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Regional Clean and Renewable Energy Market Opportunities

Study Findings

Prepared for:

Atlantic Energy Gateway

Atlantic Canada Opportunities Agency
Agence de promotion économique du Canada atlantique
Canada

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September 4, 2012

1. Revisions were made to the Executive Summary, Section 2.8 and Section 5 to reflect Nalcor's transmission access into New England that has been secured through various agreements related to the Muskrat Falls hydroelectric and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects that were executed by Nalcor and Emera on the July 31, 2012. This information was not available for the previous final report released March 30, 2012.
2. Revisions were made to the Executive Summary, Section 3.1 and Section 5 to reinforce the existence of up to three primary and distinct markets for clean and renewable energy from Atlantic Canada in New England.
3. Updated provided on August 21, 2012 action by U.S. Court of Appeals for the D.C. Circuit vacating the Cross State Air Pollution Rule (CSAPR) and its implication to New England.
4. Revisions made to the Executive Summary and Section 3.1.1 to highlight a recent amendment to the Commonwealth of Massachusetts Laws, Section 116 of Chapter 169 of the Acts of 2008, signed into law on August 3, 2012, that includes allowing hydroelectric power, regardless of whether that power is eligible under the renewable energy portfolio standard, for meeting the state's goal of at least 20 percent of the Commonwealth's electric load by the year 2020 through new, renewable and alternative energy generation.
5. Update made to Section 3.2.1 that large hydro of any size is now eligible to count towards the Vermont Sustainably Priced Energy Enterprise Development Program ("SPEED") renewable energy goals as stated in 30 V.S.A. 8005(d). Previously only hydro facilities up to 200 MW could be included towards the state renewable goal.
6. Update to Section 3.2.7 that in 2012 the Maine Legislature introduced Legislative Document 1683, "An Act to Lower the Price of Electricity for Maine Consumers." The Act proposed to eliminate the 100 MW limit on the size of hydroelectric facilities included in the definition of renewable capacity resource. This Act died on April 13, 2012 due to unresolved disagreements between the House and the Senate.
7. Clarification in the Executive Summary and in Section 2.7.2 that ISO-NE and NEPOOL participants have undertaken a Forward Capacity Market redesign effort in response to FERC's March 30, 2012 FCM Order in Docket No. ER12-953. The redesign proposals under consideration relate to various capacity pricing mechanisms.

Executive Summary

The Atlantic Canada Opportunities Agency (ACOA), in collaboration with the Federal and Atlantic Canadian Provincial Governments, retained Navigant Consulting Ltd. (Navigant) to conduct this Atlantic Energy Gateway (AEG) study to identify market opportunities within the international northeast region for Atlantic Canadian clean and renewable energy. The purpose of the study is to review and summarize provincial and state clean and renewable energy policies, supporting clean and renewable energy consumption targets and mandated clean and renewable energy procurement policies for Atlantic Canada and New England.

To assess the potential export opportunities for clean and renewable energy, Navigant analyzed the following factors: current and anticipated future regional market demand drivers, market barriers to the movement of clean and renewable energy within Atlantic Canada and New England, and regulatory issues and considerations. The study also provides a summary of renewable portfolio standards (RPS), local content requirements, domestic production and consumption targets, emission reduction targets and associated environmental regulations, general market conditions and any policies or initiatives that may impact the supply or demand for clean and renewable generated electricity. In addition to the above, Navigant also prepared a detailed overview of the New England power market to put the above factors in context with the market characteristic.

Based on the above identified factors, regulatory and market drivers, and the defining characteristics of the New England market, Navigant makes the following observations related to the opportunity for exports of clean and renewable energy to the New England power market.

1. There are three distinct "markets" for clean and renewable energy in New England: 1) the New England energy market; 2) the New England capacity market; and 3) the various state Renewable Energy Credit (REC) markets. Generally speaking, the energy market is accessible to any supplier that can physically deliver electricity into New England and, similarly, the New England capacity market is accessible to any supplier with a firm transmission path into New England. The rules for the individual state REC markets vary from state to state depending on each state's Renewable Portfolio Standard (RPS), particularly with respect to the type of renewable energy that is eligible to participate in the market.
2. The New England energy market has a significant amount of combined cycle natural gas capacity. Due to the discovery of unconventional gas resources, gas prices are low, and are projected to remain low for the foreseeable future. This has resulted in natural gas being on the margin for over 70% of the time. For example, with an average historic market average of 8,600 Btu/kWh and a natural gas price of $5/MMBtu, wholesale electricity market prices would be about $43/MWh (USD).
3. The New England capacity market has a significant surplus of capacity and is projected to remain in surplus until the end of the decade. This is the result of the implementation of a forward capacity market (FCM), and rules that support demand response resources competing against generation

resources and imports to compete for a capacity supply obligation. It is expected to result in capacity prices that are well below the cost of new entry.[1]

4. The investment required for complying with some or all of the forthcoming environmental regulations could make a number of plants candidates for retirement. These plants include older steam coal, gas, oil units that are marginally economic and at risk of retirement given their limited operation. The removal of 3,500 MW of such capacity from the market would, as ISO-NE has indicated, eliminate much of the surplus capacity.
5. Current RPS policies provide incentives for renewable generation. There are no specific requirements, policies, or incentives for clean energy (e.g., large hydro and nuclear power), and the region does not distinguish between clean resources and other resources, such as natural gas plants, that meet the federal and state emission regulations.[2] The Production Tax Credit, if extended, would provide a competitive disadvantage to the AEG initiative.
6. New England's Load Serving Entities are currently relying on a mix of renewable resources located in New England, New York and Canada to meet their RPS requirements. New England is not expected to have enough "local" renewable resources to meet future RPS requirements. New England will need to import renewable energy certificates (RECs) to meet its future RPS requirements.
7. Large hydro cannot participate in the current RPS programs. There have been proposed changes to the RPS programs in Maine, Connecticut, and New Hampshire for allowing large hydroelectric generators to qualify. However, these legislative changes have either died due to unresolved differences or have been tabled for later discussion.[3] Maine currently allows hydroelectric resources of up to 100 MW to participate in its RPS Program and Vermont allows hydroelectric resources of any size to count towards its SPEED Program renewable energy goals.
8. There have been few long-term contracts offered to renewable energy projects in New England, and no long-term contracts offered to projects located outside of New England. If regional project development stalls and demand exceeds supply, long-term contracts could be offered to projects outside of New England to ensure compliance.
9. Maine is currently export constrained, with an abundance of natural gas-fired generation capacity. This has led to low energy prices, lower capacity prices, and reliability issues. The proposed transmission projects are being developed to address reliability concerns, and do not explicitly address the export constraints between New Brunswick and Maine or between Maine and the rest of New England.

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[1] ISO-NE and the NEPOOL market participants are currently evaluating alternative capacity market frameworks for the New England capacity market. These discussions are taking place as part of confidential settlement discussions resulting from FERC's Order in Docket No. ER12-953. Based on the limited information available on the ISO-NE website, the redesign efforts are exploring a number of options, such as demand curve and mechanisms to reduce price volatility.

[2] In August 2012 Massachusetts amended its Green Communities Act now allow hydroelectric power, regardless of whether that power is eligible under the renewable energy portfolio standard, for meeting the state's previous goal of at least 20 percent of the Commonwealth's electric load by the year 2020 through new, renewable and alternative energy generation. Policies for supporting this goal have not yet been developed.

[3] Recent legislation to eliminate the 100 MW limit on hydroelectric resources died on April 13, 2012. The bill died due to unresolved disagreements between the House and the Senate.

10. Through various transmission service, access and rights agreements with Emera, Nalcor will have access through Nova Scotia and New Brunswick into the New England markets upon completion of the Muskrat Falls hydroelectric and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects. In combination with the transmission access it currently has through Quebec, these agreements will allow Nalcor to sell any available energy and capacity into the New England energy market that is not utilized by Nalcor or committed for delivery into Nova Scotia. If the electricity available from Nalcor is eligible to participate in any of the state REC markets, it would also be able to access these markets.
11. Hydro Quebec is currently well positioned to sell into the New England market and its favourable market positioning is expected to continue into the future. It has transmission access into New England, surplus energy and is building additional hydroelectric generation facilities.

This report is organized to describe the factors, drivers, and market barriers that have been identified by the AEG participants. The above findings were a result of the research and information contained in the report and presented in the order that they appear in the report.

1. Introduction

The Atlantic Canada Opportunities Agency (ACOA), in collaboration with the Federal and Atlantic Canadian Provincial Governments, retained Navigant Consulting Ltd. (Navigant) to conduct this Atlantic Energy Gateway (AEG) study to identify market opportunities within the international northeast region for Atlantic Canadian clean and renewable energy. The study was prepared with the collaboration and guidance of the AEG Project Steering Committee, which provided feedback throughout the study process.

1.1 Study Objectives

The purpose of the study is to summarize provincial and state clean and renewable energy policies, support clean and renewable energy consumption targets, and mandate clean and renewable energy procurement policies for Atlantic Canada and New England, with two primary objectives:

- Assess and quantify opportunities for both short-term and longer-term clean and renewable electricity exports (including associated renewable energy credits) from Atlantic Canada to New England; and
- Assess opportunities for increasing the flow of clean and renewable energy within Atlantic Canada based on the concept of a more fully integrated Atlantic Canadian electricity market.

The outcome and findings from this study is anticipated to support associated planning, system planning, and transmission planning models and studies.

1.2 Approach

Based on the above study objectives, Navigant prepared this study to assess the potential export opportunities for clean and renewable energy. As part of this assessment, the following factors were analyzed: 1) current and anticipated future regional market demand drivers, 2) market barriers to the movement of clean and renewable energy within Atlantic Canada and New England, and 3) regulatory issues and considerations.

The study also provides a summary of renewable portfolio standards (RPS), local content requirements, domestic production and consumption targets, emission reduction targets and associated environmental regulations, general market conditions and any policies or initiatives that may impact the supply or demand for clean and renewable generated electricity.

To more fully appreciate the market drivers, barriers, and other dynamics in the New England marketplace, we also provide a detailed overview of the New England power market to put the above factors in context with the market characteristic. We include a detailed summary of the demand forecast, RPS requirements and projections, transmission projects, capacity market rules and auction results, interregional transactions, competition from neighboring markets, and a summary of recent solicitations.

1.3 Organization of the Report

The report is organized in five sections. Section 1 contains this introduction which outlines the scope and objective of the study. Section 2 provides an overview of the New England market. Section 3 provides a summary of the export opportunities for clean and renewable energy to New England. Section 4 provides a summary of the opportunities for greater interprovincial electricity trade, summarizing major fundamental drivers associated with each provincial electric market. Section 6 provides our general observations and conclusions on the opportunities and barriers for clean and renewable resource sales in New England.

2. Overview of the New England Market

This section provides an overview of the New England bulk power market. The purpose of this section is to provide an overview of the peak demand and energy requirements, existing generation portfolio and anticipated changes to the resources, and a summary of the capacity and energy markets. The intent of this information is to provide fundamental information on these areas such that AEG participants may appreciate the market dynamics and drivers that influence the decisions and requirements for procuring clean and renewable energy.

2.1 Market Summary

The New England electricity market includes over 14 million people in six states: Connecticut; Maine; Massachusetts; New Hampshire; Rhode Island; and Vermont. The region's more than 400 market participants comprise the New England Power Pool (NEPOOL). NEPOOL was formed in 1971 by the region's electric utilities to ensure that New England would avoid any future region-wide power failure similar to the Great Northeast Blackout of 1965. Currently NEPOOL's participants own more than 350 separate generating plants and approximately 8,000 miles of interconnected transmission lines.

In 1997, ISO New England (ISO-NE) was created by the Federal Energy Regulatory Commission (FERC) to operate and oversee the reliability of the competitive wholesale electricity markets in New England. In 2003, ISO-NE adopted the FERC's Standard Market Design which includes features such as Locational Marginal Pricing (LMP). In 2005, FERC designated ISO-NE as the Regional Transmission Organization (RTO) for the New England region providing ISO-NE broader authority over the day-to-day operation of the transmission system and greater independence to manage the power grid and wholesale markets.

The New England system is summer peaking. On July 22, 2011 it experienced a peak demand of 27,702 MW, the second highest peak demand on record. New England's overall demand for electricity fell sharply from 2007–2009, primarily due to the recession, then climbed in 2010, but has remained below 2003–2008 levels. New England's bulk power generation and transmission system provides for more than 34,000 MW of capability, which currently includes approximately 2,600 MW of demand response.[4]

2.2 Demand and Energy Forecast

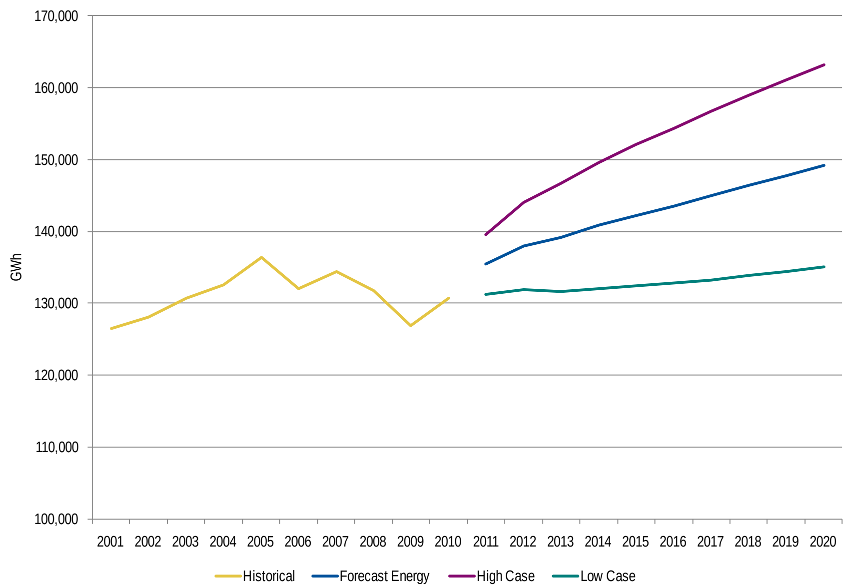
An important driver of New England's projected requirements for renewable resources is its annual energy forecast. Each year ISO-NE prepares a long-term energy and peak demand forecast using an annual model of projected total energy consumption within the ISO-NE control area. The forecast takes into account projections of personal income and gross state product forecasts. The model also incorporates flexible price elasticity to better account for structural changes over the historical period (e.g., increasing impact of energy conservation). For each region, except Maine and Vermont, the demand forecast incorporates a flexible Cooling Degree Day weather elasticity to better account for structural changes over the historical period (e.g., impact of greater penetration of air conditioners).

[4] Based on the results of the most recent Forward Capacity Auctions, there is 3,350 MW of demand response with a capacity supply obligation for the 2013/2014 capability year.

Lastly, the forecast includes estimates of the impact of new Federal Electric Appliance Standards that would not be captured by econometric models.

Based on the ISO-NE's latest forecast, the economy began a sluggish recovery from the recession in 2010, with annual energy growth averaging 1.5 percent from 2010 to 2014 and 1 percent thereafter. Summer peak demand is expected to grow slightly faster averaging 2.4 percent from 2010 to 2014 and 1.3 percent thereafter. Figure 2-1 provides a comparison of the historical and projected energy forecast. This figure also includes a high and low energy consumption forecast, driven by economic recovery and weather.

Figure 2-1. Historical and Forecast Energy Demand



Source: ISO-NE's 2011-2020 Forecast Report of Capacity, Energy, Loads, and Transmission

The energy forecast prepared by ISO-NE is a key driver in projecting the amount of renewable resources that will be required to be procured over the next ten years. As discussed later in this report, changes in projected economic recovery and demand growth are key drivers in renewable requirements.

2.3 *Demand Response and Energy Efficiency*

2.3.1 Demand Response

The ISO has active and passive demand resources. Active demand resources are dispatchable and respond to ISO dispatch instructions, while passive demand resources provide load reductions during previously established performance hours. The ISO-administered demand-resource programs fall into three basic categories: active demand resources that reduce load to support system reliability, active demand resources that respond to wholesale energy prices, and passive demand resources that reduce load through energy efficiency and similar measures. As further explained below, demand response programs participate in the forward capacity market (FCM), competing directly with generation resources for a capability obligation.

Demand response has increased significantly in New England, from under 600 MW in 2005 to just under 3,000 MW in 2010. Much of this increase is due to the economic incentives provided by the FCM rules initiated in 2005. More discussion of the FCM is contained within the markets section of this report. The last three FCMs have not seen dramatic increases in demand response, which could signal that these resources are reaching their saturation level. In terms of historic performance, demand response resources reduced actual peak demand by just under 600 MW for 2010 as reported by ISO-NE and decreased energy consumption by 4,200 GWh. The reduction in peak demand due to demand resources has ranged from 0 MW in 2004 to 714 MW in 2009.

2.3.2 Energy Efficiency

The demand forecast incorporates the expected effects of federal energy efficiency standards for appliances and commercial equipment that will go into effect in 2013 and historical energy efficiency savings. The forecasts of the energy savings attributable to federal appliance standards and FCM passive resources are 1.6 percent and 4.7 percent, respectively.[5] These represent a total energy savings of 6.3 percent of the gross consumption of electric energy projected for 2020.[6] The state-sponsored energy efficiency resources that participate in the FCM are not captured in the New England load forecasts of the annual and peak use of electric energy because they are treated as capacity resources in planning studies. However, the ISO's load forecast does capture the historical impacts of naturally occurring energy efficiency and the savings resulting from future federal appliance standards.

2.4 Generation Resources

For summer 2012, the New England market includes approximately 28,000 MW of generation capacity, 2,600 MW of demand response resources, and 1,600 MW of capacity imports, totaling 32,840 MW. New England has a diverse generation fuel mix with natural gas and dual fuel oil/natural gas capacity holding virtually equal shares and collectively making up just under half of the capacity in the market. Many of the dual-fueled generators capable of burning either oil or natural gas operate primarily on natural gas. In most cases, environmental restrictions on emissions from burning oil greatly limit the total number of hours per year a generator can operate on oil. The percentage of total generation produced by natural gas in New England was 43 percent in 2009. By comparison, about 21 percent of energy was produced by power plants fueled by natural gas nationwide. Oil-fired generation amounts to 13 percent of capacity, but only 1 percent of generation. Many of these older plants are only kept in service due to revenue from the capacity market. Nuclear generation, on the other hand, makes up only 13 percent of the capacity, but provides 31 percent of the energy due to its low variable cost. The 2010 capacity and energy by fuel type for the generation located in the region are shown in Figure 2-2. Not shown are net imports, which accounted for approximately 1,200 MW of capacity and 9,377 GWh of energy in 2010.

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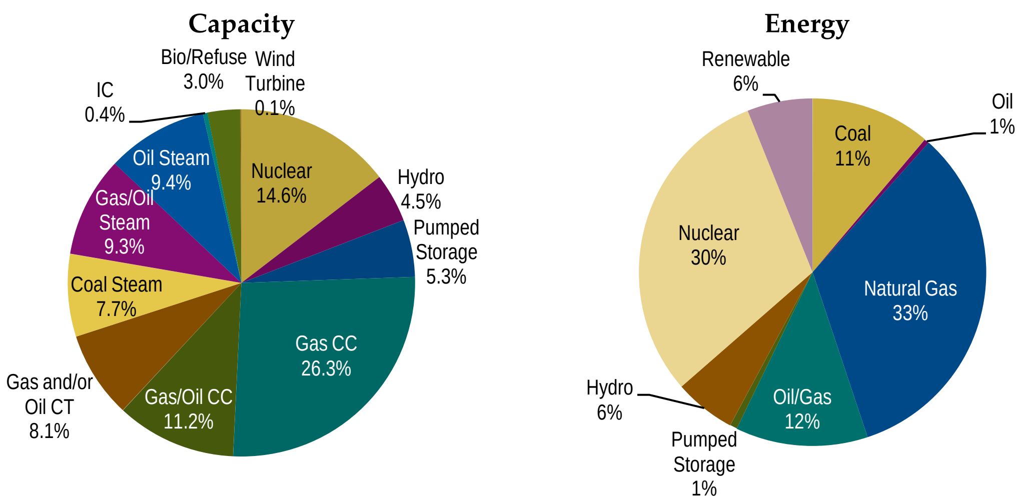
[5] *Passive* demand resources are principally designed to save electric energy use and are in place at all times without requiring direction from the ISO. *Active* demand resources reduce load in response to a request from the ISO to do so for system reliability reasons or in response to a price signal.

