>
<td>Solar</td>
<td>32</td>
<td>0.1%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>31,749</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Demand, Resources, and Planning Reserve Margins
New England’s (ISO-NE) LTRA Reference Margin Level (target reserve margin) is based on the capacity needed to meet the NPCC one day in 10 years loss-of-load expectation (LOLE) resource planning reliability criterion. The amount of capacity needed, referred to as the Installed Capacity Requirement (ICR), can and does vary from year to year, depending on expected system conditions. The ICR, which is calculated three years in advance for each Forward Capacity Auction, results in Reference Margin Level of 13.85 percent in 2014, 13.69 percent in 2015, 12.33 percent in 2016, and 13.65 percent in 2017. In this LTRA assessment, the last calculated Reference Margin Level (13.65 percent) is applied for the remaining years.

In the 2014 summer, ISO-NE’s Anticipated Resources will amount to 34,744 MW, which will result in an Anticipated Reserve Margin of 29.0 percent of the reference demand forecast of 26,929 MW. The Anticipated Reserve Margin falls just below the assumed
NPCC 2013 LONG RANGE ADEQUACY OVERVIEW

Reference Margin Level of 13.65 percent beginning in 2021, decreasing to 12.07 percent by 2023.

This Anticipated Reserve Margin during the annual peak reflects the Seasonal Claimed Capability (which could be higher than the Capacity Supply Obligation (CSO)) of all ISO-NE generators as well as demand resources and imports that have CSOs as a result of ISO-NE’s Forward Capacity Market (FCM) auctions.

The primary reason for the Anticipated Reserve Margin falling below the LTRA Reference Margin Level is that ISO-NE does not extend the import CSOs that are in place in 2016 through the remainder of the assessment period. The imports that are assumed for 2017 through 2023 are those based on long-term firm contracts, which are approximately 1,500 MW lower than the CSOs in 2016. In reality, that steep reduction in capacity will not occur because ISO-NE will procure the capacity needed to meet the Installed Capacity Requirement with its FCM. If the 2016 import amount was carried through the remainder of the assessment period, the Anticipated Reserve Margin would be nearly 20 percent in 2023. If the Anticipated Reserve Margin falls below the level required to meet the regional reliability standards due to retirements associated with environmental regulations, ISO-NE will purchase the needed capacity through its FCM.

As there has not been any change in the New England footprint or any significant changes in the economic outlook or the long-term weather outlook, the 2013 demand forecast has not changed significantly from the 2012 demand forecast. There are no particular areas where load growth is significantly above or below the regional aggregate New England load growth.

The 2014 summer peak demand forecast is 28,290 MW, and the Total Internal Demand, which takes into account 1,361 MW of passive demand resources (Energy Efficiency), is 26,929 MW. This year’s forecast of the 10-year summer Total Internal Demand compound annual growth rate (CAGR) is 0.84 percent, which is slightly higher than the 2012LTRA reference case projection of 0.79 percent, caused by changes in the economic forecast.

DSM in the ISO-NE BPS includes both active and passive demand resources. Active demand resources consist of real-time DR and Real-time Emergency Generation, which can be activated with the implementation of ISO-NE Operating Procedure No. 4 – Action during a Capacity Deficiency (OP-4). Some assets in the real-time DR programs are under direct load control by the load response providers (LRP). The LRP implements direct load control of these assets upon dispatch instructions from ISO-NE—for example, interruption of central air conditioning systems in residential and commercial facilities. Passive demand resources (i.e., Energy Efficiency and conservation) include installed measures (e.g., products, equipment, systems, services, practices, and strategies) on end-use customer facilities that result in additional and verifiable reductions in the total amount of electrical energy used during on-peak hours. Active demand resources are
based on the CSOs obtained through ISO-NE’s FCM three years in advance. The CSOs decrease slightly from 1,694 MW in 2014 to 1,621 WM in 2015 and then drop to 1,044 MW in 2016. Since there are no further auction results, the CSOs are assumed to remain at the same level through the end of the reporting period.

Energy efficiency is also secured by means of FCM CSOs. However, ISO-NE has developed an Energy Efficiency forecasting methodology that takes into account the potential impact of growing Energy Efficiency and conservation initiatives in the Region to project the amount of Energy Efficiency beyond the years when the FCM CSOs have already been procured. Energy efficiency has generally been increasing and is projected to continue growing throughout the study period, but at a continually decreasing growth rate. The amount of Energy Efficiency in 2014 is 1,361 MW, increasing by 13 percent to 1,535 MW in 2015, and then decreasing slightly to 1,520 MW in 2016. The amount of Energy Efficiency is projected to be about 2,800 MW by 2023.

Both passive and active demand resources are treated as capacity in New England’s FCM. As previously noted, the active demand resources can be triggered by ISO-NE in real time under OP-4 to help mitigate an actual or anticipated capacity deficiency by reducing the peak demand. For example, on July 22, the 2011 peak demand day, a total of 642 MW of active demand resources were activated and 644 MW responded, corresponding to a response rate of 100.3 percent. On another OP-4 occurrence on the morning of December 19, 2011, active demand resources reduced the load by 380 MW, which was 75.4 percent of the 504 MW activated. The reason for the lower response on that winter day was that the event occurred early in the morning when the loads were low and fewer demand resources were available to respond.

A significant number of active demand resources are serving as capacity in the FCM. Most of these resources are not dispatched in the ISO’s energy-market clearing process; rather, they are activated when the ISO faces a capacity deficiency during the operating day. ISO-NE is proposing market rule changes that allow DR to set market-clearing prices that better reflect the costs of activating these resources in the day-ahead and real-time energy markets.

In response to Order 745: Demand Response Compensation in Organized Wholesale Energy Markets, ISO-NE proposed two sets of market rule changes associated with the full integration of price-responsive demand into the energy markets. These market rule changes will require all real-time DR programs to participate as capacity resources, with the associated requirement to participate in the energy market starting on June 1, 2017.

ISO-NE is analyzing changing environmental compliance requirements that could impact generator availability due to economic impairment of generators complying with air, water, and GHG restrictions. Both the Salem Harbor and Vermont Yankee retirements were included in the Planning Reserve Margin calculations, and the reserve margin does fall below the 13.6 percent LTRA Reference Reserve Margin in 2021. ISO-NE has
adequate capacity up to three years in advance with its Forward Capacity Auctions and Annual Reconfiguration Auctions.

Salem Harbor Units 3 and 4, which are coal- and oil-fired units with a combined capacity of 587 MW, are scheduled to retire by June 1, 2014. As the Salem Harbor plant is located in the Boston subarea, ISO-NE performed a reliability review to determine the impact of the retirement of the full plant. ISO-NE found that under certain second contingency scenarios with a 345-kV line-out as the initial outage, thermal overloads could exist in the local area. To address these thermal overloads, ISO-NE and the affected TOs developed plans to perform 115-kV transmission line reconductoring projects on portions of five lines prior to the plant retirement. In addition, the Vermont Yankee Nuclear Power Plant, with a capacity of 600 MW, recently announced that it will be shutting down by the end of 2014.

ISO-NE continues to integrate new resources, including variable resources, into the network. All new resources are studied in detail by ISO-NE Operations Engineering prior to commercial operation. These are all integrated through the use of operating guides, interface limits, and the Energy Management System (EMS).

The ISO has made progress implementing the recommendations from the New England Wind Integration Study (NEWIS), which analyzed various planning, operating, and market aspects of wind integration for up to a 12-GW addition of wind resources to the system. The recommendations developed from NEWIS led ISO-NE to implement a centralized wind power forecast, which is currently under development. To facilitate system operation with potentially large amounts of wind power, ISO-NE Operating Procedure No. 14 Appendix F – Wind Plant Operators Guide (OP-14F) was implemented in September 2011. OP-14F is chiefly concerned with requirements for Real-time and static-type data that will facilitate accurate wind power forecasting over the intra-day, day-ahead, and week-ahead timescales, as well as data for use in situational awareness functions for ISO system operators.

The ISO will continue to analyze wind integration issues and work with stakeholders to address the issues challenging the wind interconnection process and the performance of the system with wind resources in locally constrained areas. New England is applying advanced technologies, including FACTS and HVdc, phasor measurement units (PMUs), and smart meters, which may be used to provide the regulation and reserve services required to reliably integrate variable renewable resources. Currently there is only 97 MW of on-peak wind capacity in New England, and only 135 MW (on-peak capacity) of Future-Planned wind additions during the study period.

Photovoltaic (PV) resources are rapidly developing in New England and predominantly are situated relatively close to load centers. Most of the PV resources, however, are not directly observable or controllable by the ISO and may respond differently to grid
disturbances than larger, conventional generators. New ISO initiatives are addressing these highly complex issues with stakeholders.

Firm summer capacity imports are based on FCM CSOs, which amount to 1,851 MW in 2014 and decrease to 1,607 MW in 2016. In addition to capacity imports that have CSOs, external transactions can participate in the Day-Ahead and Real-time Energy Markets. In 2012, the imports to New England from New York, New Brunswick, and Quebec at the time of the peak demand totaled 2,251 MW or 1,475 MW more than the CSO of 776 MW. At the time of the 2011 peak, the amount of actual imports was 2,001 MW, which was 765 MW more than the CSO. As the Forward Capacity Auction imports are based on one-year contracts, beginning in 2017 the imports will reflect only known, long-term Installed Capacity (ICAP) contracts totaling approximately 100 MW. If the imports beyond the 2016 summer do not clear in future FCM commitment periods, the lost capacity will be replaced by other supply or Demand-Side resources. For the 2014 summer, there is 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 holds constant through the assessment period.

Transmission and System Enhancements
There are several transmission projects projected to come on-line during the assessment period that are important to the continuation of, or enhancement to, system or subarea reliability. These projects are the result of progress made by the ISO and regional stakeholders in analyzing the transmission system in New England and developing and implementing back-stop solutions to address existing and projected transmission system needs. The major projects under development in New England include the Maine Power Reliability Program (MPRP), the New England East-West Solution (NEEWS), and the Long-Term Lower Southeast Massachusetts (SEMA) project. The new paths that are part of MPRP, many components of which are under construction, will provide the basic infrastructure necessary to increase the ability to move power from New Hampshire into Maine and improve the ability of Maine’s transmission system to move power into the local load pockets as necessary. NEEWS consists of a series of projects that will improve system reliability in areas including Springfield, Massachusetts, and Rhode Island, and increase total transfer capability across the New England east-to-west and west-to-east interfaces. The Long-Term Lower SEMA project addresses reliability concerns in the lower southeastern Massachusetts area, which includes Cape Cod.

