INTEGRATING WIND POWER IN NEW BRUNSWICK

PHASE II: Large Scale Wind Power in New Brunswick – A Regional Scenario Study Towards 2025

Detailed Scenario Analysis Report

Ea Energy Analyses
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1.1 Summary and key findings

This study examines large-scale wind power development in the Maritimes Area in a regional context and examines how Danish experiences with deployment of large amount of wind power could be utilised in a Canadian context.

The study indicates significant benefits to New Brunswick as well as neighbouring jurisdictions from a deployment of 5,500-7,500 MW of wind power capacity in the Maritimes Area towards 2025. This includes 3,000-4000 MW in New Brunswick, 500-1,500 MW in Prince Edward Island and 2,000-2,500 MW in Nova Scotia. Exploiting this potential for wind power will bring economic benefits to the Maritimes provinces as well as New England. Québec may profit from providing balancing power. Furthermore, wind power deployment will contribute to the security of supply of the region, it will be part of a climate change strategy, and it may bring benefits to the local environment by reducing air pollution.

The reasons for these benefits are several:

- New Brunswick and the Maritimes Area have very good wind resources, yielding wind power capacity factors of up to 40 percent
- The current fuel price level provides a strong incentive to invest in technologies with low or no fuel costs. Wind power generation in the Maritimes will mainly replace production from existing oil or gas fired power plants with low efficiency in the region
- Carbon regulation and Renewable Portfolio Standards in the regions improve the competitiveness of wind power and provide security of demand for wind power and other non carbon emitting technologies
- Electricity demand is projected to continue to grow in the region in a situation where it is difficult to find sites for new generation capacity in New England, including coal power plants, nuclear power and wind power plants

The potential of 5,500-7,500 MW wind power is attractive to develop in a fuel price scenario of 120 USD per bbl crude oil, as well as a fuel prices scenario in the order of 60 USD per bbl. In the case of low fuel prices CO2-regulation and Renewable Energy Portfolio standards will become the main economic drivers for the wind development.

In order to maximise the value of wind power in the electricity market and to provide balancing power at reasonable costs, a high level of cooperation between the markets in the Maritimes Area and the neighbouring systems of New England and Québec is essential. This applies to the day to day operation of systems and markets as well as to the long-term planning for new wind power capacity and new infrastructure. Further studies of load flows and the dynamic behaviour of the electricity system will be needed as part of the deployment process.

Efficient utilization of the existing transmission grid in the region allows for large scale integration of wind power. However, with increasing wind power penetration the study indicates that it will be economically attractive to increase the transmission capacity between the electricity systems within the Maritimes Area as well as to load centres in New England.

Danish experiences from developing an energy system with a large amount of wind power show that the following measures are required in order to harvest the full benefits of a large-scale deployment of wind power:

- Preparing a comprehensive wind development plan for New Brunswick (and the Maritimes), including
    - long-term targets for wind power
    - proper physical planning to develop sites with good wind conditions
    - regulation ensuring that grid access is provided at reasonable costs not disfavouring wind power as a fluctuating energy source
    - a strategy on how to harvest industrial benefits of large-scale wind power
    - A strategy for incentives to invest in wind power, including a strategy for local involvement and ownership. A key question concerns what role the government of New Brunswick, the utilities and electricity consumers of New Brunswick should play with respect to stimulating investments in new wind power capacity. Looking at mechanisms whereby electricity consumers and wind power developers share the risks and benefits of the large investments required is recommended.
- Revising existing market design and restructure the market to allow for a higher level of competition and more efficient utilization of capacity within New Brunswick and across interconnectors.
- Improving the integration of the electricity markets in the Maritimes and the neighbouring systems of New England and Québec in order to maximise the value of the wind power in the region and to provide balancing power. The long term goal should be an efficient market coupling between the markets or even a common electricity market
- Continuing the restructuring process for the electricity sector in New Brunswick, including the evolvement of a strong system operator able

to integrate wind power into the system and being engaged in comprehensive long-term system planning together with research, development and demonstration activities. As part of this process it should be considered to establish a transmission system operator with ownership of the transmission grid and interconnectors.

- Strengthening the efforts in development of the energy cooperation with neighbouring provinces and states, including development of a regional transmission expansion plan. A regional energy study could be one of the tools for evolving a common understanding of the challenges and possibilities for the future energy system in the North eastern part of North America.

These measures will not evolve by themselves. Strong political leadership and cooperation is needed throughout the region and particularly in Atlantic Canada. In New Brunswick, given the evolution of renewables, rising cost of fossil fuels and the experience to date with market re-regulation since 2004, the present situation calls for the political will to effect further restructuring in the electricity sector that supports the notions of the providing New Brunswickers with reliable, reasonably priced and environmentally sustainable supply of electricity and promoting the ability for the province to host additional generation development for the benefit of domestic and regional markets.

A firm strategy for a true market opening process will be needed, allowing for more market players, more liquidity in the market and more transparent electricity prices. Such strategy cannot be achieved without a regional consensus at the political level on the future path to evolve the whole energy system in the region.

The integration of large amount of wind power in the Maritimes is not possible without a close cooperation with the neighbouring systems on balancing, market rules, utilization of interconnectors and the establishing of new transmission lines. The development of the regional cooperation requires a strong effort from political level as well as from the system operators in the region. We recommend an open process with an extensive dialogue with all relevant stakeholders in New Brunswick and in the region as a whole with the New Brunswick Department of Energy as spearhead for this process.

The implementation of most of the above mentioned measures will not only benefit wind power integration. It will also facilitate the whole New Brunswick vision for an energy hub and help it realize its full potential.

At present a window of opportunity has emerged in the Maritimes area to benefit from the challenges in the energy supply and the need for changing the existing energy system. This window will not be open forever. Therefore firm strategies and quick response are needed at all levels to make it possible to harvest all the potential benefits from a large-scale wind power development.

1.2 Introduction

The government of New Brunswick has adopted a strategy to develop the province into an energy hub. This decision is among other things based on the abundant wind resource of the province, which could improve the security of supply of the province and meet the growing demand for electricity in neighbouring regions, especially the New England states.

This study was commissioned by the New Brunswick System Operator (NBSO) and the New Brunswick Department of Energy (DOE) from Ea Energy Analyses as part of a multi-phase process of examining the methods, impacts, costs and benefits of wind power integration in New Brunswick and the Maritimes. In the process, the Danish utility SEAS-NVE also participated.

This report consists of three main parts:

- A description of the regional scenario analyses exploring the opportunities for wind power in the analysed region, i.e., the Maritimes Area, New England and Québec.
- A presentation of the experience in wind power development in Denmark.
- A list of recommendations on wind power deployment to the NBSO and the New Brunswick DOE

More details on the scenario analyses are available in the scenario analysis report: "Scenario Analyses for the Electricity Markets of the Maritimes and New England".

First, a brief introduction to the electricity systems in the region is given.

Wind power status

Currently, wind power only plays a marginal role in the region consisting of the Maritimes Area and Québec in Canada and states of New England in the US. Some 150 MW of capacity is in place in the Maritimes at present, but existing policies and targets could increase this tenfold within the next decade. In Québec more than 400 MW of wind capacity were installed by May 2008 with a target of 4,000 MW for 2016. The region of New England holds about 50 MW of wind capacity now, but could see this amount increased very considerably in the years to come – in part as a response to the Renewable Portfolio Standard (RPS) requirements of the states in New England.

Generation mix and electricity demand

In New Brunswick, power generation consists of a mix of coal, oil, gas, hydro and nuclear capacity. In New England, natural gas is the dominant energy source for power generation, supplemented by coal, oil-fired capacity, nuclear and hydro. Electricity generation in Québec is close to 100 percent reliant on hydro power.

In terms of electricity demand, the provinces of the Maritimes Area are significantly smaller than Québec and New England (see Table 6).

Table 1: Present electricity demand (TWh). *Including Prince Edward Island and Northern Maine

TWh	New Brunswick*	Nova Scotia	Québec	New England
Annual electricity demand	17	13	188	127

New Brunswick has interconnections to Prince Edward Island, Nova Scotia, Québec and New England. New England and Québec are also interconnected. The differences in generation portfolios in the systems create potential benefits to be gained from regional electricity trade between the systems.

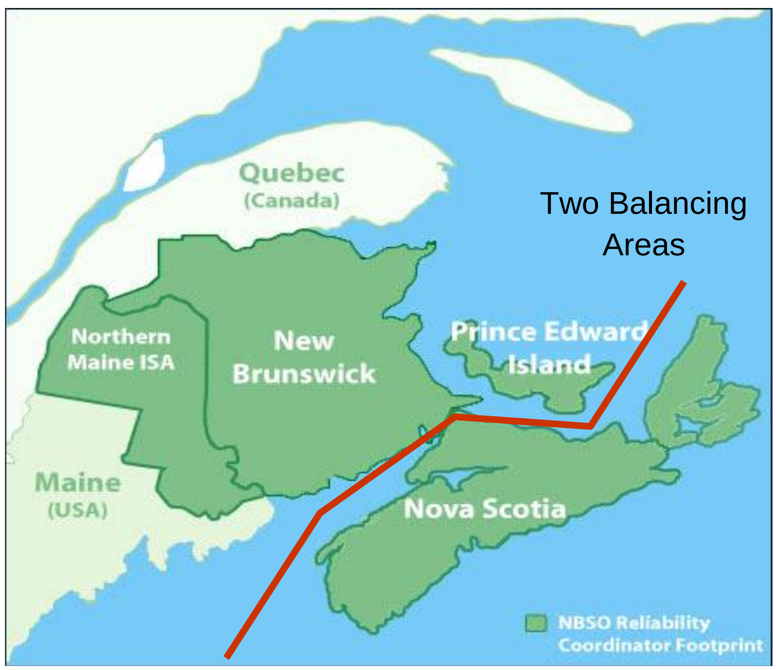


Figure 1: The Maritimes Area

Market setup

In principle, cross-border trade is driven by price differences. If the price in an adjacent area is higher, it is profitable for producers to export to that area. If the price in an adjacent area is lower, it is profitable for consumers to import from that area instead. At present the different markets of the region are not fully integrated and long term capacity reservations on the interconnectors to certain market players have the effect of limiting the exchange of electricity between the regions.

Moreover, in the case of New Brunswick the market for electricity is dominated by one company, NB Power owning almost all generation capacity (through NB GenCo/NB Nuclear Power), the transmission system (through NB TransCo) and the distribution and supply system (through NB Disco). This limits the access to the market for new players.

The independent company NBSO is responsible for system operation and market development and facilitation.

Large consumers (industry) have access to the market, but they have not yet exploited this opportunity.

Environmental regulation

In Canada it is being proposed that all major power producing entities will be required to reduce their CO_2 emissions intensity by 18 percent of the 2006 levels by 2010, with 2 percent continuous improvement every year after that, according to the federal Regulatory Framework for Industrial Greenhouse Gas Emissions.

As inter-firm trading is allowed, the scheme works on a similar basis as the RGGI (Regional Greenhouse Gas Initiative) cap and trade system, which will be in place in New England from 2009. RGGI limits CO_2 emissions to recent historic levels in the period 2009-2014 and requires 10 percent reduction towards 2018.

Renewable energy is promoted in all regions mainly through renewable energy portfolio standards. New Brunswick's Renewable Portfolio Standard requires that 10 percent of the province electricity must come from renewable sources by 2016. In New England, renewable energy policies are in place to increase the share of renewables from approximately 5 percent today to 14 percent in 2016.

1.3 Regional wind scenario analyses

As a key part of the present study, scenarios are developed towards 2025 exploring the development of the electricity markets in the region. The scenarios focus specifically on the perspective of large-scale wind power integration in New Brunswick and the Maritimes.

Since wind power integration and the development of the electricity system and market in New Brunswick are closely connected to the developments in the neighbouring regions, a simulation of the electricity systems in the Maritimes, New England and Québec areas is carried out.

The simulation considers all power generation capacity in the systems as well as important bottlenecks in the transmission grid. Generalized data on power plants and constraints in the transmission system was supplied by among others the NBSO, the US DOE and the Independent System Operator of New England (ISO-NE).

Modelling tool

For the quantitative analyses, the Balmorel model is applied[1]. In addition to simulating the electricity systems, the Balmorel model estimates electricity prices and is capable of assessing the impact of environmental regulation such as markets for green certificates and emission trading schemes.

The model takes a combined technical and economic approach. Balance between load and generation is ensured within each defined transmission sub region. It takes account of the most important transmission constraints. 624 time steps are used efficiently to represent seasonal, daily and hourly variations in load, intermittent generation etc. The system related costs of wind power intermittency are thus internalised in the model, but not the residual cost element due to forecast uncertainty.

The model does not replace the need for load flow and stability network analyses. This type of analyses require even more detailed information, such as to where specific turbines and farms are to be connected and as such is an activity which merits continuous attention by the responsible ISO or TSO, as system planning and operations activities.

In contrast to many other electricity system models, the Balmorel model makes suggestions for optimal investments in new generating capacity assuming well-functioning markets and full competition among power producers. In the present study, this feature of the model is used to analyse how the electricity systems may evolve in the future taking into consideration different framework conditions.

Four wind power policy scenarios

The quantitative analyses of the different development options in New Brunswick and the neighbouring regions have been approached by analysing four different wind power policy scenarios.

[1] Details on the model are available on www.balmorel.com.

Passive Scenario	Active Scenario	Transmission Scenario	Proactive Scenario
Passive wind power policies, e.g. with respect to physical planning, limits the usable wind power potential to 1,000 MW in the Maritimes Area.	An active policy to pursue wind power allows for exploitation of the physical potential of app. 16,500 MW in the Maritimes Area.	As the active scenario, plus increased transmission capacity within the Maritimes Area and to New England.	As the transmission scenario, plus harmonisation of environmental regulation and removal of trade barriers on interconnectors.

In the Passive Scenario it is assumed that wind power capacity in the Maritimes Area may not be developed beyond 1,000 MW e.g. due to planning constraints or grid access issues. In the Active Scenario policies are implemented allowing for the possible exploitation of up to 16,500 MW of wind capacity in the Maritimes Area, including 5,500 MW in New Brunswick[2].

In the Transmission Scenario the electric transmission capacity within the Maritimes Area and to New England is expanded to allow for more wind power. The transmission capacity from New Brunswick to the Boston area is assumed to be increased by 1,500 MW, the interconnectors to Nova Scotia by 1,000 MW and to Prince Edward Island and Northern Maine by 600 MW. In the Proactive Scenario, in addition to the above, the environmental regulation is harmonised allowing renewable energy certificates and CO_2 quotas to be sold freely across systems. Moreover, existing tariffs on using interconnectors between New Brunswick and neighbouring areas are removed, thus stimulating more trade.

1.3.1 Key assumptions

The assumptions used in the study – regarding for example the development in electricity demand and fuel prices – have been determined in cooperation with the NBSO. Table 2 summarises the most important assumptions.

[2] The technical wind power potential – considering planning constraints and the available wind resource – has been identified to be 40,000 MW for New Brunswick only (Gagnon, 2008), but for reasons of conservatism we constrain the total potential to 16,500 MW for the Maritimes region in this study.

Table 2: Key assumptions in the study

<table>
<tr><td>Fuel prices</td><td>Fuel prices are based on the prices observed in the first months of 2008, i.e. an oil price of just above 120 USD/barrel. Based on observed crude oil contracts from NYMEX, it is assumed that this price level will prevail over the period.

<table>
<tr><th></th><th>Oil (USD/barrel)</th><th>Natural gas (USD/Mbtu)</th><th>Coal (USD/ton)</th></tr>
<tr><td>2008</td><td>123</td><td>12.4</td><td>91</td></tr>
<tr><td>2015</td><td>116</td><td>11.1</td><td>86</td></tr>
<tr><td>2025</td><td>123</td><td>11.6</td><td>90</td></tr>
</table>

Moreover, a sensitivity analysis is made with lower prices (60 USD/barrel of oil).</td></tr>
<tr><td>Electricity demand</td><td>For the region as a whole, the demand for electricity is expected to increase by 25 % from 2010 to 2025 as indicated by official projections. This corresponds to an annual increase of 1.3 %.
Electricity consumption is forecasted to grow slightly faster in New England than in the Maritimes Area.</td></tr>
<tr><td>Decommissioning of power plants</td><td>No decommissioning of power plants is assumed until 2015. In the period from 2015 to 2025, 5 percent of all thermal power plants are presumed to be decommissioned annually.</td></tr>
<tr><td>Environmental regulation</td><td>Existing and planned regulation regarding CO_2 and renewables is assumed to be enforced and prolonged to 2025 following current trends.</td></tr>
<tr><td>Sites for new power plants</td><td>Siting new coal and nuclear power plants is considered to be difficult. In New England, up to 2025, the model is only allowed to refurbish coal capacity which exists today and to establish 3.6 GW additional nuclear capacity. Wind power development in New England is confined to about 3,100 MW including two large-scale off-shore wind farms.</td></tr>
<tr><td>Wind power capacity factor (CF)</td><td>New Brunswick, Nova Scotia and Prince Edward Island: Each area has a potential of 500 MW with a capacity factor (CF) of 40%, 500 MW with a CF of 39 %, 500 MW with a CF of 38 % and etc. The total potential for each area is 5,500 MW. Therefore, there is a total wind potential of 16,500 MW with capacity factors ranging from 30 to 40%.

New England: Onshore: 32 % CF, Off-shore: 46 % CF.</td></tr>
</table>

It should be noticed that investments in Québec are not explicitly modelled in the study. For Québec, a development in new hydro and wind power has been assumed; generating a surplus of 10 TWh per year from 2015 to be exported to New England and the Maritimes Area. This assumption is based on historical exports and prospective imports, but is less than the full potential. Actual annual volumes will depend upon market conditions (in Ontario, New York and New England), load growth in Québec, and on the actual development of generation projects in Québec. On an hourly and daily basis the model allows Québec to be a net-importer or net-exporter depending on the benefits of trading with neighbouring countries.

Technology data is based on the New England scenario study published in August 2007 (ISO New England, 2008). Figure 2 compares the long-run marginal costs of six of the key technologies applying the above fuel prices and including a cost of CO_2 of 20 CAD/ton. An internal rate of return of 10 percent (real) is assumed in the calculation.

Due to the relatively high fuel prices – compared to the recent decades – nuclear power and wind power appear to be the most competitive technologies.

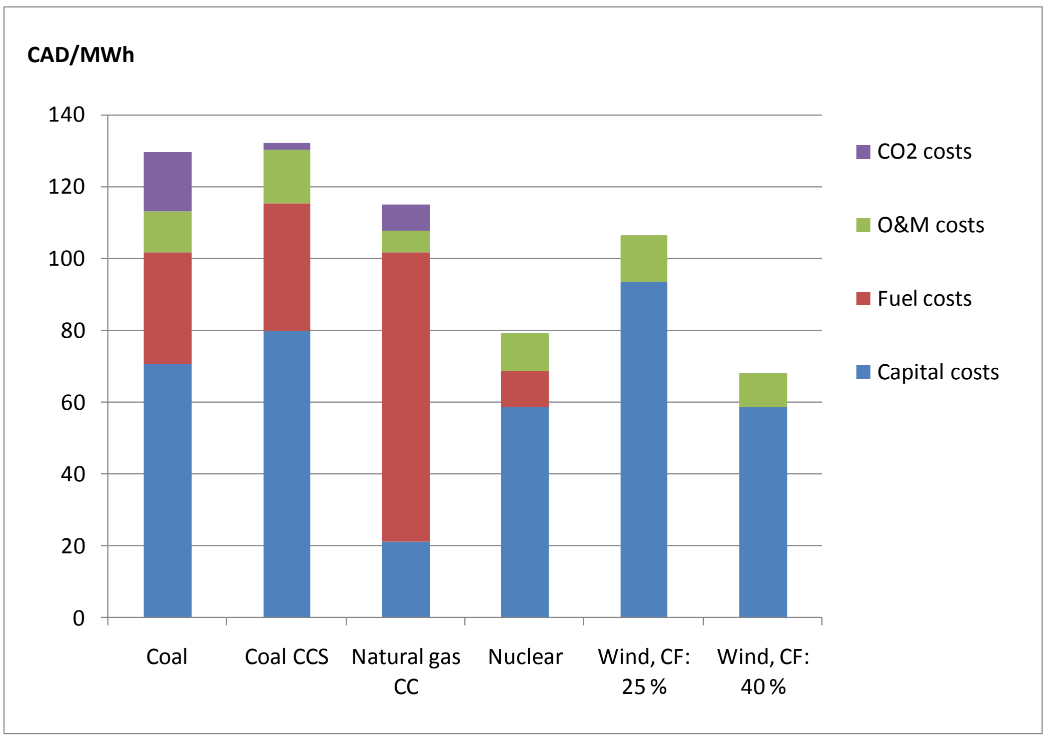


Figure 2: Comparison of long-run marginal costs of new power generation technologies (CAD/MWh). CCS: Carbon Capture and Storage, CC: Combined Cycle, CF: Capacity Factor. Two onshore wind power plants are included in the comparison with capacity factors of 25 percent and 40 percent respectively.

For the conversion from US dollars to Canadian dollars an exchange rate of 1:1 has been applied.

1.3.2 Results

In this section, the main results of the scenario analyses are summarized. We focus on the results from the Passive Scenario – where wind power in the Maritimes is restricted to 1,000 MW - and the Proactive Scenario, where it is possible to invest in a total of 15,000 MW of wind power capacity, additional transmission, harmonized environmental constraints, and removal of trade barriers.

More comprehensive results are available in the scenario background report, including details on operational issues.

Figure 3 shows the investments in new generation capacity in the two scenarios as selected by the optimization model.