[6] The ISO's *Forecast Data 2011* (May 5, 2011), sheet 9 (http://www.iso-ne.com/trans/celt/fsct_detail/index.html) shows that the gross consumption of electric energy for 2020 is 151,498 GWh. The savings attributable to federal appliance standards is 2,253 GWh for 2020. In addition, passive demand resources are projected to save 7,194 GWh.

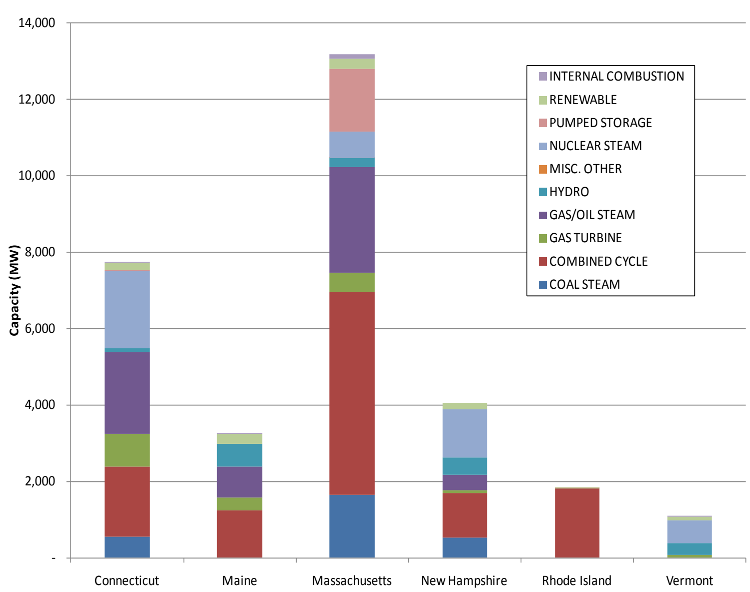
Figure 2-2. Summary of Capacity and Energy by Fuel Type for 2010



Source: ISO-NE, Navigant

The majority of New England's generation assets are located in Massachusetts and Connecticut with most of these resources being natural gas and oil fired and totaling over 20,000 MW. Hydro resources are predominantly located in Maine, New Hampshire, and Vermont.

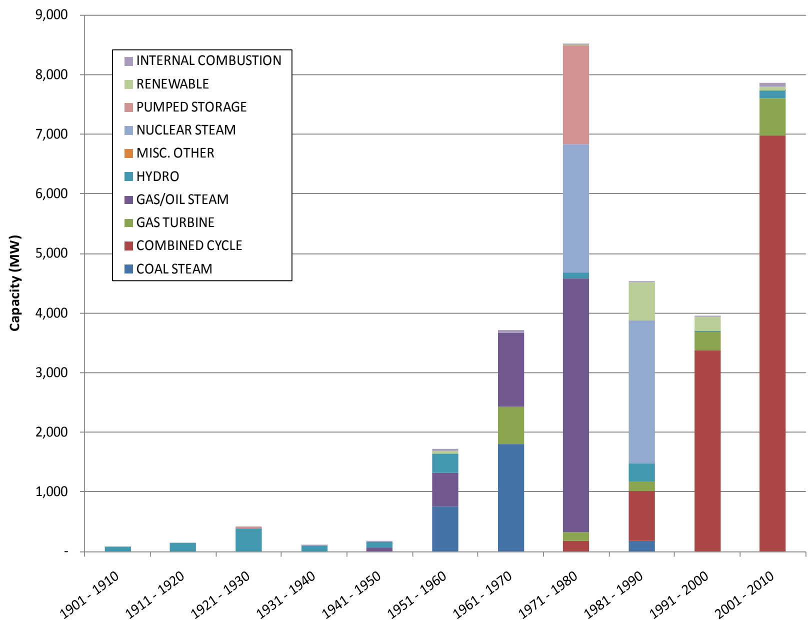
Figure 2-3. Summary of Capacity by Fuel Type and Location



Source: Energy Velocity

About half of the generation assets located in New England are over 30-years old, including about 6,300 MW that are older than 40-years. Almost 7,000 MW of natural gas combined cycle capacity is less than 10-years old. This segment is over 22% of the entire New England generation portfolio. The coal capacity in New England is between 40 and 60 years old. It is estimated that there is between 2,000 MW and 4,000 MW of capacity that will require additional capital investment to meet increased air quality standards. Based on current market conditions, many of these are considered candidates for retirement.

Figure 2-4. Net Summer Capacity by Age and Fuel Type



Source: Energy Velocity

2.4.1 Generation Retirements

There have been minimal announced retirements impacting New England's generation fleet. A plant seeking to retire must submit a permanent delist bid to the ISO to opt out of participating in the upcoming FCM. Once the permanent delist bid is submitted, a study process is triggered whereby the ISO-NE studies the impact of the proposed retirement on the system to make sure the loss of the generation resource will not have an adverse impact on the reliability of the system. A bid that is rejected for reliability reasons will be paid a just and reasonable price, as determined by FERC, for as long as the resource is required to remain in the marketplace.

In 2010, the Salem Harbor Station, located north of Boston in Massachusetts and representing 745 MW of coal capacity, submitted a permanent delist bid for the retirement of all four units. In May 2011, the ISO informed Dominion that it had accepted those bids for the retirement of Units 1 and 2, but rejected the non-price retirement bids for Units 3 and 4 because they were needed for system reliability during the upcoming forward capacity auction (FCA) commitment period. However, transmission infrastructure improvements are being developed, and we expect Units 3 and 4 to be retired by June 2014.

2.4.2 Impacts of Environmental Regulations

There are several uncertainties that could significantly reduce the reserve margin more quickly than anticipated. One is the elimination of the capacity price floor. Another is pending environmental legislation. There are currently three environmental regulations that could impact New England's supply mix and the demand for renewable generation.

- **Maximum Achievable Control Technology (MACT):** In 2011 the Environmental Protection Agency (EPA) proposed revisions to the emissions standards for hazardous air pollutants (HAP) from coal and oil-fired electric generating plants. These revisions are designed to limit HAP, most notably, for mercury and acid gases, based on current MACT. Existing units have up to 3 years to comply with MACT; with individual states granting up to an additional year for facilities to install the necessary emission control equipment. The air toxics rule could impact oil units in addition to coal units.
- **Cooling Water Intake Rules (Clean Water Act Section 316b):** Policy is currently being developed to regulate the use of cooling water for existing power plants. The proposed policy calls for the use of wet, closed-cycle cooling systems (cooling water is re-circulated through cooling towers or ponds and not released into the water system from which it was originally taken) at existing generating facilities that currently use open-loop cooling (cooling water from a river, lake or ocean is used for cooling and released back into the body of water). These regulations are designed to reduce fish entrainment and impingement caused by the use of cooling water by industrial facilities and electric generation plants. As with the air toxics rule, compliance will have a timeline stretching into the second half of the decade.
- **Cross State Air Pollution Rule (CSAPR):** On July 7, 2011, the EPA released the Cross State Air Pollution Rule, which limits emissions of NOx, SO2 and ozone that contribute to pollution in states that are downwind. The modeling completed for CSAPR determined that none of the New England states had a significant adverse impact on the air quality of neighboring states and as a result, they were not subject to emissions reductions under CSAPR. On Dec. 30, 2011 CSAPR was stayed due to a number of challenges, including a challenge to the validity of the modeling. Although not currently expected, there is a low probability that revisions to CSAPR could impact the New England states at a future date. On August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated CSAPR. However, Navigant believes this action is unlikely to notably slow the pace of coal plant retirements as a significant portion of retirements are due to stricter environmental regulations under MACT and low natural gas prices.

The ISO has provided a review in several modeling assessments and reports that evaluated the impact of upcoming EPA regulations and identified fossil and steam thermal units that would need to comply with these regulations. Drawing on these studies and conducting an independent analysis, the ISO identified that the majority of coal generation in New England is at or near compliance levels with the rules, but most liquid oil fired capacity lacks pollution controls to meet the regulation. ISO-NE estimated that the air toxics rule could impact up to 3.6 GW of oil and coal capacity. In addition, 5.6 GW of fossil fuel and nuclear capacity could be subject to more restrictive requirements associated with entrainment mortality and control options under the requirements of the cooling water rules. Even though much of this capacity will remain in service, many of the older steam gas and oil units will be at risk of retirement given their limited operation.

Regional Greenhouse Gas Initiative: The six New England states all participate in Regional Greenhouse Gas Initiative (RGGI), a carbon cap and trade program that covers nine Northeast states. Currently, RGGI auctions and secondary markets have resulted in prices around $2/ton-$3/ton for CO2 allowances – too low to have a meaningful impact on the energy market. Given that federal CO2 programs have stalled, it is unlikely carbon offset prices will increase significantly in the short to medium term.

Key Takeaway: The investment required for complying with some or all of the forthcoming environmental regulations could make a number of the older steam gas and oil units uneconomic and at the risk of retirement given their limited operation.

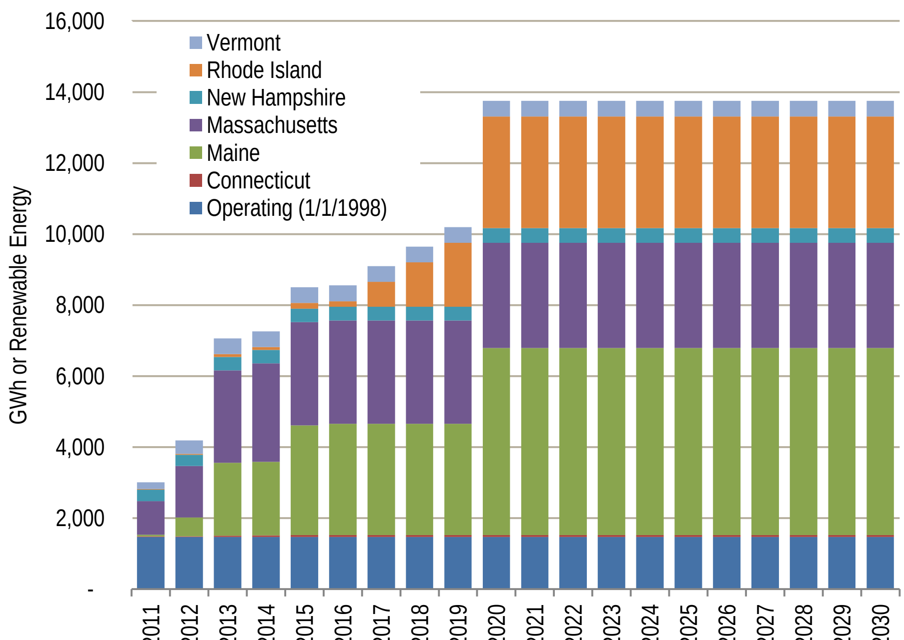
2.4.3 Renewable Resource Development

New England currently less than 500 MW of wind capacity in operation, with a significant amount of renewable resources imported for meeting RPS requirements. There have been a significant number of renewable energy projects proposed over the last several years. However, with low fuel prices and the expiration of the Production Tax Credit (PTC), many of these projects have been cancelled or put on hold until market conditions change.

There is currently over 2,200 MW of wind capacity in the ISO-NE transmission interconnection queue, with half of the resources proposed for Maine and the remaining proposed for New Hampshire, Vermont, and Massachusetts. The wind under development in Massachusetts includes almost entirely the Cape Wind project. Many of these resources are dependent on transmission infrastructure development for their successful fruition.

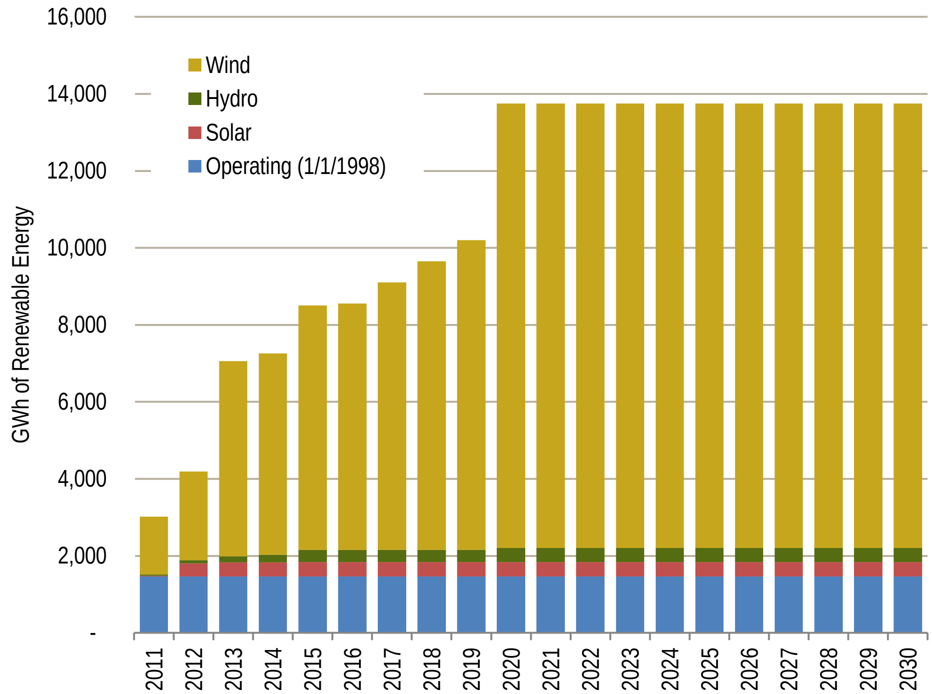
Figure 2-5 provides a summary of the renewable energy development in New England. This data is based on the information contained in the transmission interconnection queue process. Figure 2-6 presents the same information, presented by fuel type. As can be seen from both these charts, wind project are a significant source of planned renewable resources in the region.

Figure 2-5. Renewable Energy Development by State



Source: Energy Velocity, Navigant

Figure 2-6. Renewable Energy Development by Fuel Type



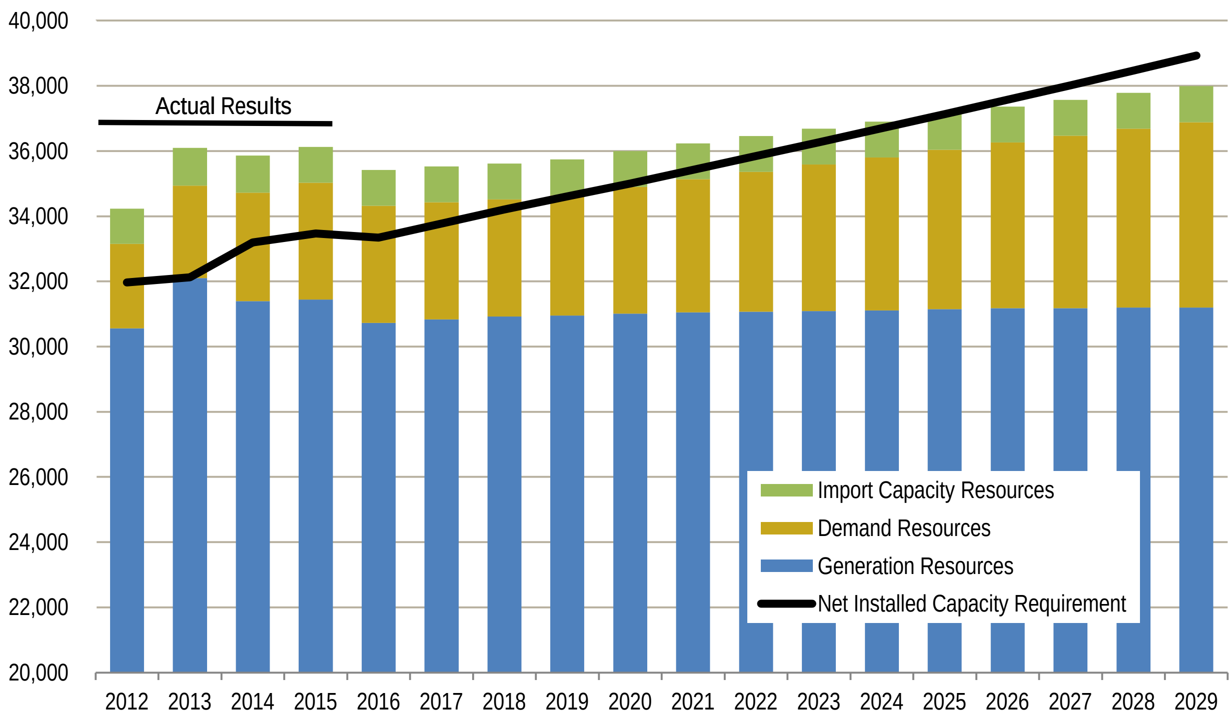
Source: Energy Velocity, Navigant

2.5 *Supply-Demand Balance*

As described above, ISO-NE implements a FCA for the procurement of capacity resources three years in advance of the delivery year. Generators and demand response resources compete for a capacity obligation, offering into the market during the descending-clock auction process. Under current rules, the FCM includes a floor price; when the auction price as set by the bidders descends to the floor price that auction is stopped and all capacity in the market receives a prorated capacity payment. There have been five auctions held so far, each one stopped when the auction price met the floor price, which has resulted in 2,000-5,000 MW of surplus capacity in the market. In the latest auction, for delivery year 2014/2015, there is over 4,000 MW of surplus capacity in the market. Under current rules, the floor price is set to terminate after the 2015/2016 auction. This is anticipated to result in extremely low prices that could result in some capacity permanently delisting (retiring) in the market.

Based on a forecast of peak demand, demand response and generation resources, and using reasonable assumptions on imports and other parameters, a projection of capacity requirements can be constructed for the New England market. Navigant has constructed such an analysis using forecasts and other information from ISO-NE and other assumptions. In constructing this forecast, we have taken a conservative approach related to incremental generation development and demand response resources. We include the recently announced retirement of Salem Harbor Station, and include 1,100 MW in imports which is consistent with the level of imported capacity from past auction results. Figure 2-7 presents a comparison of the net installed capacity requirements to the total resources and imports in the market. This assessment illustrated the significant amount of capacity that currently exists in the market, above the net installed capacity requirement. Based on this simple assessment, the New England market may not need additional capacity until between 2020 and 2025 depending on the availability of capacity imports and decisions on future retirements.

Figure 2-7. Supply-Demand Forecast for New England



Source: ISO-NE, Navigant

As can be seen from Figure 2-7, the market has the potential to remain surplus for the next 8 to 10-years, unless there are generation retirements or a reduction in imports.

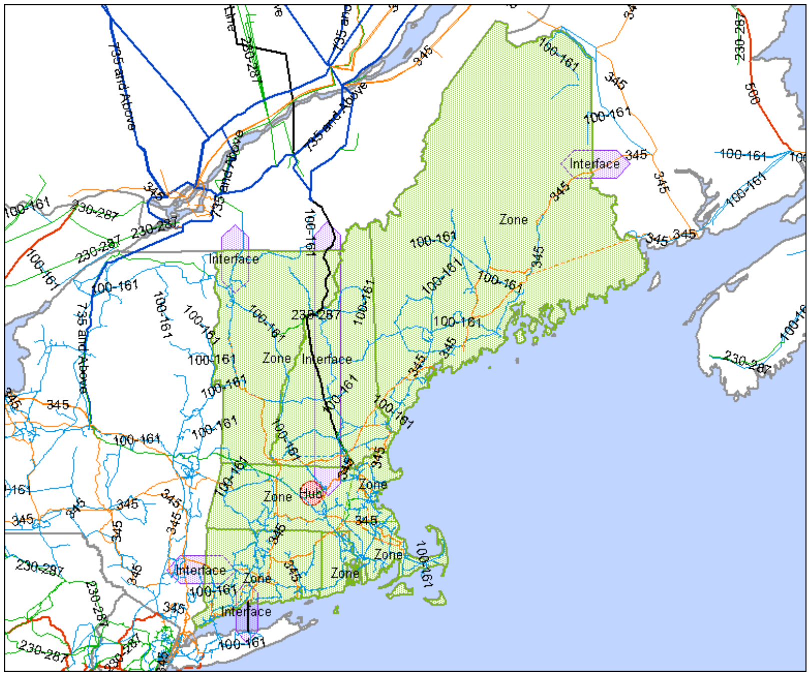
2.6 *Transmission System*

As the RTO for New England, ISO-NE is responsible for oversight of the region's transmission system, which currently includes 8,000 miles of transmission lines composed mostly of 115 kV, 230 kV, and 345 kV circuits. In addition to the transmission infrastructure within the region, New England has transmission interfaces with New Brunswick, Quebec, and New York.