At this time, there are no plans to install more UVLS schemes in New England. Currently, northern New England has the potential to use approximately 600 MW of load shedding as part of UVLS. However, it is important to recognize that a significant portion of this load shedding is normally not armed and is only armed under severe loading conditions with a transmission line or autotransformer already out of service.

Presently, two significant projects could completely eliminate the need for the UVLS or significantly reduce the likelihood of depending on such schemes: the Vermont Southern
Loop Project (completed in late 2010) and the MPRP (scheduled to be completed in 2015).

There are no SPSs that are proposed to be installed in lieu of proposed regulated transmission facilities to address system reliability needs. However, two new, temporary SPSs are to be installed in Maine as part of the MPRP. The first SPS is needed to ensure reliable system operation due to configuration changes at South Gorham while the MPRP is under construction. The second SPS is needed to ensure reliable system operation due to configuration changes in the Rumford area while the MPRP is under construction. Once construction of the necessary portions of the MPRP is complete (anticipated in 2015), these two temporary SPSs will be removed. It should also be noted that several existing SPSs will be removed from service after the MPRP project is completed.

New smart grid technologies are being used in New England to improve the electric power system’s performance and operating flexibility. Smart grid technologies, such as FACTS, are used to facilitate the integration of variable resources in the power system. Because much of the potential for wind development is remote from load centers, additional transmission development may be pursued. Some of these transmission improvements may use HVdc technology, which is cost-effective over long distances. Both HVdc and FACTS are regularly considered as part of transmission planning studies when their application economically meets system or generator interconnection needs.

On July 1, 2010, ISO-NE received a U.S. Department of Energy (DOE) Smart Grid Investment Grant Award and subsequently began a three-year Synchrophasor Installation and Data Utilization (SIDU) project. The goal of the project is to provide ISO-NE and associated TOs with a significantly expanded base of PMUs, Phasor Data Concentrators, and greatly enhanced phasor data analytical tools. The SIDU project supplements the five existing PMUs in the Region with at least 30 new PMUs at various substations around New England. The project is focused on the deployment of Synchrophasor technology as a foundation for the next generation of power grid situational awareness and serves as the smart grid technology platform upon which advanced analysis and visualization tools can be deployed. It is hoped that the SIDU project will yield efficiencies in the way the grid is operated and will improve reliability, serving as a backbone for regional smart grid efforts.

In addition, several investor-owned and municipal utilities in New England are conducting smart grid pilot programs or projects ranging from smart meter deployments to full-scale direct load control and distribution automation projects. ISO-NE anticipates that these projects may lead to more significant smart grid assets becoming available for potential utilization during the assessment period.

**Long-Term Reliability Issues**
The New England area is not currently experiencing a drought. However, in the event that the Region was to experience an extended drought, some traditional hydroelectric
stations could be temporarily capacity- or energy-constrained. Due to the relatively small contribution to overall capacity from hydroelectric facilities (1,374 MW or 4.3 percent), any potential reduction in hydroelectric energy production due to regional drought conditions could be readily supplemented by increased levels of other types of generation.

New England has witnessed significant growth in the development of solar PV resources over the past few years, and continued growth of PV is anticipated. Regional PV installations are small (i.e., less than 10 MW) and [mostly] interconnected to the distribution system. States with policies more supportive of PV (e.g., Massachusetts) are experiencing the most growth of the resource. While existing amounts of PV have yet to have a significant impact on system operations, the ISO is working on several initiatives aimed at facilitating the reliable and efficient integration of significant amounts of PV in the Region.

RPSs [and related state goals targets] are for Energy Efficiency and renewable resources [to] supply 31.8 percent of the Region’s projected electric energy by 2022, and 20.2 percent of RPSs and policies addressing renewable supply goals.

Possible solutions for meeting or exceeding the Region’s RPSs include (1) developing the renewable resources in the ISO generator interconnection queue; (2) importing renewable resources from adjacent Control Areas; (3) building new renewable resources in New England not yet in the queue; (4) using new behind-the-meter projects; and (5) using eligible renewable fuels, such as biomass, in existing generators. Achievements in Energy Efficiency in the Region that exceed the levels in the Energy Efficiency forecast could reduce the amount of new renewable resources required to meet state RPSs.

Concerns exist over the resultant impacts from compliance with state RPSs and the potential build-out of these new renewable resources. Because of concerns over the increasing amounts of wind capacity, ISO-NE completed a major wind integration study that identified the detailed operational issues of integrating large amounts of wind resources into the New England power grid. The New England Wind Integration Study (NEWIS) found that the large-scale integration of wind resources is feasible, but the Region will need to continue addressing a number of issues, including the development of an accurate means of forecasting wind generation outputs. As a result of that recommendation, ISO-NE [is implementing] a centralized wind power forecasting service. The Wind Power Forecast Integration Project (WPFIP) is being implemented in two phases. The addition of VERs, particularly wind, will likely grow with time, increasing the need for flexible resources to provide operating reserves as well as other ancillary services, such as regulation and ramping.

22 If the development of renewable resources falls short of providing sufficient Renewable Energy Certificates (RECs) to meet the RPSs, load-serving entities can make state-established alternative compliance payments (ACPs). ACPs also can serve as a price cap on the cost of Renewable Energy Certificates. (Renewable Energy Certificates are tradable, nontangible commodities, each representing the eligible renewable generation attributes of 1 MWh of actual generation from a grid-connected renewable resource.)
Distributed energy resources must be integrated into the local electric company’s distribution systems and therefore must comply with the interconnection standards applicable to such systems. Although distributed generation has not traditionally been a major concern for BPS operation, the amount of distributed generation, particularly PV, has been increasing rapidly.

ISO-NE has been informed of two impending retirements: Salem Harbor Units 3 and 4 will cease operations in June 2014, and Vermont Yankee is scheduled to close by the end of 2014. Preserving the reliable operation of the system will become increasingly challenging with other potential retirements and the need for operating flexibility, particularly in light of the reliance on natural gas resources. As a result of these factors, the need for reliable resources, especially those able to provide operating reserves and ramping capabilities, is expected to increase. To begin addressing this need, the ISO procured additional operating reserves. To compensate for the observed nonperformance of generators relied on for contingency response, the ISO increased the total 10-minute operating reserve requirement by 25 percent. Consequently, the total 10-minute operating reserve previously equivalent to the largest single contingency is now 125 percent of this contingency.

Existing and pending state, regional, and federal environmental requirements will require the addition of pollution control devices to many generators, reducing water use and wastewater discharges, and in some cases, limiting operations and increasing retirements. The ISO initiated a study to better quantify the implications of the likely retirement of several generating units and their potential replacements. Most of the at-risk capacity would face compliance or retirement decisions starting late in this decade and extending into the early part of the next decade.

Pending EPA restrictions may require existing fossil fuel and nuclear capacity to mitigate the adverse impacts of cooling water use, with compliance due between 2014 and 2021 for some generators. Modification of cooling water use may be necessary for up to 12.1 GW of generating capacity, with a subset of 5.6 GW (those with larger withdrawal capacities) potentially needing to convert from once-through to closed-cycle cooling systems.

The EPA’s proposed revisions to the Effluent Limitation Guidelines (ELG) would require many thermal generating stations to reduce or remove certain contaminants from their wastewater discharges beginning in 2017. However, based on EPA’s proposed approach to the ELG revisions, ISO anticipates limited impact on existing fossil and nuclear stations in the Region.

Approximately 7.9 GW of existing coal- or oil-fired capacity in the Region is subject to EPA’s final MATS, which require compliance by early 2015. However, much of this capacity is already retrofitted with the controls needed to comply with state air toxics regulations and less than 1 GW of affected capacity is expected to retire due to MATS.
Recent revisions to air quality standards that limit ambient concentrations of ozone and its precursors, fine particulate matter, and sulfur dioxide will require additional reductions from larger fossil fuel-fired generators while technology-based performance standards affect other generators. At this time there are no planned outages for generator environmental retrofits that would impact reliability. Any retrofits required under MATS are expected to be completed (or have already been completed) during traditional outage periods. At this time, ISO-NE does not anticipate an impact on reliability during shoulder months due to environmental regulations being implemented.

The procedures currently in place to maintain system reliability include reliability agreements and out-of-merit unit commitments. However, ISO-NE is studying longer-term solutions to the problem, such as appropriate enhancements to wholesale market design and system planning procedures. Losing a significant quantity of coal, oil, and nuclear capacity could further increase the Region’s dependence on natural gas-fired resources. If all of the Region’s older oil units were to seek retirement, new capacity would be required to satisfy the Installed Capacity Requirement.

As part of the Strategic Planning Initiative, the ISO is collecting and analyzing data to identify the units expected to face significant capital investments in the longer term because of environmental compliance deadlines. In addition, a Strategic Transmission Analysis was used to evaluate how the retirement of at-risk units would affect reliability and to locate the most favorable locations for replacing the retired units. As part of this analysis, ISO-NE is also developing a conceptual system build-out, which would be necessary for combinations of unit retirements, repowering, and integrating remote wind generators.

During the past few years, ISO-NE grid operators experienced numerous events during stressed system conditions when the performance and flexibility of power plants and demand resources were insufficient to correct these situations in a timely manner. This led to a growing concern that as the power system continues to evolve, the mix of supply resources may be unable to operate when and as needed to maintain the grid’s present level of reliability.

These concerns arise from several different challenges ISO-NE is facing: (1) the increasing reliance on natural gas as a fuel source for power plants and the potential for reduced operational performance during stressed system conditions; (2) the large number of aging, economically challenged oil- and coal-fired generators that provide fuel diversity to the resource mix; and (3) the greater future needs for flexible supply resources to balance variable renewable resources that have operating characteristics markedly different from those of traditional generating resources. These three challenges are further discussed in the 2013 NERC LTRA.
New York
The New York Independent System Operator (NYISO) is the only BA within New York state. The NYISO is a single-state ISO that was formed as the successor to the New York Power Pool—a consortium of the eight IOUs—in 1999. The NYISO manages the New York State transmission grid, encompassing approximately 11,000 miles of transmission lines over 47,000 square miles and serving the electric needs of 19.5 million New Yorkers. New York experiences its peak load in the summer period with the all-time peak load of 33,956 MW in the summer of 2013.