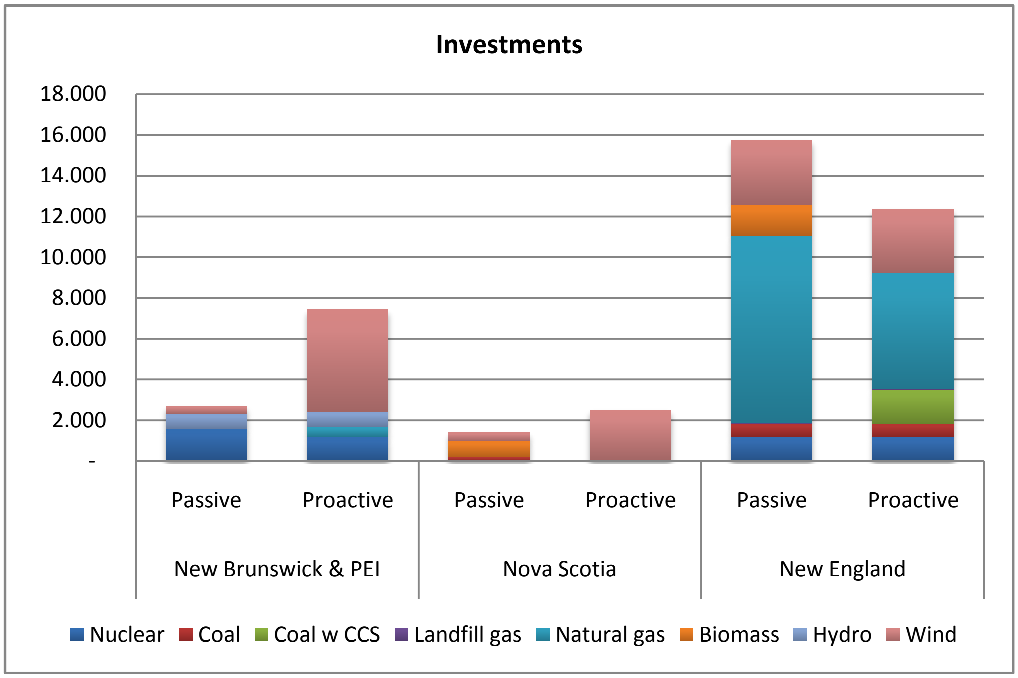


Figure 3: Investments in generation capacity in Maritimes Area and in New England in the period 2010 – 2025 (MW)

Investments in the Maritimes

In the Passive Scenario investments in the Maritimes consist of new nuclear power in New Brunswick (1,230 MW), significant amounts of biomass capacity, some gas capacity and wind power capacity up to 1,000 MW (the limit in the scenario).

Moreover, 740 MW of hydro power capacity is assumed to be imported into New Brunswick from Lower Churchill Falls in Labrador. This option is imposed on the model. The feasibility of the Lower Churchill Falls project has not been determined in the present study.

In the Proactive Scenario, the economic optimization model shows that it is feasible to invest in about 7,500 MW of wind capacity in the Maritimes Area. The remaining investments in the Passive scenario are unaltered in the Proactive scenario except for the biomass capacity, which is no longer feasible with the increasing penetration of wind power in the system. Because of the superior access to transmit power to New England, the majority of the investments in wind power, 5,000 MW, are made in the area of New Brunswick and Prince Edward Island and 2500 MW in Nova Scotia.

Investments in New England

In New England, siting issues are assumed to limit the growth of onshore wind by assumption to 1,100 MW and the offshore potential to 2,000 MW in total (1,000 MW off the coast of Maine and 1,000 MW off South-eastern Massachusetts). Because of the high fuel prices, the model shows that it is attractive to upgrade and replace older and less efficient natural gas and oil-fired generation capacity with newer, more efficient combined cycle technology. These potentials are fully utilized in the passive as well as in the proactive scenario. Moreover, the model shows that it is attractive invest in additional 3,600 MW nuclear capacity (the limit in the scenario).

All in all, around 3,000 MW fewer investments are made in the New England area in the proactive scenario compared to the passive scenario. The reason is that imports from the Maritimes Area are increased significantly due to the higher penetration of wind power and the fact that transmission capacity is increased and trade barriers between systems in the form of tariffs are removed in the Proactive Scenario.

Figure 4 shows the generation of electricity in the Maritimes and New England areas in 2025 compared to generation in 2010 (passive scenario). The major difference between the passive and the proactive scenario is less generation from natural gas and biomass in the proactive scenario and more wind generation. In the Proactive Scenario by 2025 18 percent of electricity generation in New England and the Maritimes is wind power.

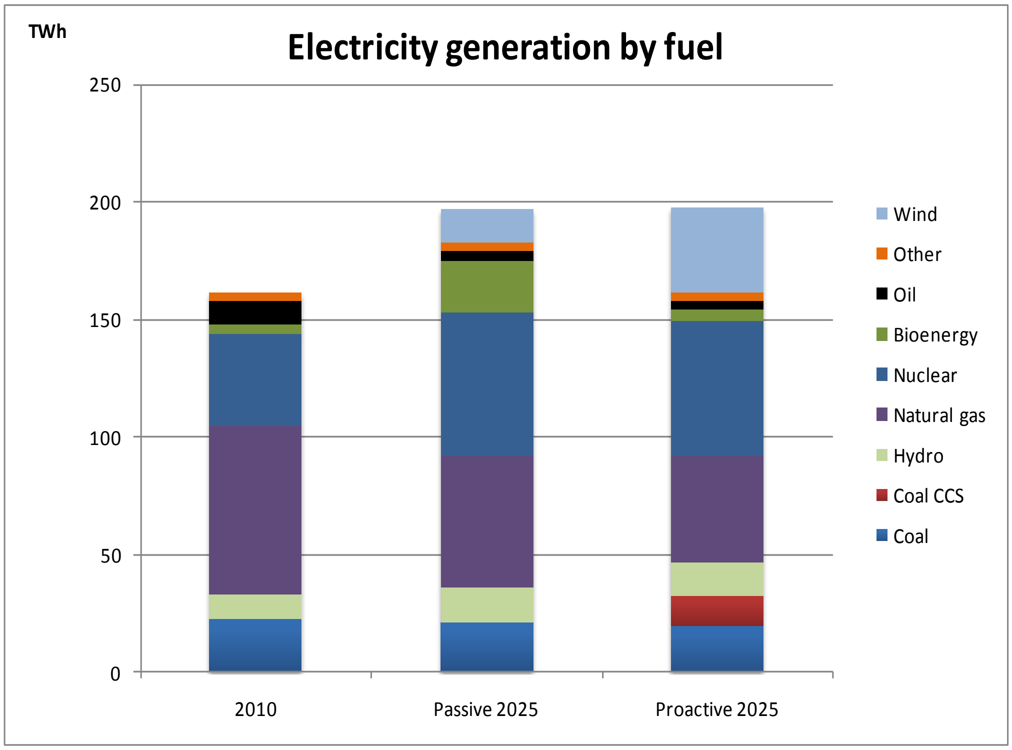


Figure 4: Total electricity generation by fuel source in the Maritimes Area and New England in 2010 (Passive Scenario) and the Passive Scenario and the Proactive Scenario for 2025

CO_2 emissions

The total sum of CO_2 emissions in the Maritimes and New England areas does not reach the total sum of the caps either in the Passive Scenario or the Proactive Scenario in the whole scenario period stretching from 2010 to 2025. However, in the passive scenario, where the CO_2 quotas are not traded across Canada and the US, of the years studied (2010,

2015, 2020 and 2025), the cap is binding in the Maritimes Area in years 2010 and 2015.

The relatively high fuel prices explain why the total CO_2 cap does not become more binding. With a price of oil above 120 USD/bbl it is attractive to shift to less carbon-intensive generation technology regardless of the CO_2 regulation.

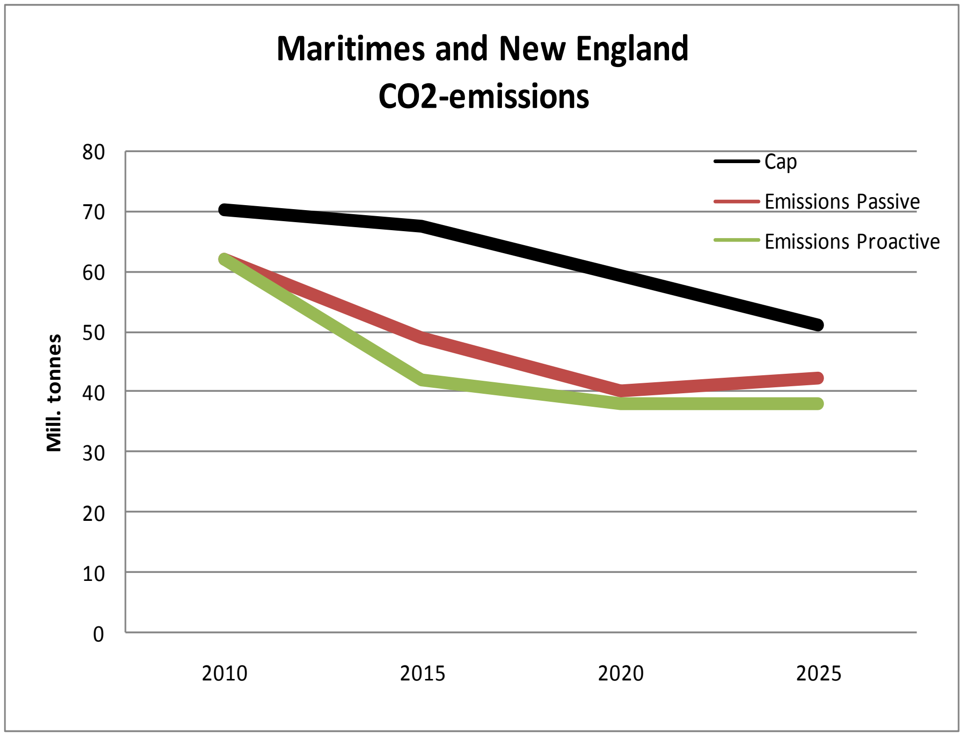


Figure 5: Total CO_2 emissions from power plants in the Maritimes Area and New England in the Passive Scenario and the Proactive Scenario compared to the total cap for the area.

Renewables requirements

In the Passive Scenario, the RPS requirements become binding in 2020 and 2025, but not in the Proactive Scenario, where the cost-competitive wind resources in the Maritimes are released to the market.

Electricity prices

Investing in new generation capacity will affect electricity prices in the long run. The current mix of generation facilities are not competitive in a world with oil prices at 120$/bbl. Wind power is particularly competitive where good sites are available. Wind power connected to hydro power is the strongest combination. Electricity prices in the Proactive scenario develop so that the prices are lowest where the wind power is generated. Therefore electricity prices in the Maritimes provinces can be expected to become lower in a future with much wind power than otherwise. Congestion in the system causes the prices in New England to find a level based on generation costs of old and new natural gas fired units. Gas remains on the margin in New England, but with higher average efficiency than today.

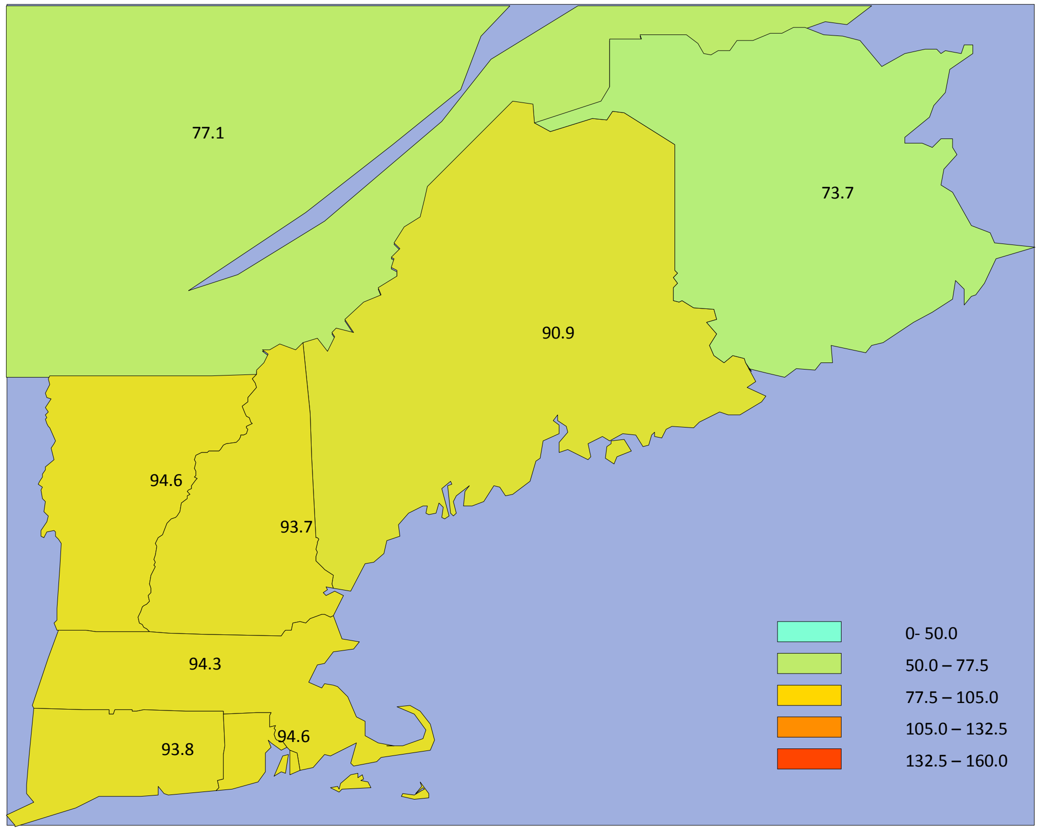


Figure 6: Consumption weighted average marginal electricity values (prices) in the Pro-active scenario in 2025.

Economic results

In all three alternative policy scenarios, there is a total economic benefit for the region and for New Brunswick compared to the Passive Scenario. The benefit for the whole region is in the range of 4.0 to 6.5 billion CAD, and the benefit for New Brunswick is in the range of 1.1 to 2.1 billion CAD (highest in the Proactive scenario).

The table below shows the costs and benefits in the Proactive Scenario compared to the Passive Scenario. In order to calculate the net present value of the benefits to society of the investments and operations, all cost streams have been discounted to 2008 using a discount rate of 6 percent.

	New Brunswick & PEI	**Nova Scotia**	**Quebec**	**New England**	**Total**
Saved costs	-12.9	-1.1	0.0	20.9	6.9
- fuel	-3.3	1.5	0.0	16.3	14.4
- variable O&M	-0.5	-0.1	0.0	0.4	-0.1
- fixed O&M	-0.9	-0.1	0.0	0.8	-0.2
- capital costs	-8.2	-2.4	0.0	3.4	-7.2
Improved trade balance	15.0	2.9	0.4	-18.8	-0.4
Sum	2.1	1.9	0.4	2.1	6.5
Investment transmission					**-1.5**
Total					**5.0**

Table 3: Costs and Benefits of the Proactive Scenario in relation to the Passive Scenario in the period 2010-2025 (billion CAD) Future cost streams have been discounted to Net Present Value (2008) using a discount rate of 6 percent p.a. [1]Including Prince Edward Island.

The Proactive Scenario features higher capital costs than the Passive Scenario due to the investments in capital-intensive technologies, which on the other hand leads to a significant reduction in fuel costs.

The trade balance shows the value of the electricity which is exported/imported across the region. Had the model not included exchange of electricity with regions outside the analyzed system (New York is modelled by a price interface), the trade balance would sum to zero.

Nova Scotia and in particular New Brunswick improve their trade balances in the Proactive Scenario as they increase their exports significantly. On the other hand, the capital costs – to pay for investments in wind power capacity – are increased in these systems. In New England the situation is reverse.

Québec is not modelled as detailed as the other areas in the region. However, the simulations indicate that Québec is able to profit significantly from balancing wind power with hydro power.

Removing bottlenecks

The study indicates that there may be significant benefits from expanding the transmission capacity between New Brunswick and the load centres in the southern part of New England. Table 10 shows the estimated costs and benefits of the transmission expansions which are included in the Transmission Scenario and the Proactive Scenario. The cost-benefit analysis does not value potential additional benefits to the security of supply or synergies related to the acquisition of ancillary services between system areas.

	Costs	Benefits	Sum
New Brunswick <=> Boston + 1,500 MW, HVDC (600 km)	-1.05		
New Brunswick <=> Nova Scotia, + 1,000 MW, 345 kV AC (100 km)	-0.15		
New Brunswick <=> Northern Maine, + 600 MW, 345 kV AC (100 km)	-0.15		
New Brunswick <=> PEI, + 600 MW, 345 kV AC, (100 km)	-0.15		
Sum	-1.50	2.3	0.8

Table 4: Cost and benefits of extending the transmission system (billion CAD). Costs and benefits of the interconnectors are accounted for in period 2010-2025 and discounted to Net Present Value using a discount rate of 6 percent p.a. An economic life time of 30 years is assumed for the investments in the transmission system. The benefits are worked out as the total benefits of the two transmission expansions by comparing the economics of the Active Scenario and the Transmission Scenario.

Sensitivity analyses – low fuel prices

Fuel prices are a critical assumption in any scenario analysis of the electricity sector. For this reason, a sensitivity analysis where fuel prices are in line with the latest official projections from the International Energy Agency's World Energy Outlook (crude oil price decreasing to about 60 USD/bbl) has also been made.

Even in this case, the economic optimisation model shows that it is attractive to invest in significant amounts of wind power capacity in the Maritimes Area, approximately 6,100 MW until 2025. However, in the case of low fuel prices, the CO_2 regulation and the renewable energy portfolio standards will become the important economic drivers for the wind development.

1.3.3 Main conclusions from scenario analyses

The scenario analyses of the electricity systems in the Maritimes Area, New England and Québec demonstrate that it is economically feasible to develop 5,500-7,500 MW of wind power capacity in the Maritimes Area, including 3,500-5,500 MW in the area consisting of New Brunswick and Prince Edward Island and 2,000-2,500 MW in Nova Scotia. Exploiting this wind potential will bring economic benefits to New Brunswick as well as to Nova Scotia and New England.

Developing wind power in this order of magnitude is economically attractive with the current high fuel prices as well as with lower fuel prices in the order of 60 USD/bbl. In the case of low fuel prices, CO_2-regulation and Renewable Energy

Portfolio standards will become the main economic drivers for the wind development.

1.4 Danish experience in wind power development

Since the 1980s there has been a steady growth in the wind power capacity in Denmark. At this point in time, more than 3,000 MW of wind power capacity is installed covering about 20 percent of total Danish electricity consumption. An additional 1,300 MW is planned to be installed within the next five years and in 2025 the government plans to increase the share of wind power to 6,000-6,500 MW corresponding to 50 percent of electricity demand.

At the same time Denmark has been able to build an extensive industry around wind power hosting companies such as Vestas, Siemens Wind Power and LM Glasfiber. In 2007, the exports of the Danish wind power industry totalled about seven billion CAD.

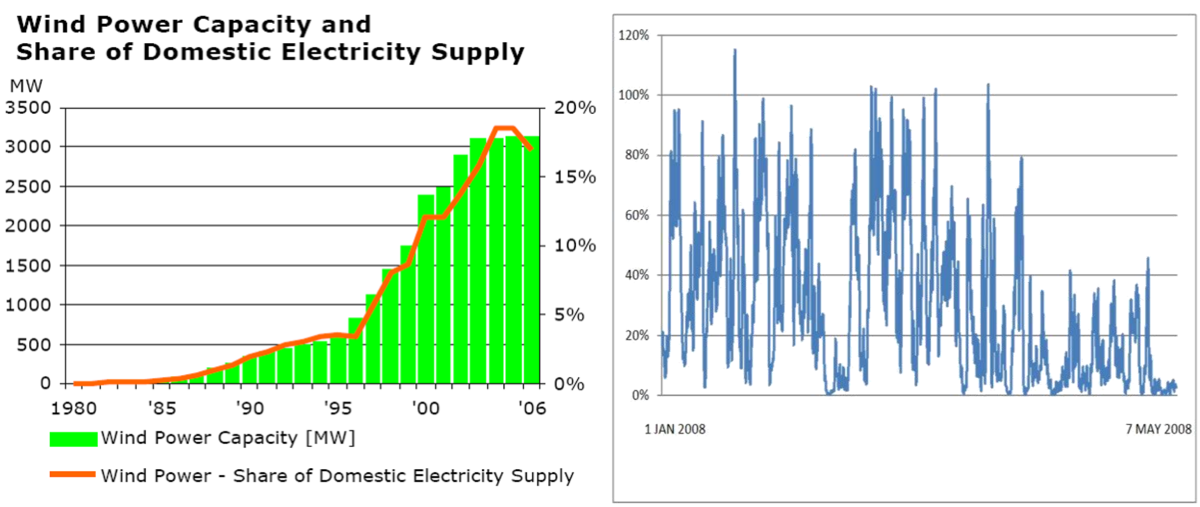


Figure 7: Left: Development in wind in Denmark 1980-2006 measured as installed capacity (MW) and generation as percentage of total electricity consumption. Right: Wind power's share of electricity consumption in the western part of Denmark in the period 1 Jan 2000 to 7 May 2008, hourly measurements.

The physical characteristics of the electricity systems in the Maritimes Area and in Denmark resemble each other to a high degree. Therefore Denmark provides a good learning case on wind power development and integration for New Brunswick and the Maritimes Area. The electricity consumption in the Maritimes Area is approximately the same size as in Denmark, both areas have access to neighbouring large-scale hydro power system (Québec and Norway/Sweden) and interconnections to large load centres (New England and Germany). Moreover both areas have good wind resources (see Figure 8).

1.4.1 The Danish lessons

Denmark has a long tradition – going back more than 30 years – for broad political alliances on energy policies. New policies have typically been negotiated in a transparent way including the majority of the political parties and with a high level of stakeholder involvement.