- New England and New Brunswick are connected through two 345 kV ties (1,000 MW);
- New England has two high-voltage direct-current (HVDC) interconnections with Quebec: a 225 MW back-to-back converter at Highgate in northern Vermont and a +/– 450 kV HVDC line with terminal configurations that allow up to a 2,000 MW delivery at Sandy Pond in Massachusetts; and
- There are nine interconnections with New York: two 345 kV ties, one 230 kV tie, one 138 kV tie, three 115 kV ties, one 69 kV, and one 330 MW HVDC tie between Connecticut and Long Island.

Figure 2-8 provides a map of the highlights the region's transmission infrastructure and the system interconnects with three other regions: New York, Quebec, and New Brunswick. Currently, import capability to ISO-NE is approximately 4,200 MW[7].

Figure 2-8. New England Transmission System and Interfaces with Neighboring Regions

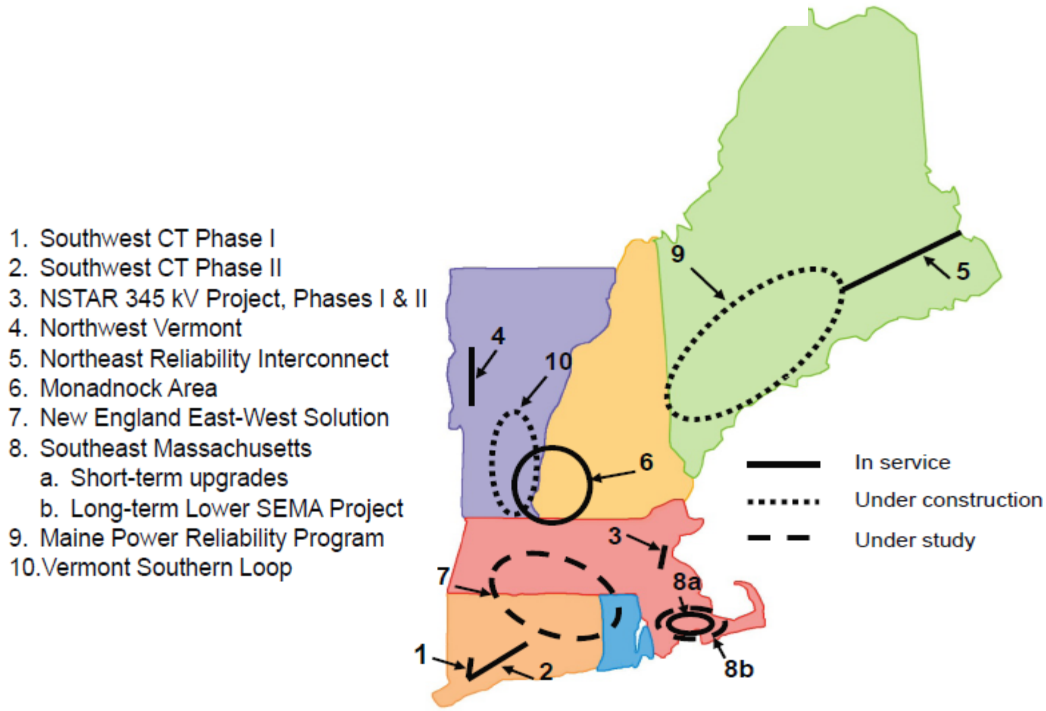


Source: Energy Velocity

New England's transmission owners have constructed a total of 341 transmission projects, representing $4.3 billion in new infrastructure investment from 2002 to 2010. An additional $5 billion of investment is still underway or planned. Fourteen of the projects are major 345 kV transmission lines that have been identified as critical for maintaining transmission system reliability. The location of these projects is shown in Figure 2-9. Eight of those projects are already complete — phases 1 and 2 of the Southwest Connecticut Reliability Projects; the Northeast Reliability Interconnection Project; phases 1 and 2 of the Boston Transmission Reliability Project; the Short-Term Lower South-East Massachusetts (SEMA) Upgrades, the Northwest Vermont Reliability Project, and the Vermont Southern Loop.

[7] Sum of Total Transmission Capability, TTC, as reported by the ISO-NE for noon on November 29, 2006

Figure 2-9. ISO-NE Completed and Proposed Transmission Projects



Source: ISO-NE 2011Regional System Plan

There are a number of projects that are currently under development or being planned by either ISO-NE or market participants. Relevant projects to the AEG initiative are discussed in more detail below

2.6.1 Northeast Reliability Interconnection

The Northeast Reliability Interconnection (NRI) is a 144-mile, 345 kV transmission line connecting New Brunswick, Canada to Orrington, Maine. This line increases transfer capability from New Brunswick to New England by 300 MW. The Northwest Vermont Reliability Project is composed of a series of 345 kV and 115 kV transmission lines intended to address system reliability in the northwestern area of Vermont and the Vermont Southern Loop and will address significant system performance concerns for key contingencies occurring under heavy import conditions. The substation involves installing a new Vernon–Newfane–Coolidge 345 kV line with several 345/115 kV substation upgrades. This project was completed in early 2011.

2.6.2 The Maine Power Reliability Program

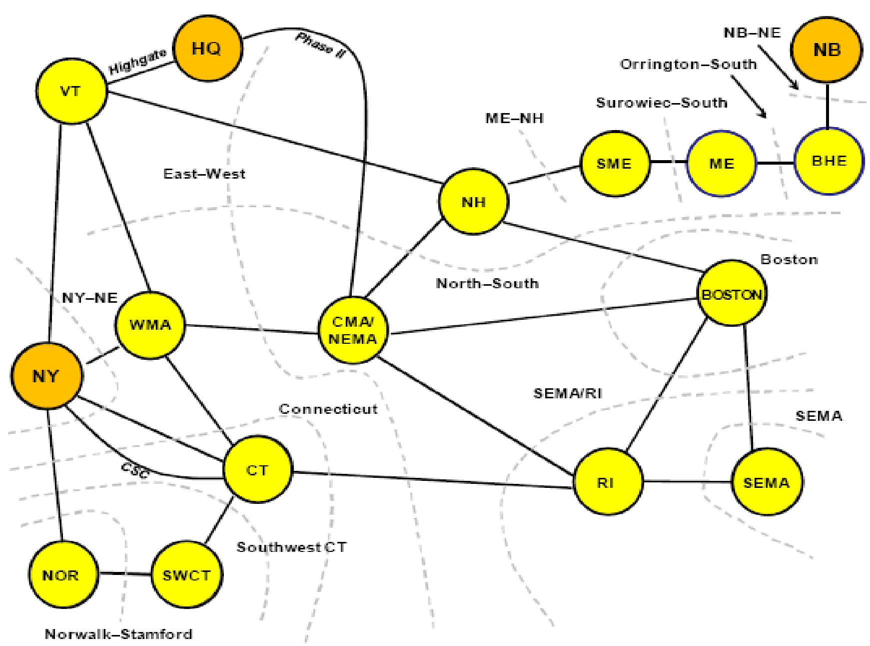
Central Maine Power (CMP) has identified several transmission upgrades required to alleviate load pockets and increase the ability to move power into Maine from New Hampshire and improve the ability of the transmission system within Maine. The Maine Power Reliability Program (MPRP) includes the construction of approximately 500 miles of new or upgraded transmission lines, largely in CMP's existing transmission corridors, plus four new 345 kV substations and related facilities. The MPRP was conditionally approved in May 2010 by the Maine Public Utilities Commission (MPUC), and upgrades are planned to be phased in over a number of years. Although ISO-NE is still performing stability studies, this project is estimated to increase the interface limit between Maine and New Hampshire by about 150 MW.[8] The expansion of this interface is critical for facilitating power sales from Maine and into the rest of New England. This project is also estimated to reduce congestion costs in Maine.

2.6.3 Northern Pass HVDC Line

The proposed Northern Pass transmission line, an HVDC line being proposed from southern Quebec to southern New Hampshire (not shown on map) is being proposed to import 1,200-1,500 MW from Hydro Quebec. This project is still in the planning phases but may have a significant impact on energy prices and congestion in Southern New Hampshire and Vermont, and the ISO-NE FCM.

Important considerations for exports from New Brunswick to New England are 1) the capability of the transmission system at the interface and 2) the capability of the transmission system in Maine to move the power to the load centers south of the North-South Interface. This second limitation on the transmission has been a noted constraint on the system, especially between Maine and neighboring New Hampshire. There has been a significant amount of generation capacity developed in Maine over the last decade, primarily due to its access to Canadian natural gas and available and suitable sites. This significant generation, coupled with a minimal local load growth has caused an export constraint in Maine. The export constraint has led to lower capacity clearing prices in each of the FCA. Figure 2-10 provides a "bubble" representation of the transmission system in New England.

Figure 2-10. Transmission Representation for New England



Source: ISO-NE

The existing interface limits are as follows: New Brunswick–New England; 1,000 MW[9]; Orrington–South Export 1,200 MW; Surowiec–South 1,150 MW; and Maine–New Hampshire 1,600 MW. Additionally,

[8] See ISO-NE's filing to FERC in Docket No. ER12-757-000, dated February 13, 2012.

since the MPRP falls within Maine and serves to increase the reliability of the Maine system, this project is not anticipated to significantly increase the capability of the system for exports from Maine to New Hampshire.

Key Takeaway: Maine is currently export constrained, with an abundance of natural gas-fired generation capacity. This has led to low energy prices, lower capacity prices, and reliability issues. The proposed transmission projects are being developed to address reliability concerns, and do not explicitly address the export constraint between Maine and New Hampshire.

2.7 Markets

ISO-NE operates energy, capacity, and ancillary service markets. Energy prices are determined on a nodal and zonal base; generators are paid the nodal price, reflecting the point of interconnection to the system, and load pays the zonal price, calculated as the load-weighted nodal price within the zone. ISO-NE operates two energy markets, a day-ahead and real-time market. The day-ahead market is financially binding where offers and bids are accepted the day before the operating day. The day-ahead market is simulated to determine a least-cost dispatch for the resources bidding into the market. The ISO also operates a real-time market to account for any unexpected changes to the day-ahead schedule. ISO-NE also manages the FCM. Through the FCA, resources are procured on an annual basis for three years in advance to create price and revenue certainty for new resources. Table 2-1 provides a summary of the competitive markets managed by ISO-NE for New England.

Table 2-1. Description of the ISO-NE Markets

Energy	Day-ahead Energy Market	• Forward market in which hourly LMPs are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions.
	Real-time Energy Market	• Spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions.
Capacity	Forward Capacity Market (FCM)	• Compensates generators and demand response resources for future capacity commitments. Provides efficient long-term market signals to govern decisions to invest in new generation and demand resources and to maintain existing resources.
Ancillary Services	Regulation Market	• Compensates resources that are instructed to increase or decrease output instantaneously to balance the variations in demand and system frequency.
	Forward Reserve Market (FRM)	• Compensates generators for the availability of their unloaded operating capacity that can be converted into energy within 10 or 30 minutes when needed to meet system contingencies.
	Real-time Reserve Pricing	• A mechanism used to implement scarcity pricing, which compensates on-line generators above the marginal cost of electric energy for the increased value of their energy when the system or portions of the system are short of reserves.
Transmission Market	Financial Transmission Rights (FTR)	• Used to hedge against the economic impacts associated with transmission congestion and provides a financial instrument to arbitrage differences between expected and actual day-ahead congestion.

Source: ISO-NE, Navigant

[9] For capacity purposes, ISO-NE has assumed this value to be 1,000 MW for the next several Forward Capacity Auctions, through 2013/2014. Beginning in 2014/2015, ISO-NE is giving this interface capacity value of 700 MW thereafter.

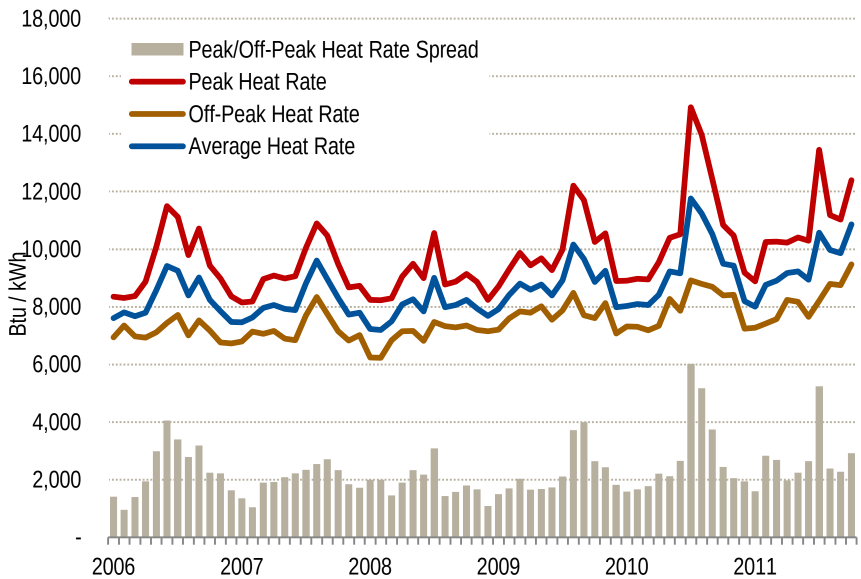
2.7.1 Energy Market

ISO-NE has a nodal market structure. In a nodal market, the LMP is determined at thousands of nodes across New England, highlighting transmission congested areas. Higher marginal cost generators will need to be used in load pockets because lower cost power cannot be brought to the load at a sufficient level during times of transmission congestion. This provides incentives for generators to site close to load or in constrained areas of the transmission system. LMPs are generally higher in the southern parts of ISO-NE, primarily the Boston area and Connecticut, but due to the recent transmission upgrades and new generation additions, the price differentials across New England are relatively small (generally less than $1/MWh difference between most nodes and Mass Hub).

Generator operation in New England can either be dispatched by the ISO-NE or be self-scheduled to meet the obligations of the market participant. Generators that are dispatched are done so around the self-scheduled resources. Dispatchable resources serve between 20 and 30 percent of the energy requirements in a typical month, with self-scheduled resources not controlled by the ISO-NE meeting the remaining monthly energy requirements.

As a measure of the efficiency of the energy market, the implied market heat rate provides a simple way of studying market trends where a simple analysis of energy prices can be misleading. The historical market heat rate for New England has been consistent, reflecting natural gas on the margin with oil and demand response for peaking as can be seen in Figure 2-11. Energy prices are based on the Boston zonal price for the day-ahead market and natural gas prices are based on Algonquin City Gate. The heat rate consistently peaks in the July and August around 11,000 to 12,000 Btu/kWh. ISO-NE's energy prices are driven predominantly by natural gas prices, since natural gas-fired generation is on the margin over 70% of the hours in the year. The New England system's market heat rate appears to be stable, exhibiting a diurnal and seasonal shape that has averaged about 8,600 Btu/kWh over the last five years. At a natural gas price of $5.00/MMBtu, wholesale electricity market prices would be about $43 MWh. The 2011 market heat rate did not follow the previous years' trend. In June 2011 New England experienced a heat wave where emergency purchases from neighboring regions and 600 MW of demand response were needed to meet operating reserve requirements.

Figure 2-11. New England Historical Market Heat Rate



Source: Navigant

Key Takeaway: NE historical market heat rate has averaged 8,600 BTU/kWh over the past several years. At a natural gas price of $5.00/MMBtu, wholesale electricity market prices would be about $43/MWh (USD).

2.7.2 Forward Capacity Market

The ISO-NE administers a FCM to assure that there are sufficient resources available to meet the projected capacity requirements for the system. The FCM allows generators to sell their capacity three years (40 months) ahead through an annual FCA. Capacity can be from new or existing resources including generation, demand resources, and imports. Resources must undergo a "qualification process" to participate in the FCA. Existing resources must demonstrate historic performance for the past five years. New resources can lock in auction clearing prices for up to five years, but must undergo a more rigorous qualification process, demonstrating development feasibility, interconnection reliability impacts, timing for commercially availability, and that they can provide the capacity bid into the auction.

The capacity auctions use a descending-clock format, in which the auction price is lowered in prescribed increments until total offered capacity equals the installed capacity requirement (ICR). Resources enter a dynamic delist bid at which they will withdraw from the auction. When the price drops such the available resources equal the ICR, the auction is stopped and the price that capacity clears the market is established for all capacity resources remaining in the auction process. The starting price of the first auction was set at two times the estimated cost of new entry (CONE). CONE was set at $7.50 per kW-month for FCA1, $6.00 per kW-month for FCA2, and $4.92 per kW-month for FCA3 and FCA4[10]. For

[10] Based on the current market rules, CONE was set at $4.918 per kW-month for FCA4 because there was no need for additional resources in FCA3.

FCA2 and FCA3, CONE was calculated as a function of the clearing price in the preceding auction. For FCA4, CONE was left at the same value as FCA3, and for FCA5 CONE was escalated at the Handy Whitman Index. A floor price is set at 0.6 times CONE to ensure that the resulting market pricing compensated capacity resources.

Another important provision of the market rule is Proration, which occurs when the auction price reaches the floor price in an FCA and the auction is stopped. There are two Proration options available for resources remaining in the auction: maintain the full Capacity Supply Obligation with a reduced payment rate (Price Proration); or receive a reduced Capacity Supply Obligation with the full capacity clearing price (MW Proration). The Proration option chosen by resources does not have an effect on the total amount of money paid by load and received by a resource.

The ICRs are determined based on an assessment of load, resources, and transmission limitations, resulting in a projected capacity requirement for each capacity zone. To calculate the amount of capacity needed in the auction, ISO-NE first subtracts the reliability benefits associated with the Hydro Quebec Phase II Interface. This benefit, called HQ Interconnection Capacity Credit ("HQICC") was 1,400 MW in the first auction and about 900 MW for subsequent FCAs. Based on the current market design, capacity zones with separate supply requirements can be established as they may become necessary due to transmission constraints on the system. Since the first auction, the Maine load zone has been defined as an export constrained zone, due to the transmission limitations between Maine and New Hampshire. Similarly, beginning with FCA7 the Northeast Massachusetts (NEMA) and Connecticut load zones have been defined as import-constrained areas and will be modeled separately.[11] As such, these three zones will likely clear at slightly different prices than the remaining zones.[12]

Results of the first five FCA are presented in Table 2-2. As can be seen, for each of the auctions the Capacity Supply Obligation exceeded the net installed capacity requirement (NICR), resulting in a capacity surplus of between 2,000 and 5,000 MW. The surplus is the result of the auction reaching the floor price and was stopped per auction rules with excess capacity remaining in the auction. Under the rules, all capacity remaining in the auction will receive a Capacity Supply Obligation. As discussed, the winning bidder will be able to take either the prorated payment or the full capacity clearing price with its capacity prorated. As can be seen, the surplus capacity has depressed the clearing price for capacity.

It is important to note that ISO-NE and the NEPOOL participants are currently exploring several market design frameworks that address alternative clearing price structures for the existing New England capacity market. These discussions are taking place as part of confidential settlement discussions. Based on the limited information available on the ISO-NE website, the redesign efforts are exploring a number of options, such as demand curve and mechanisms to reduce price volatility.

[11] See FERC Order ER12-953-000, dated March 30, 2012.