Generation
As shown in Table 7, the primary source of fuel in the New York Area is natural gas, followed by oil and nuclear. Other capacity major sources include hydro and coal.

### Table 7

<table>
<thead>
<tr>
<th>Energy Source</th>
<th>2013 Existing Capacity (MW)</th>
<th>Share (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1,992</td>
<td>5.6%</td>
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<tr>
<td>Petroleum</td>
<td>8,948</td>
<td>25.3%</td>
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<tr>
<td>Gas</td>
<td>13,143</td>
<td>37.2%</td>
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<tr>
<td>Nuclear</td>
<td>5,411</td>
<td>15.3%</td>
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<tr>
<td>Hydro</td>
<td>3,826</td>
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</tr>
<tr>
<td>Pumped Storage</td>
<td>1,407</td>
<td>4.0%</td>
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<tr>
<td>Geothermal</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Wind</td>
<td>137</td>
<td>0.4%</td>
</tr>
<tr>
<td>Biomass</td>
<td>449</td>
<td>1.3%</td>
</tr>
<tr>
<td>Solar</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>35,311</strong></td>
<td><strong>100.0%</strong></td>
</tr>
</tbody>
</table>

Demand, Resources, and Planning Reserve Margins
The current Installed Reserve Margin (IRM) requirement that covers the period from May 2013 to April 2014 (2013 Capability Year) is 17.0 percent. For the LTRA assessment, the IRM is applied as the Reference Margin Level for the entire 10-year period. This requirement is set by the New York State Reliability Council (NYSRC) based upon an annual study conducted by its Installed Capacity Subcommittee (ICS). This is an increase of 1.0 percent compared to the 2012 LTRA reference case. The principal drivers for the increased IRM are a change in Special Case Resource (SCR) modeling, an updated LFU model, and an updated external area model.

There have been no footprint changes since the 2012LTRA. The economic outlook was updated in January 2013 with projections resulting in lower annual energy growth compared to a year earlier—0.47 percent per year in 2013 versus 0.59 percent per year in 2012. The long-term weather outlook has not changed compared to the 2012LTRA.

Due to the higher levels of consumer spending and economic growth associated with the Nassau and Suffolk counties, energy growth is projected to be higher in Long Island than
the state as a whole. There has been a gradual increase in the share of annual energy use during summer months—from 27.5 percent in 2000 to 28.6 percent in 2012. This is attributed to an increase in air conditioning usage.

The peak demand forecast shows a higher annual average rate of growth in the 2013LTRA reference case compared to the 2012LTRA reference case—0.96 percent in 2013 versus 0.85 percent in 2012. This is related to a gradual decline in the state-wide annual load factor that has been observed during the past eight years (a decrease in load factor occurs when the ratio of average annual energy to peak demand decreases from one year to the next). This indicates that summer peak demand is growing faster than annual energy supply.

DR is reported under Load as a Capacity Resource and treated on the supply-side in the calculation of Planning Reserve Margins. Voluntary DR is also reported as a resource. DR resources are modeled conservatively in planning studies to account for the possibility of the resources being unavailable or nonresponsive.

The New York Public Service Commission has authorized budgets for the state’s investor-owned utilities (IOUs) and the New York State Energy Research and Development Agency through 2015. In addition, the state’s two power authorities, Long Island Power Authority and the New York Power Authority, each have authorized spending through at least 2015 and have long-term plans for additional spending beyond 2015.

The Indian Point Power Plant (2 nuclear units) is speculated to retire by the end of 2015. If the Indian Point Power Plant licenses were not renewed and the plant was retired by the end of 2015 or thereafter, it would result in immediate violations of resource adequacy criteria. As reliance on natural gas as the primary fuel for electric generation increases, disruptions of natural gas supplies will have a greater impact on generator availability.

During the 10-year period, there is only one scheduled retirement amounting to 97 MW in June 2015. There are an additional 402 MW of proposed retirements, but no retirement dates are known. Two of those units (309 MW) submitted notices of intent to mothball or retire. As a result of the generator outage process described in the next paragraph, those units are currently operating under a Reliability Support Services agreement as their retirements would result in a reliability need.

The NYBA neither plans for nor relies on behind-the-meter generation for reliability purposes, except for those resources that opt to participate in one of the NYBA’s DR programs.

There are only two nontraditional resources in the NYBA’s markets: a 20 MW flywheel and an 8 MW storage battery, as listed in the 2013 Load and Capacity Data Report (Gold Book). 23 There is no reliability impact from these resources expected during the assessment period.

23 2013 Load and Capacity Data - "Gold Book".
As variable resources, such as wind, have been added to the resource mix, procedures have been modified and updated. For example, the NYBA implemented a centralized wind forecasting program to provide NYBA operations with a better estimate of the amount of energy produced by wind resources over various time frames.

Capacity transactions modeled in NYBA reliability studies are part of the NYBA’s resource mix to meet LOLE criteria. These transactions would be expected to perform on peak, or any other time, as needed to meet the demand.

Unforced Capacity Deliverability Rights (UDRs) are rights associated with new incremental controllable transmission projects that provide a transmission interface to a NYBA 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. A fourth project, the Hudson Transmission Project (HTP), with a 660 MW transmission capability went into service May 2013. Capacity transactions associated with UDRs are considered confidential market data. Only net capacity import totals can be publicly disclosed in order to maintain market confidentiality.

External capacity (ICAP) purchases and sales are administered by NYISO. An annual study is performed to determine the maximum level of capacity imports from neighboring BAs allowed without violating the LOLE criteria. For the Capability Year 2013–2014, the amount is 2,480 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 NYBA border when scheduled. All external ICAP suppliers must also meet the eligibility requirements as specified in the Installed Capacity Manual.

The NYBA does not rely on emergency imports to meet the assessment area’s Reference Margin Level. However, transfer capability is reserved on the ties with the Region’s neighbors in planning studies to allow for emergency imports as one potential emergency operating procedure step in the event of a system emergency.

Capacity transactions modeled in NYBA’s assessments have met the requirements as defined in NYBA’s tariffs. Both NYBA and the respective neighboring assessment areas agreed upon the terms of the capacity transaction, including, for example, a) the megawatt value, b) the duration (minimum of one year), c) the contract path, d) the source of capacity, d) the capacity rating of the resource. Transfer capability is reserved on the ties with the Region’s neighbors in planning studies to allow for emergency imports as one potential emergency operating procedure step in the event of a system emergency.

Transmission and System Enhancements
The HTP is a new market-based tie line between PJM and NYISO from PSE&G’s Bergen 230-kV substation to Con Edison’s W.49th Street 345-kV station. The project consists of a back-to-back HVdc converter in New Jersey with a submarine 345-kV ac

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cable from the converter station to New York City. The project is capable of transferring 660 MW, but has firm capacity withdrawal rights from PJM of 320 MW. The project went into service May 2013. Additional local TO plans include transmission and sub transmission system reinforcements throughout the state.

The NYISO 2012 CRP identified solutions to thermal overloads identified in the RNA. The reliability needs identified in the Rochester and Syracuse areas will be resolved by 2017 with permanent solutions identified in the most recent TO Local Transmission Plans. These permanent solutions include a new RG&E 345/115-kV substation and reconductoring of a National Grid 115-kV line. In the interim, mitigating measures, including local operating procedures, will be called on—if required—to prevent overloads. The reliability need identified for Ramapo 345/138-kV transformers was mitigated by the installation of new independent protective relay in 2013.

Historically, the most congested transmission paths in New York are Central East, Leeds–Pleasant Valley, and Dunwoodie–Shore Road. The constraints on Central East and Leeds–Pleasant Valley are driven by demands in the lower Hudson Valley resulting in high transfers of power from Upstate New York to New York City. The Dunwoodie–Shore Rd. constraint is driven by Long Island demand. These constraints could be mitigated through additional transmission, generation, or demand reduction.

There are no project delays or temporary service outages for any transmission facilities that will impact long-term reliability of BPTFs during the assessment period. However, if the Indian Point Power Plant licenses are not renewed and the plant was to retire by the end of 2015 or thereafter, it would result in immediate violations of transmission security criteria.

As part of the DOE Smart Grid Investment Grant, 938 Mvar of smart grid-enabled capacitor banks will be installed at various subtransmission voltage levels and 39 PMUs will be installed at bulk power stations throughout New York by June 2013.

NYBA BPS security is maintained by limiting power transfers according to the determined transfer limits, including voltage-constrained transfer limits. Therefore, UVLS schemes are not expected to be needed.

There are no current plans to install additional SPSs in NYBA. The Athens generation rejection SPS is currently used to mitigate curtailment of Athens generation in securing the UPNY–SENY interface. This SPS is expected to be removed if a permanent solution, such as the addition of bulk power transmission facilities, was installed.

The deployment of a NYBA-wide, open, flexible, interoperable, secure, and expandable Phasor Measurement Network (PMN) system will work in concert with the existing control and monitoring systems. The PMN system will operate using standard information models and communication protocols and will be the integral part of the interconnection-wide North American Synchrophasor Initiative Network (NASPInet). The PMN system will enhance NYISO’s ability to detect system vulnerabilities and disturbances in real time and potentially mitigate their impact.
Integration of new reactive power sources through the installation of additional shunt capacitors will enhance the control and coordination of the voltage profile on the New York power grid, resulting in improvements to the efficiency and reliability of the state’s grid. These switched or controllable capacitor banks will provide for additional reactive power resources, which will be available to the BPS during system conditions in which they are most needed.

Three operational system tools are in the process of acceptance, testing, or deployment. Real-time Dynamics Monitoring System (RTDMS), a situational awareness application from Electric Power Group (EPG), was tested in 2012 and is currently in site acceptance testing. An enhanced State Estimator application was tested in 2012 and deployed in the first quarter of 2013. A voltage stability monitoring application was deployed to production in June 2013.

**Long-Term Reliability Issues**

NYBA has a significant amount of hydro resources. Many of these resources are located on rivers throughout the state. The output of these run-of-river resources is subject to water levels, which may vary greatly on a month-to-month basis based on weather conditions (e.g., snowfall amounts, temperature, rainfall amounts, etc.) For reliability purposes, these units are modeled with a 45-percent derate factor. This derate factor represents a severe scenario case for drought or low water level.

RPS resources are incorporated into NYBA’s planning studies as information becomes available and these resources meet criteria to be in-service. As the amount of variable resources, such as wind, has been added to the resource mix, procedures have been modified and updated. For example, the NYBA has implemented a centralized wind forecasting program to better estimate the amount of energy to be produced by wind resources over various time frames.