Wind power has had strong political support in Denmark since the oil crises in the 1970s. In the first phase, the key drivers were self-sufficiency and security of supply. In the two last decades wind power has been viewed as an important tool to reduce domestic CO_2 emissions as well.

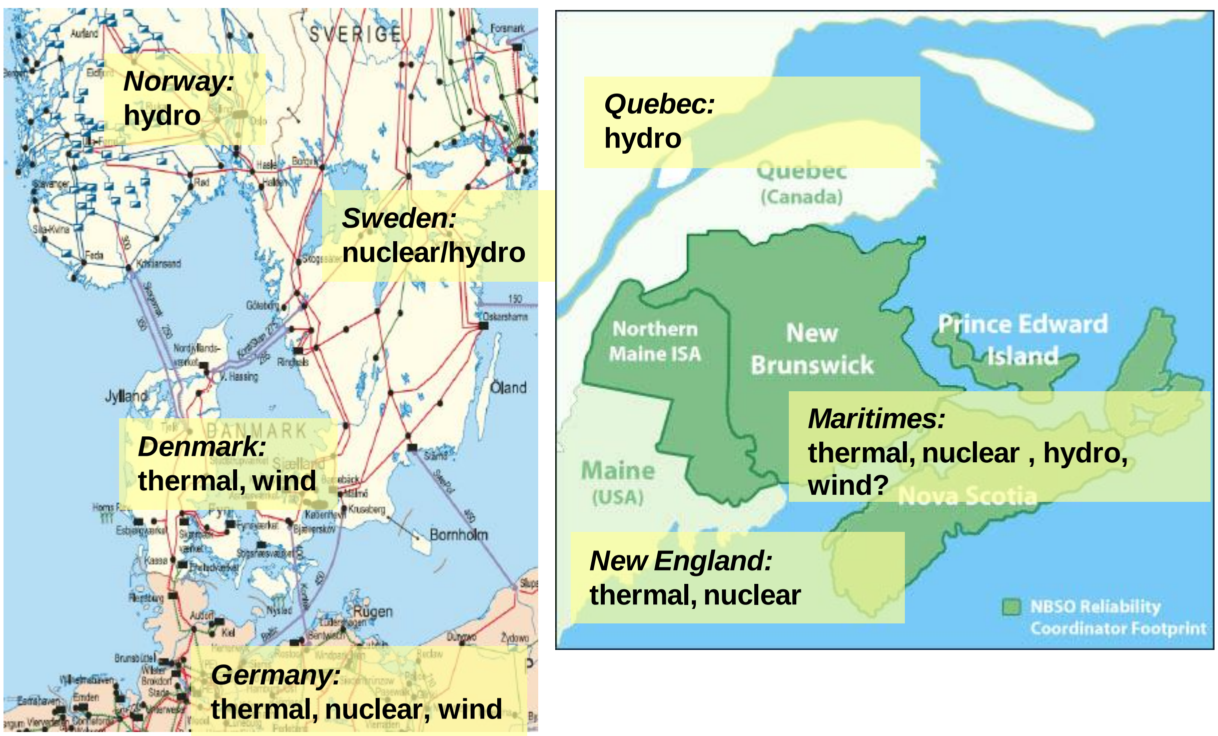


Figure 8: Maps of the Nordic-German electricity system and the Maritimes-Québec-New England area with indication of the dominant fuels for electricity generation.

A number of concrete measures have been essential for the development of wind energy in Denmark, including financial support schemes, grid access, physical planning, development of a well-functioning market, a pro-active system operator, local involvement and ownership and strong research development and demonstration efforts. The Danish experience on each of these issues is briefly dealt with in the following sections.

Financial support schemes

A range of different support schemes have been used to support wind power development in Denmark. In the 1980s, when wind power was still a rather immature technology, turbines were supported through investment subsides, feed-in tariffs and tax incentives. Subsequently, as the cost of wind power plants decreased, the investment subsidies were abandoned and the support schemes were revised to fit the framework of the liberalised electricity sector.

Today, onshore wind power receives a premium of 50 CAD/MWh on top of the price, which the owner of the turbine can obtain in the electricity market. Offshore wind farms are put up for tender on specific sites competing for the lowest fixed electricity price. The most recent off-shore tenders have yielded prices between 100 and 120 CAD/MWh.

The support for wind power is financed by the Danish electricity consumers and can be viewed upon as a risk sharing mechanism between producers and consumers. Though wind power is competitive with more conventional types of generation (compare with Figure 2, p. 14) its high capital costs poses a significant barrier taking into consideration the inherent risks in the electricity market. A fixed price for wind power generation gives producers certainty about future revenue and at the same protects consumers against high electricity prices in the future.

A well-functioning day ahead and real-time market

Denmark benefits from a high degree of cooperation with neighbouring countries. In the liberalised Nordic electricity market, power is traded on a common exchange, Nord Pool, to ensure optimal dispatching of generators. Denmark has strong interconnectors to neighbouring countries, and within the Nordic area all transmission capacity is made available to the electricity spot market.

The market mechanism ensures that hydro power plants and thermal power plants have incentives to respond to the variations in wind power generation in a flexible manner.

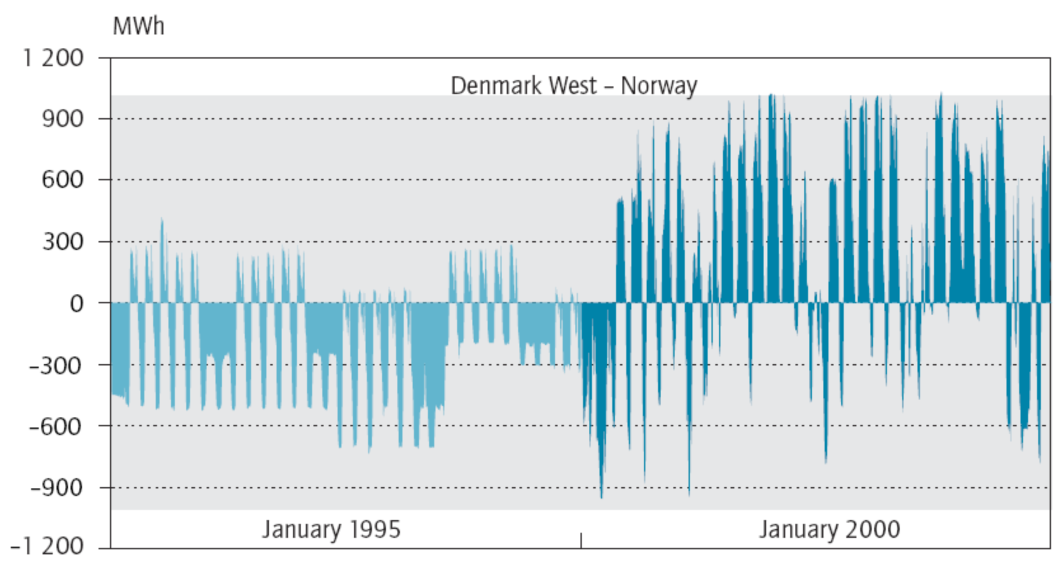
Balancing power is traded on a least-cost basis across system areas in the hour of operation. This is done according to agreements between the Nordic transmission system operators. In Denmark, the actual balancing costs – based on the prices in the market for balancing power – are approximately 3.5 CAD/MWh

The common Nordic market has been of benefit to all the involved countries, not only regarding wind integration, but to the general electricity system and to the consumers as a whole.

It has been developed during the recent 15 years as a long process with strong and sustained political commitment, extensive and detailed preparation, and continuous development to allow for necessary improvements.

One of government's most decisive roles was to establish a framework that allows for the development of effective competition. The first step was to break down the monopolies that existed in traditional vertically integrated utilities. Transmission network activities were separated from all commercial activities through true ownership unbundling. Networks and system operation are natural monopolies and should be subject to economic regulation, whereas generation and sales should be subject to competition.

In countries, where electricity markets have been liberalized, some of the consequences of have been a reduction in over capacity on the generation side (power plants being mothballed) and increased trade, resulting in increased utilization of the transmission system and interconnectors. Previously, power was mostly traded between utilities according to long-term contracts for so-called firm power. With the introduction of the market, the power flows according to short term price signals. This change is reflected in the figure below, showing the exchange of power between Western Denmark and Norway before and after the liberalization of the electricity market in Denmark.



Positive numbers are import and negative numbers are export; the shaded area marks the rated capacity of the interconnectors. (1,000 MW in 1995 and in 2000). (Source: Energinet.dk)

Creating a level playing field and developing effective, competitive market places requires establishing detailed market rules, design and regulation. There is one common feature of all successful markets: some sort of formal price quotation, conceived through formal market design. In this respect market operation is needed. Trading hubs may be organized by private companies, but in many jurisdictions the system operators are responsible for the daily market operation. In context of the Nordic countries, the common power exchange Nord Pool Spot, operating the Nordic day-ahead market, is jointly owned by the national transmission system operators.

Furthermore, with a decentralized decision-making process transparency is a prerequisite for achieving efficiency gains. Transparency improves the decision-making framework for all actors – policy makers, industry and consumers alike. Competitive market players do not voluntarily collect and publish fundamental market data and statistics. Therefore, it is important to redefine responsibility for this necessary task in liberalized markets. Increased transparency is a proven, strong instrument to ensure continuous development towards more effective markets. In the Nordic countries the transmission system operators have played an important role in ensuring the transparency in the electricity market.

Market concentration remains a serious concern in several electricity markets. Effective markets and transparency have been vital to easing access for newcomers. In addition, extending markets across countries and regions helps enable the "import of competition"; this is particularly important in smaller jurisdictions in which the need for consolidation limits the number of market players that can operate efficiently. In Europe the energy regulators have the role of monitoring the market concentration, assisted by the system operators.

Grid access and tariffs

In Denmark, grid connection costs are shared between the wind turbine developer and the electricity utility. Developers of onshore wind turbines pay for the low-voltage transformer as well as the connection to the nearest point in the distribution grid (10/20 kV), whereas the grid company covers the costs for reinforcement of the distribution and the transmission grid where needed.

Traditionally, wind turbines have not paid a network tariff. This has changed during recent years, however, and now new wind turbines are charged the same tariff as any other production facility. This tariff is rather small – less than 1 CAD per MWh of electricity that is generated – and it is not dependent on either peak production or the capacity of the generation facility. This is beneficial to wind power development, as individual wind turbines usually have relatively high peak production compared to average production.

Physical planning

Compared to New Brunswick, Denmark is rather densely populated. The population is around seven times higher and size of the country only 60 percent of New Brunswick. Therefore finding sites for wind turbines is a critical issue in

Denmark – and one of the reasons why new wind power capacity in Denmark mainly will be located offshore.

For onshore planning there is a "one-stop-shop" approval procedure where the project developer collects all approvals (environmental, building, power production) from one entity: the local authority[3]. Also the local authorities are responsible for pointing out locations suitable for wind power production as part of their physical planning. Similarly for offshore projects, the Energy Authority is responsible the siting for wind power and is the one-stop-shop approval authority. Access to grid and ensuring reasonable grid costs is one criterion together with others in the siting of new wind power farms in Denmark. Therefore the TSO and the local distribution system operators also play a part in the physical planning for wind power.

The one-stop-shop procedures and pre-planning for wind power are of benefit to wind power developers, avoiding lengthy bureaucratic approval procedures, and to authorities and electricity companies. It ensures that new wind power plants are sited in coordination with other considerations of spatial planning and at locations with low grid connection costs.

Local involvement and ownership

The early expansion with wind power in Denmark was to a large extent started by cooperatives and private individuals. This development was among others things made possible by restricting the financial support for wind turbines to people living within some distance of the facilities.

In recent years utilities and professional private developers have become important investors as well and the locational requirements for receiving support have been abandoned. Even so, the Danish experience shows that joint local ownership of wind power in any form creates considerable economic interest and pride amongst the local population. This is also likely to lead to a higher level of public acceptance of wind power. Together with dialogue with the local population on new sites, local ownership has been essential to reduce the so-called NIMBY (Not In My Back Yard) effect in Denmark.

A strong system operator

Following the liberalisation of the electricity market in Denmark in the late 1990s, system operation and the ownership of the transmission system has been unbundled from generation and supply activities. Today, the high-voltage transmission system, as well as the gas transmission infrastructure, is owned by the Danish state through the Transmission System Operator, Energinet.dk.

Energinet.dk has the short and long-term responsibility for maintaining the security of supply of electricity and gas in both the short and the long-term, moni-

[3] For wind turbines above 150 meters, the regions are the one-stop-approval authority.

toring and developing energy markets and developing the Danish electricity and gas transmission infrastructure.

Moreover, the transmission system operator is responsible for carrying out coherent and comprehensive planning taking into account future transmission capacity requirements and the future security of supply. Developing the grid and the electricity in order to further large-scale introduction of wind power – particular off-shore – is probably the main issue of the Danish Transmission System Operator at this time.

Within Nordel, the associations of the Nordic transmission system operators, investments in interconnectors are coordinated between the Nordic countries.

Research, development and demonstration

In Denmark, the transmission system operator, as well as the energy authority, manages significant funds for the development and demonstration of technologies for environmentally friendly energy production. A large share of the Danish funds for R&D is placed with the TSO on the grounds that the TSO has a key insight into the future needs of the electricity system and the interplay between different technologies.

As the wind power technology is mostly commercial today the wind research programmes focus mainly on the integration and optimisation of wind energy and other renewable energy sources in the electricity system. Core research areas include the development of demand response, utilizing and strengthening the coupling between the electricity system and district heating systems using electric boilers and heat pumps, developing and exploiting the coupling to the transport sector (electric vehicles as price dependent demand) and examining energy storage technologies such as hydrogen, Compressed Air Energy Storage and batteries.

1.4.2 Change of mindsets

Traditionally, wind power was looked upon as a problem – and not as an opportunity – by the Danish utilities. However, during recent years, the mindsets of the power engineers and energy planners have changed. Today, the Transmission System Operator approaches wind power integration as a manageable challenge and makes an effort to deal with some of the myths that wind power is often faced with in relation to system integration, e.g. that wind turbines cannot contribute to ancillary services and that minimum generation capability of coal-fired power plants seriously limit wind power penetration.

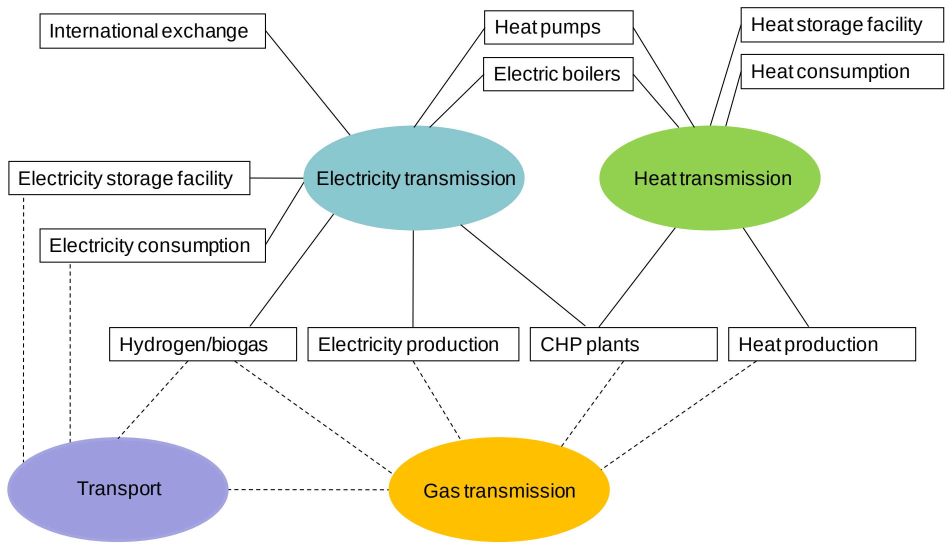


Figure 9: It is important to look at the whole energy system when integrating a large amount of fluctuating energy production. From Energinet.dk's system plan 2007

Cooperation is key

In Denmark it is generally recognised that in order to fulfil the vision of an efficient and flexible energy system with a large share of wind energy a high level of cooperation is required between politicians, energy industry, consumers and the players in the energy market.

Two activities have contributed to this need for cooperation: the project "The Future Energy System in Denmark" carried out by the Danish Board of Technology from 2004 to 2007 and the so-called energy camps initiated by the Danish Energy Association.

"The Future Danish Energy System"

The main aim of the project "The Future Danish Energy System" was to involve the politicians in the Danish Parliament and the players in the energy sector in a close dialogue on the future Danish energy system and to do it on a solid ground of knowledge.

The project was founded on a so-called Future Panel composed of members from the Danish Parliament. The Future Panel represented all political parties and was serviced from a Steering Group with experts and stakeholders, researchers and representatives of NGOs and authorities in the energy field.

During the project five public hearings were held in the Parliament and a number of quantitative scenarios for the Danish energy future were developed. The hearings were led by politicians from the panel with experts from the energy field contributing knowledge and ideas for the future. A comprehensive collection of consultation documents and a short newsletter were produced after each hearing.

As part of the project, a publicly available modelling tool, STREAM, was developed. It is now used at Danish universities.

Energy camps

At energy camps a number of experts (from industry, organizations, universities and NGOs) and possible investors from the energy sector are gathered to solve a particular problem. The participants are divided into predefined groups of about 10 people dealing with issues such as how we make modern transportation or modern housing possible in a sustainable way without CO_2 emissions The participants are isolated at a resort for 24 or 48 hours, but provided with web-access and communication lines to the outside so that they easily can find information from ministries and other institutions.

At the end of the camp, the groups present their solutions in a very condensed form to the press and to the minister of energy, or other high levels persons, who join the camp for the last couple of hours.

The experience with the energy camps is that you often create new but realistic solutions to difficult problems – and you get a consensus between groups of people who used to work against each other.

2 Introduction

The government of New Brunswick has adopted a strategy to develop the province as an energy hub. This decision is based on the abundance of wind, biomass and natural gas resources in New Brunswick and nuclear and hydro capacity that could supply the growing demand for electricity in neighbouring regions especially the New England states. It is estimated that New England alone will require 8,000 MW of new capacity to cover the burgeoning demand for electricity by 2020.

The high quality wind resources in New Brunswick could play an important role in the development of the energy hub, but the large scale development of wind generation also provides technical and economic challenges for the power sector. New Brunswick wishes to maximize economic development through the exporting of wind power and the intermittency of production inherent in wind generation provides technical challenges for ensuring system reliability.

The project "Integrating Wind Power in New Brunswick - Phase II" was commissioned by The New Brunswick System Operator (NBSO) and the New Brunswick Department of Energy (DOE) from Ea Energy Analyses, the Consultant, as part of a multi-phase process of examining the methods, impacts, costs and benefits of wind power integration New Brunswick and the Maritimes. The goal of the report is to present consistent scenarios for the development of the electricity markets of the Maritimes and New England and specifically scenarios where large scale wind power integration in New Brunswick and the Maritimes are allowed to play a cardinal role.

2.1 Overall project objective

The overall objective of the project is to optimize the development of wind power in New Brunswick to ensure local economic benefits and to address the challenges in integrating large scale wind generation into the New Brunswick balancing area.

The project was divided into two phases in accordance with the requirements of NBSO and the DOE.

The first phase was a review of documentation available from NBSO on the integration of wind energy and transfer of knowledge from the Danish experience with wind power integration. The first phase concluded with a two day workshop in Fredericton in November 2007 and a debriefing meeting with the board of NBSO, the management of NBSO and representatives from the DOE. The main conclusion from the first phase was that New Brunswick will be able to integrate a fair amount of wind into the energy system with the present conditions. A large scale deployment of wind power would, however, call for more cooperation with the neighbouring system areas as well as a review of the current market structure and institutional set up, in order to ensure the most efficient integration and to maximize the total benefits of the deployment of wind power.

These scenario analyses for the electricity markets of the Maritimes and New England are a part of phase 2 of the project. In addition a road map for wind power integration as part of an energy hub in New Brunswick has been developed, and also the role of NBSO as a system operator has been discussed based on the Danish experiences for the Transmission System Operator.

Another part of phase 2 has been the facilitation of meetings with relevant organisations on a visit to Denmark in order to further expedite the transfer of experiences.

2.2 Reading this report

The total reporting of the project "Integrating wind power in New Brunswick - Phase II" consists of the following three documents:

- A main report: Regional Wind Integration Study
- A scenario analysis report: "Scenario Analyses for the Electricity Markets of the Maritimes and New England" (this report)
- A data report: "Data and assumptions used for the scenario analyses"

The main report covers the full project consisting of the following three parts:

- A description of the regional scenario analyses exploring the opportunities for wind power in the analysed region, i.e., the Maritimes area, New England and Quebec.
- A presentation of the experiences with wind power development in Denmark.
- A list of recommendations on wind power deployment to the NBSO and the New Brunswick DOE

The scenario analysis report (this report) contains results and documentation of applied methodological approach, data and modelling tool. The report is structured so that Chapter 1 includes summary and conclusions. Chapter 0 gives an overview of the electricity market in New Brunswick and the neighbouring regions and Chapter 4 gives details on methodology and main data foundation of the analyses, as well as the process and modelling tool which is known as the Balmorel model. And finally, Chapter 0 contains the results of the scenario analyses.

Upon completion of this draft a number of issues have been identified:

- The treatment of hydro, in particularly in New Brunswick, may be too flexible. During the spring flood in particular hydro in New Brunswick may be too flexible in the model. Additionally, the hydro inflow from the Lower Churchill Falls is completely flexible, which may not be the case should the project be realised.
- In the year of investment in the Lower Churchill Falls the capacity factor is unrestricted on account of an error in the model (now corrected). This means that lower Churchill effectively has a capacity factor of 100% in 2020, and as such there is too much hydro power in 2020 in comparison with the assumptions.
- A large pumped storage plant in Massachusetts was accidentally duplicated in the input data, causing this facility to effectively have double capacity both in terms of storage volume and generation capacity.
- The sensitivity analyses with lower fuel prices have individual RPS targets with non-tradable credits between New England, New Brunswick & PEI and Nova Scotia respectively, in contrast with the main scenarios.