[12] NEPOOL participants are currently evaluating alternative capacity market structures that are designed

Table 2-2. FCA Results

FCA Capacity (MW)	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
AUCTION INPUT					
Peak Demand Forecast	28,160	28,575	29,020	28,570	29,025
Installed Capacity Requirement (ICR)	33,705	33,439	32,879	33,043	34,154
HQ Interconnection Capacity Credit (HQICC)	1,400	911	914	916	954
Net Installed Capacity Requirement (NICR)	32,305	32,528	31,965	32,127	33,200
AUCTION RESULTS					
Existing Generation Resources	30,239	31,050	30,558	32,103	31,397
Existing Demand Resources	1,366	2,483	2,588	2,834	3,327
Existing Imports	934	769	1,083	1,162	1,140
New Generation Resources	626	1,157	1,670	144	42
New Demand Resources	1,188	448	309	515	263
New Imports	0	1,529	817	831	871
Capacity Supply Obligation	34,077	37,283	36,995	37,589	37,040
Capacity Surplus	2,047	4,755	5,030	5,462	3,718
AUCTION PAYMENT ($/kW-month)					
Capacity Clearing Price	$4.50	$3.60	$2.95	$2.95	$3.21
Prorated Payment Rate	$4.25	$3.12	$2.54	$2.68	$2.88

Source: ISO-NE, Navigant

2.8 Import and Exports

New England has consistently been a net importer over the last several years, relying on significant intertie capacity with Canada to import from the north and several smaller interties with southern New York for exports from southern New England. As mentioned above, New England and New Brunswick are connected through two 345 kV ties; the average hourly energy flow is predominantly from New Brunswick to New England. The flow is greater during the on-peak hours. The flows have averaged about 140 MW, annually into New England. There seems to be no consistent pattern for the monthly flows for the 2006-2009 period.

New England has two HVDC interconnections with Quebec: a 225 MW back-to-back converter at Highgate in northern Vermont and a +/– 450 kV HVDC line with terminal configurations that allow up to a 2,000 MW delivery at Sandy Pond in Massachusetts. The average hourly energy flow pattern from HQ is shaped to flow at a higher rate during on-peak hours and less during off-peak hours. Flows from HQ are highest in winter and summer months and decrease in the spring and fall months. Flows have increased from Quebec consistently from 2006-2009 from 6 TWh to 11 TWh.

There are nine interconnections with New York: two 345 kV ties, one 230 kV tie, one 138 kV tie, three 115 kV ties, one 69 kV tie, and one 330 MW HVDC tie between Connecticut and Long Island. Exports to Long Island over the Cross Sound Cable have been almost at the line’s full rating of 330 MW during the on-peak periods. An illustrative summary of annual energy imports and exports for 2010 is provided below.

Table 2-3. Electricity Trade with Neighboring Systems - 2010

Interface	Imports (MW)	Exports (MW)	Net (MW)
New Brunswick	1,224	487	737
Keswick	760	180	580
Pt. Lepreau	464	307	157
Hydro Quebec	9,561	347	9,214
Highgate	1,464	38	1,426
Phase II	8,096	309	7,787
New York	1,997	6,408	(4,412)
Cross Sound Cable	0	2,397	(2,396)
AC Ties	1,997	4,011	(2,016)
Total	12,781	7,242	5,539

Source: ISO-NE

Despite the large capacity for imports, most of the transmission import capability from New Brunswick is being used by Hydro Quebec and Boralex for 2013-2015. Transmission capacity between New Brunswick and New England appears limited, with no capacity available in the short term. Hydro Quebec secured fifteen year transmission rights to the 300 MW intertie between New Brunswick and Maine.[13] This will limit the ability for clean and renewable energy from Atlantic Canada to participate in the New England energy and capacity markets in the short term. Table 2-4 illustrates the available and unused transmission capacity between New Brunswick and Maine for the first five FCAs in ISO-NE through 2015. The annual periods are based on the FCA procurement period, from June 1-May 31.

Table 2-4. FCA Results New Brunswick

FCA Assumptions (New Brunswick)	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
Existing Interface Limits (MW)	1000	1000	1000	1000	700
Tie-Line Benefits (MW)	360	716	609	584	439
Available for Import (MW)	640	284	391	416	261
FCA Auction Results (New Brunswick)	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015
Existing Imported Cleared (MW)	0	0	0	0	0
New Imports Cleared (MW)	0	0	0	366	286
Unused Capacity (MW)	640	284	391	50	-25

Source: ISO-NE, Navigant

[13] Carr, J, *Power Sharing: Developing Inter-Provincial Electricity Trade,* C.D. Howe Institute Commentary, pg. 10, available online: http://www.cdhowe.org/pdf/commentary_306.pdf

Looking beyond 2015 to the 2017/18 expected in-service date for the proposed Muskrat Falls hydroelectric project, Nalcor has secured access through Nova Scotia and New Brunswick into the New England markets through various transmission service, access and rights agreements with Emera. These agreements were among thirteen agreements that Nalcor and Emera executed on July 31, 2012[14] related to the Muskrat Falls and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects. In combination with the transmission access it currently has through Quebec, these agreements will allow Nalcor to sell any available energy and capacity into the New England energy market that is not utilized by Nalcor or committed for delivery into Nova Scotia. If the electricity available from Nalcor is eligible to participate in any of the state REC markets, it would also be able to access these markets.

[14] The agreements are available at: http://www.nalcorenergy.com/formal-agreements.asp

3. Export Opportunities for Clean and Renewable Energy to New England

As discussed in the previous section, there are three distinct "markets" for clean and renewable energy in New England: 1) the New England energy market; 2) the New England capacity market; and 3) the various state Renewable Energy Credit (REC) markets. Generally speaking, the energy market is accessible to any supplier that can physically deliver electricity into New England and, similarly, the New England capacity market is accessible to any supplier with a firm transmission path into New England.[15] The rules for the individual state REC markets vary from state to state depending on each state's Renewable Portfolio Standard (RPS), particularly with respect to the type of renewable energy that is eligible to participate in the market.

The energy and capacity market demand and supply dynamics for clean energy in New England are distinct and different than those for the REC markets for renewable energy in New England. In this section we will review the demand and supply drivers for each separately. The potential for clean energy exports from Atlantic Canada that would sell into the New England energy and capacity markets include nuclear and large hydro power. Unlike some types of renewable resources, there is no legislative requirement in New England to procure energy from either of these fuel types. Therefore, the demand for clean energy in New England is dictated by the prevailing demand and supply dynamics in the ISO New England administered market. Clean energy exports from Atlantic Canada compete with all other fuel types in the market. Currently, New England has sufficient supply to serve its demand and is expected to have sufficient capacity and energy for the next 10-20 years, or short to medium term based on the most recent FCM auction.

The New England REC opportunities are driven by state level RPS requirements. These legislative requirements oblige utilities and load serving entities to supply a certain percentage of their energy demand with RPS compliant renewable generation. The legislation also generally requires physical delivery of the renewable energy into New England, so renewable energy exports will generally need to sell into the New England energy market in order to access the REC markets, and could potentially access all three of the New England markets (energy, capacity and RECs) depending on the nature and firmness of capacity offered by the renewable energy source.

The types of renewable generation that comply towards RPS requirements vary slightly by state. For example, some do not include large-scale hydro to count towards RPS compliance, while others allow it. The extent to which states within New England are short on renewable energy to satisfy their RPS compliance targets will dictate the size of the export opportunity for renewable energy from Atlantic Canada.

Although the demand drivers for clean and renewable energy exports from Atlantic Canada vary, there are at least two common limitations: transmission capacity and competition from both in-region and out-of-region resources. The transmission path from Atlantic Canada to New England runs through New Brunswick to Maine then further south into the rest of the New England. Limitations throughout the

[15] While not a requirement, a firm transmission path for renewable resources participating in the New England REC market may be a prudent business decision depending on any delivery shortfall charges or other penalties associated with not fulfilling specific contractual obligations for the sale of RECs.

transmission system, like those currently experienced in northeastern Maine, will tend to depress prices for deliveries of clean and renewable exports into Maine as compared to prices in ISO-NE's load centres in the south, such as around Boston. Competition from proposed projects in New England as well as exports from Quebec and New York will compete with generation coming from Atlantic Canada, both on the clean and renewable side.

This section of the report provides an update on the demand and supply for clean energy, followed by a similar discussion on the demand and supply for renewable energy.

3.1 *Clean Energy*

As described above, there is no formal or legislated distinction within any of the New England states between clean energy, as defined as large-scale hydro and nuclear power, and more polluting forms of power including coal or oil fired steam generation. The demand for clean energy is driven by the New England electricity market demand and supply fundamentals, and will compete with all forms of electricity on a cost basis. However, these demand and supply fundamentals are influenced by ISO-NE market rules evolution and federal environmental regulations. This section provides an overview of each state's position towards nuclear and large hydro, as well as the developments of new out-of-region capacity in Quebec.

3.1.1 Demand for Clean Energy

Each state has a varying degree of receptiveness towards electricity generated from large-scale hydro and nuclear sources. This section describes each state's objectives and outlooks as presented their state energy plans and other state objectives.

1. **Vermont:** In Vermont, nuclear is a contentious issue – there is a pending lawsuit to determine if a nuclear plant should be closed by March 2012.[16] Vermont's Comprehensive Energy Plan (CEP) states that utilities should plan for alternative supply sources, including out-of-state nuclear. While no specific clean energy provisions exist, Vermont does allow large-scale hydro to count towards its 90% renewable energy target by 2050.
2. **Connecticut:** Connecticut has a moratorium on the siting and construction of new nuclear generating facilities until the issues concerning the disposal of high level nuclear waste have been resolved. Furthermore, the state budget includes a tax of $2.50 / MWh on fossil and nuclear generation effective July 1, 2011 to June 30, 2013.
3. **Maine:** The State of Maine Comprehensive Energy Plan 2008–2009 demonstrates it is receptive to electricity imports from Atlantic Canada. In regard to transmission investment and improved coordination with the Eastern Canadian Provinces (including Quebec), the Energy Plan states that the ISO New England and its stakeholders are discussing bringing additional renewable and non-carbon emitting (such as nuclear) into the ISO New England energy portfolio.
4. **Massachusetts:** The Massachusetts Clean Energy and Climate Plan for 2020 (CECP) plans for more stringent EPA power plant rules and clean energy imports. This plan also notes that a new transmission line connection with Hydro Quebec will provide up to 15% of the state's electricity

[16] Vermont Department of Public Service, *Comprehensive Energy Plan 2011*, pg. 150, available on line: http://www.vtenergyplan.vermont.gov/sites/cep/files/Vol%202%20Public%20Review%20Draft%202011%20CEP.pdf

demand when it is complete.[17] The report also suggests that a Clean Energy Performance Standard could be developed to encourage increased imports. However, this policy idea is built on the premise that: "*Canada has substantial hydroelectric resources, which have very low emissions, and are available at relatively low cost and with no need for renewable energy subsidies.*"[18] Recently, the Massachusetts Green Communities Act, which establishes policies and goals for renewable and alternative energy and energy efficiency was amended to allow hydroelectric power, regardless of whether that power is eligible under the renewable energy portfolio standard, for meeting the state's previous goal of at least 20 percent of the Commonwealth's electric load by the year 2020 through new, renewable and alternative energy generation.

5. **New Hampshire:** New Hampshire has no explicit policy on the development or use of large-scale hydro, outside of its RPS legislation, which does not allow it to count towards its target. See Table 3-1 for more information. It does have an operating nuclear power plant that it anticipates to continue to operate to 2020.

6. **Rhode Island:** The majority of the electricity used in Rhode Island comes from out-of-state, with nuclear power representing 27.5% of power consumed.[19] RI's vision statement included in its March 2011 planning document is "*In 20 years, energy in Rhode Island will be more efficient, reliable, and secure and at least 30% of all energy used in the State will come from clean and renewable resources, with at least 20% of the total coming from within the State.*" Given the current level of imports, limited inside state generating capacity and target for future imports, RI is a state that is receptive to clean energy imports.

Based on our review of the state energy plans and other regional and state-level objectives, Table 3-1 summarizes the northeast states' perceived receptiveness towards nuclear and large-scale hydro imports.

Table 3-1. Receptiveness towards Clean Energy Imports

State	Nuclear	Large Hydro
Vermont	+/-	+
Connecticut	-	+/-
Maine	+	+
Massachusetts	+	+
Rhode Island	+	+
New Hampshire	+/-	+

Source: Navigant

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[17] Massachusetts Clean Energy and Climate Plan, page 45, available on line: http://www.greenneedham.org/blog/wp-content/uploads/2011/02/2020-clean-energy-plan.pdf

[18] Ibid.

[19] Rhode Island Government Technical Committee Presentation, *RI Energy Plan (Update) and The Renewable Energy Siting Guidelines & Standards*, March 4, 2011, available on line: http://www.planning.ri.gov/landuse/Energy%20plan311.pdf

3.1.2 Out-of-Region Supply – Quebec

Quebec's market is dominated by Hydro Quebec a vertically integrated provincially owned corporation that includes three primary divisions: Hydro Quebec Distribution, the division that is responsible for operating Quebec's distribution system and ensuring there is sufficient supply to satisfy indigenous electricity demand; Hydro Quebec Production (HQP), which operates its generating assets including 34,500 MW of hydro, 675 MW of nuclear and 1,500 MW of thermal resources; and Hydro Quebec Transenergie, the division which operates and manages its bulk transmission system. Although they report their activities separately, these divisions operate collectively to maximize value for their common shareholder and to facilitate provincial government policy objectives.

Hydro Quebec's *Strategic Plan 2009 – 2013* includes increasing energy exports as one its strategic objectives for HQP, and has a number of hydroelectric expansion and infrastructure investments underway to support that objective.

1. **HQP's Major Projects:** One of the objectives identified in Hydro Quebec's *Strategic Plan 2009 – 2013* was the increase in Hydro Generating Capacity. The plan called for an increase of 1,000 MW of new capacity between 2008 and 2013, representing 8.7 TWh of new energy. The breakdown of new energy and capacity is provided in Table 3-2.

Table 3-2. Hydro Quebec Major Projects

Project	Energy (TWh)	Capacity (MW)	Commissioning
Construction: Eastmain-1-A/Sarcelle/Rupert	8.7	918	2009 - 2012
Refitting (capacity gains) La Tuque		38	2008 - 2009
Total – 2013	8.7	956	
Romaine Complex	8.0	1,550	2014 – 2020
Total – 2020 Horizon	16.7	2,506	

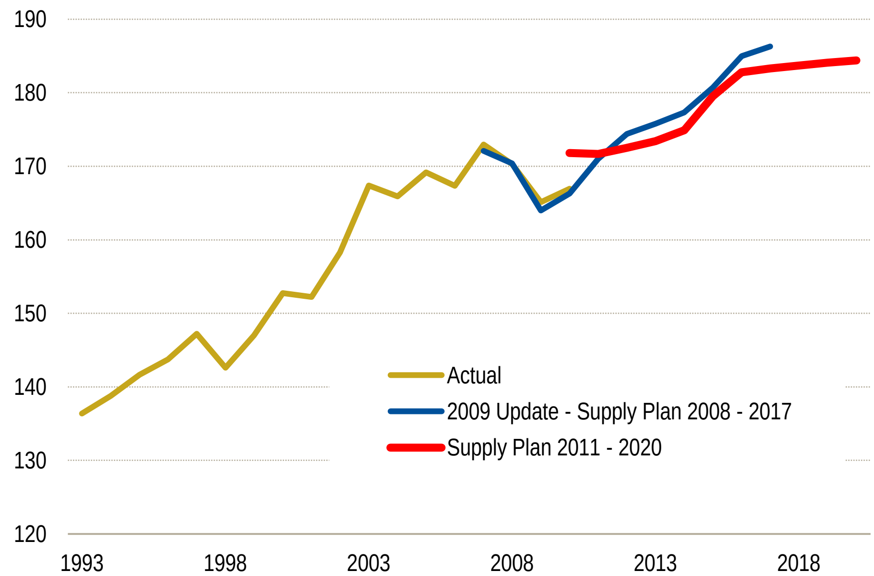
Source: Hydro-Quebec, Navigant

In addition to the investments in Eastmain-1-A/Sarcelle/Rupert and La Tuque, Hydro Quebec has broken ground on the Romaine Complex, which is a planned 1550 MW of new capacity, representing 8.0 TWh per year. Collectively these investments represent over 2,500 MW of capacity and 16.7 TWh of new energy supply. The energy from the Romaine project is planned to be used for export and is also part of Quebec's Northern Plan which calls for a total 4,500 MW of new generation investment (including the 1,550 from the Romaine Complex). Hydro Quebec is currently in a screening process for new projects.

2. **Hydro Quebec Distribution's 2011 – 2020 Supply Plan**: In November 2010, Hydro Quebec filed its 2011–2020 Supply Plan with the Regie de l'Energie. The 2011 – 2020 Supply Plan forecasted slower growth in electricity demand as compared to the previous supply plan as well as an energy surplus in the near term, causing Hydro Quebec Distribution (HQD), the retail load serving entity, to suspend existing supply contracts with independent power producers as well as cycling contracts it has in place with Hydro Quebec Production (HQP), the entity owning and operating the generation. The November 2011 update to the 2011 – 2020 Supply Plan has further

revised the energy forecast lower than in the November 2010. See Figure 3-1 below. The result of HQD forecasting lower growth is that HQP will have additional energy to export, over and above any new supply that it is developing or refurbishing.

Figure 3-1. Quebec's Forecasted Energy Demand (TWh)



Source: Hydro Quebec Supply Plans, Navigant

Key Observation: Hydro Quebec will have increased capacity and energy available for export as domestic demand remains lower than expected until 2020.

3.2 Renewable Energy

3.2.1 Demand for Renewable Energy

With the exception of Vermont, each of the New England states has a mandatory RPS requiring that a percentage of the retail consumption be procured from eligible renewable resources. These resource generally include wind, landfill gas, solar, photovoltaic (PV), small hydro, tidal power, biomass, and other technology types. Many of the states' RPS programs include separate requirements for new and existing renewable resources, with the requirement for new resources increasing over time. New resources may be used to fulfill either requirement. Load serving entities (LSEs), such as retail energy suppliers and electric utilities offering standard offer service, are required to meet state RPS requirements. In most states, municipal loads are not required to meet the requirement. Table 3-3 provides an estimate of the RPS requirements for new resources the New England states. A description of each States' requirements is also provided below.

Table 3-3. Overview of State RPS Standards

State	Incremental Amount	Year
Connecticut	20%	2020
Maine	10%	2017
Massachusetts	15%	2020
New Hampshire	16%	2019
Rhode Island	16%	2020
Vermont	20%	2017

Source: DSIRE, Navigant

Maine initially passed one of the highest percentage requirements of any state standard, requiring 30 percent of the generation sold in the state to come from eligible resources by 2000. This requirement, includes any renewable resources regardless of when it was developed (i.e., existing resources including hydro). Additionally, in June 2006, Maine adopted a renewable portfolio goal to increase new renewable energy capacity by 10 percent by 2017. This portion includes only new renewable energy sources entering commercial operation after September 1, 2005.

Massachusetts set incremental rising standards, beginning with a minimum requirement of 1 percent of renewable generation by 2003, with an annual increase of 0.5 percent through 2009, and a nominal 1 percent annual increase thereafter. Massachusetts LSEs are required to either procure a specified percentage of their retail sales from approved renewable sources or make an Alternative Compliance Payment (ACP). Ultimately, these monies provide incentives for renewable project development but there is not a requirement for actual renewable projects to be developed.

Rhode Island also set incrementally increasing requirements in its RPS program, requiring a minimum of 3 percent in 2007 and rising to 16 percent by 2019. Similar to Massachusetts, Rhode Island LSEs can also either procure renewable energy from a certified resource or make an ACP.

Connecticut set standards requiring that 7 percent of the energy procured by the LSEs come from Class I renewable resources and 10 percent from Class I or Class II renewable resources by 2010.