Retirement of additional generating units beyond those already contemplated for either economic or environmental factors could adversely affect the reliability of NYBA’s BPS. NYISO recognizes that numerous risk factors can contribute to reliability concerns with the need to take swift actions to maintain reliability, which may need to be preceded by putting sufficient replacement resources into operation depending on the units in question.

Historically, this Region has actively participated in the development of the environmental policies and regulations that govern the permitting, construction, and operation of power generation and transmission facilities. Currently, New York’s standards for permitting new generating facilities are among the most stringent in the nation. The combination of tighter environmental standards coupled with competitive markets administered by NYISO since 1999 has resulted in the retirement of older plants equaling approximately 5,000 MW of capacity and the addition of over 10,000 MW of new efficient generating capacity. In turn, these changes have led to marked reduction of power plant emissions and a significant improvement in the efficiency of the generation fleet.
Notwithstanding the progress toward achieving New York’s clean energy and environmental goals, various environmental initiatives that will affect the operation of the existing fleet are in place or pending. Environmental initiatives that may affect generation resources may be driven by either or both the state or federal programs. Since the previous LTRA, the EPA has promulgated several regulations that will affect the majority of NYBA’s thermal fleet of generators. Similarly, New York State Department of Environmental Conservation (NYSDEC) has undertaken the development of several regulations that will apply to most of the thermal fleet in New York.

The purpose of the development of this analysis is to gain insight into the population of resources that are likely to be faced with major capital investment decisions in order to achieve compliance with several evolving environmental program initiatives. The premise of this analysis is that the risk of unplanned retirements is related to two factors: first, the capital investment decisions resource owners need to make in order to achieve compliance with the new regulatory program requirements, and secondly the recent change in the relative attractiveness of gas vs. coal has challenged the viability of some former Base Load units. The goal of this scenario analysis is to identify when and where these risks occur on the New York Power System.

Five environmental initiatives are sufficiently broad in application and have requirements that may require retrofitting environmental control technologies. Therefore, generator owners will likely need to address the retirement vs. retrofit question. These environmental initiatives are: (1) NYSDEC’s Reasonably Available Control Technology for Oxides of Nitrogen (NOx RACT), (2) Best Available Retrofit Technology (BART), (3) Best Technology Available (BTA), (4) U.S. EPA’s Mercury and Air Toxics Standards (MATS), and (5) Clean Air Interstate Rule (CAIR). These environmental initiatives are further discussed in the 2013 NERC LTRA.
Ontario
Ontario’s electrical power system is, geographically, one of the largest in North America covering an area of 415,000 square miles and serving the power needs of more than 13.5 million people. Ontario is interconnected electrically with Quebec, Manitoba, Minnesota, Michigan, and New York. No footprint changes occurred during the past two years and no changes are anticipated.

Generation
As shown in Table 8, the primary source of fuel in the New York Area is nuclear, followed by natural gas and hydro. Other capacity major sources include coal and oil.

### Table 8
**2013 Ontario Capacity**

<table>
<thead>
<tr>
<th>NPCC-Ontario</th>
<th>2013 Existing Capacity (MW)</th>
<th>Share (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>3,166</td>
<td>10.2%</td>
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<tr>
<td>Petroleum</td>
<td>2,145</td>
<td>6.9%</td>
</tr>
<tr>
<td>Gas</td>
<td>6,753</td>
<td>21.8%</td>
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<tr>
<td>Nuclear</td>
<td>12,844</td>
<td>41.5%</td>
</tr>
<tr>
<td>Hydro</td>
<td>5,662</td>
<td>18.3%</td>
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<tr>
<td>Pumped Storage</td>
<td>89</td>
<td>0.3%</td>
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<tr>
<td>Geothermal</td>
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<tr>
<td>Wind</td>
<td>197</td>
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<td>Biomass</td>
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<tr>
<td>Solar</td>
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<td>0.0%</td>
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<tr>
<td><strong>TOTAL</strong></td>
<td><strong>30,963</strong></td>
<td><strong>100.0%</strong></td>
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Demand, Resources, and Planning Reserve Margins
The Reference Margin Levels (target reserve margins) for the first five years of the LTRA assessment period vary from 18.6 percent in 2014 to 19.3 percent in 2018. The Ontario Power Authority’s (OPA’s) Reference Margin Level (target reserve margin) of 20 percent is applied from 2019 to 2023, which has not changed from the 2012LTRA reference case. The OPA target reserve margin, like the IESO’s, is also based on meeting NPCC LOLE criteria. The OPA calculations include additional allowance for project uncertainty.

Anticipated Reserve Margins are projected to fall below the target reserve margin in 2018. Some of the Bruce and Darlington nuclear units will be out of service for refurbishment during this time frame. Various options described below are under consideration to ensure that future resources are available to maintain adequacy.

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25 The Reference Margin Level requirements are calculated annually for the next five years and published on the Independent Electricity System Operator (IESO). The IESO determines the required reserve levels based on probabilistic methods deemed by NPCC to be acceptable for meeting regional LOLE criteria.

26 The IESO and the OPA recognize the potential for certain adverse conditions (e.g., extended forced outages, drought conditions, and particular fuel interruptions) to result in higher-than-expected resource unavailability and have established planning reserves sufficient to address many of these conditions. To the extent resource procurement exceeds the planning reserve requirements,
This forecast for Net Energy for Load has an average annual growth rate of -0.2 percent during the 10-year period, similar to last year’s forecast of -0.3 percent average growth for 2012–2022. This is the product of modest economic expansion, conservation impacts, and growing embedded generation capacity. Due to a number of factors, the growth rate for overall consumption is lower than the peak growth rates. Conservation is initially aimed at reducing peaks, but as those peak reduction opportunities are realized, conservation and embedded generation will start to impact nonpeak hours, affecting overall energy demand.

Since the underlying drivers are very similar to last year, the projected growth rates remain similar as well. Canada is expected to post modest growth during the assessment period, though Ontario will lag in the near-term. The oil-producing regions in Canada will see stronger growth than Ontario’s manufacturing- and export-based economy. In fact, Canada’s oil wealth puts upward pressure on the dollar, which is more detrimental to central Canada.

Throughout the forecast, Ontario’s economy will continue to undergo structural changes. By the fifth year of the assessment period, projections indicate the economy will see a continued transition from energy-intense industrial processes to a larger service sector and specialized or high-value added manufacturing. This will lead to a less energy-intense economy. However, the very end of the forecast will see the rise in mineral extraction as Ontario begins exploiting its vast but untapped mineral resources in the far North.

The forecasting methodology has not changed since last year’s forecast. The models have been updated and re-estimated to incorporate the latest information regarding the relationship between electricity demand and the economy, demographics, and weather.

Within Ontario there will be some localized variation in demand. The Golden Horseshoe, which encapsulates the Greater Toronto area and the Niagara peninsula, has the largest share of Ontario’s population and economy. This area will maintain its dominant position in the province. The northern areas of the province will see a rebound later in the forecast at the location of the aforementioned mineral resources. The northwestern area, in particular, will see a rebound as its load drops due to lower demand from the pulp and paper sector. Mining will help boost demand in the northern areas of the province.

IESO treats demand measures as a resource and conservation as a decrement to demand. Conservation is projected to increase throughout the assessment period, whereas demand measures will increase through 2015, remaining constant thereafter.

Over the course of the forecast, effective Demand Measures Capacity 27 is expected to be just over 500 MW, rising to just under 600 MW at the end of the forecast. The effective resource adequacy can be maintained for higher than normal contingencies. However, there are always conditions that can exceed those planning assumptions. In such extreme situations, IESO’s operations would rely on interconnection support and available control actions to maintain system reliability. Through retention and further development of a diverse resource mix, the potential consequence of these events is reduced.

27 Considered in this assessment as Load as a Capacity Resource, a category of Demand Response.
NPCC 2013 LONG RANGE ADEQUACY OVERVIEW

capacity of these programs has been significantly reduced compared to last year. The Global Adjustment Allocation (GAA) has led to a significant reduction in the offers of dispatchable loads during peak periods. The GAA allows customers with peak demands of greater than 5 MW to reduce their share of the Global Adjustment costs by reducing demand during the five highest peak demand days. As a result, this has led to a reduction of roughly 400 MW in the offers of dispatchable loads during peak conditions. The GAA has acted to reduce peak demands by over 900 MW, a greater reduction in the peak than the reduction in demand measures resources. The conservation projections are consistent with those included in the 2012LTRA reference case. Conservation is expected to yield incremental peak savings of more than 3,000 MW by 2023.

Two coal units at Lambton will be shut down in October 2013 and four units at Nanticoke are expected to be shut down by the end of 2013. As coal inventories are depleted, the Nanticoke units will be removed from service by the facility owner. By 2014, all coal units in Ontario will be phased out in accordance with government policy. In the years following the coal phase-out, the province’s next reliability challenge will be to carefully manage the renewal of its nuclear fleet.

Units at the Pickering B, Bruce B, and Darlington Nuclear Generating Stations will be reaching their end of service lives during the 10-year period. The Canadian Nuclear Safety Commission granted a five-year renewal of Ontario Power Generation's operating license for the Pickering Nuclear Generating Station, valid until August 31, 2018. The license prohibits the operation of the Pickering B NGS beyond 210,000 effective full power hours. The Commission will consider OPG’s request to remove this regulatory hold point at a future public hearing.

Units at Bruce and Darlington will undergo mid-life refurbishment to extend their operating lives. The OPA is working with two nuclear operators to develop a coordinated plan for nuclear fleet renewal. Unit outages will be coordinated to minimize the number of nuclear units simultaneously on outage. The plan for nuclear renewal is complex as there are a number of aspects related to operational and technical coordination, regulatory and contractual terms, financing and revenue recovery, and risk allocation that need to be resolved.

Supply options for maintaining resource adequacy over this time period are being considered. These options include conservation, recontracting Non-Utility Generator (NUG) facilities, new gas-fired generation, conversion of some or all of the Lambton and Nanticoke coal-fired units to natural gas, imports, and energy storage. There are about 1,500 MW of NUG contracts with the opportunity to be renegotiated as the contracts are expiring now and within the next decade. Currently, the structure of the contracts consists of fixed-price payments that limit the effective operation of resources and efficient participation within the electricity market. The OPA is in the process of assessing the opportunities and merits of renegotiating the NUG contracts, and the procurement process for some NUGs has already begun.