These shortcomings are not expected to affect any of the overall conclusions from this study. However, there will hopefully be an opportunity to address these issues in future regional study work.

3 The Electricity Market in New Brunswick and the Region

The scenarios in this report investigate the opportunity of New Brunswick to supply energy, and in particular wind energy, to the New England market. The competitive advantage of New Brunswick as a supplier of clean energy is a high potential for developing wind power due to good wind resources. There is an essentially strong transmission grid to serve as a platform for exports and local consumption. Proximity to hydro intensive Quebec, and a large organised market in New England inclusive of ancillary services, provides a potential for balancing the intermittency of wind generation. There is also an opportunity to connect with hydro power in Labrador.

The market of New England is expected to grow in demand for electricity. Several New England states have introduced renewable energy portfolio standards (RPS), which generate a demand specifically from renewable sources. The Regional Greenhouse Gas Initiative (RGGI) also encompasses the New England states generating a demand for carbon free electricity generation. Meanwhile the siting of both new generation stations and wind farms is met with resistance in many New England states, whereas in the Maritimes there is generally stronger support for siting of wind farms and other generators and the opportunities for community and business alike, to reap benefits from wind power expansion.

In addition to the export agenda, the provinces in the Maritimes also have targets in the form of renewable portfolio standards and a framework has been finalised at Canadian federal level to apply CO2 reduction targets to include the electricity sectors in the provinces.

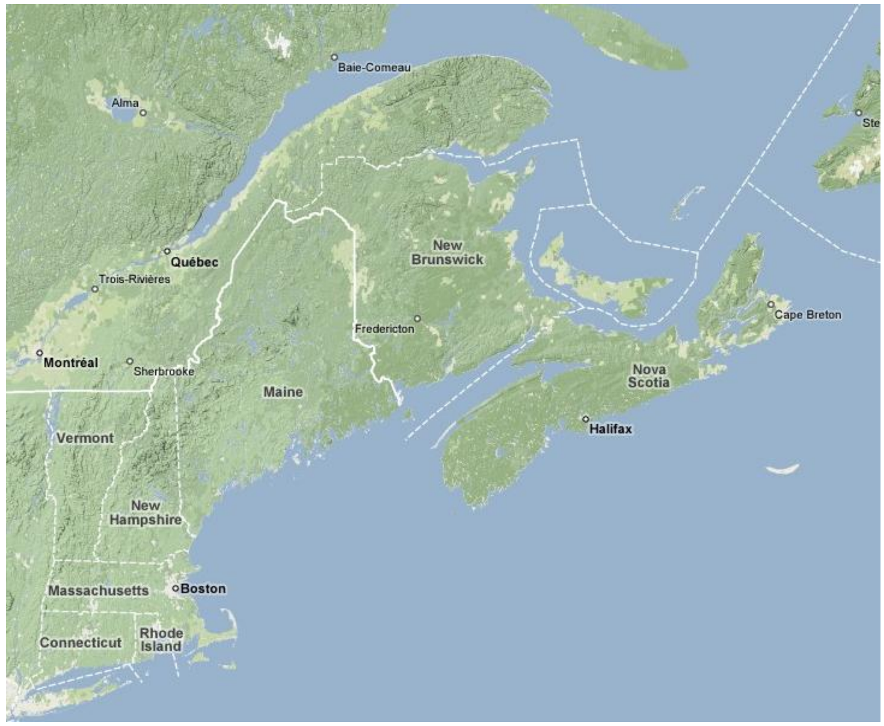


Figure 10: Map of the Maritimes, Quebec and the New England states.
(map source: Google)

3.1 The electricity system in New Brunswick and the Maritimes

The electricity demand in New Brunswick has been heavily increasing during the last decades. The figure below shows the actual annual demand from 1973 to 2007 and the forecast from 2008 to 2017. In 2007, the electricity demand was approximately 16,000 TWh with at peak demand of approximately 3,200 MW.[4]

[4] 10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities In New Brunswick 2007 – 2016, NBSO

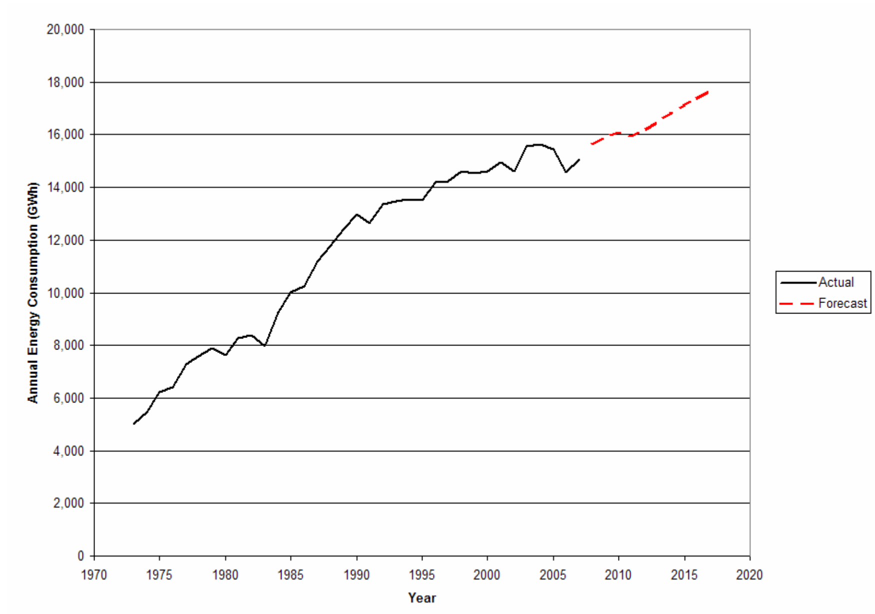


Figure 11: Development in annual electricity demand in New Brunswick

New Brunswick has an essentially strong transmission network characterised by a ring design. The province has interconnections to Nova Scotia, Quebec and New England. The table below shows the transfer capacities between New Brunswick and the neighbouring systems.

Table 5: Transfer capacities to neighbouring systems[5]

Neighbouring systems	Transfer capacity to New Brunswick, MW	Transfer capacity from New Brunswick, MW
Quebec	1185	735
New England	100	700
Nova Scotia	350	300
Prince Edward Island	124	222
Northern Maine	90	100
Eastern Maine	15	15

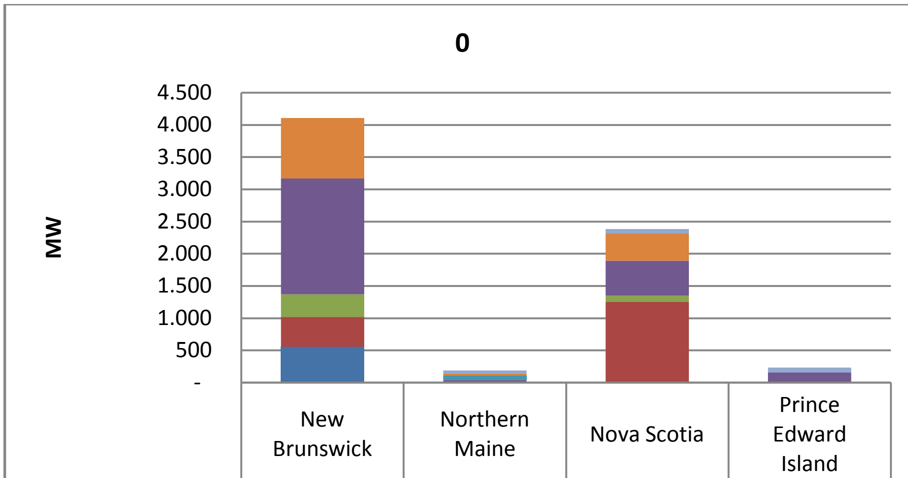
More details on the transfer capacities between systems and sub systems are available in the data appendix.

The New Brunswick has a number of different types of electricity generators. The Lepreau 1 plant has 558 MW of nuclear generation capacity and is currently undergoing in refurbishment. Colson Cove and Dalhousie are oil fired. Colson Cove can also use Orimulsion™ but there is not currently a supply of this available. The Beldune and Grand Lake are coal fired plants, of which Beldune is the largest.

[5] A recent loss of load in New Brunswick may have the side effect of reducing the actual capacity from Quebec to New Brunswick. This has not been taken into consideration in the calculations.

Bayside 6 and the Grandview plants are natural gas fired and the Grandview plants are combined heat and power plants. Grand Manan, Millbank 1-4 and Ste. Rose are all diesel units. In addition to these fossil fired plants there are a number of hydroelectric units with a diverse range in capacities from 4-116 MW.

The following figure shows the installed generation capacity in New Brunswick and the Maritimes.



	New Brunswick	Northern Maine	Nova Scotia	Prince Edward Island
Wind		42	66	73
Hydro	938	38	424	
Biomass		67		
Fuel oil & Diesel	1.800	41	543	159
Natural gas	353		98	
Coal	460		1.252	
Nuclear	558			

Figure 12: Generation capacity in the Maritimes divided by fuel types.

Nova Scotia is dominated by coal fired generation, but also has a large potential for expansion of wind power. Prince Edward Island is dominated by oil or diesel fired units but here wind power has begun to come online. There is also a wind power test station on PEI. Northern Maine is included in the figure as it is electrically a part of the New Brunswick system.

3.2 Market structure

The market in New Brunswick is currently dominated by one company, NB Power owning almost all generation capacity (through NB GenCo/NB Nuclear Power), the transmission system (through NB TransCo), and the distribution system and supply (through NB Disco). A small amount of generation capacity is owned by independent power producers such as Irving Oil. The independent company NBSO is responsible for system operation and market development and facilitation. Large consumers (industry) have access to the market, but most have not yet exploited this opportunity. The wholesale market is structured as a physical bilateral contract market in which merchants each submit individually balanced schedules for supply and load.

In New Brunswick all customers have access to standard electricity service at cost-based rates. To ensure that adequate supplies of electricity will be available, the New Brunswick's market structure implies:

- NB Power Distribution and Customer Service or other suppliers must arrange to acquire adequate power and energy, including reserves, one year ahead of time.
- NB Power Distribution and Customer Service will have long-term contracts for the generation it requires to meet the needs of its provincial customers from the Heritage Pool (which are the existing NB Power generating resources).
- The sector of the market that is competitive in New Brunswick (large industrial and wholesale customers - 42 in total) is a bilateral, negotiated contractual relationship. Prices are set by negotiation between buyers and sellers for a minimum 12-month period. There is not a bidding process with hourly pricing like a commodity or stock exchange.

New transmission capacity to neighbouring areas is sold through open seasons as long-term contracts (reservations) to players in the market. Any remained transmission is available largely on a first come first served basis for reservation of various lengths. Unscheduled transmission is available on a non-firm basis in the operating timeframe.

3.3 System Operation

The New Brunswick System Operator (NBSO) came into existence 2004, when the provinces electricity utility company, NB Power, was restructured.

NBSO is a not-for-profit corporation whose primary responsibilities are to ensure the reliability of the electrical system and to facilitate the development and operation of a competitive electricity market in New Brunswick.

The NBSO are responsible for:

- transmission system reliability;
- system planning;
- access to and use of the transmission grid;
- administration of the Open Access Transmission Tariff and the Market Rules.

NBSO's geographical area of responsibility for balancing covers New Brunswick, Prince Edward Island as well as the northern part of the state of Maine. Nova Scotia Power is the system operator of Nova Scotia, but the NBSO is the reliability coordinator for the entire Maritimes area.

3.4 New Brunswick in a Regional Context

The regional electricity market in the Maritimes, Quebec and New England is characterized by differences in the power systems as summarized on Table 6.

Table 6: Main characteristics of New Brunswick and neighbouring systems

	New Brunswick[6]	Nova Scotia	Quebec	New England
Annual power demand, TWh	16.8	12.5	188.1	126.6
Peak demand, MW				27,360
Generation resources	A mix of many resources including nuclear, oil and hydro.	Coal is the largest resource (53 %)	Mainly hydro power, additionally some nuclear, natural gas and biomass	Natural gas and oil additionally some nuclear, coal and renewable sources.
RE capacity share	App. 22 % (hydro and biomass)	App. 21 % (hydro and wind power)	App. 94 % (mainly hydro but also some biomass and wind)	App. 8 % (hydro and others)

The differences in the power systems create potential benefits to be gained from regionally electricity trade between the systems. Wind power and nuclear power have low short-term marginal costs compared to thermal power. It is therefore often profitable to use available wind power and nuclear power instead of thermal power; however both nuclear power and wind power have very limited regulation possibilities.

[6] Including Prince Edward Island and Northern Maine

Hydro power has low short-term marginal costs and good regulation possibilities - especially in combination with reservoirs. The production of hydro power is optimised over the day, the week and the year (or even several years if it is a multi-year reservoir) in order to maximise the benefit from the available water in the reservoirs.

There is also a difference between the Canadian provinces and particularly the southern New England states regarding peak-load requirements. While the Canadian load peaks are in the cold winters, the New England load peaks are more a result of air conditioning in the summer months. Planning of outages for maintenance is consequently scheduled at different times and this also provides an opportunity for beneficial trade.

These benefits can be increased by promotion of a market oriented approach to electricity generation and trade within the individual sub regions and through interregional trade.

In principle, cross-border trade is driven by price differences. If the price in an adjacent area is higher, it is profitable for producers to export to that area. If the price in an adjacent area is lower, it is profitable for consumers to import from that area instead. If prices are visible to market participants and generated frequently by the market function, and market access including access to transmission capacity is granted on a continuous basis, i.e. hourly or even sub hourly on the basis of market value, the electricity market can perform as if coordinated through a centrally optimized international dispatch.

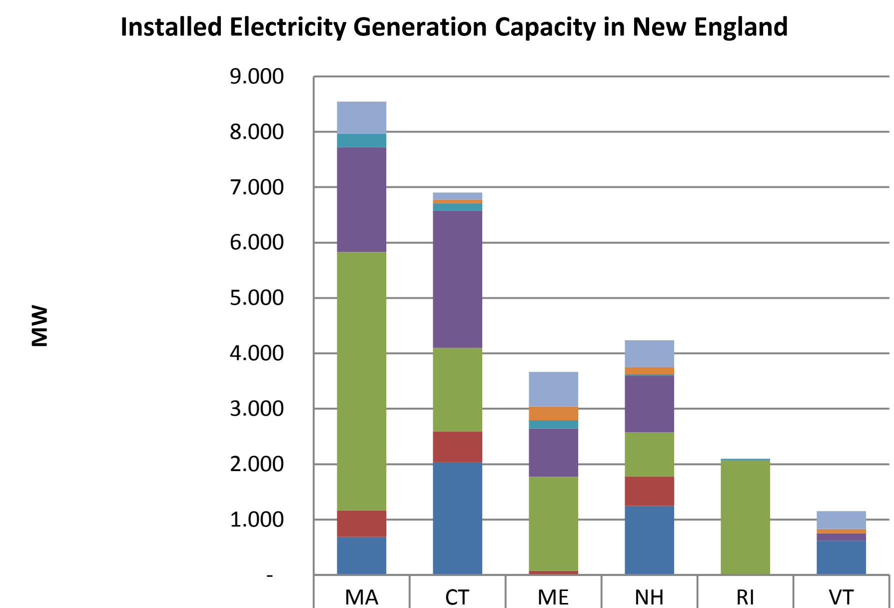
In this perspective long term physical capacity reservations or the wide spread establishment of unregulated merchant lines, has the effect of foreclosing the market, preventing either necessary or beneficial investments, or yielding suboptimal dispatch. Alternative solutions should be considered which guarantee open and transparent access to consumers, optimize allocation of capacity on the short and long term, while still providing financial security for investors and financiers.

3.4.1 The New England Market

The New England market is developing a deficit of electricity supply. The annual energy consumption in New England is projected to grow at a compound annual growth rate (CAGR) of 1.2% for 2007 through 2016 and 1.2% for the winter peak. New England's summer peak demand is projected to grow at a CAGR of 1.7% from 2007 through 2016, or approximately 500 MW per year. [7]

[7] 2007 Regional System Plan, ISO New England Inc.

The New England states have mostly oil or natural gas fired electricity generation with some hydro and nuclear and renewable generation. The make up of the generation capacity mix is represented on Figure 13.



	MA	CT	ME	NH	RI	VT
Wind	4					2
Hydro	570	128	625	484	3	313
Biomass & biogas	7	61	247	125		75
Landfill gas, MSW & tires	241	137	153	29	21	7
Fuel oil, diesel, etc	1.891	2.478	872	1.023		132
Natural gas	4.669	1.509	1.696	798	2.075	
Coal	479	553	75	532		
Nuclear	685	2.037		1.245		620

Figure 13: Generation capacity in New England. The acronyms on the category axis refer to Massachusetts (MA), Connecticut (CT), Maine (ME), New Hampshire (NH), Rhode Island (RI) and Vermont (VT).

New England applies the so-called Standard Market Design. This market consists of day-ahead and real-time markets for electricity, each producing its own separate and unique financial settlement. The first settlement relates to the day-ahead market's costs and payments while the second settles the difference between energy scheduled day-ahead and that which is actually delivered in real-time. Moreover, *Locational Marginal Prices (LMP)* reflect the marginal value of transmission losses and congestion in the electricity system. This means that each location on the network gets a price reflecting the marginal system cost of meeting load at that location. More specifically, Locational Marginal Prices are published for five types of locations: External interfaces, Load nodes, Individual generator unit nodes, Load zones and the Trading hub (”average system price”).

All transmission capacity is made available to the spot market for free in the New England area. To hedge against price differences caused by congestion market players can buy Financial Transmission Rights on a monthly basis or longer.

3.5 Environmental regulation

The regulation relates to different issues in the electricity market such as for instance environmental regulation. With respect to that, the following three initiatives are of particular relevance for the region:

- The Regional Greenhouse Gas Initiative (RGGI)
- Regulatory Framework for Industrial Air Emissions and the Electricity Sector
- Renewable Energy Portfolio Standards (RPS)

3.5.1 Greenhouse Gas Initiative (RGGI)

The Regional Greenhouse Gas Initiative (RGGI) provides indirectly an incentive for wind power, through an incentive against competitive energy sources from carbon based technologies. RGGI is a cap-and-trade system whereby a cap on CO2 emissions is defined politically for the region. By creating scarcity on the right to emit carbon dioxide the market generates an incentive to abstain from emission. In the scenarios, the RGGI commitments of the New England states have been pooled and a cap is enforced as a model constraint. The shadow price of this constraint reflects the market value of emission permits and therefore the CO2 price.

3.5.2 Regulatory Framework for Industrial Air Emissions and the Electricity Sector

The regulatory framework for carbon emissions reductions in Canada is structured differently from RGGI. Obligations are put on emitters to reduce emissions in relation to business as usual projection from historical 2006 values.

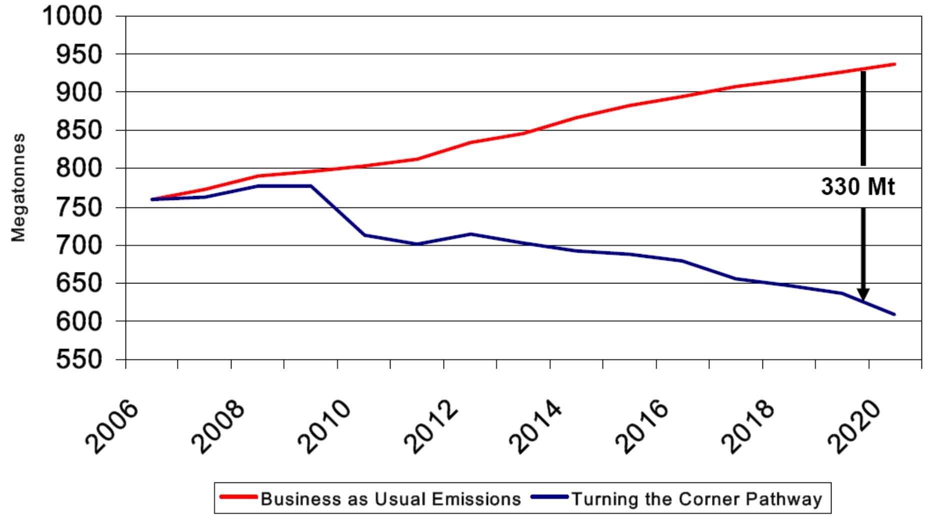


Figure 14: Final framework for greenhouse gasses.

In Figure 14 the overall reduction target for Canada is shown going forward to 2020. This includes however, not just the electricity sector, but most major sources of emissions including the electricity sector and industry. Target application is corporate specific. Each company within the sector receives a target of an 18% reduction from the average 2006 emission intensity of its entire fleet of facilities for 2010 and a subsequent 2% reduction each year after that.[8]

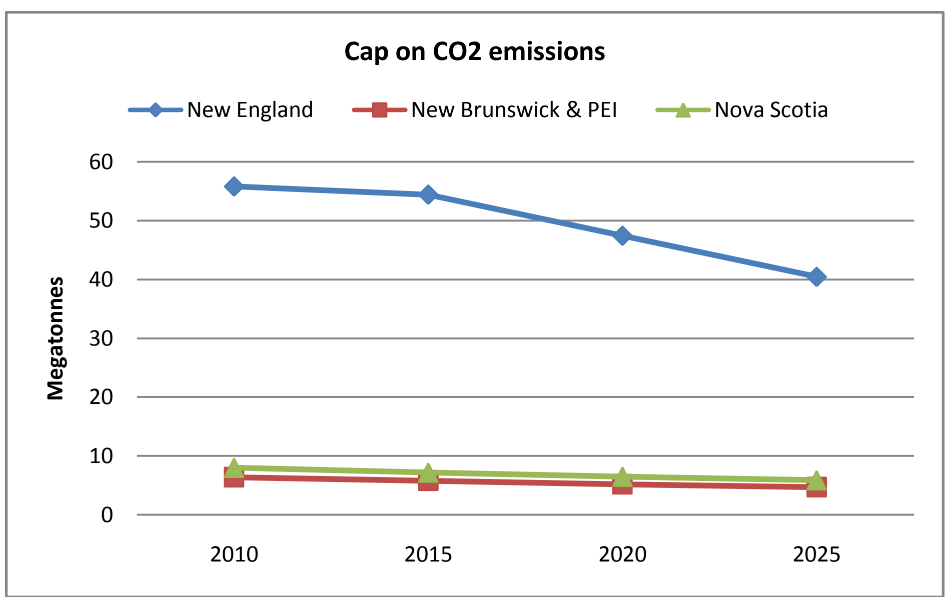


Figure 15: CO2 caps as simplified from RGGI (New England) and the Regulatory Framework for Industrial Air Emissions and the Electricity Sector (RFIAEES).