In April 2007, New Hampshire became the last state in the Northeast to enact a RPS by requiring 25 percent of the state's energy to come from renewable sources by 2025. Similar to the above programs, LSEs may either procure renewable energy from a certified resource or make an ACP.

Renewable resources can be imported from neighboring states or regions to meet the state requirements. For example, in 2007 Massachusetts LSEs purchased RECs from New York and Canada to meet their annual requirements. However, not all resources are qualified to provide RECs; each state has specific rules related to project size limits and other requirements.

Vermont does not have a typical RPS, but has a Sustainably Priced Energy Enterprise Development (SPEED) Program, created by to promote renewable energy development. Legislation enacted in March 2008 established a goal that 20% of total statewide electric retail sales be generated by new SPEED resources by 2017. Per state law, the SPEED Program must meet certain criteria by 2012. If the Vermont

Public Service Board (PSB) determines that the established minimum obligations of the SPEED program are not met, then a binding RPS would be developed. Currently large hydro resources of any size to count towards its SPEED Program renewable energy goals.[20] Provided below is summary of the programs and types of resources that qualify for participating in each of the state programs.

Table 3-4. Summary of RPS Rules and Requirements

State	Eligible Resources	Requirements
Connecticut	• Class I resources include: Solar, wind, fuel cells, landfills, sustainable biomass facilities, wave or tidal power, small hydro, and others. • Class II resources include: trash-to-energy, and existing biomass and small run-of-the-river hydro. • Class III includes combined heat and power (CHP) and energy efficiency.	• Class I renewable energy obligation begins in 2004 with 1%, increasing to 20 percent by 2020. • Class II is fixed at 3%. Class III begins at 1% in 2007 and increases to 4% by 2010, and is fixed thereafter.
Massachusetts	• Class I resources include: PV; solar; wind; ocean thermal, wave or tidal energy; fuel cells utilizing renewable fuels; landfill gas; and new hydro facilities. Class I is for facilities installed after December 31, 1997. • Class II includes PV; solar; wind energy; ocean thermal, wave or tidal energy; fuel cells utilizing renewable fuels; landfill gas; energy generated by certain existing small hydro facilities, and others. Class II resources include facilities operating before December 31, 1997.	• Class I begins in 2003 with 1%, increasing to 4% by 2009 and increasing thereafter annually by 1%. • Class II begins in 2009 and is fixed at 3.6%. Class II also includes a Waste Energy Minimum Standard that requires 3.5% of all sales to be met by waste energy.
New Hampshire	• Class I includes source which began operation after January 1, 2006 and includes wind; geothermal; biomass fuels; landfill gas; wave or tidal energy; solar, and other sources. • Class II includes new solar and solar technologies that began operation after January 1, 2006. • Class III includes existing biomass technologies (less than 25 MW) that began operation prior to January 1, 2006. • Class IV includes existing small hydro that began operation prior to January 1, 2006.	• Class I begins at 0.5% in 2009, increases to 1% in 2010, and increases by 1% annually thereafter to 16% by 2025. • Class II begins in 2010, increasing to 0.3% by 2014 and is fixed thereafter. • Class III begins at 3.5% in 2008, increasing to 6.5% in 2011 and is fixed thereafter. • Class IV begins in 2008 at 0.5%, increases to 1% in 2009, and is fixed thereafter.
Rhode Island	• The RPS includes: solar, PV, landfill gas, wind, biomass, hydro, geothermal, anaerobic digestion, tidal and wave energy, biodiesel, fuel cells using renewable fuels.	• The requirement begins at 3% by the end of 2007, and then increases an additional 0.5% per year through 2010, an additional 1% per year from 2011 through 2014, and an additional 1.5% per year from 2015 through 2019.
Maine	• Class I facilities include fuel cells, tidal power, solar, wind, geothermal, certain hydro, and biomass facilities that began operation after September 1, 2005. • Class II resources include all facilities included in Class I, including MSW and hydro that do not meet the requirements of Class I. Class II does not have any date restrictions. • Except for wind power installation, Class I and Class II renewable energy facilities must not have a nameplate capacity that exceeds 100 MW.	• The Class I requirement begins at 1% in 2008 and increases by 1% annually thereafter. • Class II is fixed at 30% annually.

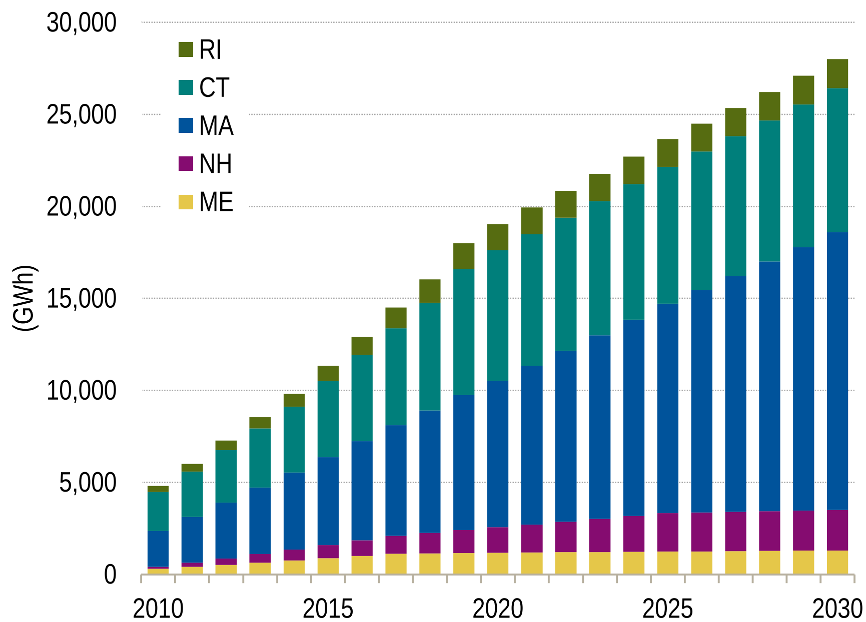
Source: Summarize from Dsireusa.org

[20] See Mary G. Powell, *Treatment of Large Hydropower as a Renewable Resource,* Energy Law Journal, Volume 32 at 553 for a discussion on the development of this program.

3.2.2 Supply of Renewable Energy

Based on ISO-NE assumptions on state energy growth, Navigant has prepared a projection of the state RPS requirements. As noted in Table 3-4, the RPS requirement increases as a percent of retail energy sales and as load grows. Figure 3-2 provides projection of the RPS requirements by New England state.

Figure 3-2. Projection of RPS Requirements by State



Source: ISO-NE, Navigant

The RPS programs for New England states required roughly 3,500 GWh of certified renewable energy resource be purchased in 2008. The RPS requirement is projected to increase from approximately 5,000 GWh in 2010 to over 19,000 GWh by 2020.

Based on state compliance reports, New England's LSE's have met their RPS requirements with a combination of new resources and imported purchases. This requirement was met through a mix of resources located in New England, New York, and Canada.

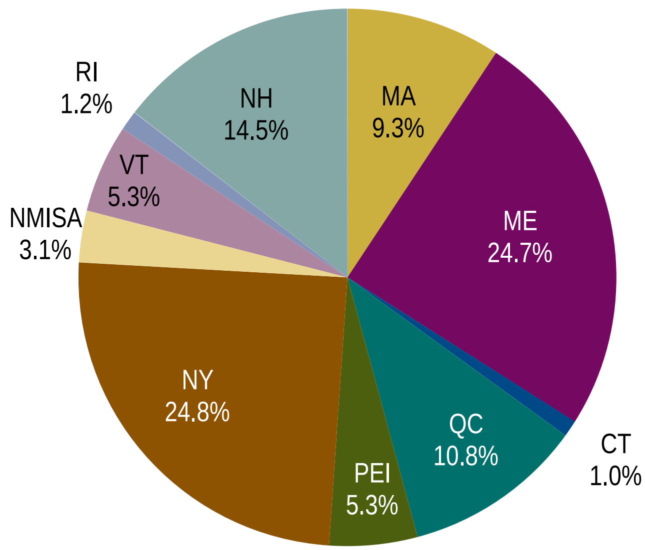
By way of example, Navigant researched where Massachusetts retail suppliers are purchasing renewable energy resources to meet their requirements. Based on our findings, we have identified that LSE's are purchasing RECs from entities located outside of the region to meet their requirements. Based on a compliance report prepared by the Massachusetts Division of Energy Resources (DOER), we have found the following:

- In 2009, Massachusetts retail electricity suppliers purchased 56% of the credits from suppliers inside New England, 28% from suppliers in Northern Maine and NY, and 16% from Canadian entities.
- Imports from Prince Edward Island (PEI) have increased significantly from 2007-2009. Other notable increases came from NH and VT.

- In addition to these purchases, NSTAR and National Grid, two of the largest REC purchasers in the region, banked credits for use in future years.
- NSTAR recently procured NEPOOL GIS RECs through a competitive bidding process that resulted in two long-term contracts.

Based on the DOER's analysis, Figure 3-3 identifies where Class I RECs as purchased by Massachusetts LSE's were sourced.

Figure 3-3. 2009 RPS Class I Compliance by Generator Location



Source: Compliance Report[21]

The renewable market will become increasingly more competitive as RPS requirements increase and the available sites for renewable resources are developed. The region will need to provide increased incentives and coordination as well as expansion of the transmission system if New England is to be self-sufficient in meeting its renewable resource requirements.

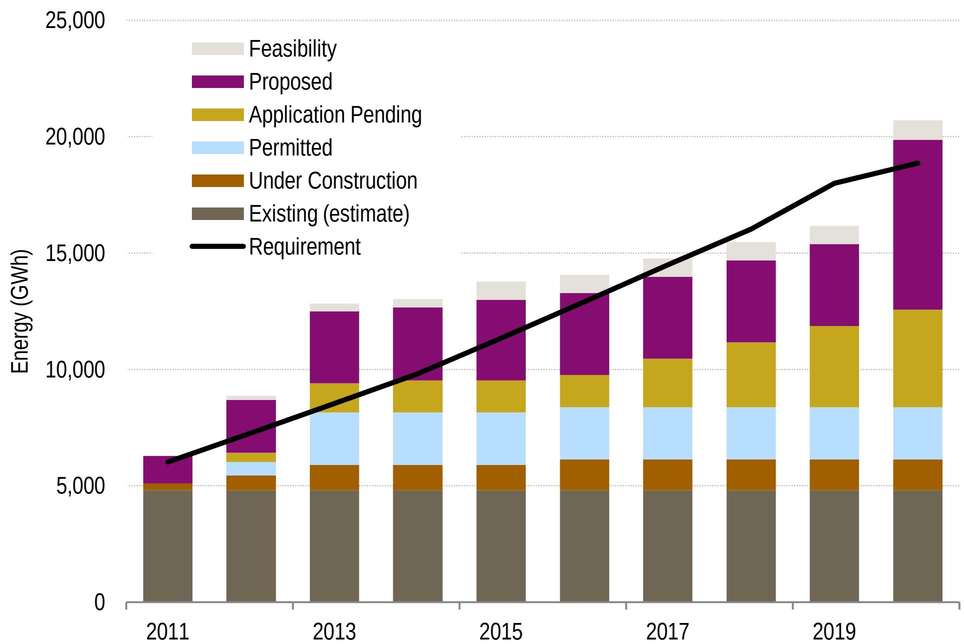
3.2.3 Current State of In-Region Supply

Wind resource development will likely make up the majority of renewable resources that are developed within New England, with minimal biomass and solar development. Wind resources will be predominantly located in Northern Maine, New Hampshire, Vermont, and off the coast of southeastern Massachusetts. These are the locations that have been identified in several studies related to renewable energy potential studies. However, to date renewable resources have been slow to develop, with energy providers opting for less expensive imports as opposed to developing new resources. As a result, regionally developed renewable resources are not expected to meet the projected RPS requirements, providing an opportunity for imports.

[21] Massachusetts Renewable and Alternative Energy Portfolio Standards (RPS & APS) Annual Compliance Plan for 2009, November 17, 2010 as revised January 11, 2011.

The chart below provides an estimate of the supply and demand balance for RECs New England. Assuming that the RPS requirements were completely met in 2010, there is a significant gap projected between future requirements and planned resources. The planned resources include Cape Wind, a controversial 500 MW wind farm planned for Nantucket Sound in Massachusetts. If this project does not materialize, the potential shortfall could be significantly larger than projected.

Figure 3-4. Projected Supply of Renewable Resources



Source: Energy Velocity, Navigant

3.2.4 Purchases of Renewable Energy in New England

New England's electric utilities, who are LSEs to those customers taking standard offer service, have issued solicitations to meet their state's RPS requirements. National Grid, the utility serving portions of Massachusetts, New Hampshire and Rhode Island, has held several renewable energy solicitations. For the most part they are issued in conjunction with RFPs for energy to shape their demand, and the renewable energy is required as a percentage of that – however, each solicitation specifies that the renewable energy can be in the form of NEPOOL GIS certified RECs, with REC prices to be offered separately. National Grid will accept energy bids separately from the RECs, so they are essentially running energy and REC RFPs in parallel, as they don't need to come from the same supplier. They have RFPs available for download back to 2008 on their web-site and most of them are essentially the same. Contract length tends to be anywhere from a few months to a few years. They also have a few RFPs for long-term contracts in Rhode Island based on their desire to have some renewable energy contracted long term even though they have already fulfilled their requirement for long-term contracts. One was also for renewable energy on Shoreham Island in Rhode Island. National Grid also had a couple of long-term RFPs for distributed energy offered in 15-year contracts. Unitil and NSTAR RFPs were also reviewed. Their RFPs appear to be for RECs only and relatively short term (1 year at a time).

3.2.5 Renewable Energy from Atlantic Canada

Currently, large hydro cannot participate in the RPS programs administered by the five New England states that have requirements (Maine is the one exception that will allow large hydro to qualify). Legislative changes would be necessary to change these rules. Recent legislative attempts to change these rules have stalled or have been tabled for discussion at a later time.

Table 3-5. State RPS Programs Regarding Large Hydro

State	Allows Imports from Canada to Meet RPS	Large Hydro Included in RPS	Class I RPS Requirement 2020 (GWh)	Market Potential for AC	Class I RPS Requirement 2030 (GWh)	Market Potential for AC
Connecticut	No – Must be located in ISO-NE or select states to qualify	No	7,100	0	7,800	0
Rhode Island	Yes – Must be located within or delivered into NEPOOL	No (30 MW limit)	1,400	1,400	1,600	1,600
Maine	Yes – Must be located within or delivered into NEPOOL	No (100 MW limit)	1,200	1,200	1,300	1,300
New Hampshire	Yes – Must be located within or delivered into NEPOOL	No	1,400	1,400	2,200	1,400
Massachusetts	Yes – Must be located within or delivered into NEPOOL	No	8,000	8,000	15,000	15,000
Total			19,100	12,000	28,000	20,200

Source: Navigant

3.2.6 Potential Changes to State RPS Programs

State's attempts in New England to change legislation to allow large hydro to count towards RPS requirements have not been successful.

Maine

- In 2012 the Maine Legislature introduced Legislative Document 1683, "An Act to Lower the Price of Electricity for Maine Consumers." The Act proposed to eliminate the 100 MW limit on the size of hydroelectric facilities included in the definition of renewable capacity resource. This Act died on April 13, 2012.

Connecticut

- The re-written SB493 removed the RPS Class I requirement rollbacks originally included in SB463, but retained the incentives for energy efficiency, CHP technology, and residential/commercial scale solar.[1,2]
- Another bill was proposed in early 2011 aimed at reducing the cost of renewable energy in Connecticut. Part of the bill would allow large-scale hydroelectric resource to count towards the RPS requirement. The bill was tabled in May, 2011 and has not had any progress since.[3,4]

New Hampshire

- Similarly to CT, the New Hampshire legislature proposed a new bill that would allow large-scale hydro to count towards its RPS requirements. However, the bill was halted in the house and deemed "inexpedient to legislate."[5,6]

3.3 Project Economics

This section of the report reviews the economics of selling the output of clean and renewable resources from Atlantic Canada into the New England market. For this assessment, we provide a comparison of the all-in costs of a wind project developed in Maine to the revenue that the project would receive from selling into the spot capacity and energy markets. For this analysis, the difference between the total costs and the total revenue is the value that the REC payment would need to be to support the project. We also calculate the "net back" value that would be realized by a project located in Atlantic Canada and selling into New England, net of transmission charges that would be required to deliver the output to the ISO-NE transmission system. Our assessment is based on a 20-year levelized cost analysis presented in 2013 dollars on a dollars per kWh basis. Note that these estimates reflect specific assumptions regarding the capital cost for wind generation, natural gas prices and ISO-NE market prices as provided to Navigant by the AEG participants for consistency with other AEG studies.

3.3.1 Levelized Cost Scenarios

To calculate the value of REC payments under a diverse but realistic set of assumptions, Navigant prepared an analysis of the costs and payments related to a wind plant developed in Maine. The wind turbine is considered the least-cost renewable resource option for New England. The analysis considered a 2013 commercial operation date, and relied on capital costs of $2,200/kW and energy pricing assumptions as provided by the AEG Project Steering Committee for consistency with other analysis being performed. We assume a 27% capacity factor and a $43/kW-year fixed O&M charge. Capacity payments are based on FCM results and Navigant forecasts, and a 6.0% nominal discount rate was used for the analysis.

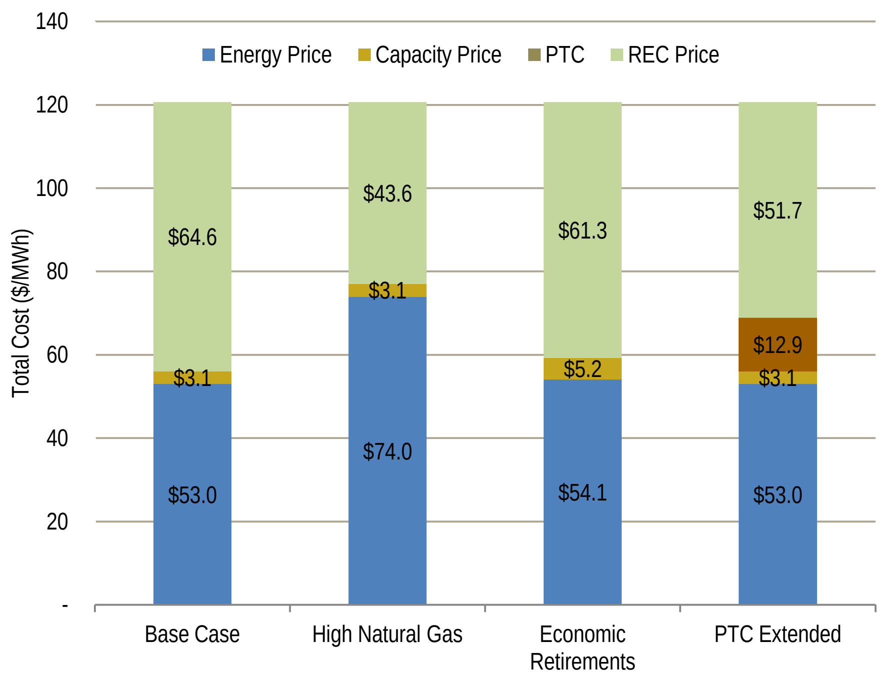
We prepared this analysis under four scenarios, reflecting several industry uncertainties as identified in this report. The analysis is presented in the form of a levelized price analysis, presented in $/MWh. The cases are as follows:

1. A base case, reflecting expected natural gas prices, no retirements, and no extension of the PTC;
2. A high natural gas price case, reflecting gas prices at 150% of base case gas prices and with all other parameters as above;
3. A retirement case, reflecting 3,500 MW of oil and coal assets being retired from the ISO-NE capacity market in 2016 and 2017. There is also a small impact to energy prices as a result of these retirements; and
4. A PTC extension case, reflecting all base case assumptions and the extension of the PTC for the first 10-years of the project.