A 280-MW, gas-fired generating station under construction in Mississauga was cancelled in the fall of 2011. The power plant has been relocated to the Lambton Generating
Station site and is expected to be in-service by third quarter of 2017. In 2010, a 900-MW, gas-fired generating station intended to be constructed in Oakville was cancelled. Work is underway to relocate the generating station to the existing gas- or oil-fired Lennox generating station site in the Napanee by fourth quarter of 2018. The new station will include two gas turbine units and one steam turbine unit. They will be connected to two 500-kV buses at Lennox Substation. No other major generation or transmission projects have been cancelled or significantly deferred that affect reliability.

During the LTRA assessment period, the amount of renewables’ penetration is expected to increase significantly through the Feed-in Tariff (FIT) and microFIT programs, some of which will be behind-the-meter generation. Much of this generation could be variable in nature, which adds more volatility as on-grid demand is impacted by underlying demand and variable generation within the distribution system. The majority of distribution-connected generation is expected to be solar, with lesser amounts of wind.

While a vast number of storage technologies are available for development, five are particularly promising and are being developed by companies within Ontario. These include batteries, pumped hydro, compressed air energy storage (CAES), flywheels, and hydrogen storage. While most of these technologies are only recently seeing major development for grid applications, some technologies have a long history in the province such as hydroelectric pumped storage at the Sir Adam Beck Pump Generating Station in Niagara Falls.

While all these technologies offer energy storage, each provides its own specific utility to the grid. Short-term storage systems, which can supply power for less than two minutes, are generally used for frequency regulation and to maintain grid power quality. Technologies such as batteries and larger flywheels can supply limited energy storage suitable for providing frequency regulation and ramping capability and can help improve system reliability. More sustained energy supply can be provided from technologies such as pumped hydro, CAES, hydrogen, and some battery technologies that are capable of lasting more than one hour. These solutions, among others, can be used to increase grid capacity, offering firm output. If installed in the right location, energy storage can also defer transmission and distribution system upgrades.

As renewables make up an increasingly large portion of the supply, energy storage systems can address some of the problems caused by the intermittent nature of some renewable energy sources such as wind and solar.

Through a Request for Proposals issued last year, IESO sought to procure up to 10 MW of regulation from alternative sources such as dispatchable loads, aggregated DR, and storage technologies, including batteries and flywheels. To allow IESO to acquire experience with a range of technologies, the request for proposal (RFP) sought proposals from multiple vendors, each providing a small quantity of regulation.

IESO has entered contracts with the three successful proponents. This procurement process is part of IESO's efforts to broaden access to Ontario's electricity markets. These resources have significantly different operating characteristics than conventional units,
allowing them to contribute to Ontario's energy needs in different ways and complement the performance of existing generators.

As the supply mix quickly evolves, IESO is adapting the manner in which the electricity grid is operated while preparing for a continuing increase in variable renewable generation. By 2018, an estimated 10,700 MW of wind and solar generation is expected to be in-service, with substantial amounts by 2014.

About 14 percent of the installed wind capacity is assumed to be available at the time of summer peak, and 33 percent is assumed to be available at the time of winter peak. 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. WCC values are updated annually.

Ontario’s solar capacity value is forecast to be 30 to 34 percent of installed capacity for the summer peak and 0 to 4 percent contribution for the winter peak. The difference is due to the fact that the summer peak occurs in the afternoon whereas the winter peak occurs after sunset in the evening. The projected solar output is observed for the top demand hours during the summer and winter months.

On average, the assumed capacity contribution for biomass generation is about 95 percent of installed capacity. The assumed capacity contribution for hydroelectric is 72 percent for the summer and 76 percent for the winter.

A formal review of Ontario’s Long-Term Energy Plan (LTEP) is currently underway which will include province-wide consultations on a variety of topics including the province's mix of energy sources such as wind, solar and nuclear, and conservation. The updated LTEP will be released in the fall.

IESO is working with OPA and industry stakeholders to develop and implement the necessary changes to accommodate increased renewable generation. As Ontario’s renewable energy landscape changes and evolves so must the operation of the grid. Specifically with the influx of wind generation facilities connected to the Ontario electricity transmission system, a new set of operational and reliability considerations have emerged. An IESO stakeholder initiative, Renewables Integration Initiative (RII), is nearing completion by addressing three major issues facing wind and solar generation. The RII addresses the following issues:

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28 The hydroelectric generation output forecast is based on historical values of median hydroelectric production and contribution to operating reserves during weekday peak demand hours. Routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data.
Forecast: the implementation of a centralized forecasting service for wind and solar generation;
Visibility: access to Real-time information on embedded renewable generation; and,
Dispatch: the dispatch of directly connected wind and solar generation.

RII has already yielded results, including the integration of the hourly centralized forecast into IESO scheduling tools and enhanced visibility of renewable output within the IESO control room, which will provide greater levels of awareness of system conditions.

The dispatch of grid-connected renewable resources, which started the second week of September, 2013 will provide increased flexibility from available variable generation resources and will allow IESO to operate the system more efficiently.

No firm imports into Ontario or firm exports to other Regions or emergency generation are considered in the LTRA assessment. However, for use during daily operation, operating agreements between IESO and neighboring jurisdictions in NPCC, RFC, and MRO include contractual provisions for emergency imports directly by IESO. IESO also participates in a shared activation of reserve group, which includes IESO, ISO-NE, the Maritimes, NYISO, and PJM.

Transmission and System Enhancements
A new 176-km (110 mile), 500-kV double-circuit line from the Bruce Power nuclear complex to Milton Switching Station was officially declared in-service in June 2012. This new line was built to accommodate the output of all eight generating units at the Bruce complex, approximately 500 MW of existing wind generating capacity, and 1,200 MW of new renewable generating capacity that is forecasted for development within the area. With all eight Bruce nuclear generating units and new renewables, the combined generation in the Bruce area can reach 8,000 MW.

Northwestern Ontario is connected to the rest of the province by the double-circuit, 230-kV East–West Tie. The northwest region has significant amounts of hydroelectric generation as well as other resources such as coal, gas, and biomass. As part of the coal shutdown, Thunder Bay Generating Station (totaling 300 MW of capacity) will cease coal-fired operation by 2014. In addition, strong local load growth is forecast as a result of an active mining sector in the Region. Additional supply is required to maintain supply security in this area under the wide range of possible system and water conditions. The reinforcement of the East–West Tie with the addition of a new 230-kV transmission link will provide reliable, cost-effective, and long-term supply to the Northwest. The line is anticipated to be in-service in 2018. Additional options are being developed to address interim needs and any supply requirements that may exceed the capabilities of the new transmission.

The Lambton to Longwood transmission upgrade consists of replacing approximately 70 km of existing double-circuit transmission line between Lambton Transmission station (near Sarnia, Ontario) and Longwood Transmission station (near London, Ontario) with a
higher ampacity conductor. This project will increase the transfer capability from southwestern Ontario toward London. The purpose of this project is to incorporate additional renewable resources and increase deliverability of system capacity located west of London. It is anticipated that the project will be completed by 2014. Two new 500-kV switching stations planned to be in-service by the end of 2014, Evergreen and Ashfield, are being built to accommodate 384 MW and 270 MW of wind generation respectively.

The transmission projects that are under various stages of construction and other planned projects will address the transmission constraints identified. The TOs 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 dates of bulk transmission projects caused by delays in obtaining required approvals or delays in construction may result in increased congestion or usage of SPSs in the interim.

System reinforcements are also being considered in a number of regional areas (e.g., Kitchener–Waterloo–Cambridge–Guelph, York region, and Ottawa) throughout the province in order to maintain a reliable, local supply of electricity. The OPA’s regional planning approach develops options for each need, in a coordinated manner, 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 solutions that are required for each locale. This approach also addresses interim needs when projects are delayed.

To enable the connection of additional renewable generation in the Bruce area, a static var compensator (SVC) rated at 350 MVA and connecting to the 500-kV voltage level at the Milton station was planned to be in-service by 2015. However, the project is delayed pending a stakeholder consultation on the issue.

Ontario will monitor the progress of the continued operation of nuclear units at Pickering Nuclear Generating Station. Pickering Nuclear Generating Station units connect directly to the 230-kV system at Cherrywood Transformer Station, east of the greater Toronto area. The retirement of Pickering NGS would require an additional 230-kV supply source for the Pickering and Oshawa areas. This will be provided by a new Clarington 500/230-kV transformer station with a 2017 in-service date. Clarington Transformer Station will also improve load restoration capabilities to loads east of Cherrywood following certain contingencies.

As demand increases in the western part of the greater Toronto area, the loads on the 500/230-kV transformers at Claireville Transformer Station and Trafalgar Transformer Station are forecast to exceed capacity near the end of this decade. An additional 500 to 230-kV supply source—involving the installation of 500/230-kV transformers at the 500-kV Milton Switching Station by 2018—would be required to relieve the loading on these existing transformers.

There are no wide-area UVLS programs in Ontario, and there are no plans to install any such UVLS schemes in future. The majority of the SPSs that are in use within Ontario
are intended to address the effects of contingencies under outage conditions and are not intended to avoid or delay the construction of bulk transmission facilities. The principal exception is the North–East load and generation rejection SPS that mitigates the effects of contingencies involving the single-circuit, 500-kV line that services the North-East area. This SPS is designed to achieve a post-contingency match between the load and available generation in the area to minimize load loss and prevent possible separation and islanding of a portion of the North–East system.

The existing Bruce SPS has been enhanced to accommodate the two new 500-kV circuits between the Bruce complex and Milton Switching Station and to address other contingency conditions not previously 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 repreparation 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 planned outages and is not intended for normal operations or to avoid or delay the construction of bulk transmission facilities. The enhanced system was approved by NPCC and placed into service in 2012. The current Bruce SPS hardware is approaching its end-of-life. A replacement is being developed and is scheduled to become fully operational in 2015.

To coincide with the completion of the new Bruce–Milton 500-kV line, a 350-Mvar SVC was installed at Nanticoke Switching Station, connected to the 500-kV bus, and another 350-Mvar SVC was installed at Detweiler Transformer Station, connected to the 230-kV bus. These SVCs were required to provide dynamic reactive support following a critical double-circuit contingency involving the 500-kV lines between the Bruce complex and Milton Switching Station.