[8] Environment Canada: WILLIAM LEFFLER (Regulatory Framework for Industrial Air Emissions and the Electricity Sector), Presentation at the 2008 Energy Conference in Saint John, New Brunswick May 15-16, 2008.

The graphs on Figure 15 show jointly the targets defined in this analysis for RGGI and RFAE.

The RFAE suggest that following 2020 the system may change to a CAP and trade system, contingent on developments in other countries, in particular the USA. In the scenario analyses both systems are treated as cap and trade regimes. We also assume that targets apply only to the analysed systems. In the Proactive scenario, trade of carbon emission permits is allowed between the systems.

3.5.3 Renewable Energy Portfolio standards (RPS)

Many states in New England have adopted renewable energy portfolio standards. Some of the complexities regarding RPS have been disregarded, such as different states recognising different forms of energy generation as renewable. In a timeframe of 10-15 years it is likely that these systems have been harmonised.

In Atlantic Canada an effort is also being made to increase the share of renewable resources. Recently, requests for proposals have been made for 400 MW wind in New Brunswick and RPS standards have been established moving forward in New Brunswick as well as in Nova Scotia.

The assumptions made in the scenario analyses are shown on Figure 16.

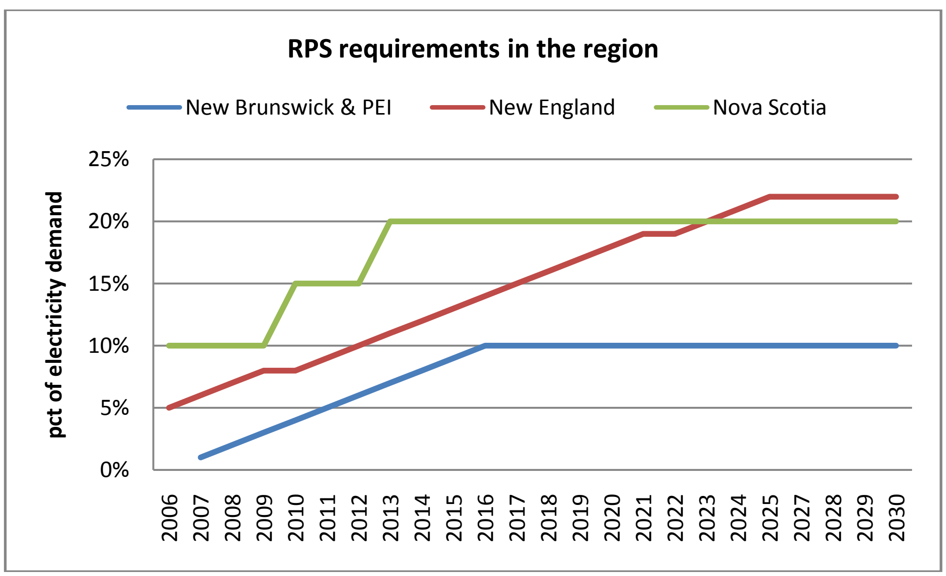


Figure 16: The percentage of electricity demand which must be supplied by new renewable technologies.

RPS require that energy distributors (merchants supplying end-users) produce documentation that a certain fraction of their portfolio originates from renewable sources. This can either be done by forming a power purchase agreement with a renewable generator, or by purchasing a certificate from a third party, having in turn acquired this from a renewable source. This implies that renewable energy becomes a product separate from the physical supply of electricity (in an economic sense). A wind turbine could sell electricity to one agent and “green energy” to another.

3.5.4 Summary of policy representation

The accurate representation of specific policies is always a challenge in modelling issues. Primarily, this is because policy is specific to a context by nature. There will always be specific bylaws or exceptions to handle heritage policy. Secondly, policy will be changed and adapted in the future in an unpredictable fashion. The most import aspects of the environmental policies are represented here with a sufficient accuracy, i.e. the incentive to reduce carbon and to introduce renewable technology, the overall political targets and the conditions under which burdens can be traded. Along with fundamental market assumptions prevalent to the model make the formulation of policy cohesive with the model structure as a whole.

4 Methodology and Main Assumptions

The intention behind the scenarios presented in this report is to provide a basis for evaluating wind power in the Maritimes, and also to outline the effects of specific initiatives on wind power development and the economy. These scenarios can serve as a basis for qualified debate on the issue of wind power development and will hopefully help to catalyse a regional discussion on best practices going forward. Wind power integration is a multifaceted issue. The aim here is to comprehensively combine issues relating to economics, technology, policy and system related aspects.

4.1 Scenario methodology

The scenario methodology we apply uses a quantitative model of the electricity system as well as rational behavioural assumptions on the part relevant stakeholders. The Balmorel model is a suitable tool for this as the development of the electricity market can be simulated, simultaneously considering operational perspectives and investment perspectives.[9]

Scenarios are formed by describing the current situation with respect to infrastructure, generation capacity, forecasts of demands and fuel prices etc. and combining this with information regarding the market framework, political framework, potential for expansions and technology investment options.

Any model is at most a suitable representation of a real world situation but no model can accurately predict what will happen from now and until 2025. However, the generation of a multitude of possible futures based on the best quality data available and rational expectations and feedback mechanisms can give an indication of how the future could develop under a series of assumptions. This gives perspective on which directions the inertia of market and technology will drive development and which barriers and obstacles should be addressed.

[9] The Balmorel model has been applied in projects in Denmark, Norway, Estonia, Latvia, Lithuania, Poland, Germany, Austria, Mauritius and Ghana. It has been used for analyses of, e.g., security of electricity supply, the role of flexible electricity demand, hydrogen technologies, wind power development, the role of natural gas, development of international electricity markets, market power, heat transmission and pricing, expansion of electricity transmission, international markets for green certificates and emission trading, environmental policy evaluation and more.

This project has been an opportunity to start from the beginning. The model used has no previous known application in North America, so all core data has been gathered, structured and integrated from scratch. It was clear from the beginning, that wind power integration and the development of the power system and market in New Brunswick, would be closely connected to developments in neighbouring regions in the Maritimes, New England and Quebec. The model and scenarios have therefore been defined to cover this entire region. The NBSO was able to supply much of the data and other data has been supplied by the DOE, and from public sources. New England data has also been assessed by the Independent System Operator of New England (ISO-NE) and with appreciation their feedback has been integrated in the core data assumptions.

The scenario development process has had a number of stages and key milestones.

- Upon commencement of the project, data was collected and implemented.
- First model simulations and preliminary data was discussed and evaluated in detail at a three day workshop in Fredericton in February of 2008 with participation of the NBSO staff and board, and the DOE. At the workshop, also the structure and content of the policy scenarios as well as a screening process was laid out.
- Over a series of phone meetings between the Consultant the NBSO and the DOE an additional number of screening scenarios was discussed and the details regarding structure and content of the policy scenarios was agreed upon.
- In early May a delegation from New Brunswick with members from the NBSO management and board, the DOE as well as industry representatives, were on a visit to Denmark to meet with Danish actors and thereby facilitate transfer of Danish experiences with large scale wind power integration. In this connection there were additional meetings also on the scenario study between the NBSO, DOE and the Consultant.
- At NBSO Energy Conference in May 15-16, 2008 in Saint John the preliminary main results in this study were presented in a public forum. Also, the final draft of this report was discussed by the Consultant, the NBSO and the DOE.
- Finally, the final version attempts to encompass both the results of the process up to the Energy Conference and not least the feedback received at and about the conference.

A final step to complete the process has been delivery of the complete model, the developed dataset with core assumptions and scenario configurations to the NBSO with no reservations. This is possible as the model used is open source and data is entirely based on data available to the NBSO or on public sources.

4.2 Policy Scenarios

This scenario report covers four comprehensive policy scenarios. The scenarios have been dubbed policy scenarios to emphasise that markets drive the development of the sector subject to alternative policy frameworks, and market frameworks.

The line of thought is that there are four high level options open on a political level.

1. Policy makers take a passive laissez-faire posture towards wind power and the general development of the energy sector. This implies that market barriers, infrastructure plans and physical planning as well as incentives will remain as present. The market will develop but perhaps miss out on opportunities.
2. A second stance could be an active approach to the development of the electricity market. This would involve doing away with barriers, ensuring that the public service was available to facilitate private and communal investment. That expansion in grid capacity took place where there is positive social welfare in doing so, in order to get the wind turbines online.
3. To facilitate wind power integration in the Maritimes and export options, a third scenario involves expansion of transmission capacity within the Maritimes and towards the New England market.
4. Finally, a proactive policy approach is considered, which would involve engaging and coordinating the political and environmental framework in the region. A common market for carbon credits in addition to the transmission capacity expansions and the removal of pancaking transmission tariffs make up the final policy scenario.

The scenario process evolved so that each new scenario would build on the positive actions undertaken in the previous scenario.

Table 7: The four Policy Scenarios

	Passive	Active	Transmission	Proactive
Renewable energy portfolio standards	Existing RPS standards.	Existing RPS standards.	Existing RPS standards.	Existing RPS standards.
CO2 regulation	RGGI covers New England states. A separate framework established in the Maritimes.	RGGI covers New England states. A separate framework established in the Maritimes.	RGGI covers New England states. A separate framework established in the Maritimes.	CO2 policy introduced in the Maritimes, with credits tradable with New England RGGI.
Physical planning	Low availability of sites in NB (no planning) Potential: 500 MW in NB 500 MW in NS	Physical planning for wind power to increase number of sites for wind power	Physical planning for wind power to increase number of sites for wind power	Physical planning for wind power to increase number of sites for wind power
Market	Pancaking of transmission tariffs. Otherwise market assumed to function effectively.	Pancaking of transmission tariffs. Otherwise market assumed to function effectively.	Pancaking of transmission tariffs. Otherwise market assumed to function effectively.	Market assumed to function efficiently. Transmission tariffs removed.
Transmission	Existing and firm plans for transmission system capacities are assumed for the whole period.	Existing and firm plans for transmission system capacities are assumed for the whole period.	Additional transmission capacity.	Additional transmission capacity.

In the transmission and proactive scenarios, the additional transmission capacity which is installed is the following:

- 600 MW between New Brunswick and Prince Edward Island
- 600 MW between New Brunswick and Northern Maine
- 1000 MW between New Brunswick and Nova Scotia
- 1,500 MW between New Brunswick and Maine
- 1,500 MW between Maine and New Hampshire
- 1,500 MW between New Hampshire and Boston

The cost of this transmission capacity does not enter the simulations, however, ballpark cost estimation is provided based on cost indicators.

4.3 Modelling tool

The model used for the analyses is the Balmorel model[10], which is a flexible technical/economical partial equilibrium model. The model structure (formulated in the GAMS modelling language[11]) can be downloaded from the model homepage.

The model essentially finds a least-cost solution for electricity and district heating markets (if district heating is also relevant), taking into account:

- Electricity and heat demand;
- Technical and economic characteristics for each kind of production unit, e.g. capacities, fuel efficiencies, operation and maintenance costs, and fuel prices;
- Environmental regulation
- Transmission capacities between regions and countries.

As output, the model derives production and transmission patterns on a total cost-minimizing basis. The model produces estimates of electricity and heat prices and suggestions for optimal based investments in generating units assuming well-functioning markets with full competition or optimal planning among power producers, subject to market distortions such as taxes and tariffs.

The model with investments is most often run as a continuous model. This implies that unit commitment, ramping and minimum production levels etc are not modelled explicitly in the core scenarios where the investment path is defined. However, it is possible to take investment results and rerun the model in a unit commitment configuration, in order to test the feasibility of the electricity system resulting from the scenarios. The continuous model is used for all calculations in this scenario report, with the exception of the simulation of three selected weeks for operational verification.

4.4 Economic analyses and assumptions

The economic analyses are based primarily on the results generated by the model. By the assumption of well functioning markets, shadows prices of the overall cost-minimization problem are interpreted as market prices, i.e. assuming market clearing in each time segment of the scenario run. This makes it possible

[10] www.balmorel.com
[11] www.gams.com

to extrapolate costs and benefits for different stakeholders or stakeholder groups, i.e. consumers, generators, grid owners and public proceeds. The costs and benefits can further be attributed to stakeholders in different regions or with specific interests i.e. wind developers as a subset of generators. For the most part we consider the regional distribution of costs and benefits for the purpose of this analysis.

In brief, the results derived are the following:

- Costs and benefits of large scale wind power integration
- Economic opportunities for wind to be part of the New Brunswick the energy hub vision
- Impact of efficient market coupling with neighbouring regions

The scenarios are compared using the first scenario, i.e. the Passive policy scenario, as a baseline.

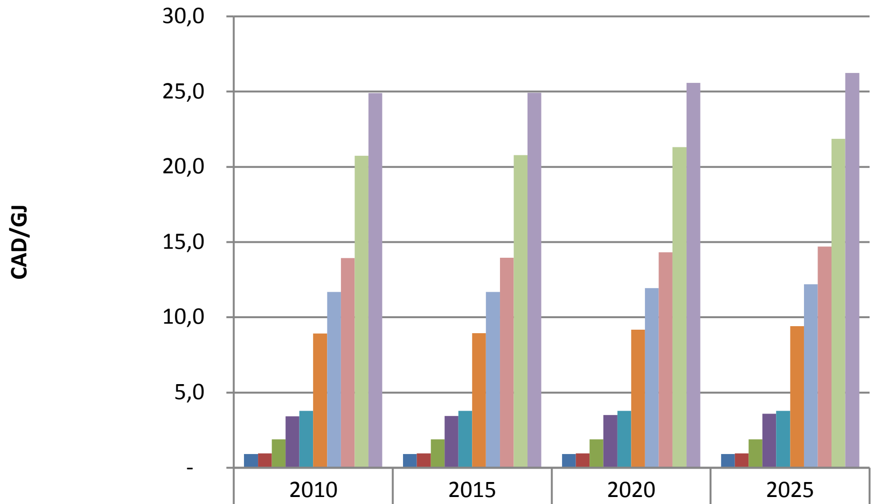
4.5 General Economic Assumptions

A number of general assumptions regarding the economy, which is not covered by the model must be made. These are boundary conditions with respect to the geographical scope of the model, terminal conditions with respect to the continuous development in time, but most importantly relevant associated sectors.

4.5.1 Fuel prices

It is a key assumption in these scenario analyses that the oil prices which have been experienced recently are not a temporary phenomenon, but rather express an enduring trend. This means that the price of fuel will reflect this going forward, and therefore a fuel price forecast based on this assumption has been produced. There are few official sources that support this assumption with hard numbers. However, statements supporting this in principle have become more frequent as of late by both industry and financial experts as well as by relevant organisations. The International Energy Agency (IEA) and the Energy Information Administration (EIA) are still projecting a fall in fuel prices followed by a modest increase to low 60s $/barrel in 2025 in real terms. Oil futures traded at the New York Mercantile Exchange (NYMEX) are less optimistic regarding a drop in oil prices. For the scenarios presented here, the core assumption is that oil prices will follow recent settlements of NYMEX future deliveries to 2015. After 2015, a modest annual increase in oil prices is assumed. Since this estimate was made, the oil price on the NYMEX has increased substantially and therefore it is reasonable to call the fuel price scenario a conservative estimate.

The assumed price evolution of the most important fuel types for electricity generation is indicated on Figure 17.



	2010	2015	2020	2025
Nuclear	0,9	0,9	0,9	0,9
Biogas	0,9	0,9	0,9	0,9
MSW & landfill gas	1,9	1,9	1,9	1,9
Coal	3,4	3,4	3,5	3,6
Biomass	3,8	3,8	3,8	3,8
Waste oil	8,9	8,9	9,2	9,4
Natural gas	11,7	11,7	11,9	12,2
Residual fuel oil	13,9	14,0	14,3	14,7
Diesel	20,7	20,8	21,3	21,9
Jet fuel	24,9	24,9	25,6	26,2

Figure 17: Fuel price projection used in the scenario analyses.

Fuel prices are a critical assumption in any scenario analysis of the electricity sector. For this reason we supplement the central scenarios with sensitivity analyses where fuel prices are in line with the latest official projections from the IEA World Energy Outlook 2007.

4.5.2 Investment approach

The model performs endogenous investments according to a least cost market oriented approach. There are a number of key elements to this process which must be addressed.

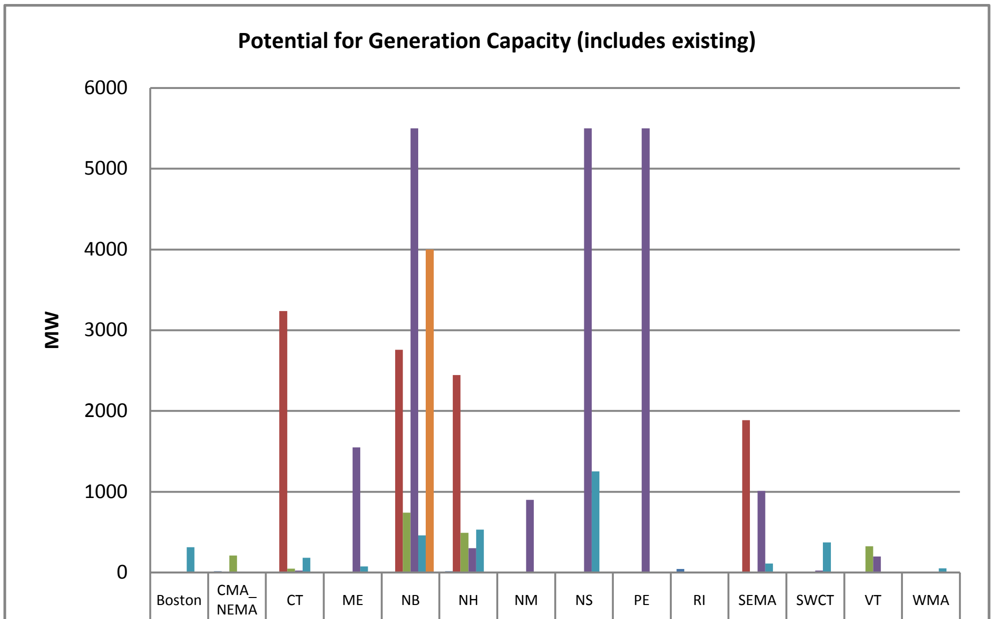
Firstly, the model is myopic in its investment approach, and thereby does not explicitly consider revenues beyond the year of installation. This means that investments are undertaken in a given year if the annual revenue requirement (ARR) in that year is satisfied by the market. A balanced risk and reward characteristic of the market is assumed, which means that the same ARR is applied to all technologies, specifically 11.75%, which is equivalent to 10% internal rate for 20 years. In practice, this rate is contingent on the risks and rewards of the market which may be different from technology to technology. For instance, capital intensive investments such as wind or nuclear may be more risk prone unless there is a possibility to hedge the risk without too high of a risk premium. This could be through requests for proposals (RFPs), feed-in tariffs, power purchase agreements or a competitive market for forwards/futures on electricity, etc.

4.5.2.1 Options considered for the development of the electricity generation capacity

For New Brunswick, there are no firm plans for new major conventional power generation facilities. However, there are some projects in the pipe line regarding establishing wind farms and biomass fired plants as well as talk of a second nuclear reactor at Lepreu. We do not assume that these pipeline projects will be completed by default, but leave it up to the economics and the competition of other options to determine which will actually be established in the scenarios.

The figure below shows the estimations of potential for different resources in New Brunswick and the neighbouring systems as applied in the simulations. Note that the wind potential in the Maritimes in the Passive scenario is limited beyond what is presented here. Also, certain investments such as nuclear and coal with carbon capture and storage (CCS) is restricted with respect to first possible installation time.

Specifically for nuclear, the assumption is that a second Lepreu reactor could be completed in the period 2016-2020. Additionally we allow for the establishment of Lepreau 3 & 4 in the time period 2021-2025. In the period 2016-2020 we allow for the possibility to invest in a total of 3600 MW nuclear power capacity in certain states in New England (Connecticut, Massachusetts and New Hampshire).



	Boston	CMA_ NEMA	CT	ME	NB	NH	NM	NS	PE	RI	SEMA	SWCT	VT	WMA
Landfill gas		19	2			17				45			12	
Nuclear			3.237		2.758	2.445					1.885			
Hydro		210	46		740	492							324	
Wind	13	13	25	1.549	5.500	300	900	5.500	5.500		1.013	25	200	13
Coal	314	5	181	75	460	532	-	1.252	-	-	109	372	-	51
Coal w CCS					4.000									

Figure 18: Potentials defined for expansion of renewable and nuclear.

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4.5.3 Socio-economic discounting

In order to calculate the net present value of the benefits to society of the investments and operations, all cost streams must be discounted using a discount rate. The discount rate is the risk free interest rate plus a premium on the value of time. The higher the economy values consumption today rather than tomorrow, the higher the discount rate. The discount rate is generally used to evaluate public investments as well as welfare effects over time.