Results of the levelized analysis are presented in the chart below. As mentioned above, the required REC price is calculated as the net revenue shortfall for the wind project, and does not reflect current REC prices. The results of the analysis indicate that the REC price would need to be $64.60/MWh under base case conditions to support the all-in costs of the project. The results for the high natural gas case indicate the REC payment would need to be $43.60/MWh to support the all-in costs of the wind project. Under this case, natural gas prices would need to return to the $7-8/MMBtu range. The results of the retirement case, where approximately 3,500 MW of oil and coal capacity is retired from the New England market, indicates the levelized REC payment would need to be $61.30/MWh to support the project. Finally, under the PTC case, which includes an extension to the PTC that impacts project revenue, require REC payment of $51.70/MWh to support the all-in costs of the project.

The Alternative Compliance Payment (ACP) in Massachusetts for 2012 is $64.02/MWh. This rate has increased at an average rate about 2.3% per year for the last 5-years. However, current REC market is significantly less than the ACP, due to a regional supply that will outpace demand for the next few years. Additionally, if a large-scale project is developed, such as the Cape Wind, the market could remain soft for several more years. Although the current REC market will not support wind development under any of the cases, results of this analysis conclude that when the market reaches equilibrium, the cases with high fuel costs or an extension of the PTC are most favourable for project development. Figure 3-5 provides a comparison of the revenues associated with the capacity and energy markets and the resulting REC pricing to support the all-in costs of the project.

Figure 3-5. Comparison of the Costs of a Wind Resource in New England



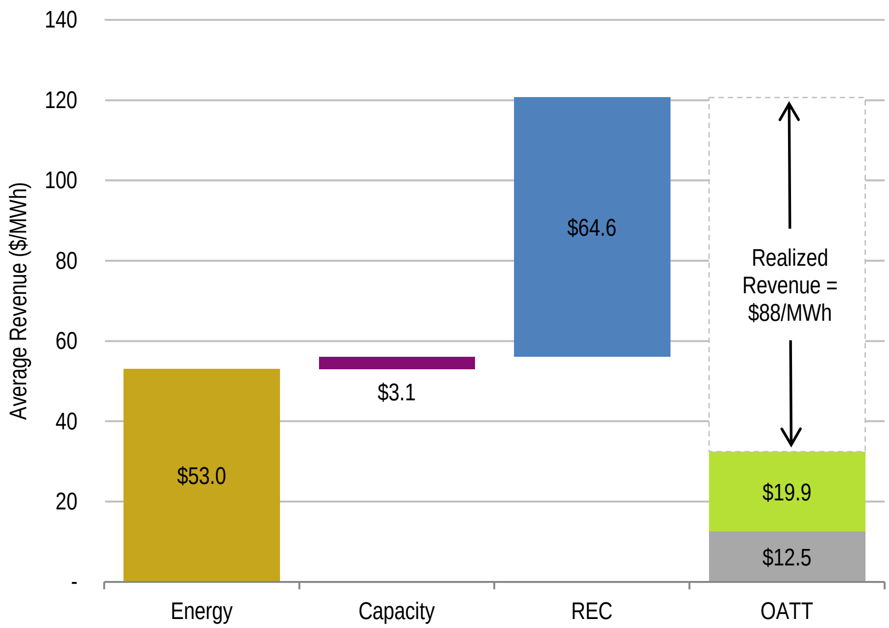
Source: Navigant

3.3.2 Netback Analysis

As mentioned above, as part of the scenario analysis Navigant also analyzed the "net back" price that would be realized by a project located in Atlantic Canada and selling into New England. The netback amount would be net of any transmission charges or losses required for delivering the energy into New England. Figure 3-6 provides a calculation of the netback price for a wind resource located in Nova Scotia and selling into New England. This analysis relates to the base case analysis described above. As can be seen, the netback price to wind located in Nova Scotia will be less transmission costs (identified as

OATT in Figure 3-6)[22]. A similar assessment can be developed for projects located in other provinces and for each of the scenarios presented in Figure 3-5.

Figure 3-6. Realized "Netback" Price of a Wind Resource from Nova Scotia

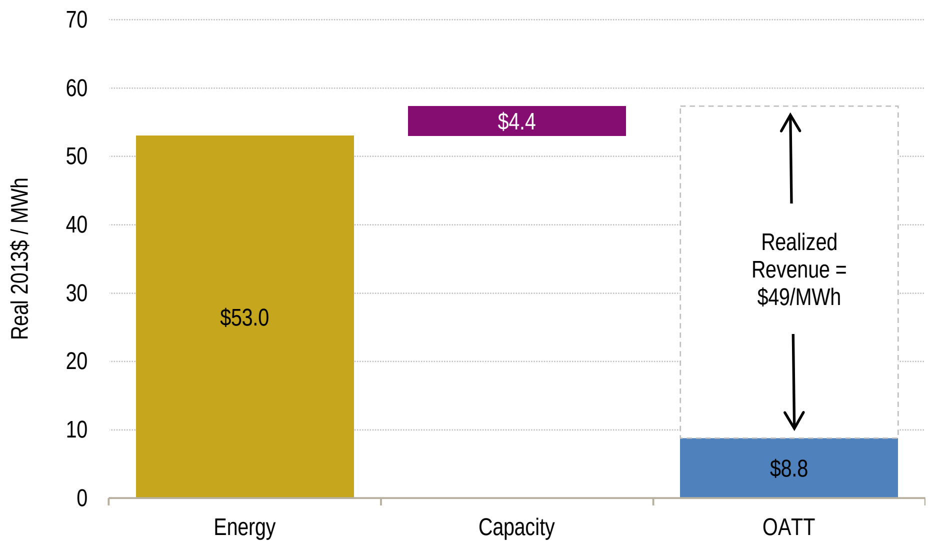


Source: Navigant

Similar to above, the netback price was also calculated for baseload clean energy sited in Nova Scotia. Under this case, the netback price firm clean energy would be the prevailing energy and capacity rate, less any transmission charges. A similar analysis can be constructed for each of the provinces and under each of the scenarios.

[22] For this illustrative analysis we have included non-firm transmission service. It should be noted that firm transmission service, while not a requirement for participating in the New England REC market, may be a prudent business decision depending on the non-delivery charges or other penalties associated with not fulfilling specific contractual obligations for the sale of RECs. For example, in a recent REC solicitation held by NSTAR, the standard form purchase agreement included a delivery shortfall charge which is based on the difference between the Alternative Compliance Rate and the contract price.

Figure 3-7. Realized "Netback" Price for Firm Clean Baseload from Nova Scotia



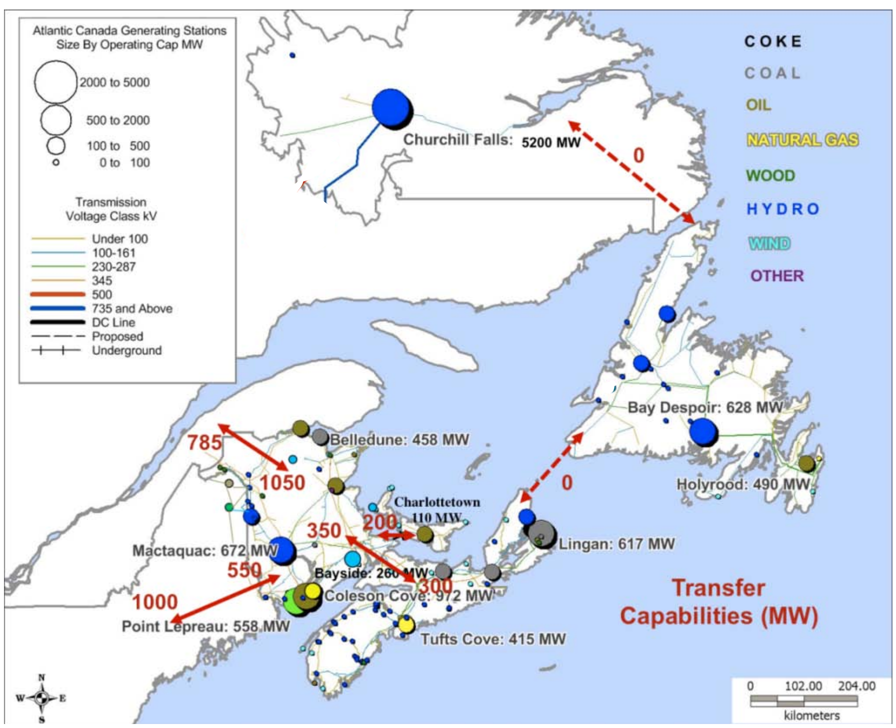
Source: Navigant

4. Opportunities for Greater Interprovincial Electricity Trade

The electricity system in the Atlantic region is comprised of three main components: (1) the Maritimes system, which is part of the Eastern Interconnection in North America and serves Nova Scotia (NS), New Brunswick (NB), Prince Edward Island (PEI) and portions of Northern Maine; (2) The Labrador system, which includes export transmission lines from Churchill Falls to the Labrador/Quebec border and serves the majority of customers in Labrador, with the exception of some remote areas; and (3) the Newfoundland system, which is currently isolated from other interconnections and serves all major communities in Newfoundland.

This region comprises five different utilities (Newfoundland and Labrador Hydro, Newfoundland Power, Nova Scotia Power Inc., NB Power, and Maritime Electric), and a number of different municipal electricity providers. Nova Scotia currently has six municipal electric utilities, New Brunswick maintains three, while PEI has one. While a few of these municipal utilities own and operate their own generating stations, the majority purchase bulk power from their larger counterparts to service their communities' needs. In addition to the primary electricity system, there are a number of remote or isolated areas relying primarily on small-scale diesel generators or wind power to supply isolated communities.

Figure 4-1. Atlantic Area Generation and Interconnections



Source: WKM Energy Consultants Inc.

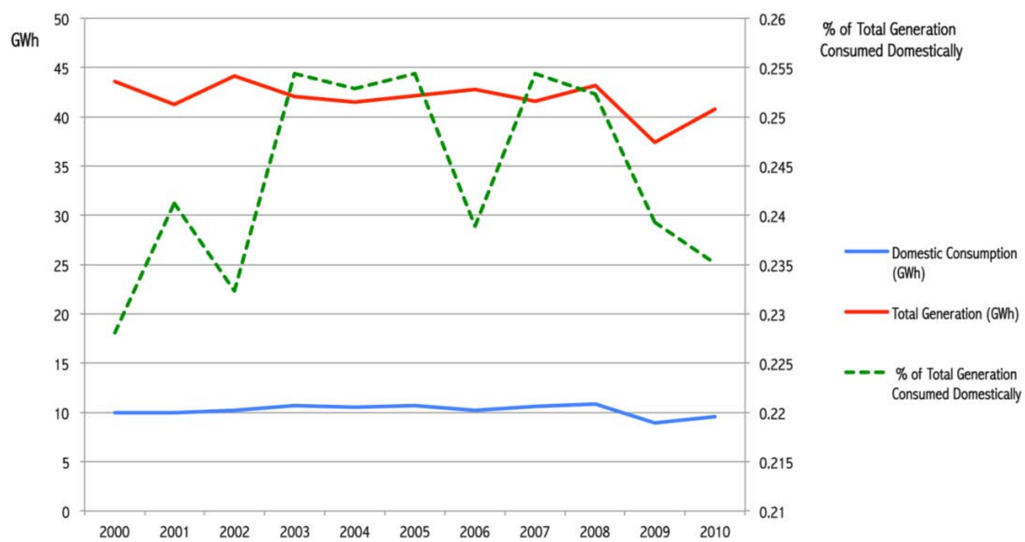
NAVIGANT

4.1 *Newfoundland and Labrador*

4.1.1 Current Supply and Demand Dynamics

Newfoundland and Labrador generates electricity from a variety of different sources, including hydropower, wind, heavy fuel oil, and diesel. The majority of electricity generated within the Province comes from hydroelectricity, and is exported to Quebec through a long-term supply contract. As a result, Newfoundland and Labrador is a net exporter of electricity, producing roughly four times more power than it consumed in 2010.[23] Figure 4-2 depicts the Province's electricity consumption relative to its overall generation.

Figure 4-2. Newfoundland and Labrador Electricity Generation and Consumption



Source: National Energy Board

Approximately 97% of total provincial electricity generation in 2010 was hydroelectric. Most of this is generated by the Churchill Falls generating station in central Labrador, which has a total capacity of 5,428MW, making it the second largest hydroelectric facility in Canada and the ninth largest in the world. In addition to Churchill Falls, the Province has a number of smaller hydroelectric facilities, adding a further 1,200 MW of capacity, a large oil-fired generating station at Holyrood (490 MW), four gas turbines generating stations and 25 diesel-fired thermal plants servicing mostly remote areas. In 2006, the Province also completed feasibility studies to develop several new small-scale hydro projects, which would collectively add approximately 59 MW of new capacity. Additionally, various long-term supply options have been considered including wind, small hydro, thermal, and Lower Churchill.

There are two utilities supplying power to the Province: Newfoundland Power, a private utility owned and operated by Fortis Inc., and Newfoundland and Labrador Hydro, a government owned energy service provider that owns many energy assets in the Province, including the existing Churchill Falls hydroelectric facility. Despite being the smaller of the two utilities with roughly 140MW of generating

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[23] Source: National Energy Board (2011), http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/nrgyftr-eng.html#s7

capacity, Newfoundland Power services 86% of the Province's customers, with a customer base of 243,000 in 2010.[24] With annual sales in 2010 of 5.4 TWh, the utility has over 11,000km of transmission and distribution lines serving communities throughout the island portion of the province.

Newfoundland and Labrador Hydro has a smaller customer base than Newfoundland Power, but boasts a much larger asset base. Due to the Province's sparse population, Newfoundland and Labrador Hydro also provides electricity to several remote communities; many of these are located along the eastern coast of Labrador and southern Newfoundland.

Newfoundland and Labrador also has abundant wind power resources. A wind resource map completed for the Province shows that it has large expanses with average wind speeds at 50 meters of 8-10m/s, making it one of Canada's premier sites for wind power development. Operating wind farms in Newfoundland and Labrador include installations on the island of Ramea, as well as in St. Lawrence and Fermeuse. Collectively, these generation resources add 54 MW to the Province's total electrical capacity, and constitute less than 1% of the Province's overall generation mix. In total, approximately 97% of total provincial electricity generation in 2010 was hydroelectric, including Churchill Falls.

In a recent supply-side development, Nalcor Energy has recently proposed a plan for the long-term electricity supply for the Island of Newfoundland comprising development of the 824 MW Muskrat Falls hydroelectric facility in conjunction with the 900 MW, 1,100 km HVdc Labrador-Island Link (LIL) from Labrador to just outside St. John's[25]. This proposal was the subject of a recent Public Utilities Board proceeding and the Board's final ruling is expected by March 31, 2012.

Nalcor Energy and Emera, owner of Nova Scotia Power Inc., also reached agreement for the long-term supply of a 1 TWh block of power from Muskrat Falls (representing a portion of the projected supply in excess of the Island of Newfoundland's requirements) through the 500 MW HVdc Maritime Link from Newfoundland to Nova Scotia. The agreement also includes provision for Emera to upgrade intertie capacity with New Brunswick to facilitate potential export power sales from Newfoundland and Labrador into New Brunswick and New England.

In addition to Muskrat Falls, potential significant generation development opportunities in Labrador include the 2250 MW Gull Island hydroelectric facility. The federal government announced its support for the Muskrat Falls and associated HVdc links in August 2011 by agreeing to provide a loan guarantee.[26] It is estimated that the Muskrat Falls project will deliver 4.9 TWh of electricity per year.

Figure 4-3 provides an overview of the potential pathways for the export opportunities from the Lower Churchill project. Currently, the route being investigated would run into Newfoundland via an undersea cable, and then link to Nova Scotia at Lingan via a 180km HVDC undersea line.[27]

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[24] http://www.newfoundlandpower.com/Content/ContentManagement/3464/File/2010%20Annual%20Report%20Final%20Mar%2021%202011.pdf

[25] Independent Supply Decision Review, Navigant Consulting Ltd,, September 14, 2011

[26] Source: NRCAN Press release: http://www.nrcan.gc.ca/media-room/news-release/2011/77/1395

[27] See Atlantica Center for Energy (2011). http://www.atlanticaenergy.org/uploads/file/Atlantica%20Centre%20for%20Energy%20Paper%20-%20Lower%20Churchill%20Final%20June%2030th%202011.pdf

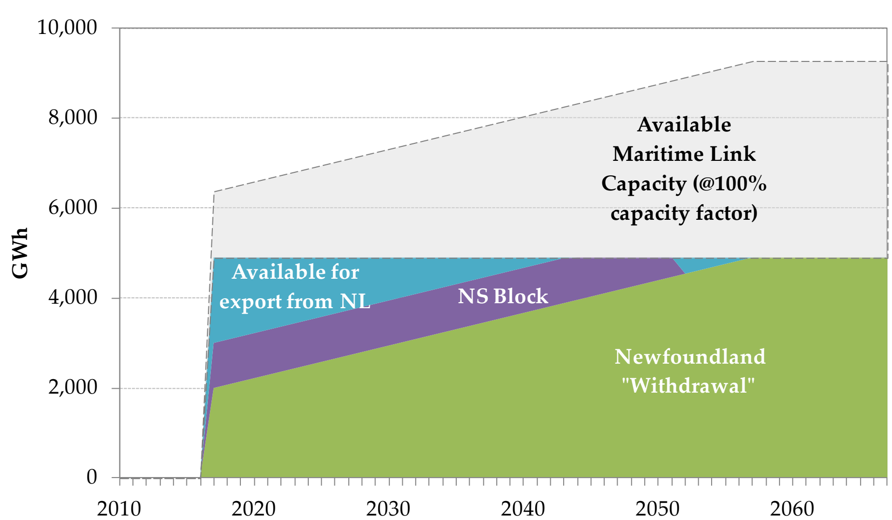
Figure 4-3. Map of the Lower Churchill Falls Projected Pathway

Source: Nova Scotia Power

The Island of Newfoundland's electricity requirements from Muskrat Falls are expected to increase with island demand until all of the Muskrat Falls output would serve the Island of Newfoundland by approximately 2055.

The following chart illustrates the approximate projected requirements of Newfoundland relative to the projected 4.9 TWh annual output from Muskrat Falls along with the 1 TWh "NS Block". The blue "slice" represents the projected Muskrat Falls output in excess of 1) the Newfoundland requirements and 2) the NS Block and would be available for export from NL.

Figure 4-4. Approximate Breakdown of Muskrat Falls Output and Available Maritime Link Capacity



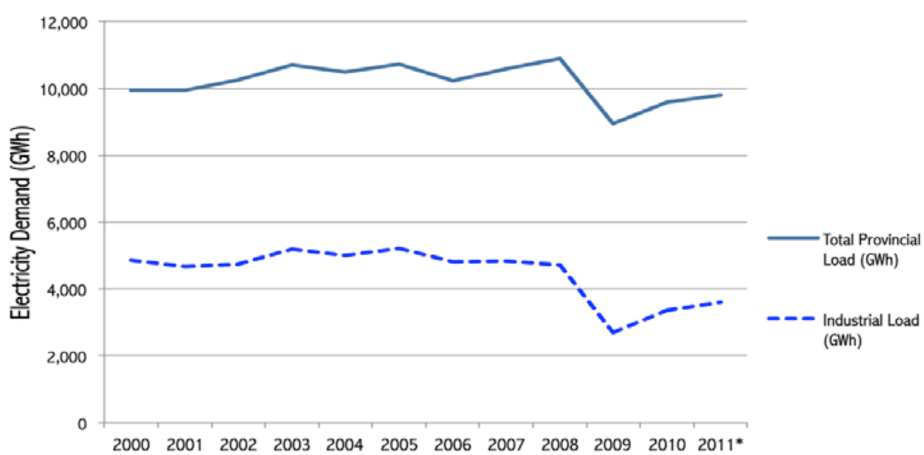
Source: Independent Supply Decision Review, Navigant Consulting Ltd, September 14, 2011

On July 31, 2012, Nalcor and Emera executed thirteen agreements covering the commercial and physical arrangements between these companies related to the Muskrat Falls hydroelectric and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects.[28] Transmission access for Nalcor through Nova Scotia and New Brunswick into the New England markets is among the many arrangements covered in these agreements. The transmission capacity available to Nalcor through these agreements would allow any surplus energy from Muskrat Falls (the blue wedge of energy labeled as "*Available for export from NL*" in Figure 4-4) to be sold into New England if desired. Other possible markets for this energy include Nova Scotia, New Brunswick and, using the transmission access Nalcor currently has through Quebec, Ontario or New York.