IESO has advanced the development of an on-line limit derivation tool to maximize transmission capability in the operating time frame. Currently, this tool is used in operational planning to calculate a limited set of operating security limits in southern, northeast, and east Ontario. The use of the tool is being extended to other parts of the province with an aim to use this tool for the entire province by mid-2014. The limits calculated by the tool are used to plan and schedule equipment outages and to re-prepare the power system following forced outages that impact Interconnection Reliability Operating Limits (IROLs).

Long-Term Reliability Issues

Hydroelectric generation capacity contributions are based on median historic values of hydroelectric production plus operating reserves that have been observed during weekday peak demand hours. Hydroelectric production is monitored on a monthly basis and due allowance is made for the median historical values when drought conditions are expected in the midterm forecasts. However, it is expected that the production would bounce back to median levels for the longer time frame.

The renewable resources target for wind, solar, and bioenergy is 10,700 MW by 2018, accommodated through transmission expansion and maximized use of the existing system. Ontario will add a few hundred MW of hydroelectric capacity to reach a target
of 9,000 MW by 2018. A substantial amount of renewable generation is embedded and included in the demand forecast. This will be achieved through the development of new facilities and significant investments to upgrade Ontario's existing facilities. The operational and adequacy concerns of integration of new variable generation are addressed through RII.

IESO includes a quantity of demand measures termed the “Reliably Available Capacity” in its reliability analyses. This does not represent the total registered capacity of DR programs. For market-based programs, IESO uses historical information to ascertain the amount of DR capacity that is typically bid into the market at the time of the weekly peak demand. For programs that have contracts, IESO uses both historical information and contract information in order to determine the quantity of Reliably Available Capacity. The quantity of reliable capacity was significantly reduced after the introduction of the GAA.

IESO’s initial studies indicated that there is no threat to system reliability based on the projected distribution connected generation. The majority of the generation is solar, small scale, and geographically diverse. These factors combine to mitigate much of the variability in the generation output.

As a result of the increase in the level of penetration of variable generation combined with the return of two units at Bruce Nuclear Generating Station, potential surplus energy is expected to continue well into the decade. Potential surplus energy conditions, referred to as surplus Base Load generation, are expected to be significantly reduced when the nuclear refurbishment programs begin. A vast majority of surplus Base Load generation is being managed via IESO tools and processes, such as nuclear maneuvering and managing inter-tie trades. In September 2013, IESO gained another tool to help manage surplus Base Load generation as wind became a dispatchable resource and helps maintain market efficiency.

The Ontario government has implemented GHG emissions targets for coal-powered generation between 2013 and 2014, ensuring that annual emissions are two-thirds lower than 2003 levels. Moving forward, Ontario’s low carbon portfolio mix has the potential for producing surplus energy. As described earlier, potential surplus energy conditions are expected to significantly diminish when nuclear refurbishment programs begin. A low carbon portfolio will also increase operability complexities. Increases in wind resources in the system increases the ramping requirements during periods when demand picks up and wind output drops off. Traditionally, coal-fired generation contributed to ramping flexibility, but that capability will be reduced with the coal phase-out. In the years ahead, gas-fired generation will play an important role in Ontario’s balance supply mix, providing the flexibility to cushion the electricity system when demand and intermittent resources rise or fall.

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

Technological change is always challenging to capture in long-term forecasts. IESO is evaluating two pilot project storage technologies. The success of these programs could provide further growth in storage capacity within Ontario. To date, the time-shifting impacts have not been factored into the demand forecast but, if widespread, could impact the hourly demand profile. Other unforeseen technological changes may also present forecasting challenges.

Asset renewal is a systematic approach for continuous modernization of aging energy infrastructure. Much of the current power system infrastructure, be it generation, transmission, or distribution equipment, is aging and needs to be refurbished, replaced, or upgraded to comply with new standards and meet demand. A long-term plan is required to coordinate the renewal of infrastructure to manage reliability, environmental, and cost impacts.

Within the next 10 years, nuclear units at the Bruce, Darlington, and Pickering facilities reach the end of their service lives and will be taken out of service for refurbishment or retirement. Elsewhere, some transmission and distribution components are over 80 years old and require upgrading. Although owners have programs in place for asset renewal, the overall scope of the problem is what presents the challenge. Moreover, challenges can be expected in the coordination between parties and the competition for resources from other major nonelectrical infrastructure developments.
Québec

The Québec Assessment Area (Québec Area) is a NERC subregion in the northeastern part of the NPCC Region, covering 643,803 square miles with a population of eight million (province of Québec). The Area is winter peaking and one of the four NERC Interconnections in North America with ties to Ontario, New York, New England, and the Maritimes, consisting either of HVdc ties or radial generation or load to and from neighboring systems.

Generation

As shown in Table 9, the primary source of fuel in the Québec Area is hydro. Other capacity sources include wind, oil and biomass.

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<tr>
<th>Québec Capacity</th>
<th>2013 Existing</th>
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<td>Coal</td>
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<tr>
<td>Petroleum</td>
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<td>Gas</td>
<td>0 (0.0%)</td>
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<td>Nuclear</td>
<td>0 (0.0%)</td>
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<td>Hydro</td>
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<td>Pumped Storage</td>
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<tr>
<td>Geothermal</td>
<td>0 (0.0%)</td>
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<tr>
<td>Wind</td>
<td>483 (1.2%)</td>
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<td>Biomass</td>
<td>254 (0.6%)</td>
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<tr>
<td>Solar</td>
<td>0 (0.0%)</td>
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<tr>
<td>TOTAL</td>
<td>39,449 (100.0%)</td>
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Demand, Resources, and Planning Reserve Margins

The Reference Reserve Margin Levels are drawn from the Québec Area’s 2012 Interim Review of Resource Adequacy, which was approved by NPCC’s Reliability Coordinating Committee on November 27, 2012. These levels vary between 10 and 11 percent during the four-year planning assessment.

The Québec Area demand forecast has decreased compared to the 2012LTRA reference case, reaching -1,000 MW for the 2015–2016 winter peak period. This decline in the demand forecast is mainly attributed to lower than expected load from the industrial sector.

Energy efficiency and conservation programs and energy saving trends are accounted for directly in the assessment area’s demand forecasts and count for 2,150 MW toward the 2014–2015 winter peak demand. Energy efficiency and conservation programs are implemented throughout the year by Hydro-Québec Distribution and by the provincial government through its Ministry of Natural Resources. Energy efficiency will continue to grow throughout the assessment period.
DR programs in the Québec Area—specifically designed for peak load reduction during winter operating periods—are interruptible demand programs (for large industrial customers), totaling 1,439 MW for the 2014–2015 winter period. DR is usually used in situations in which load is expected to reach high levels or when resources are not expected to be sufficient to meet load at peak periods. DR is considered as a resource and is relatively stable during the assessment period, with a maximum reached for the 2014–2015 winter peak period then settling down to 1,300 MW starting at the 2019–2020 winter period. The total on-peak DR and Energy Efficiency and conservation for the 2023–2024 winter period is projected to be approximately 4,900 MW.

There are no significant unit retirements planned during the assessment period. A few small hydroelectric projects, totaling 80 MW, have been cancelled by the provincial government. TransCanada Energy’s 547 MW natural gas combined-cycle power plant in Bécancour is mothballed. Each summer, Hydro-Québec Distribution must decide whether to mothball the Bécancour power plant for an additional year or restart it for the coming year. Although this plant is expected to be mothballed until December 2020, it could be restarted sooner if needed. For that reason, it accounts for the total Existing-Other resources. On the other hand, hydro generator uprates will be adding close to 500 MW of capacity during the assessment period. Behind-the-meter generation is negligible and is accounted for in the load forecast.

Biomass and wind resources are owned by Independent Power Producers (IPPs). These IPPs have signed contractual agreements with Hydro-Québec. Therefore, for biomass resources, maximum capacity and expected on-peak capacity are equal to contractual capacity, representing almost 100 percent of nameplate capacity. For wind resources, capacity contribution at peak is estimated at 30 percent of contractual capacity, representing 840 MW and 1,210 MW respectively for the 2014–2015 and 2023–2024 winter periods. Maximum wind capacity is set equal to contractual capacity, which generally equals nameplate capacity. For summer peak period calculations, the expected on-peak wind capacity is set to zero as wind resources are derated by 100 percent.

Wind generation integration has not significantly impacted day-to-day operation of the system, and the actual level of wind generation does not require particular operating procedures. However, with the increasing amount of wind in the system, the foreseeable impact on system management may show up.

Currently, the studies are underway, examining the following issues (1) wind generation variability on system load and interconnection ramping; (2) frequency and voltage regulation problems; (3) increase of start-ups and shutdowns of hydroelectric units due to load following coupled with wind variability; (4) expected efficiency losses in generating units; and (5) reduction of low load operation flexibility due to low inertia response of wind generation coupled with must-run hydro generation.
Expected capacity purchases are planned as needed for the Québec internal demand by Hydro-Québec Distribution. These purchases are set at 1,100 MW throughout the assessment period and may be supplied by resources located in Québec or in neighboring markets. In this regard, Hydro-Québec Distribution has designated the Massena–Châteauguay (1,000 MW) and Dennison–Langlois (100 MW) interconnections’ transfer capacity to meet its resource requirements during winter peak periods. These purchases are not backed by firm long-term contracts. However, on a yearly basis, Hydro-Québec Distribution proceeds with short-term capacity purchases (UCAP) in order to meet its capacity requirements, if needed. The Québec Area does not rely on any emergency capacity imports to meet its Reserve Margin Reference Level. The Québec Area will support firm capacity sales totaling 626 MW to New England and Ontario (Cornwall) during the 2014–2015 winter peak period, backed by firm contracts for both generation and transmission, declining to 145 MW in 2020.

Transmission and System Enhancements

**ROMAINE RIVER HYDRO COMPLEX INTEGRATION**

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

For 2014, main system upgrades for this project will require construction of a new 735-kV switching station to be named “Aux Outardes” and located between existing Micoua and Manicouagan Transformer Stations. Two 735-kV lines will be redirected into the new station and one new 735-kV line (5 km or 3 miles) will be built between Aux Outardes and Micoua.

**BOUT-DE-L’ÎLE 735-KV SECTION**

Hydro-Québec TransÉnergie (TransÉnergie) is adding a new 735-kV section at Bout-de-l’Île substation (located at east end of Montréal Island). This was originally a 315/120-kV station. The Boucherville – Duvernay line (line 7009), which passes by Bout-de-l’Île, will be looped into the new station. A new -300/+300-Mvar SVC will be integrated into the 735-kV section in 2013.