Determining the correct level of the discount factor is very complex. The discount rate used is 6 pct p.a. The capital costs incurred are discounted on the basis of the annual investments costs (i.e. the 11.75% of plant capital costs for each year of operation) thereby implicitly assuming that risk premiums for investors reflect real costs, an assumption which is appropriate when simulating deterministically.

5 Scenario Analyses to 2025

In the following sections, the results of each of the four policy scenarios are presented.

Particular focus is on:

- Investments in new generation resources
- Production and transmission
- Electricity prices or marginal values
- Fuel consumption
- Costs and benefits
- Environmental impact
- Emissions and CO_2/RE credit prices

5.1 Passive scenario (baseline)

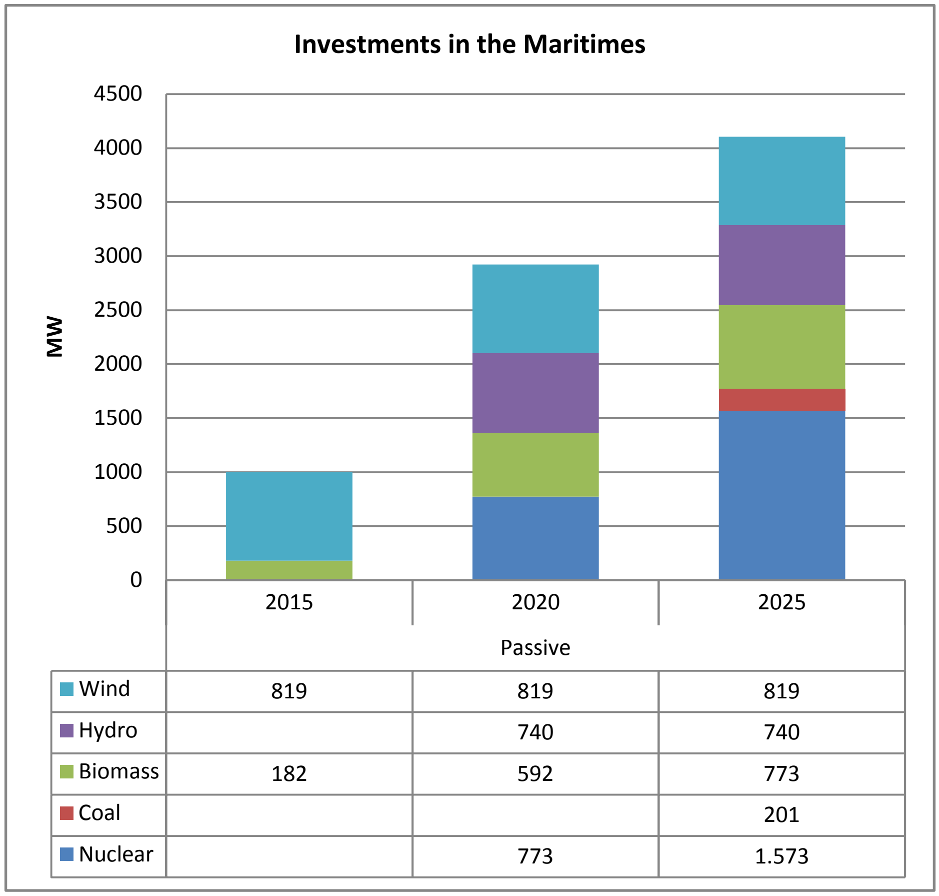
This section presents the results of the Passive scenario. In the Passive Scenario it is assumed that wind power capacity in the Maritimes is not developed beyond 1,000 MW e.g. due to lack of planning or market barriers.

5.1.1 Investments in new generation resources

Looking forward to 2015 and 2025, the market can be expected to invest in new generation capacity. Investments are driven on the basis of a number of things:

- Demand growth
- Change in cost structure making existing technology less competitive against new technology.
- Technological development
- Regulatory instruments
- Development of resource potential

Figure 19 and Figure 20 below show the cumulated investments in the Passive scenario from year 2011 to 2025 in the Maritimes and New England, respectively.

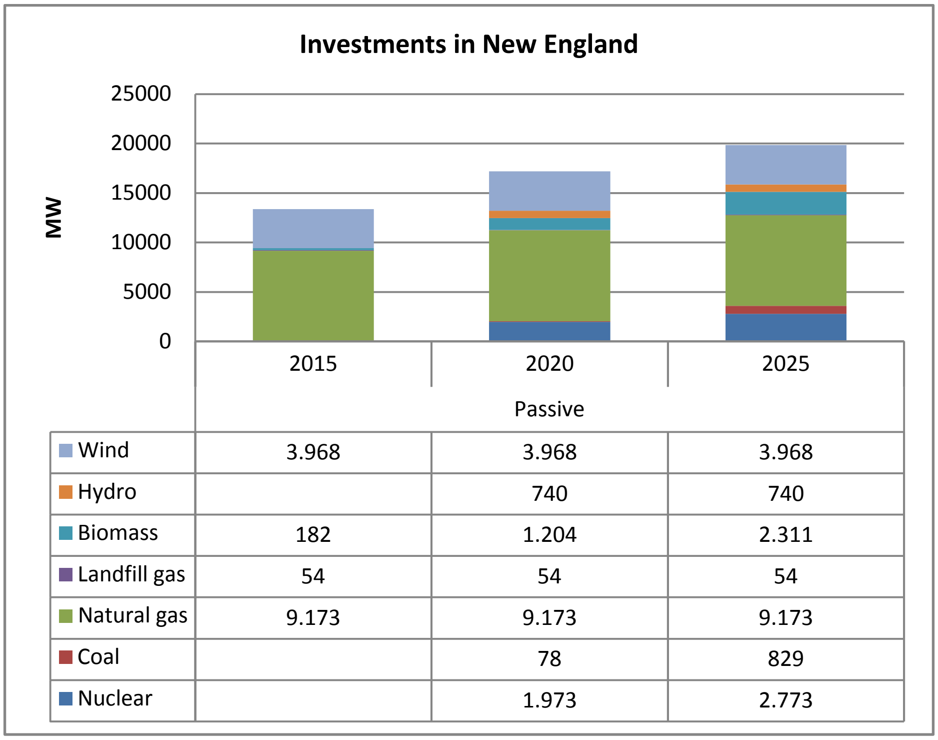


	2015	2020	2025
Wind	819	819	819
Hydro		740	740
Biomass	182	592	773
Coal			201
Nuclear		773	1.573

Figure 19: Investments in generation capacity in the Maritimes in the Passive scenario.

The full potential for wind power in this scenario of approx. 800 MW is installed as soon as permitted by the model, i.e. by the year 2015. This is a first indication that expansion of wind power may be attractive in the Maritimes. Secondly, it appears that considerable investments are made also in conventional generation capacity including the Lepreau 2 nuclear.

A small amount of biomass-fired capacity is also installed to meet RPS requirements. It is reiterated that the model invests in continuous quantities and therefore the precise sizes of investments in particular years may not always be technically feasible, but rather should be seen as indications that a technology is attractive, and the optimal dimensioning in the particular year of investment would be the quantity output.



	2015	2020	2025
Wind	3.968	3.968	3.968
Hydro		740	740
Biomass	182	1.204	2.311
Landfill gas	54	54	54
Natural gas	9.173	9.173	9.173
Coal		78	829
Nuclear		1.973	2.773

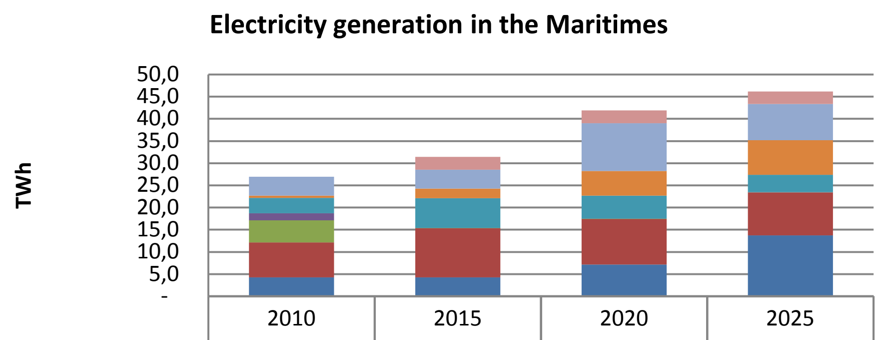
Figure 20: Investments in generation capacity.

On Figure 20 it is shown which investments are undertaken in the New England states. In New England siting issues limit the growth of onshore wind by assumption to 1.1 GW and the offshore potential to 2 GW in total (1 GW of the coast of Maine and 1 GW off South-eastern Massachusetts). These potentials are fully utilized in the passive as well as in the proactive scenario. Because of the high fuel prices the model shows that it is attractive to upgrade and replace older and less efficient natural gas and oil fired generation capacity with newer, more efficient combined cycle technology. Moreover, the model shows that it is attractive to invest in new nuclear capacity in New England.

5.1.2 Production and transmission

The model simulations are carried out under the basic assumption that the market works efficiently, implying that the correct incentives are present to make rational agents make the optimal choices for the system. Therefore, operations are executed optimally with regard to achieving the maximum overall benefit for the system. From an operational standpoint, this implies that common sense criteria should hold, as long as one steers clear of generalisations. In general, however, units should be committed in order of lowest variable costs. Usually, this implies that wind, hydro without storage and nuclear are committed first. Subsequently, the thermal units with the cheapest fuels, lowest heat rates, lowest tax, or subjected to limitations (i.e. emissions caps etc) are committed. As endogenous investments are brought online, i.e. investments chosen by the model, the generation mix is affected.

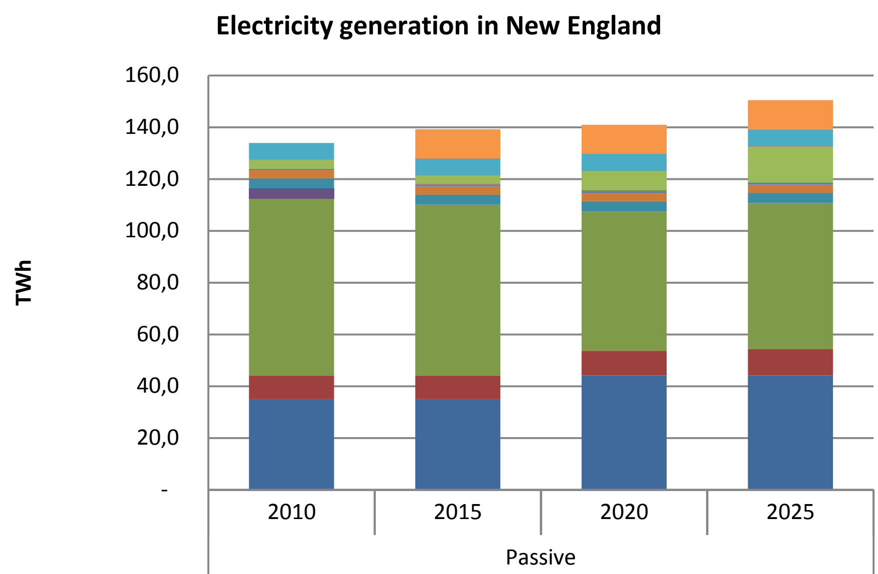
The development in electricity generation is shown in Figure 21 and Figure 22 below for the Maritimes and New England, respectively.



	2010	2015	2020	2025
Wind		2,8	2,8	2,8
Hydro	4,3	4,3	10,8	8,2
Biomass	0,5	2,2	5,6	7,8
Natural gas	3,5	6,7	5,1	3,9
Diesel	1,6			0,0
Residual fuel oil	5,0	0,0	0,0	0,0
Coal	7,9	11,1	10,4	9,7
Nuclear	4,3	4,3	7,2	13,7

Figure 21: Electricity generation in the Maritimes as it develops in the Passive scenario.

Figure 21 shows how the total annual generation in the Maritimes increases from app. 27 TWh in 2010 to 46 TWh in 2025. The generation from wind power increases from naught to 2.8 TWh and the generation based on residual fuel oil expires, due to the high oil prices. The generation from nuclear facilities increases to 13.7 TWh, and the generation from coal units first increases to 11.1 TWh in 2015, and then decreases to 9.7 TWh in 2025 as older coal capacity is decommissioned.

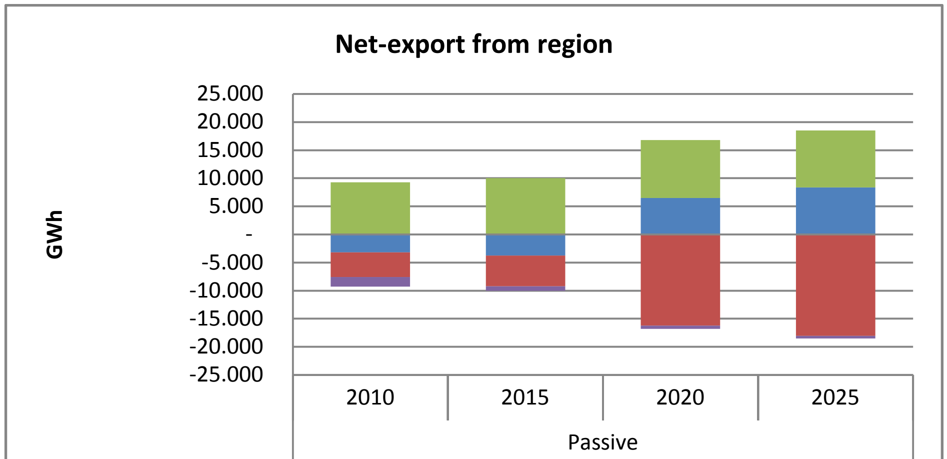


	2010	2015	2020	2025
Wind		11,2	11,2	11,2
Hydro	6,4	6,4	6,4	6,4
Biogas	0,1	0,1	0,1	0,1
Biomass	3,4	3,4	7,7	14,0
Tires	0,2	0,2	0,2	0,2
Landfill gas	0,4	0,7	0,7	0,7
MSW	3,2	3,2	3,2	3,2
Waste oil	3,9	3,9	3,9	3,9
Residual fuel oil	3,9			
Natural gas	68,3	65,9	53,9	56,3
Coal	9,1	9,1	9,4	10,2
Nuclear	35,1	35,1	44,3	44,3

Figure 22: Electricity generation in New England as it develops on an annual basis through each policy scenario.

Figure 22 shows that in New England the total electricity generation increases from app. 134 TWh in 2010 to app 151 TWh in 2025. The generation from nuclear power increases from 35.1 to 44.3 TWh, whereas the generation based on natural gas decreases from 68.3 to 56.3 TWh. The generation from wind power increases from naught to 11.2 TWh annually.

The changes in generation patterns over time result in changes also in the transmission patters. Figure 23 shows the development in annual net export from each region (negative values imply net import).



	2010	2015	2020	2025
Nova Scotia	-1.754	-806	-597	-422
Quebec	9.300	10.032	10.343	10.113
New England	-4.348	-5.491	-16.214	-18.071
New Brunswick & PEI	-3.198	-3.734	6.468	8.380

Figure 23: The overall transmission patterns are illustrated on this figure. Positive values indicate that the net-export from a region is positive, where as a negative value indicate a positive net-import.

In the Passive Scenario New England is a deficit area with an annual net import each year of up to 18.1 TWh. New Brunswick is a net importer in 2010, but in the longer run, New Brunswick becomes a net exporter of electricity. Nova Scotia is a net importer of electricity during the whole period with an annual net import in the range of 400 to 1,800 GWh.

In all years, Quebec is the largest net exporter. The development in Quebec is not directly determined by the model. Here a development in hydro and wind has been assumed, whereby given existing capacities and current thermal generation levels, a surplus of 10 TWh per year is generated. This is in excess of exports to neighbouring regions of Quebec not included in the model.

5.1.3 Electricity prices

Figure 24 shows the development in electricity prices from 2010 to 2025 including also the weekly variation for seven selected regions.

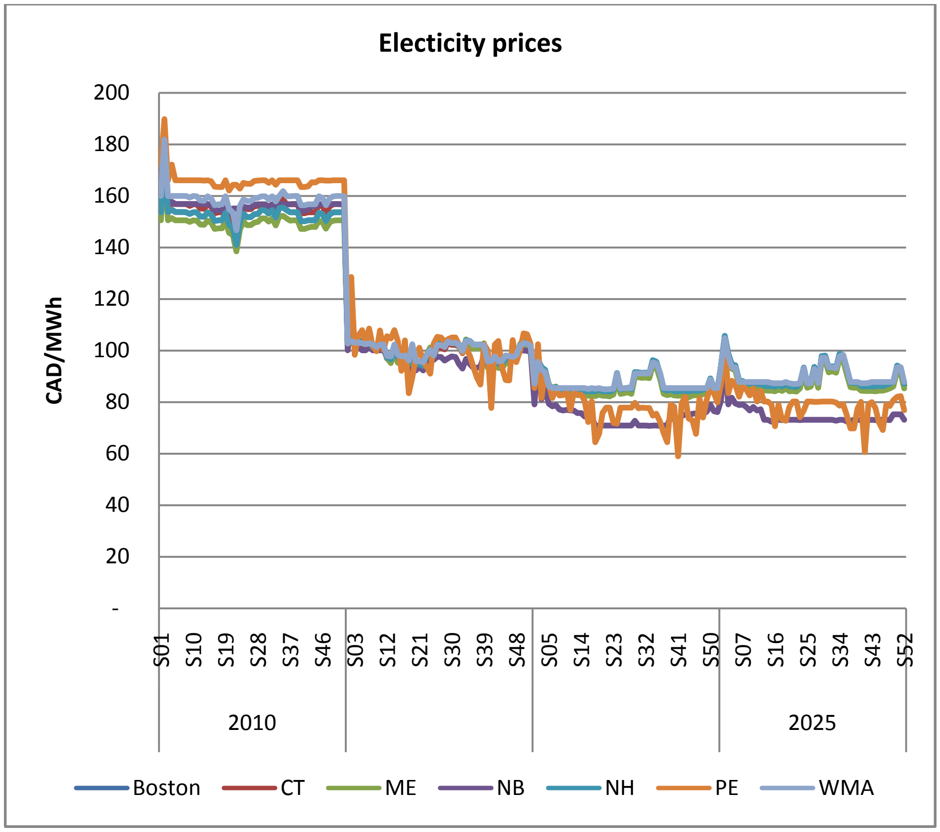


Figure 24: Electricity prices in eight selected regions (weekly averages). The labels S01 to S52 indicate weeks of the year in these simulations.

In 2010, it is not yet possible to bring new capacity online, and the electricity price is therefore determined by the short run marginal costs at existing production facilities. Large scale hydro especially in Quebec causes significant transfer of high prices between hours. Hence the price (as interpreted from marginal values) is indirectly set by peak generation such as oil and diesel for most hours of the year.

From 2015, the model can invest in new production facilities including also renewable technologies, and therefore the electricity price is set by equilibrium between short run marginal cost of existing units and new units as well as the long run marginal costs of new units.

There is a general trend of lower prices in the Maritimes than in the New England states. The reason is that marginal production costs are lower and that there is congestion on the transmission lines out of the region. If there were no congestions, market prices would equate (adjusted only for losses and tariffs) as a consequence of the assumption of well functioning markets.

There is an additional price element when generating with carbon emitting generation, and whenever this generation is on the margin, a premium is observable on the local marginal electricity supply cost. The direction of the power flows are from the Maritimes and towards the load centres in New England. On the way, losses are incurred and reflected on the marginal supply cost from imports as well as scarcity rent on transmission capacity, until these marginal supply costs from imports equate the marginal supply costs of local generation.

The price differences between the areas are shown in more detail in Figure 25.

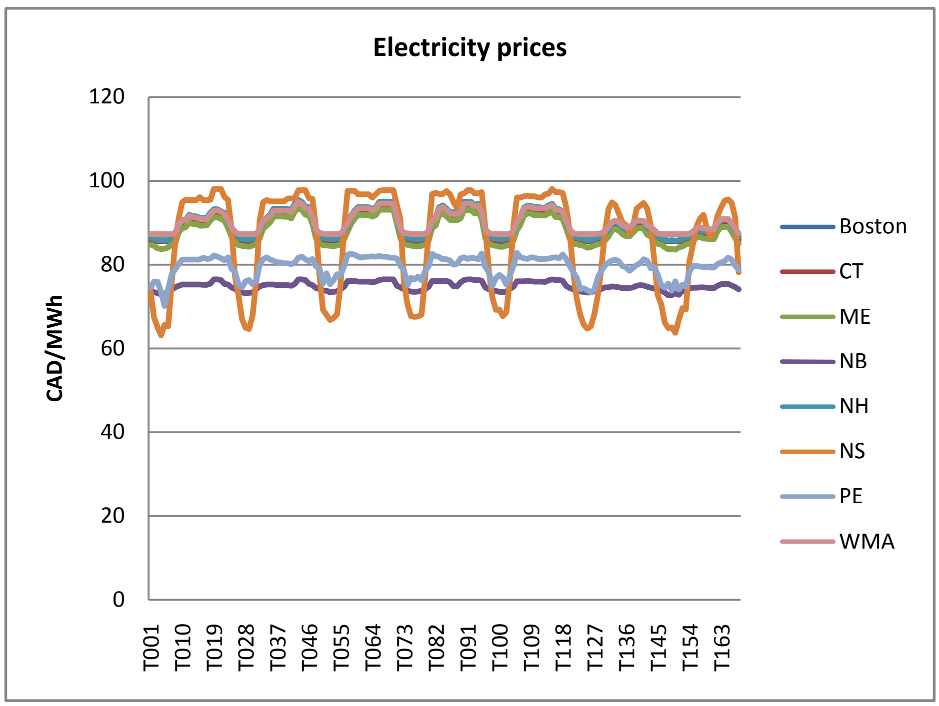


Figure 25: Electricity prices for eight selected regions – average hourly price variation over an average week in 2025 of the Passive Scenario.