The chart also shows the additional Maritime Link power transfer capacity of up to 4,400 GWh by 2055 (assuming 100% capacity factor) that would be available for additional exports from NL into Nova Scotia and beyond.

Turning to electricity demand, it can be seen that load in Newfoundland and Labrador is slightly below its level in 2000 (1-2% decline), despite a growing population in the St. John's area. This decrease in load is largely due to a decrease in industrial electricity demand in the Province. Figure 4-5 maps this decline in demand over the last decade. However, Newfoundland and Labrador's most recent energy forecast projects a near-term period of overall load growth for the Island interconnected system. The compound annual growth rate between for the Island System is projected at 2.7% between 2009 and 2014, 1.7% between 2009 and 2019, and 1.3% between 2009 and 2029[29].

Figure 4-5. Load Trends in Newfoundland and Labrador, 2000-2011



Source: National Energy Board

[28] The agreements are available at: http://www.nalcorenergy.com/formal-agreements.asp

[29] Source: Summary of Newfoundland and Labrador Hydro 2010 Long Term Planning Load Forecast, Muskrat Falls Project - Exhibit 27.

4.1.2 Policy and Regulatory

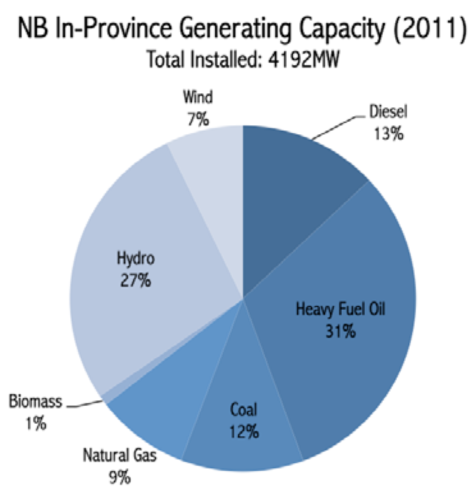
As for policy and regulatory developments, the Province remains committed to phasing out its Holyrood Generating Station if the Muskrat Falls project is completed. The Holyrood Generating Station is a significant source of price volatility and a major contributor to the Province's greenhouse gas (GHG) emissions. While the Province does not have a formal Renewable Portfolio Standard – largely due to the fact that approximately 97% of total provincial electricity generation in 2010 was hydroelectric and approximately 90% of capacity is clean/renewable – it is likely to continue to increase its domestic renewable energy capacity in the years ahead, both from the above noted Lower Churchill projects and continued wind power development.

4.2 New Brunswick

4.2.1 Current Supply and Demand Dynamics

New Brunswick has a highly diversified electricity generation mix, including hydro, coal, nuclear, wind, heavy fuel oil, diesel, biomass and natural gas. It has the most diversified supply mix of any Province in the region.

Figure 4-6. Total Electrical Capacity in New Brunswick



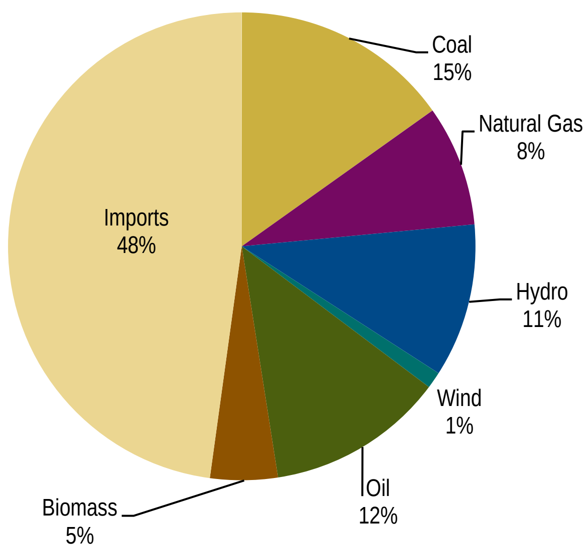
Source: New Brunswick System Operator 2011

While this represents the current installed capacity, it does not entirely reflect current generation trends. First, the Province's sole nuclear power plant, Point Lepreau, is currently under refurbishment; it is expected that when it comes back online in fall 2012, it will have a slightly higher installed capacity at 660MW, and will contribute approximately 30% of the Province's total generation. Combined with the recent closure of Grand Lake (a small, 57MW coal-fired generating station) and the pending closure of Dalhousie Generating Station (a 299MW facility burning primarily heavy fuel oil), the Province is poised to become less reliant on fossil fuel sources and more reliant on a combination of imports and low carbon power.

New Brunswick is currently benefiting from a number of favourable market circumstances. While the Province has historically been a net exporter to Maine and New England, it has recently become a significant net importer while Point Lepreau has been off-line, purchasing low-cost gas-fired generation. In addition to imports, it continues to benefit from competitively priced hydroelectricity from Quebec. These two sources of imports are currently less expensive than much of the Province's own generation fleet; as a result, they have helped NB Power uphold a government mandate to freeze rates for three years starting in 2010.

The current reliance on imports is most notable during the winter months. For instance, in January and February 2011, imports represented approximately half of total electricity consumed in the Province.

Figure 4-7. New Brunswick Electricity Generation Mix (Jan 2011)



Source: New Brunswick System Operator

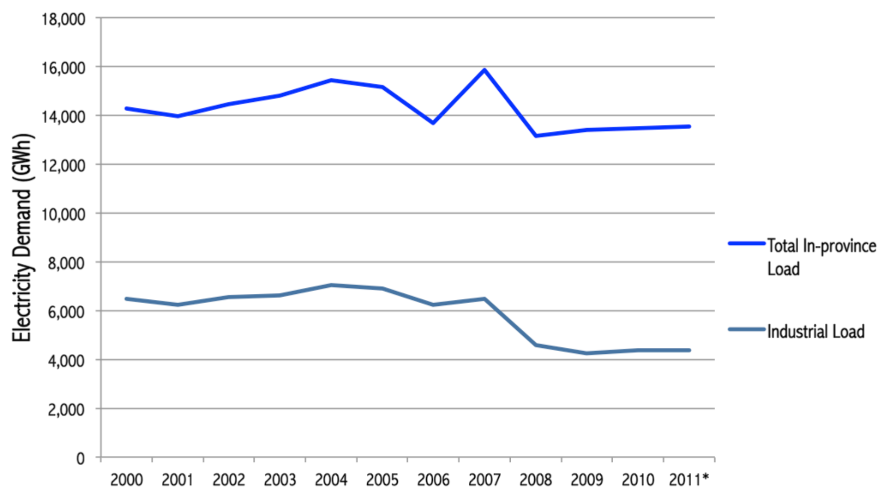
Other supply-side options that have been discussed to boost the supply of competitively priced electricity within the Province include the possibility of converting one or more units at the Coleson Cove generation station from heavy fuel oil to natural gas.[30] However, no concrete timeline has yet been set out for such a conversion.

Wind power represents roughly 300 MW of electrical capacity in the Province. When wind power flowing into New Brunswick from Northern Maine and PEI are included, the Province is responsible for balancing 550 MW of wind. Citing reliability and cost concerns, the government's recent *Energy Blueprint* has signaled a shift in strategy, and has chosen to put the brakes on further large-scale wind power development in New Brunswick, instead focusing on smaller, more widely distributed and locally owned renewable generation projects to meet its renewable energy targets. Aside from the return-to-operation of 660 MW of capacity from Point Lepreau, the Province's system operator does not foresee a requirement for any additional generation resources or electrical capacity over the next decade. In light of decreasing load, and the availability of low-cost imports, the Province has access to more than enough electricity to meet its own energy and reliability needs for the foreseeable future.

[30] http://www.cbc.ca/news/canada/new-brunswick/story/2011/05/18/nb-coleson-cove-natural-gas.html

Looking at the trend in electricity demand over the last decade, total load in New Brunswick has declined, with an acceleration of the trend since 2007. Since 2004, industrial electricity demand in the Province has decreased by 38%, representing a drop of almost 20% of total in-Province electricity use.[31] Considered as a whole, New Brunswick's in-Province load has decreased by approximately 2TWh since that time, or almost 13%. The downward trend in industrial demand is responsible for the largest share of this decline, but Efficiency NB's successful residential, commercial and industrial conservation initiatives have also contributed to this decline.

Figure 4-8. New Brunswick Electricity Demand, 2010-11



Source: National Energy Board

Despite this downward trend, current forecasts expect New Brunswick's electricity demand to return to an annual growth rate of 0.6%/year over the next decade. This includes an anticipated demand reduction of 390GWh/year from demand side management measures and naturally occurring efficiency improvements.

From a financial perspective, NB Power's high levels of debt, and ratio of debt to assets, remain among the highest in Canada. Debt service and depreciation make up between 30-35% of NB Power's annual expenses. This will remain a challenge in the years ahead, and will serve to further constrain NB Power's operational flexibility, as well as its ability to invest in new transmission or generation infrastructure on a stand-alone basis. However, the debt should not limit NB Power's ability or willingness to cooperate or partner on regional energy developments and projects. Further, the government has announced plans to initiate a debt reduction plan at NB Power with a goal of achieving a debt to equity ratio of 80/20 within ten years.

4.2.2 Policy and Regulatory

New Brunswick has recently revamped its RPS, aiming for a higher target, but with looser restrictions on eligible technologies. The previous RPS policy, adopted in 2006, established a target of 10% of total in-Province sales from new renewable sources by 2016. Changing market circumstances combined with a

[31] Source: NEB 2011, NBSO 2011

change in government have prompted a change in this strategy. The *New Brunswick Energy Blueprint*, launched in October 2011, establishes a new target of 40% renewable energy by 2020. Along with this new target, the eligibility requirements have been modified to include out-of-Province generation, and in particular, existing large hydroelectric and industrial biomass generation. The revised policy also places a greater focus on biomass resources, both for heating and for electricity generation.

The *Energy Blueprint* also sets out policies that require NB Power to purchase electricity generation from community-based renewable energy projects, including those developed by First Nations. If this proceeds to plan, it is expected to add another 75 megawatts of renewable capacity. A second development that aims to increase supply is the Large Industrial Renewable Energy Purchase Program (LIREPP) set out in the *Energy Blueprint*, which recognizes existing industrial biomass generation from the Province's pulp and paper mills for the purpose of the provincial RPS, and in future could result in new, in-Province generating capacity as eligible customers in other industrial sectors install renewable generation capacity to participate in the program.

4.3 Prince Edward Island

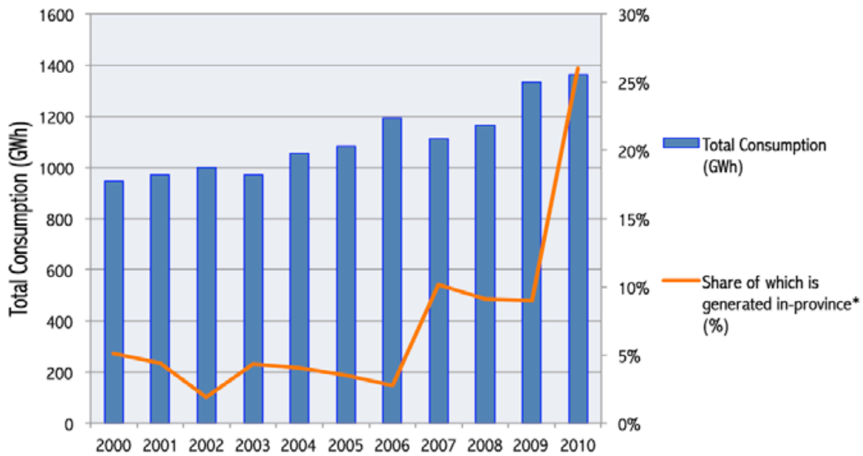
4.3.1 Supply and Demand Dynamics

PEI gets most of its electricity supply via two submarine cables that cross the Northumberland Strait and link up with the New Brunswick system. Each cable has a nominal capacity of 100 MW. There is currently 124 MW of export capacity from PEI to New Brunswick, and 200 MW of import capacity. The remainder of PEI's electricity comes from a combination of domestic wind power, biomass, and fossil fuel generation, including heavy fuel oil and diesel. The latter supply options are used primarily to service peak loads, and to provide reliability support.

From a technical standpoint, PEI is considered a load on the NBSO system. The latter has to manage load following and reliability for both provinces. The provincial utility, Maritime Electric, has recently renewed its purchase contract with NB Power, and both utilities are currently partnering to expand the transmission capacity linking the two provinces to enable greater interprovincial power flows.

Maritime Electric operates two generating stations in Charlottetown, one that burns heavy fuel oil with a capacity of 60 MW and the other a diesel-fired combustion turbine with a capacity of 49 MW. Maritime Electric also operates two diesel-fired combustion turbines with a combined capacity of 40 MW in the Town of Borden. The City of Summerside has a diesel-fired generating station as well, totaling a further 10 MW of available capacity. Due to the high cost of diesel generation, however, the Province relies far more on imports from New Brunswick than on domestic generation. While wind power has begun to increase the share of power generated for the island in recent years to over 20%, with a total installed capacity of over 160 MW, imports continue to supply the bulk of the island's electricity needs. Figure 4-9 highlights this trend.

Figure 4-9. PEI Electricity Demand, 2000-2010[32]



Source: NEB 2011; StatsCAN 2011

As the chart above shows, unlike other Atlantic Provinces, PEI's electricity demand has continued to grow steadily, and was only minimally impacted by the recent financial crisis. Since 2000, electricity demand has increased by 30%, making it the Atlantic Province with the highest and most sustained load growth over the past ten years.

4.3.2 Policy and Regulatory

In 2004, PEI became the first Province in the Atlantic region to adopt an RPS target, which aimed to meet 15% of its electricity needs with renewable energy by 2010.[33] It met its target three years ahead of schedule. Since then, PEI has adopted a comprehensive energy strategy that includes a goal of having 500 MW of wind power on line by 2013. While most of this will be for export, 100 MW is to be reserved for domestic use. By 2013, PEI aims to double the share of renewable energy in its electricity mix from 15% to 30%, and it has expressed a commitment to increase the share of renewable energy on the island from local and community-owned projects. This includes a stated objective to increase the use of biomass and biogas for electricity generation.

However, PEI has recently faced challenges delivering on this ambitious vision, partly due to transmission constraints and the difficulties of finding a suitable export market.

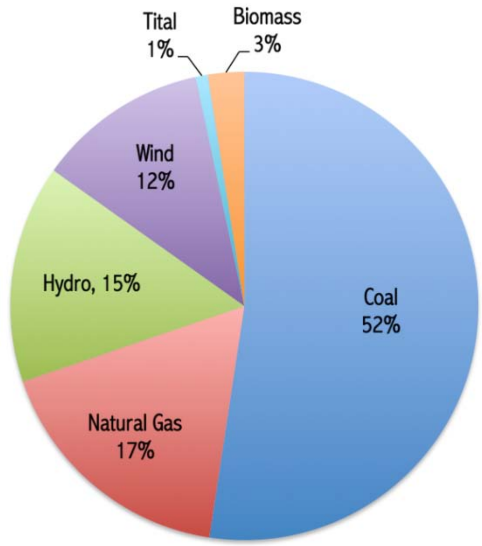
4.4 Nova Scotia

4.4.1 Supply and Demand Dynamics

Nova Scotia generates electricity from coal, fuel oil, natural gas, wind, hydropower, and tidal. The single largest source of generation in the Province, however, comes from coal, which represents over half of total installed capacity and approximately two thirds of total in-Province generation.

[32] Note that much of the growth in-province generation is wind power, and a significant share of this is being exported so the proportion of total consumption that is generated in province is less than implied.
[33] http://www.gov.pe.ca/news/getrelease.php3?number=3622

Figure 4-10. Nova Scotia Generating Capacity (2011)



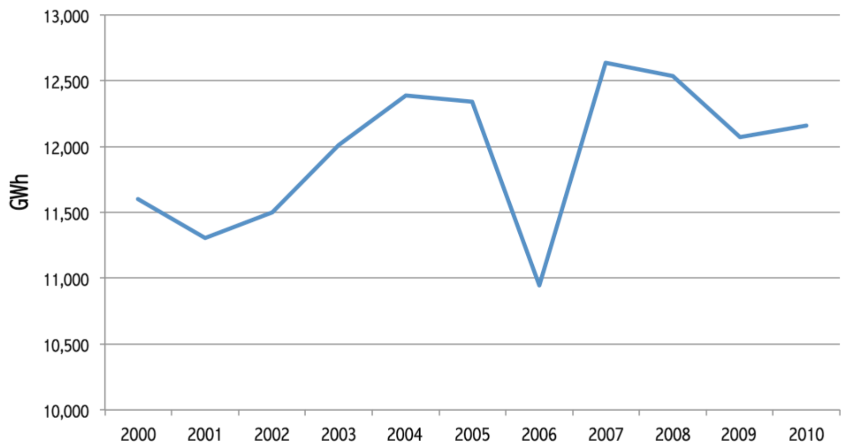
Source: NSPI 2011; StatsCAN 2011

In total, Nova Scotia Power Inc. (NSPI) has approximately 2,400 MW of installed electrical capacity. In addition to in-Province resources, it has three grid ties with New Brunswick that enable it to import up to 300 MW, and export up to 350 MW. In terms of renewable electricity (RE) capacity, Nova Scotia has 360 MW of hydroelectric capacity spread over several small and medium-sized facilities, and an additional 20 MW from the tidal power plant in Annapolis Royal. In recent years, it has added to that capacity a significant amount of wind power, totaling over 280 MW as of early 2011. Also, 2012 is expected to see several small wind projects added to the mix, including a 31.5 MW project in the Amherst area.[34]

In addition, and as discussed in the above section on Newfoundland and Labrador, Emera has recently signed an agreement with Nalcor to develop the 500 MW HVdc Maritime Link from Newfoundland to Nova Scotia and bring a minimum of 1 TWh of power from the Muskrat Falls hydroelectric facility into Nova Scotia. This will help meet Nova Scotia's ambitious energy and environmental objectives, and help gradually reduce its reliance on coal-fired generation. The proposed project will enable the province to replace a portion of its largest coal plant in Lingan at 620 MW. Electricity demand in the Province has experienced significant changes over the last five years, with a major decline in 2006, which rebounded back to previous levels by 2007.

[34] http://www.nspower.ca/en/home/environment/renewableenergy/wind/map.aspx

Figure 4-11. Nova Scotia Load (2000-2010)



Source: National Energy Board

This drop in demand, a decline of approximately 1.5TWh, was due to the temporary closure of a large pulp and paper mill in the Province in December 2005; the mill came back online at the end of 2006, returning provincial load back to its previous highs.[35] However, the onset of the financial crisis triggered a new downward trend in provincial demand. Since 2000, total electricity demand has increased by 4.5%, or just under 0.5%/year on average.

4.4.2 Policy and Regulatory

Nova Scotia's RPS sets out an ambitious target of supplying 25% of in-Province demand from renewable sources by 2015, and 40% by 2020. A significant driver of the RPS policy is to reduce the Province's reliance on coal-fired generation and meet federal air pollution regulations. In addition to these mercury-based regulations, Nova Scotia also has instated a hard cap on GHG emissions, aiming to reduce emissions by 10% below 1990 levels by 2020. This hard cap is only on the electricity sector, requiring a 2.5 MT reduction by 2020 or half of the Province's total GHG reduction goal of 5 MT.

In order to meet its RPS, Nova Scotia aims to use two tools: competitive solicitations, and a community-based feed-in tariff policy. The recently launched COMFIT policy, which came into effect in September 2011, is targeted at distribution-interconnected RE projects with a minimum annual load on the point of interconnection that is large enough to accept the rated generation output. This practically limits the average projects to less than 6 MW in size and in some cases less than 1 MW. In total, the Province aims to encourage some 300 GWh of new renewable electricity generation (up to 100 MW of new capacity) from locally owned renewable energy projects by 2020. Like many other feed-in-tariffs policies around the world, the tariffs are differentiated by technology type, including wind, tidal, biomass and small hydro, as well as by project size in the case of wind power.[36] If successful, this policy could lead to a significant surge in small, locally owned renewable energy projects in the Province, and help meet both environmental and energy security objectives..