The project also includes the addition of two 735/315-kV 1,650-MVA transformers in 2014. This new 735-kV source will allow redistribution of load around the Greater Montréal area and absorb load growth in eastern Montréal. This project will enable future major modifications to the Montréal area regional subsystem. Many of the present 120-kV distribution stations will be rebuilt into 315-kV stations and the Montréal regional network will be converted to 315-kV. The addition of a second -300/+300-Mvar SVC at Bout-de-l’Île in 2014 is also projected.
NPCC 2013 LONG RANGE ADEQUACY OVERVIEW

CHAMOUCHOUANE–MONTRÉAL 735-KV LINE
Planning studies have shown the need to consolidate the transmission system with a new 735-kV line in the near future. Generation additions (such as the Romaine Complex and wind generation) and new transmission services are the reason the new line is warranted. The line will extend from the Chamouchouane substation on the eastern James Bay subsystem to the Duvernay substation just north of Montréal (about 400 km or 250 miles).

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

The new line will also reduce transfers on other parallel lines on the Southern Interface, thus optimizing operation flexibility and reducing losses.

OTHER 735-KV PROJECTS
Additionally, a 735-kV series compensation upgrade at Bergeronnes switching station is scheduled for 2014.

THE NORTHERN PASS TRANSMISSION PROJECT
This project will increase interconnection transfer capability between Québec and New England by 1,200 MW and is now being studied. The project involves construction of a ±300-kV dc transmission line about 75 km (46 miles) long from Des Cantons 735/230-kV substation to the Canada–United States border. This line will extend to a substation in Franklin, New Hampshire. The project in Québec also includes the construction of two 600-MW converters at Des Cantons and a 300-kV dc switchyard. Permitting for this project is presently ongoing. The initial planned in-service date (fall 2015) has been re-evaluated to 2017–2018.

THE CHAMPLAIN-HUDSON POWER EXPRESS PROJECT
This project will increase interconnection transfer capability between Québec and New York by 1,000 MW and is now under study. The project involves construction of ±320-kV dc underground transmission line about 50 km (31 miles) long from the Hertel 735/315-kV substation just south of Montréal to Canada–United States border. This line will be extended underground and underwater (Lake Champlain and Hudson River) to Astoria station in New York City. The project in Québec also includes the construction of two 550-MW converters at Hertel and a 320-kV dc switchyard. Permitting for this project is presently ongoing. The planned in-service date is fall 2017.

WIND GENERATION INTEGRATION PROJECTS
Hydro-Québec Distribution has issued different calls for tenders for wind generation in past years. A total of approximately 3,350 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 Québec, but most are near the shores of the Gaspésie Peninsula, along the Gulf of St. Lawrence down to the New Brunswick border.

OTHER 735-KV CONCEPTUAL PROJECTS
The subregion is planning a new 735/315-kV transformer station near the existing Lebel 315/120-kV station in the Abitibi region of the system. This will consolidate the Abitibi subsystem, which presently has a 120-kV infrastructure with a 315-kV feed at Lebel and Figuery substations. A new 142-km (88-mile), 735-kV line is projected from Abitibi 735-kV station on the western James Bay system to feed this new station. Two 735/315-kV, 1650-MVA transformers and four 315-kV line feeders will complete the station. The projected in-service date is fall 2018, but this may vary depending on the projected industrial loads in the area.

UPCOMING REGIONAL PROJECTS
There are a number of regional projects now underway. The three important projects scheduled for fall 2014 are:
• Charlesbourg 315/25-kV substation and 315-kV transmission (Québec City)
• Lefrançois 315/25-kV substation and 315-kV transmission (Québec City)
• St-Césaire–Bedford 230-kV, double-circuit line (Eastern Townships to upgrade feed to Highgate)

Other regional substation and line projects are now in the planning and permitting stages. There are about a dozen regional transmission projects in the Montréal and Québec City areas and another dozen in other areas with in-service dates from 2013 to 2018, consisting mostly of replacing the 120-kV and 69-kV infrastructure with 315/25-kV and 230/25-kV satellite (distribution) substations. Other regional upgrade projects (i.e., in the Abitibi and Manicouagan subsystems) will also be commissioned in the upcoming years.

Planning studies leading to system enhancement projects, such as those mentioned above, ensure that there will be no long-term transmission constraints in the assessment area. Generation on the system is integrated on a 100 percent firm basis.

SYSTEM ENHANCEMENTS
In the Québec Interconnection, load shedding caused by an under voltage is initiated by a specific remote UVLS named TDST. A maximum of 1,500 MW is targeted by TDST. It has been designed to operate following contingencies involving the loss of two or more 735-kV lines. Contingencies range from the loss of two parallel 735-kV lines to the loss of a 735-kV line with series compensation bypass on parallel lines. These contingencies do not require more than 1,500 MW of load shedding, although TDST operates on a pre-defined pool of 2,500 MW located in the Montréal Area. The last NPCC Comprehensive Review Assessment of the Québec transmission system for the year 2017—conducted by
TransÉnergie (approved by NPCC June 2013)—shows that TDST is adequate to preserve system stability after the contingencies for which it is designed.

No additional load is expected to be assigned to UVLS during the next 10 years.

There are no plans to install SPSs or Remedial Action Schemes in lieu of planned bulk power transmission facilities in the Québec Area.

Hydro-Québec intends to deploy a number of new technologies, systems, and tools (including smart grid incentives) to improve future BPS reliability. Government policies and targets for renewable energy integration, Energy Efficiency, electric or rechargeable hybrid vehicles, and GHG emission reductions are among the major drivers for the development of smart grid programs. These initiatives are further discussed in the 2013 NERC LTRA.

**Long-Term Reliability Issues**

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

Also, as a member of the Western Climate Initiative, the Province of Québec implemented a cap-and-trade system in 2012, with compliance beginning January 1, 2013. Given the significant proportion of renewable generation in the Québec Area, this new regulation will not impact reliability in the Québec Area.

However, there are several important issues that may impact system reliability during the assessment period. While there is no doubt that during recent years technical developments have contributed to creating a more reliable system, sustainable system reliability may be challenged by several issues. The two issues described and analyzed below are considered as standing reliability issues.

**WIND PLANT INTEGRATION TO GRID**

As a separate NERC Interconnection, the Québec Area is responsible for its own frequency regulation. System inertia is quite low compared to the Eastern Interconnection, for example. Large post-contingency frequency excursions—up to ±1.5 Hz—can occur after normal contingencies, and operating limits related to post-contingency frequency behavior are required.
Through 2015, Hydro-Québec will have integrated around 3,350 MW of nameplate wind capacity. This kind of large-scale wind capacity integration on the system has triggered a need for frequency support by wind plants as it displaces conventional hydro generation that inherently provides inertia. In order to maintain present system performance, TransÉnergie (the Transmission Planner) has requested from manufacturers an inertia emulation function that would cover lack of inertia and spinning reserve from modern variable speed wind turbine generators. In 2012, the first wind plants able to provide this function were commissioned. TransÉnergie is now beginning to observe and assess the performance of the inertia emulation function for real system events. Further studies are needed to implement fine-tuning of the feature. Inertia emulation is required for Hydro-Québec’s wind generation resulting from the second and third calls for tenders, totaling 2,295 MW of capacity.

EQUIPMENT AGING AND SUSTAINABILITY

Equipment aging and sustainability (i.e., for line and station equipment) have been standing issues at TransÉnergie for more than 15 years. However, during the years 2000–2010, it became obvious that a global strategic investment policy was needed to tackle the issue. The strategy is based on the risk (sustainability) of losing equipment due to a major failure as the equipment approaches the end of its life cycle. This risk assessment considers the probability of a major failure and its impact on the transmission system and on TransÉnergie as an asset owner. In 2007, the strategy and an accompanying annual budget were presented to and authorized by the Québec Energy Board.

Significant investment cuts, personnel and equipment availability for maintenance outages as well as new projects, and system availability for outages are all issues that could impact reliability in the context of equipment aging.
PJM
PJM Interconnection is an RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability of an area that spans 214,000 square miles and serves more than 60 million people. PJM’s long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to the grid to ensure reliability and economic benefits on a system-wide basis. PJM is the Planning Coordinator, RC, and BA for the entire PJM Region.

Boundary Change
This year’s LTRA report includes the load and generation of Duke Energy Ohio/Kentucky (DEOK), which was integrated into the PJM regional transmission organization (RTO) on January 1, 2012, and the generation and load of East Kentucky Power Cooperative (EKPC), which was integrated into PJM on June 1, 2013.

Generation
As shown in Table 10, the primary source of fuel in the PJM Area is coal and natural gas. Other capacity sources include nuclear and oil.

Table 10
2013 PJM Capacity

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>2013 Existing Capacity (MW)</th>
<th>Share (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>76,540</td>
<td>41.3%</td>
</tr>
<tr>
<td>Petroleum</td>
<td>12,208</td>
<td>6.6%</td>
</tr>
<tr>
<td>Gas</td>
<td>52,783</td>
<td>28.5%</td>
</tr>
<tr>
<td>Nuclear</td>
<td>33,771</td>
<td>18.2%</td>
</tr>
<tr>
<td>Hydro</td>
<td>2,683</td>
<td>1.4%</td>
</tr>
<tr>
<td>Pumped Storage</td>
<td>5,145</td>
<td>2.8%</td>
</tr>
<tr>
<td>Geothermal</td>
<td>0</td>
<td>0.0%</td>
</tr>
<tr>
<td>Wind</td>
<td>872</td>
<td>0.5%</td>
</tr>
<tr>
<td>Biomass</td>
<td>1,107</td>
<td>0.6%</td>
</tr>
<tr>
<td>Solar</td>
<td>55</td>
<td>0.0%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>185,164</td>
<td>100.0%</td>
</tr>
</tbody>
</table>

Demand, Resources, and Planning Reserve Margins
The PJM RTO Reserve Requirement is 15.9 percent for the 2014–2015 planning period, which runs from June 1, 2014, through May 31, 2015. The PJM RTO Reserve Requirement is 15.3 percent for the 2015–2016 planning period, which runs from June 1, 2015, through May 31, 2016. The PJM RTO Reserve Requirement is 15.6 percent for the 2016–2017 planning period through the end of the LTRA assessment period. For more
information, see the 2012 PJM Reserve Requirement Study. The PJM RTO will have an adequate Anticipated Reserve Margin and the Adjusted-Potential Resources Reserve Margin is above the PJM Reserve Requirement though the entire assessment period.