The figure strongly indicates that there is an economic value in generating electricity in the Maritimes and transporting it to New England. The figure also shows that the main bottlenecks are between Prince Edwards Island and New Brunswick, New Brunswick and Nova Scotia and especially between New Brunswick and Maine. The most fluctuating prices are found on Nova Scotia, as this

Island system is only thinly connected to the larger region, and since there are large differences in the short term costs between the coal fired units on one side, and the gas fired units on the other.

Figure 26 and Figure 27 below show the marginal area prices weighted by consumption in 2010 and 2025.

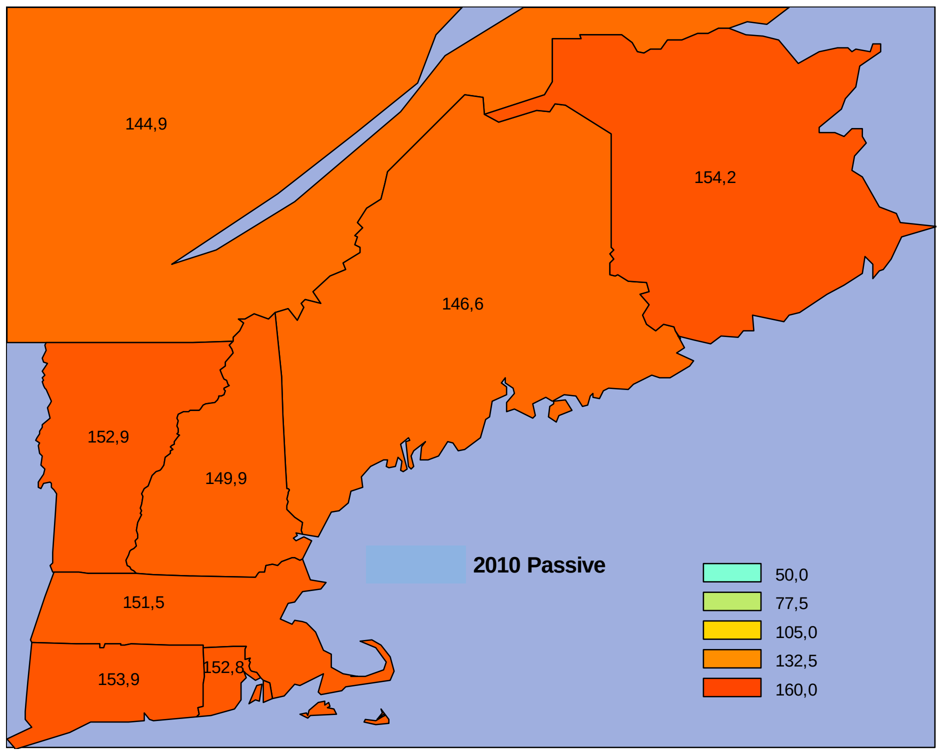


Figure 26: Marginal area prices weighted by consumption (CAD/MWh) in 2010 of the Passive Scenario.

In 2010 the electricity price is relatively high in all areas, i.e., in the range of 150 CAD/MWh. The reason for this is high fuel prices and the fact that in 2010 the production system has not yet adapted to these high prices, and often the marginal price is set by technologies using oil and transferred via hydropower to all time periods. The price is highest in New Brunswick and lowest in Maine and Quebec.

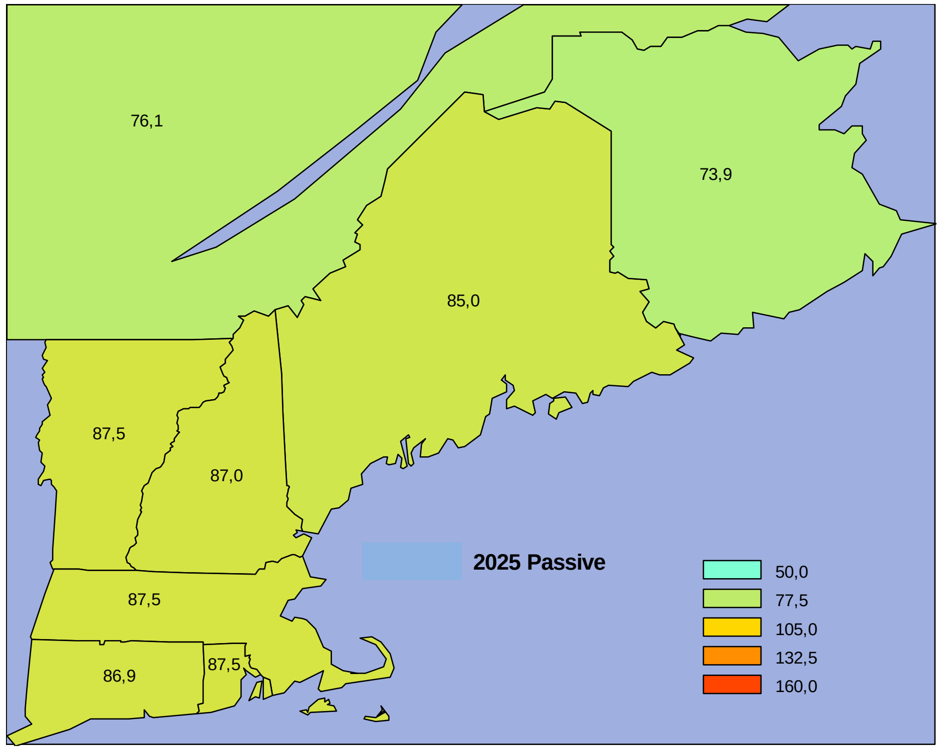


Figure 27: Marginal area prices weighted by consumption (CAD/MWh) in 2025 of the Passive Scenario

In 2025 the prices are much lower than in 2010, which are caused by investments in new generation technologies with lower costs. The average price is now lowest in the Maritimes due to the fact that most investments in new generation facilities take place here. In addition to the wholesale price of electricity as represented here, there is a cost of renewable credits for the distributor, which would be added to the retail side as is demonstrated in the next section.

5.1.4 Emissions and CO2/RE certificate prices

The marginal cost of electricity supply, which has previously been shown, includes the certificate price of CO2 emissions.

Figure 28 shows the value of the emissions permits in the market. It is evident that there is only a binding constraint of CO2 in the Maritimes market, whereas the CO2 requirements for New England are easily met by new renewable energy sources and imports.

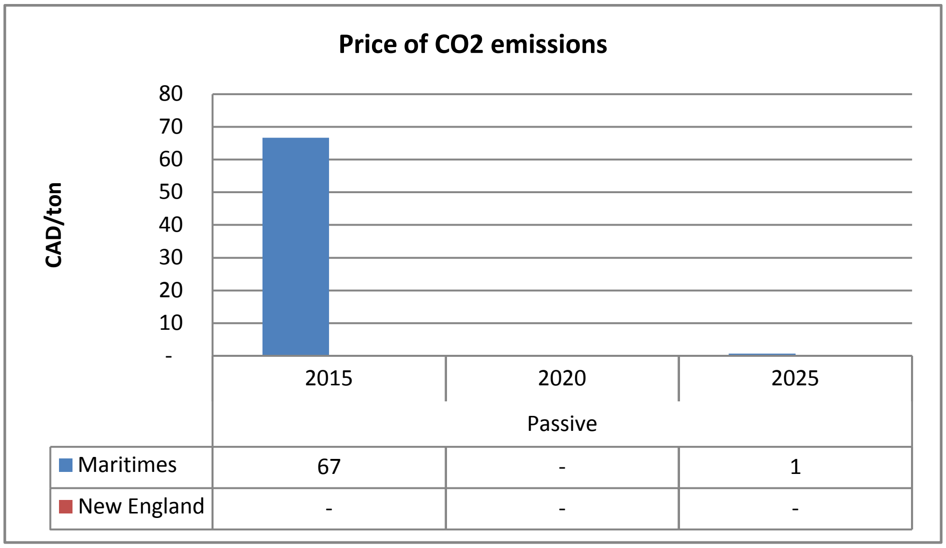


Figure 28: Price of CO2 credits in the passive scenario under the RGGI system. The RGGI system covers only the New England states.

The CO2 price is zero at the end of the period which means that the CO2 price is only a binding constraint in the first year.

One reason why the CO2 price is zero by the end of the period is that the RPS certificate price is relatively high. The RPS certificate price gives a premium to renewable technologies which in general also have low CO2 emissions. Thereby the costs of reducing CO2 decrease. Figure 29 shows the calculated RPS credit values as CAD/MWh of renewable energy generated.

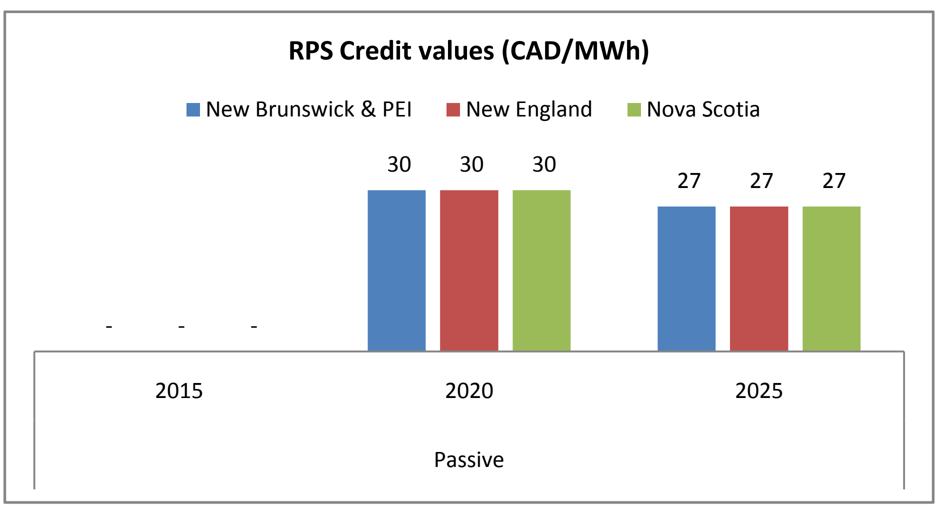


Figure 29: Price of RPS credits in the Passive Scenario.

In 2015, the incentives provided by other sources, specifically CO2 and fuel prices, are sufficient to ensure that the RPS standard is fulfilled. In 2020 the RPS value is 30 CAD/MWh and in 2025, the value is 27 CAD/MWh. The reason for this decrease is that fuel prices increase and therefore RE technologies become relatively more competitive in the market. The RPS standards in New England average 22% of electricity by 2025. This implies that roughly 6 CAD/MWh of electricity would be added to the retail price on account of RPS credits in 2025. In New Brunswick this would only be 10% i.e. 3 CAD/MWh.

5.1.5 Summary of indicators in the Passive Scenario

What has been illustrated in the Passive Scenario is a number of indicators that wind energy development would be a profitable venture.

- The model determined that it was optimal to use the full wind resource, which was made available as soon as possible. This gives an indication that more wind might be feasible.
- The energy prices, in particular natural gas and oil prices result in very high marginal generation costs, thereby indicating very high electricity prices unless alternatives are found. This could be seen from the drop in marginal generation costs from 2010 to 2015 where investments were permitted in 2015.
- There is a positive price on either carbon or renewable credits throughout the simulations; however as these are two targets pulling in the same direction only one of them has a positive price at any one time.

The next step in the scenario process is to define a political instrument to improve the situation beyond the passive scenario. In order to ease interpretation of results, only one change is made one at a time between scenarios.

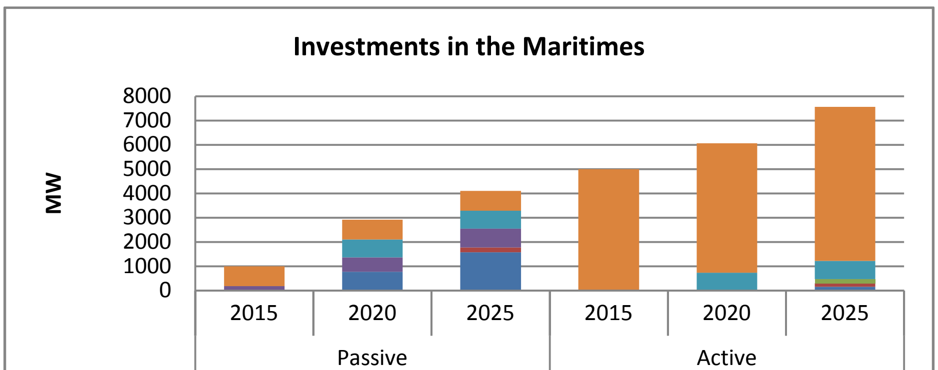
5.2 Active scenario

This section presents the results of the Active scenario. The Active policy here implies that the Maritimes region is characterised by efficient and timely planning for wind power. Connection points in the grid are made available where wind developers create projects. Access to outside transmission as well as to the local grids is granted on an equal opportunity basis. Thereby, grid access is granted to the generator which provides the highest overall value to the system on an hourly basis.

The potential for investing in wind power is increased to 5,500 MW in New Brunswick, 5,500 MW on Prince Edward Island, 5,500 MW in Nova Scotia and 900 MW in Northern Maine. Implicitly, this may imply a number of local grid reinforcements and some adjustments in the market design, but no additional expansion of transmission capacity between the New Brunswick and neither Prince Edward Island nor Nova Scotia. Nor is there any additional expansion of transmission capacity towards New England or Quebec.

5.2.1 Investments in new generation resources

The type and amount of investments in the Maritimes change quite substantially compared to the Passive scenario as shown in Figure 30. The amount of wind power investments is substantially increased upon the release of the potential. Over 6,300 MW of wind power capacity is installed in the Maritimes.

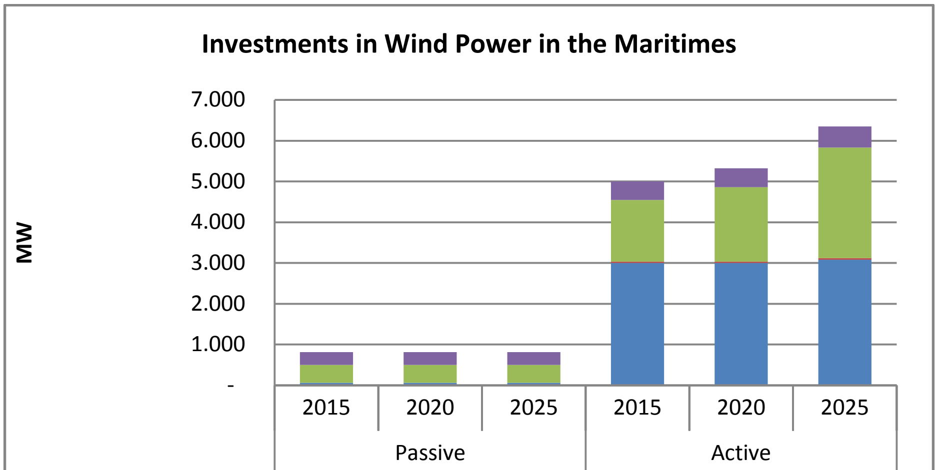


	Passive 2015	Passive 2020	Passive 2025	Active 2015	Active 2020	Active 2025
Wind	819	819	819	5.005	5.320	6.347
Hydro		740	740		740	740
Biomass	182	592	773			
Natural gas						182
Coal			201			136
Nuclear		773	1.573			162

Figure 30: Cumulated investments in the Maritimes in the Passive and Active Scenarios.

As in the Passive scenario, the second nuclear plant at Lepreau is not established in the Active Scenario. But there is some indication in 2025 that it is beginning to look like an attractive option. Again, it comes down to some of the simplifications in the model that a fraction of a plant can be purchased, which could be interpreted as an indication that it may be prudent to wait and see.

Figure 31 shows how the aforementioned wind power investments are distributed throughout the Maritimes.

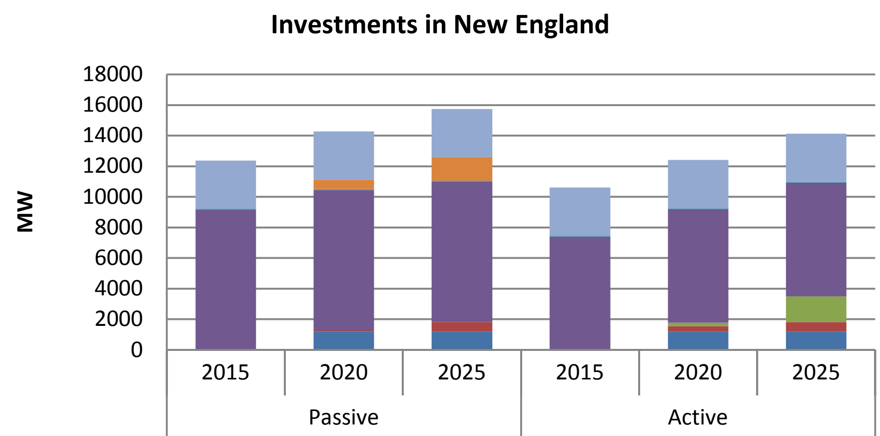


	Passive 2015	Passive 2020	Passive 2025	Active 2015	Active 2020	Active 2025
Prince Edward Island	320	320	320	460	460	519
Nova Scotia	434	434	434	1.509	1.824	2.709
Northern Maine				37	37	37
New Brunswick	65	65	65	3.000	3.000	3.082

Figure 31: Wind power investments in the Passive and Active Scenarios and how these are distributed in the Maritimes.

The distribution of wind power investments between regions is a result of a number of factors. Firstly, by assumption, quality of the wind resource in each region is not homogenous. This gives an incentive to pick the best spots in each region. Secondly, the ties to adjacent markets are of varying strength. All the Maritime regions connect to New England through New Brunswick, thus giving a favourable position to wind power sited in New Brunswick. Finally, the local composition of existing generation comes into play, as well as how much wind power the local market can absorb.

On Figure 32 the investments in New England in the Active scenario compared to the Passive scenario.



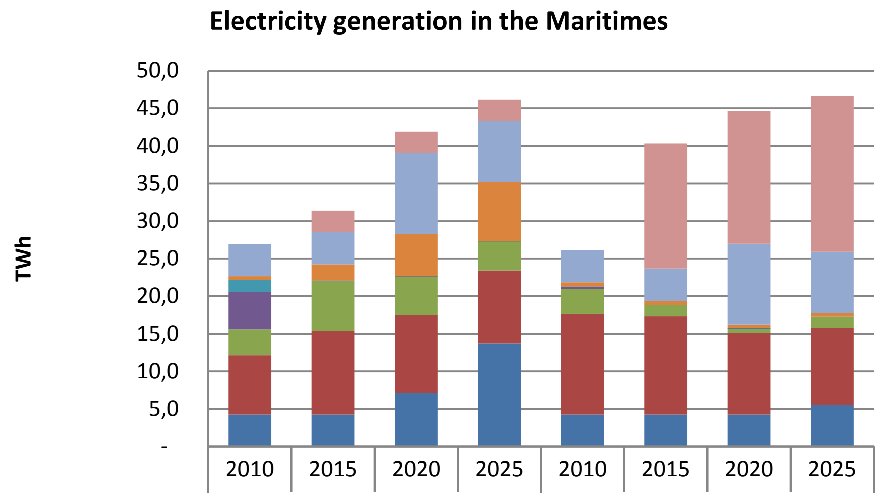
	Passive 2015	Passive 2020	Passive 2025	Active 2015	Active 2020	Active 2025
Wind	3.149	3.149	3.149	3.149	3.149	3.149
Biomass		613	1.538			
Landfill gas	54	54	54	54	54	54
Natural gas	9.173	9.173	9.173	7.418	7.418	7.418
Coal w CCS					231	1.676
Coal		78	628		354	628
Nuclear		1.200	1.200		1.200	1.200

Figure 32: Cumulated investments in the New England in the Passive and Active Scenarios.

In New England, the difference between the two scenarios is not as large as it was for the Maritimes. In the Active scenario, the local wind resource is still fully used, indicating a positive value of additional siting in the New England states. Also the investments in nuclear and landfill gas are still the same. The investments in biomass and natural gas are lower in the Active scenario than in the Passive scenario, and regarding coal a shift towards investments in coal with CCS is made in the Active scenario.

5.2.2 Production and transmission

The large investments in wind power capacity in the Maritimes affects the electricity generation considerably as shown in Figure 33.

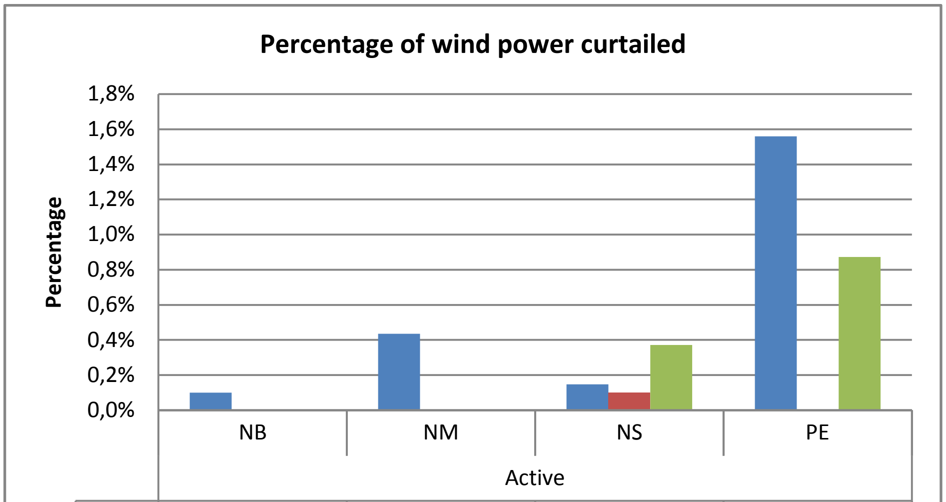


	2010	2015	2020	2025	2010	2015	2020	2025
	Passive				Active			
Wind		2,8	2,8	2,8		16,6	17,6	20,7
Hydro	4,3	4,3	10,8	8,2	4,3	4,3	10,8	8,2
Biomass	0,5	2,2	5,6	7,8	0,5	0,5	0,5	0,5
Diesel	1,6			0,0	0,0		0,0	0,0
Residual fuel oil	5,0	0,0	0,0	0,0	0,4	0,0	0,1	0,0
Natural gas	3,5	6,7	5,1	3,9	3,3	1,5	0,6	1,5
Coal	7,9	11,1	10,4	9,7	13,4	13,1	10,9	10,2
Nuclear	4,3	4,3	7,2	13,7	4,3	4,3	4,3	5,5

Figure 33: Generation in the Maritimes in the Passive and Active scenarios.