[35] http://oasis.nspower.ca/site-nsp/media/Oasis/20110630%20NSPI%20to%20UARB%2010%20Year%20System%20Outlook%20Report%281%29.pdf

[36] See http://nsrenewables.ca/feed-tariffs

4.5 Regional Considerations

In addition to the specific considerations occurring in each of the four Atlantic Provinces discussed in the previous sections, there are a number of regional developments currently taking place that could have significant impacts on individual provinces' strategies in the years ahead. On one hand, these developments could serve as a catalyst for greater cooperation and could provide a template from which to discuss the opportunities for greater interprovincial power flows; alternatively, some provincial developments could be seen to be at odds with the AEG initiative and could even impede the expansion of interprovincial electricity trade. This section will briefly outline some of these developments.

The AEG strategy was launched by the federal government in collaboration with the Atlantic Provinces in 2009 in recognition of the region's significant potential for greater cooperation on energy issues. In the past, provinces have shown limited interest in expanding regional collaboration on energy trade, as each Province sought to further its own interests. However, both the Atlantica initiative[37] and the AEG initiative suggest the case for expanding such collaboration is enduring, and not simply a passing interest.

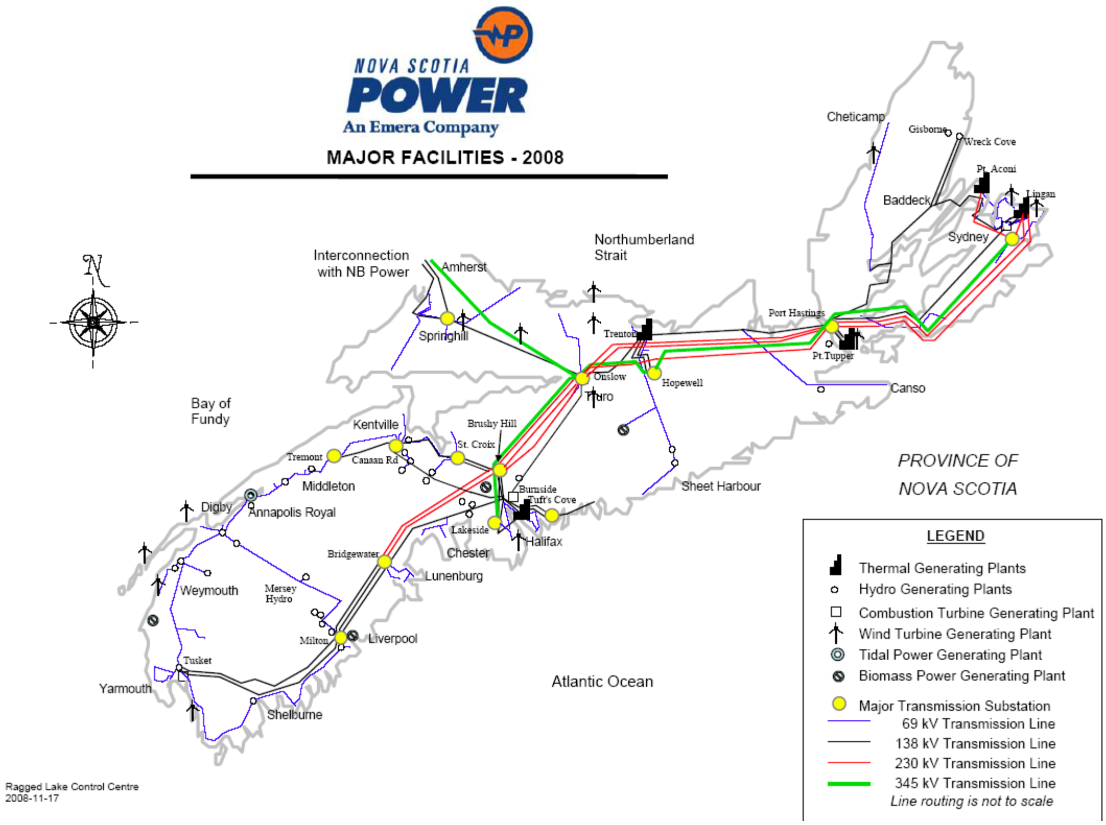
As the sections above have demonstrated, aside from the recent discussions between Nova Scotia and Newfoundland and Labrador to partner on the Lower Churchill project, and an upgrade to transmission links between New Brunswick and PEI, policymaking in the region is still largely undertaken on a Province-by-Province basis.

At a high level, the Maritime electricity system alone features three different electricity grids, five utilities and approximately a hundred power plants all within an electricity system of just over 6,000 MW. This presents significant challenges not only for power system efficiency; it also suggests a sub-optimal level of integration in the bulk power system in the region. While the development of Muskrat Falls will likely act as a catalyst for further system integration, by linking the Newfoundland and Labrador system with the Maritime Provinces, it will take greater cooperation for the full benefits of this integration to be achieved.

Nova Scotia currently has three major transmission interfaces, one linking Cape Breton to the rest of the Province, the other two splitting at Onslow to meet both Halifax and New Brunswick respectively. On July 20 2010, NB and NS announced that a new 345kV transmission line between the two provinces was being discussed with a transfer capacity of approximately 500 MW.

[37] Weil, G. (2003) "The Atlantica Power Market: A Plan for Joint Action," AIMS, Available at: http://www.aims.ca/site/media/aims/weilfinal.pdf

Figure 4-12. Transmission Map of Nova Scotia



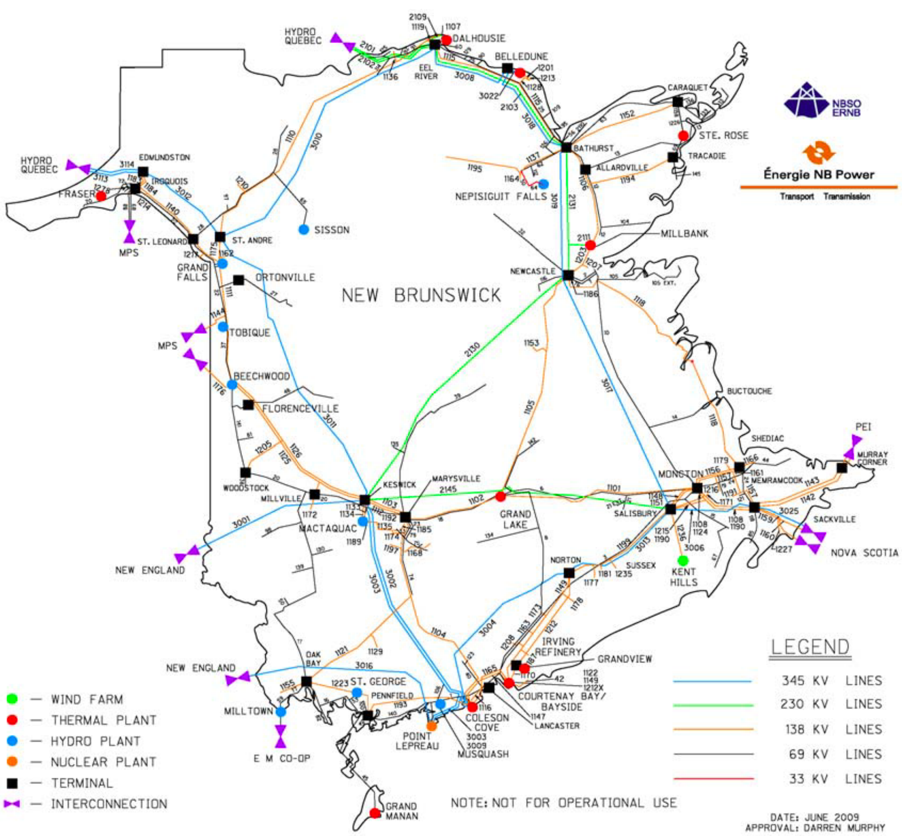
Source: SNC Lavalin 2009

Also, the Province is connected to New Brunswick via one 345kV line, and two 138kV lines for a total export capacity of 350 MW, and an import capability of approximately 300 MW. Despite this, Nova Scotia relies on NB at times for upwards of 10% of its in-Province demand, which means that any interruption to the primary 345kV intertie poses a tangible risk to electrical system reliability to many NSPI customers. Expanding this intertie would provide not only increased reliability and robustness for the NS system; it could provide value for New Brunswick as well, by boosting its ability to import power from Nova Scotia to meet load growth in the Moncton area, particularly during the winter months. Expanding the NB-NS intertie could also enable NSPI to import power from the Bayside Power Plant in Saint John, owned by NSPI's parent company, Emera, or from existing or future New Brunswick generation capacity, boosting system reliability and reducing the risks of interruption on both sides of the provincial border.

As highlighted in the section above, Nova Scotia also has significant coal and heavy fuel oil-fired generating capacity that it seeks to phase out in the years ahead. This will create a demand for greater electricity supply resources, whether domestic or imported. Regardless of the final decision on the Muskrat Falls project, Nova Scotia stands to benefit from greater interprovincial power flows. If the project proceeds, Newfoundland and Labrador will be the first recipient of Muskrat Falls power. Nova Scotia will also receive its allocation at in-service; if the project does not proceed, it will need to explore other opportunities to purchase or develop clean and renewable resources. While part of this can be met from existing policies and programs such as tendered wind and biomass projects, as well as the Province's recent COMFIT program, it is likely that it will need additional power from its neighbors to maintain system stability. This makes Nova Scotia a key player in determining the nature, scale and timing of discussions aimed at increasing interprovincial electricity trade.

On the northwestern front of the Maritime region, New Brunswick has approximately 1,100 MW of intertie capacity with Quebec, with one major intertie in Campbellton and another near Eel River, which is soon likely to be upgraded. The import transfer capability is 1100 MW while the export capability stands at 770 MW. However, the above-cited constraints on exports from NB to NS remain, and will likely need to be addressed to increase such power flows. In this area, New Brunswick will assume an important role and could ultimately help wheel power from Quebec to supply in-Province loads in the winter and eventually on to Nova Scotia, if the latter is in need of additional supplies to meet its energy and environmental targets.

Figure 4-13. Transmission Map of New Brunswick



Source: SNC Lavalin 2009

This notwithstanding, concerns remain over the recent shift in direction in New Brunswick, a key player in the region due to its strategic geographic location as the interface between the Atlantic Provinces and the U.S. Northeast. New Brunswick's recent *Energy Blueprint* has been identified as a turn inward, a shift toward focusing more on in-Province dynamics than on regional cooperation and collaboration.[38]

In parallel, some have argued for developing a regional or 'Maritime System Operator' that could provide coordinated balancing and load following services for the Maritime region.[39] A regional system operator could provide a more efficient and economic structure to facilitate interprovincial power flows. More specifically, it could help avoid "rate pancaking", which negatively impacts the economics of cross-provincial electricity trade. Paying for multiple transmission tariffs along the way makes the case for interprovincial flows, and by extension, for power exports more challenging to make. In addition to streamlining the tariff system, a regional system operator that had independence from individual provinces' political decision-making could improve market access for independent producers.

While the possibility has been discussed for over a decade, the initiative to develop a regional system operator has made little progress. It remains possible that if the Muskrat Falls project proceeds according to plan, the possibility of a sub-sea cable between Nova Scotia and New England could become more appealing, as it would help avoid tariff stacking and circumvent lengthy over-ground transmission expansions.[40] However, in light of recent developments, any discussion of such an export route remains speculative at best.

Turning to the U.S. side of the equation, due to the completion of a recent transmission project in 2007, New Brunswick now has two 345kV lines into Maine, linking it with the New England market. While rights to the new 345kV line's capacity have already been purchased, some additional developments are underway south of the border. As previously discussed, Maine has recently embarked on a $1.4 billion investment program for Maine's transmission system. The development plan is scheduled over five years, from 2009 to 2013, and involves the construction of six new substations, upgrades to more than 40 existing substations, as well as the addition of 700km of new transmission lines throughout the state of Maine.[41]

The addition of a new 345kV line south of Orrington, ME is also included as part of the MPRP plan, as are additional upgrades on existing substations. Although still under study by ISO-NE, this transmission project is estimated to increase the ability of the bulk power system to move power from the Northern Maine system to the rest of New England by approximately 150 MW.[42] While further bottlenecks in the New England system remain, the development of this intertie south of Orrington could eventually help facilitate the development of a regional power strategy between Maine, New England, and Atlantic Canada.

On the other hand, the Maritimes region has the opportunity to secure significantly more power in the years ahead, from a combination of Lower Churchill, New England, and even Hydro Quebec. Any of

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[38] Weil, G. (2011) "A New Plan for NB Power: Analysis and Comment," Atlantic Institute for Market Studies (AIMS), Available at: http://www.aims.ca/site/media/aims/A%20New%20Plan%20for%20NB%20Power.pdf

[39] Weil (2003).

[40] SNC Lavalin 2009. Transmission and System Operator Options for Nova Scotia, Accessed September 15th 2011 at: http://www.gov.ns.ca/energy/resources/EM/renewable/NS-Transmission-SO-Options.pdf

[41] See http://www.mainepower.com/index.htm for further details.

[42] See ISO-NE's filing to FERC in Docket No. ER12-757-000, dated February 13, 2012.

these options could enable the Maritime Provinces to phase out some existing fossil fuel generation, while stabilizing rates in the years ahead. If this remains the case, the region's ability to market its power in an environment of abundant electricity supplies may be limited, at least in the near term.

One significant challenge that remains is the difficulty of lining up both the political and the technical (i.e. construction) timelines on cross-border energy initiatives like the AEG initiative. There are times when the technical, pre-feasibility work is well ahead of the politics and others when the politics are well ahead of the technical aspects. This will continue to be a challenge both for boosting interprovincial electricity flows, as well as for any power export strategy targeting the New England market. Making the case for greater interprovincial power flows will therefore likely require a clearly articulated vision of the shared value that such an approach can create.

History suggests that provinces will only cooperate, and truly "buy-in", if there is mutual gain. Given that greater interprovincial power cooperation is likely necessary for a successful New England export strategy; this puts a high premium on greater collaboration.

5. Conclusions on Market Opportunities

Navigant was retained to assess and quantify opportunities for both short-term and longer-term clean and renewable electricity exports (including associated renewable energy credits) from Atlantic Canada to New England; and assess opportunities for increasing the flow of clean and renewable energy within Atlantic Canada based on the concept of a more fully integrated Atlantic Canadian electricity market. Based on the above objectives, Navigant prepared this study to assess the potential export opportunities for clean and renewable energy. As part of this assessment, the following factors were analyzed: 1) current and anticipated future regional market demand drivers, 2) market barriers to the movement of clean and renewable energy within Atlantic Canada and New England, and 3) regulatory issues and considerations.

Based on the above identified factors, regulatory and market drivers, and the defining characteristics of the New England market, Navigant makes the following observations related to the opportunity for exports of clean and renewable energy to the New England power market:

1. There are three distinct "markets" for clean and renewable energy in New England: 1) the New England energy market; 2) the New England capacity market; and 3) the various state Renewable Energy Credit (REC) markets. Generally speaking, the energy market is accessible to any provider that can physically deliver electricity into New England and, similarly, the New England capacity market is accessible to any provider with a firm transmission path into New England. The rules for the individual state REC markets vary from state to state depending on each state's Renewable Portfolio Standard (RPS), particularly with respect to the type of renewable energy that is eligible to participate in the market.
2. The New England energy market has a significant amount of combined cycle natural gas capacity. Due to the discovery of unconventional gas resources, gas prices are low, and are projected to remain low for the foreseeable future. This has resulted in natural gas being on the margin for over 70% of the time. For example, with an average historic market average of 8,600 Btu/kWh and a natural gas price of $5/MMBtu, wholesale electricity market prices would be about $43/MWh (USD).
3. The New England capacity market has a significant surplus of capacity and is projected to remain in surplus until the end of the decade. This is the result of the implementation of a forward capacity market (FCM), and rules that support demand response resources competing against generation resources and imports to compete for a capacity supply obligation. It is expected to result in capacity prices that are well below the cost of new entry.[43]
4. The investment required for complying with some or all of the forthcoming environmental regulations could make a number of plants candidates for retirement. These plants include older steam coal, gas, oil units that are marginally economic and at risk of retirement given their limited

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[43] ISO-NE and the NEPOOL market participants are currently evaluating alternative capacity market frameworks for the New England capacity market. These discussions are taking place as part of confidential settlement discussions resulting from FERC's Order in Docket No. ER12-953. Based on the limited information available on the ISO-NE website, the redesign efforts are exploring a number of options, such as demand curve and mechanisms to reduce price volatility.

operation. The removal of 3,500 MW of such capacity from the market would, as ISO-NE has indicated, eliminate much of the surplus capacity.

5. Current RPS policies provide incentives for renewable generation. There are no specific requirements, policies, or incentives for clean energy (e.g., large hydro and nuclear power), and the region does not distinguish between clean resources and other resources, such as natural gas plants, that meet the federal and state emission regulations. The PTC, if extended, would provide a competitive disadvantage to the AEG initiative.
6. New England's LSEs are currently relying on a mix of renewable resources located in New England, New York and Canada to meet their RPS requirements. New England is not expected to have enough "local" renewable resources to meet future RPS requirements. New England will need to import RECs to meet its future RPS requirements.
7. Large hydro cannot participate in the current RPS programs. There have been proposed changes to the RPS programs in Maine, Connecticut, and New Hampshire for allowing large hydroelectric generators to qualify. However, these legislative changes have either died due to unresolved differences or have been tabled for later discussion.[44] Maine currently allows hydroelectric resources of up to 100 MW to participate in its RPS Program and Vermont allows hydroelectric resources of any size to count towards its SPEED Program renewable energy goals.
8. There have been few long-term contracts offered to renewable energy projects in New England, and no long-term contracts offered to projects located outside of New England. If regional project development stalls and demand exceeds supply, long-term contracts could be offered to projects outside of New England to ensure compliance.
9. Maine is currently export constrained, with an abundance of natural gas-fired generation capacity. This has led to low energy prices, lower capacity prices, and reliability issues. The proposed transmission projects are being developed to address reliability concerns, and do not explicitly address the export constraints between New Brunswick and Maine or between Maine and the rest of New England.
10. Through various transmission service, access and rights agreements with Emera, Nalcor will have access through Nova Scotia and New Brunswick into the New England markets upon completion of the Muskrat Falls hydroelectric and associated HVdc transmission (Labrador-Island Link and Maritime Link) projects. In combination with the transmission access it currently has through Quebec, these agreements will allow Nalcor to sell any available energy and capacity into the New England energy market that is not utilized by Nalcor or committed for delivery into Nova Scotia. If the electricity available from Nalcor is eligible to participate in any of the state REC markets, it would also be able to access these markets.
11. Hydro Quebec is currently well positioned to sell into the New England market and its favourable market positioning is expected to continue into the future. It has transmission access into New England, surplus energy and is building additional hydroelectric generation facilities.

Based on the above observations and findings, there are two critical issues that must be addressed to maximize the New England market opportunity for Atlantic Canada clean and renewable electricity

[44] Recent legislation to eliminate the 100 MW limit on hydroelectric resources died on April 13, 2012. The bill died due to unresolved disagreements between the House and the Senate.

exports. First, the transmission capability from Atlantic Canada to New England is presently limited. The transmission infrastructure will need to be expanded to support significant long-term exports into New England. Second, large-scale hydro currently does not qualify to participate in state-mandated RPS programs. Legislative changes would need to be made to these programs to enable participation of Atlantic Canada's hydroelectric generation facilities. However, it is important to recognize that Vermont and Massachusetts have defined goals for "alternative" energy that may provide opportunities for Atlantic Canada's hydroelectricity facilities, but no penalties have been established for non-compliance with these goals (in contrast to the mandated RPS programs that have established penalties for non-compliance).