With the exception of the addition of EKPC demand on June 1, 2013, the demand forecast for the rest of PJM has remained at a historically typical rate of 1.3 percent. DEOK was integrated into the PJM RTO on January 1, 2012, and added approximately 5,400 MW to the PJM forecast at the time. The load of EKPC added approximately 1,910 MW of load to the PJM RTO forecast.

The total amount of Energy Efficiency for the PJM Area that is expected to be available on peak for summer 2014 is 924 MW. This value decreases to 891 MW in 2015 and remains constant through the end of the assessment period. Demand-Side resources available during the 2014 summer peak period are forecasted to total 11,250 MW and remain relatively constant through the entire assessment period. DSM used for reserves is limited by the RFC criteria to 25 percent of the PJM Operating Reserve requirement. This type of DSM is typically fully subscribed and can range up to approximately 2,500 MW during a peak summer day.

PJM has announced plans for over 13,000 MW (6.9 percent of the PJM Existing-Certain fleet) of generator retirements during the assessment period. Of the announced retirements, approximately 9,700 MW is coal, 2,000 MW is gas, and 1,300 MW is oil-fired generation. From a Regional Transmission Expansion Plan (RTEP) perspective, generation deactivations coupled with steady load growth and sluggish generation additions can lead to the emergence of reliability criteria violations in many areas of PJM. Each generation deactivation is reviewed and any required transmission upgrades to address the transmission network reliability needs as result of the generation deactivation are included in the RTEP.

In the PJM RTEP analysis, generator uprates are considered exactly the same as adding a new generator. There are over 100 generator uprates in the PJM Interconnection Queue ranging from 200 MW to less than 1 MW. No significant generation is planned to be out-of-service during the peak periods. Behind-the-meter-generation is not counted as PJM capacity and has no effect on the PJM reserve margin.

Capacity transactions amount to a net import of 4,255 MW in 2014 and then increasing to 4,340 MW in 2015. In 2016, and for the remainder of the assessment period, the net import is expected to be 3,022 MW. This import is composed of specific transactions for each generator. These transactions include the firm reservation rights for the generation and firm transmission rights to transfer the power across the PJM border. All import and export contracts that are counted toward the PJM Reserve Margin are firm for both capacity and transmission service. PJM has no reliance on outside assistance for emergency imports. Capacity Benefit Margin is reserved on transmission across the PJM border but there is no reservation of capacity with our neighbors. The original
transaction agreements include the firm reservation rights for the generation and firm transmission rights to transfer the power across the PJM border.

Transmission and System Enhancements

**SUSQUEHANNA TO ROSELAND**
The Susquehanna–Roseland 500-kV line (Susquehanna–Lackawanna–Hopatcong–Roseland) had a required in-service date of June 1, 2012. Regulatory process delays pushed the expected in-service to June 1, 2015. In February 2010, the Pennsylvania Public Utility Commission approved the line, and the New Jersey Board of Public Utilities approved it in April 2010. The line received final approval from the National Park Service (NPS) when they issued a Record of Decision on October 2, 2012, affirming the route chosen by PPL and PSE&G; the NPS issued a Special Use (Construction) Permit on December 12, 2012. PJM will continue to operate to double circuit tower line limits in real-time operation until the new line is placed in-service.

**MID-ATLANTIC POWER PATHWAY (MAPP)**
PJM’s 2011 RTEP analysis, which included various generation sensitivities, indicated that the need for the MAPP 500-kV line (Possum Point–Burches Hill–Chalk Point–Calvert Cliffs–Vienna–Indian River) had moved several years into the future, beyond 2015. In 2011, the PJM Board decided to hold the project in abeyance with a 2019–2021 in-service date. On August 24, 2012, the Board formally removed the MAPP project from the PJM RTEP.

**POTOMAC–APPALACHIAN TRANSMISSION HIGHLINE (PATH)**
PJM’s 2011 RTEP analysis also indicated that the need for the PATH 765-kV line (Amos–Welton Springs–Kemptown) had moved out several years, beyond 2015. Based on these analyses, the PJM Board decided to hold the project in abeyance and requested that the TO suspend development activities. On August 24, 2012, the Board formally removed the PATH project from the PJM RTEP.

**MOUNT STORM–DOUBS**
The 2011 RTEP analysis identified a required in-service date of June 2020 for the Mount Storm–Doubs line rebuild. However, recognizing the urgency of upgrading these aging facilities, Dominion indicated its intention to complete the reconductoring project by June 1, 2015. To that end, the capacity of the rebuilt line—with a rating 65 percent higher than the original—was reflected in PJM’s 2017 power flow case modeling.

**THE HUDSON TRANSMISSION PARTNERS (HTP) PROJECT**
The HTP project—a back-to-back HVdc interconnection between PJM and New York City (New York Zone J)—went into service in May 2013. While the interconnection facility is rated at 660 MW, only 320 MW are designated for firm transmission service, with the remaining 340 MW designated for non-firm transmission service. Currently, only a small portion of the firm transmission rights (13 MW) are available because the required network transmission upgrades needed to make the full 320 MW deliverable in
the PJM system will not be in-service until June 1, 2014. The remaining capability will be available for non-firm service.

Current plans include over 9,000 Mvar of reactive reinforcements that will be installed on the PJM system during the next five years. The reactive reinforcements include both static (capacitor and reactor) as well as dynamic (SVC) installations.

**PLANNED SVCS**
- 138th Street 138-kV Dayton 75 Mvar (December 31, 2013)
- Meadowbrook 500-kV FirstEnergy (AP) 600 Mvar (June 1, 2014)
- Mt. Storm 500-kV Dominion 250 Mvar (June 1, 2014)
- Hunterstown 500-kV FirstEnergy (ME) 500 Mvar (June 1, 2014)
- Altoona 230-kV FirstEnergy (ME) 250 Mvar (June 1, 2014)
- Loudon 500-kV Dominion 450 Mvar (June 1, 2014)
- New Castle 138-kV FirstEnergy (ATSI) 150 Mvar (June 1, 2015)
- Prospect Heights (Red) 138-kV ComEd 300 Mvar (June 1, 2015)
- Prospect Heights (Blue) 138-kV ComEd 300 Mvar (June 1, 2015)
- Crawford (Green) 138-kV ComEd 300 Mvar (June 1, 2016)
- Crawford (Yellow) 138-kV ComEd 300 Mvar (June 1, 2016)
- Landstown 230-kV Dominion 500 Mvar (June 1, 2016)

**PLANNED FAST-SWITCHING CAPACITORS**
- Mansfield 345-kV FirstEnergy (PN) 100 Mvar (June 1, 2014)
- Pleasant View 500-kV Dominion 150 Mvar (June 1, 2014)
- Jack's Mountain 500-kV FirstEnergy (PN) 100 Mvar (June 1, 2017)
- Jack's Mountain 500-kV FirstEnergy (PN) 500 Mvar (June 1, 2017)

**PLANNED SERIES COMPENSATIONS**
- 0.5 percent reactor in the Red Bank–Oakley 138-kV line Duke
- 3.8 ohm 138-kV reactor in Red Bank–Ashland 138-kV line Duke

**PLANNED VARIABLE REACTORS**
- Cedar Creek 230-kV Dayton 100 Mvar
- New Castle 138-kV Dayton 100 Mvar
- Churchland 230-kV Dominion 100 Mvar
- Shawboro 230-kV Dominion 100 Mvar

UVLS is utilized at two 138-kV buses in PJM. The relays trip approximately 25 MW of load and work in conjunction with other non-BES UVLS installations. The relays are installed to prevent voltage collapse or instability for one possible Type C (loss of two 345-kV lines) contingency and three Type D (two loss of right-of-way and one loss of substation - two voltage levels) contingencies.
Two new SPSs are planned. The first SPS is a load drop scheme that was installed on June 1, 2013 in Delmarva due to low voltage after a double contingency, voltage drop, and nonconvergence problems. The SPS will be retired when the Wye Mills–Church 138-kV line is installed on June 1, 2015. The second SPS is to sectionalize the Stanton 230-kV bus in PPL for several double-contingency losses. This SPS will go into service on November 1, 2014, and will be retired when line upgrades are completed on November 30, 2019.

**Long-Term Reliability Issues**

PJM has very little hydro generation and reservoir levels are adequate. PJM expects no problems with warm cooling water. Significant development of wind, solar and biomass has already occurred in PJM. Much of this development is in response to existing RPSs. The challenges of integration this variable generation will grow as more and more generation of this type is added. Demand side resources are not of a significant enough size to be of great concern for unresponsiveness. Penalties exist to make unresponsiveness financially unattractive. Distributed energy resources has been increasing in PJM especially solar installations which are mostly connected to lower voltage lines. No special operating procedures required. PJM has developed a Wind Power Forecast tool and visualization to assist operations.

PJM developed an analysis of coal generation at risk of retiring based on an assessment of required environmental retrofit costs vs. the cost of constructing a new natural gas-fired turbine. This at risk generation analysis concluded that there is no overall resource adequacy concern for the PJM footprint, however there may be localized reliability concerns that will need to be addressed either with replacement generation capacity or transmission upgrades if the impacted units are retired or need lengthy environmental retrofit outages. PJM continues to coordinate closely with PJM Generation Owners, PJM TOs and neighboring systems through the PJM Committee structure and consistent with the PJM Tariff and manuals. In order to maintain system reliability, PJM will designate units as "Reliability Must Run" if their retirement date is targeted to be in advance of required system reinforcements.

PJM requested that all impacted generation owners provide the most accurate information regarding unit retirements, environmental retrofits, unit derates and potential regulatory issues related to the environmental regulations. Combined with the publically announced unit retirements and the deactivation analysis results, PJM is utilizing this information to address short term impacts and long term projections through 2018. PJM is communicating with interconnected TOs as required to address local reliability issues, and also communicating with MISO to compare reliability analyses and coordinate outages.

At this point PJM has added the environmental retrofit outages, to the extent provided by the generation owners, to projections for maintenance outages from 2012–2018, and we are continuing to assess the impact to off-peak reliability. PJM will continue to
coordinate closely to analyze the impact of retiring generation, planned outage to perform retrofits, normal generation and transmission maintenance outages as well as transmission outages required to perform planning upgrades to resulting from retiring generation.

Generation owners have indicated that while at this time there appears to be sufficient time to complete environmental retrofits, if there are delays in scheduling retrofit outages due to system constraint issues or capital budget limitations, then there may be significant challenges in completing the retrofit outages in the required time to comply with environmental regulations.