In year 2025, the generation from wind turbines is almost 21 TWh compared to 2.8 TWh in the Passive scenario. Opposite the generation from wind turbines, the generation from all other technologies decreases in the Active scenario compared to the Passive scenario.

One could be led to believe, that with that amount of wind power in the system, it will be necessary to frequently curtail wind power generation. Figure 34 illustrates the proportion of wind energy with is curtailed in each region of the simulation.

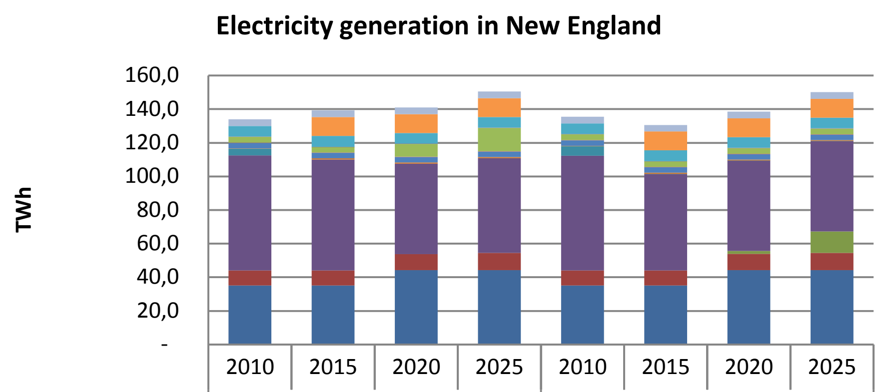


	NB	NM	NS	PE
2015	0,1%	0,4%	0,1%	1,6%
2020			0,1%	
2025	0,0%	0,0%	0,4%	0,9%

Figure 34: Curtailment of wind power occurs when demand plus export capacity minus "must-run" generation (due to reliability) is less than the generation from wind power.

The figure shows that although there is some curtailment in the simulations, it is not substantial. The aggregation of profiles used in the model does however shelter a slightly lower necessity for curtailment compared to what will be reality. Investments in transmission capacity or demand response would also reduce the amount of curtailment.

Figure 35 shows the changes in the Active scenario compared to the Passive scenario.

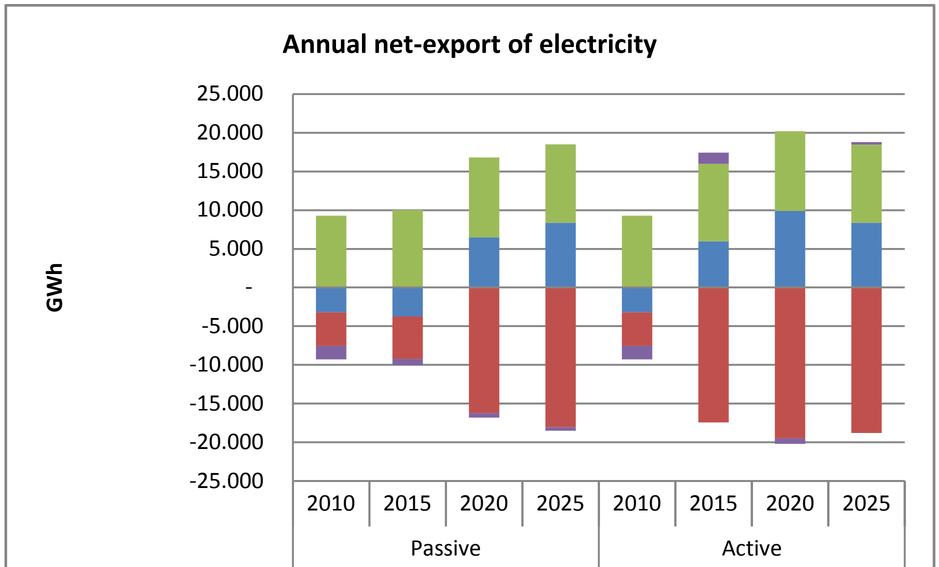


	Passive 2010	Passive 2015	Passive 2020	Passive 2025	Active 2010	Active 2015	Active 2020	Active 2025
Waste oil	3,9	3,9	3,9	3,9	3,9	3,9	3,9	3,9
Wind		11,2	11,2	11,2		11,2	11,2	11,2
Hydro	6,4	6,4	6,4	6,4	6,4	6,4	6,4	6,4
Biogas	0,1	0,1	0,1	0,1	0,1	0,1	0,1	0,1
Biomass	3,4	3,4	7,7	14,0	3,4	3,4	3,4	3,4
Tires	0,2	0,2	0,2	0,2	0,2	0,2	0,2	0,2
MSW	3,2	3,2	3,2	3,2	3,2	3,2	3,2	3,2
Landfill gas	0,4	0,7	0,7	0,7	0,4	0,7	0,7	0,7
Residual fuel oil	3,9				5,6	0,0	0,0	0,0
Natural gas	68,3	65,9	53,9	56,3	68,2	57,3	53,6	53,7
Coal w CCS							1,8	12,8
Coal	9,1	9,1	9,4	10,2	9,1	9,1	9,7	10,2
Nuclear	35,1	35,1	44,3	44,3	35,1	35,1	44,3	44,3

Figure 35: Generation in New England in the Passive and Active scenarios.

It appears that for most technologies, the generation in 2025 is the same in the Passive and Active scenario. However, for biomass and natural gas the generation decreases in the Active scenario and coal with CCS generation increases.

A reflection of this is the annual net export picture from earlier, but augmented with the Active Scenario on Figure 36. The annual net exports are in the same ballpark as in the Passive scenario.



	Passive 2010	Passive 2015	Passive 2020	Passive 2025	Active 2010	Active 2015	Active 2020	Active 2025
Nova Scotia	-1.754	-806	-597	-422	-1.754	1.450	-717	332
Quebec	9.300	10.032	10.343	10.113	9.300	10.008	10.308	10.108
New England	-4.348	-5.491	-16.21	-18.07	-4.348	-17.43	-19.49	-18.81
New Brunswick & PEI	-3.198	-3.734	6.468	8.380	-3.198	5.973	9.900	8.372

Figure 36: Annual net-export of electricity in the Passive and Active scenarios.

An attempt to gauge the value of additional transmission capacity can be made on the basis of shadow prices to the transmission capacity constraints in the model. These accumulated over the year give indication of an annual marginal value of transmission capacity to the system as a whole. In other words, how much would be saved in terms of total costs, if this extra unit of capacity was developed, without consideration of the costs of investment.

Table 8: Marginal value of transmission capacity

	CMA_NEMA	ME	NB	NS	QB	VT	NH
2015							
Active							
ME			505				2,382
NB		80,835			1,049		
NM			77,516				
NS			2,942				
PE			37,595				
QB	100,835		341			95,275	
2025							
Active							
ME							725
NB		140,496		112,975	2,639		
NM			98,568				
NS			44,958				
PE			54,091				
QB	118,925		0			122,321	

Table 8 shows the marginal values of 1 MW of transmission capacity from the regions indicated on the rows headings towards the regions listed on the column headings. The indication from this table is that it would be prudent to further investigate options for increasing transmission capacity

- between New Brunswick and Prince Edward Island;
- between New Brunswick and Nova Scotia;
- between New Brunswick and Northern Maine;
- between New Brunswick and Quebec;
- between New Brunswick and Maine;
- between Maine and New Hampshire;
- between New Hampshire and Boston;
- and between New England and Quebec.

These indications have been taken into consideration in the formulation of the Transmission Scenario which follows in section 5.3.

5.2.3 Electricity prices

Figure 37 shows the development in electricity prices in the Active scenario including also the weekly variation. As in the Passive scenario, the level decreases from 2015 when it is possible to invest in new generation facilities. Also in this scenario, the prices are in general higher in the New England states than in the Maritimes.

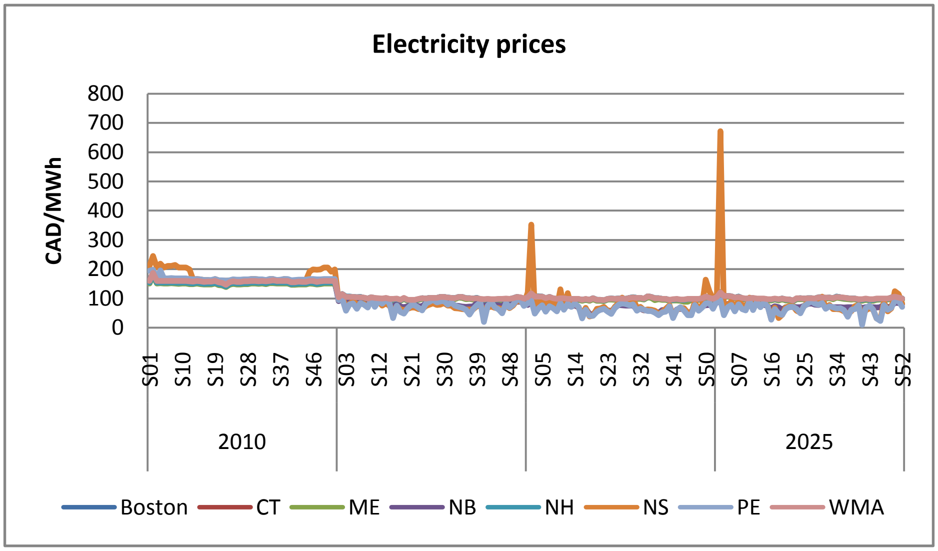


Figure 37: Electricity prices for eight selected regions - weekly variation.

Figure 38 below shows the marginal area prices weighted by consumption in 2025.

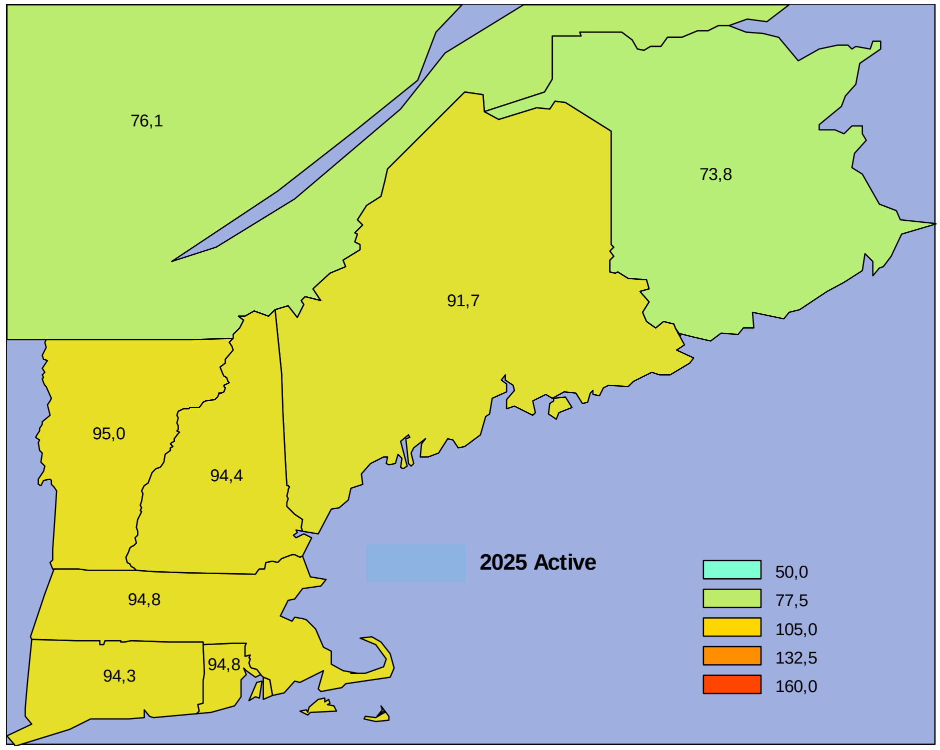


Figure 38: Marginal area prices weighted by consumption (CAD/MWh) in 2025 of the Active Scenario

Compared to the Passive scenario, it appears that the price is the same in New Brunswick, i.e., in the range of 74 CAD/MWh by 2025. However, the RPS credits are now down to 9 CAD/MWh which means less than 1 CAD/MWh on the retail price.

In the New England states, however, the wholesale price is now higher. Here also the RPS credits come into play, adding only 22% of 9 CAD/MWh, i.e. app. 2 CAD/MWh. Additionally, the wholesale prices in the Passive Scenario of 2025 was defined 80% of the time by the short-term marginal cost of the new highly efficient natural gas fired generation capacity. Since the active scenario less of this capacity is installed early on, the electricity price more often equates to the short-term marginal cost of existing CC units or less efficient units. This indicates that the model has 'over invested' to some extent in 2015 of the Active scenario, thereby pressing down wholesale prices in 2025.

5.2.4 Emissions and CO2/RE shadow prices

Figure 39 shows the value of the emissions permits in the market.

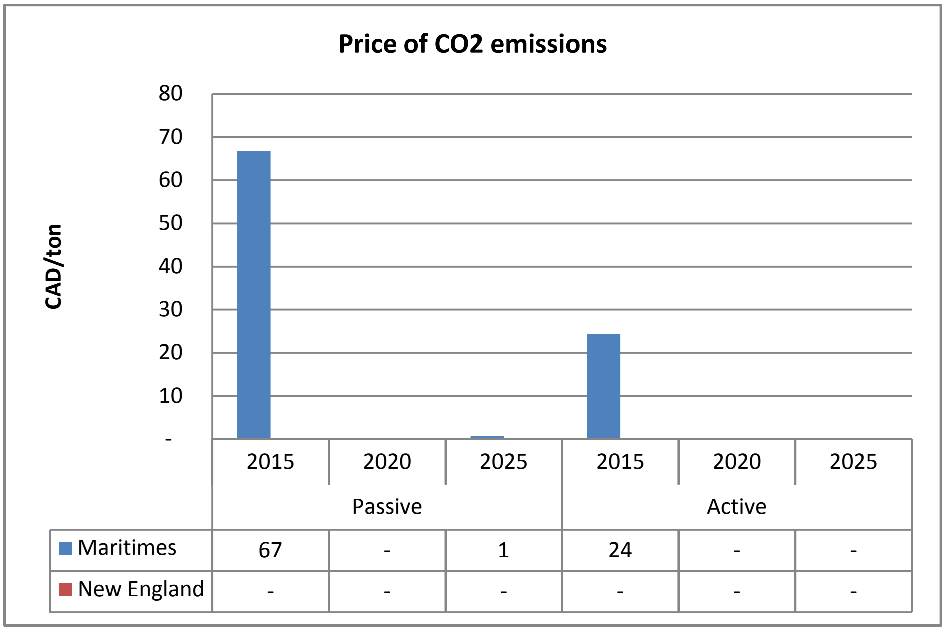


Figure 39: Price of CO2 credits in the Active scenario compared to the Passive scenario.

In the Active scenario, the CO2 price is zero except from one case, i.e. the Maritimes in 2015.

5.2.5 Costs and Benefits

The scenarios are by construction gradually less restrictive regarding a number of assumptions. For instance, in the Active scenario, investments in wind power are not restricted as much as in the Passive scenario. The release of restrictions/constraints result in economic benefits compared to the Passive scenario.

In Table 9 the costs and benefits in the Active scenario are shown in relation to the Passive scenario.

Table 9: Costs and Benefits of the Active Scenario in relation to the Passive Scenario (bnCAD)

	New Brunswick & PEI	Nova Scotia	New England	Total
Reduced costs	-3.6	0.6	7.4	4.4
- fuel	0.4	1.9	5.2	7.5
- variable costs	-0.2		0.2	
- fixed costs	-0.3		0.4	0.1
- capital costs	-3.6	-1.3	1.6	-3.2
Trade balance	4.7	0.8	-6.0	-0.4
Total	1.1	1.4	1.4	4.0

There are additional capital costs in the Active scenario (of 3.2 billion CAD) which is mainly due to the investments in wind power facilities in the Maritimes. On the other hand, there is a considerably reduction in fuel costs of 7.5 bnCAD. The tota0l benefit of the Active scenario compared to the Passive scenario has been estimated to almost 4 bnCAD, whereof the benefit to New Brunswick is 1.1 bnCAD.

The term trade balance is the difference in traded value between regions. This value is determined according to marginal costs of electricity, and where there is a price between regions, the average price between the two is used, reflecting that congestion rents are shared on each side of the border by means of a 50-50 spilt. The trade balance totals -400 mCAD (and not zero) because there is trade with New York. However, as New York is a boundary condition this number is not firm.

The differences in capital costs and other costs at selected technologies are illustrated on Figure 40 below. For instance, it can be seen that gas technologies have relatively low investment costs but high fuel costs. This is opposite to wind technologies with have high investment costs but no fuel costs at all. Assumptions are made in the figure regarding to the capacity factor of the thermal units as well and the figure is intended simply to illustrate the effects on Table 9.

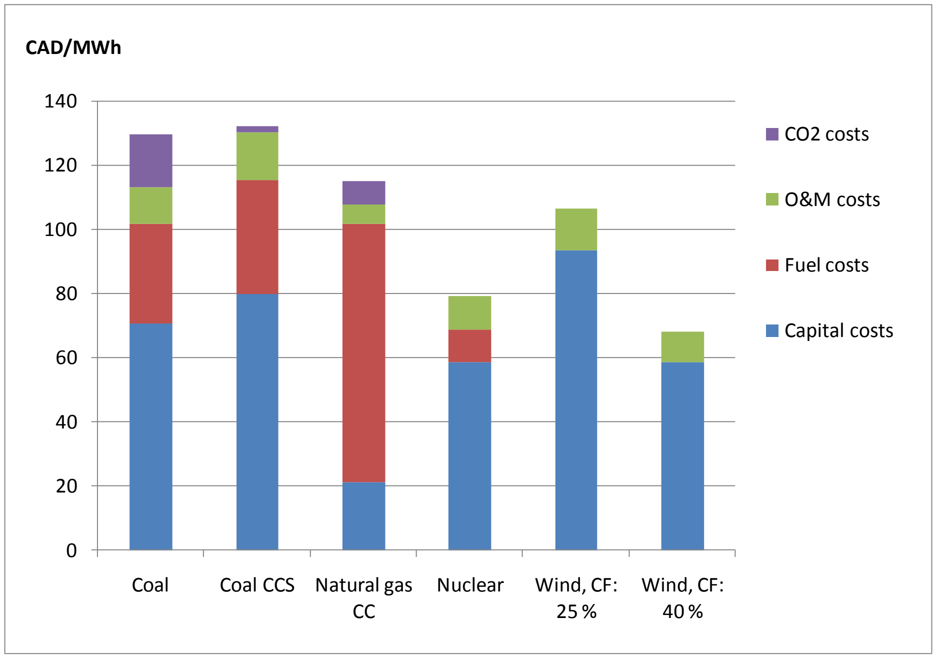


Figure 40: Comparison of long-run marginal costs of new power generation technologies (CAD/MWh). CCS: Carbon Capture and Storage, CC: Combined Cycle, CF: Capacity Factor. Two on-shore wind power plants are included in the comparison with capacity factors of 25 per cent and 40 per cent respectively.

5.2.6 Summary of key findings from the Active Scenario

Moving from **Passive** to the **Active** scenarios the key developments are:

- Active policy releases the potential of wind power development in the Maritimes, causing investments in the Maritimes region to increase from roughly 800 MW of new capacity in the Passive scenario to 6.3 GW in the Active scenario.
- Maritime wind investments in the Active scenario are distributed with about 3.1 GW in New Brunswick, 2.7 GW in Nova Scotia, 500 MW in PEI and a lesser amount in Northern Maine.
- In the active scenario, the second nuclear plant at point Lepreau is not established; however this is due to transmission constraints beyond what is expected today.
- The regional economic benefit of the Active approach versus the Passive approach has an estimated net-present value of 4 bnCAD from 2010-2025. The cost savings are fuel costs and reduced RPS and CO2

compliance costs. Additional costs are capital costs since wind is a more capital intensive form of generation.

5.3 Transmission scenario

This section presents the results of the Transmission scenario. This scenario further builds upon the Active policy scenario. In addition, a number of new transmission lines are assumed to have been completed by 2015. The new transmission lines has been derived by considering the indications regarding marginal value of transmission capacity, and by assuming investments in some of the most valuable connections.

The following transmission capacity reinforcements are assumed to have been completed:

600 MW between New Brunswick and Prince Edwards Island
600 MW between New Brunswick and Northern Maine
1000 MW between New Brunswick and Nova Scotia
1,500 MW between New Brunswick and Maine
1,500 MW between Maine and New Hampshire
1,500 MW between New Hampshire and Boston

No reinforcements are made in direction of Quebec, in spite of the high value indication in Table 8. The modelling of Quebec is more rudimentary than the rest of the region and therefore specific analyses of connections towards Quebec would be of questionable quality.

The benefits from expanding the transmission capacity must be seen in relation to the cost of expansion. Table 10 shows the estimated costs of the transmission expansions which are included in the Transmission Scenario (and and subsequently the Proactive Scenario).

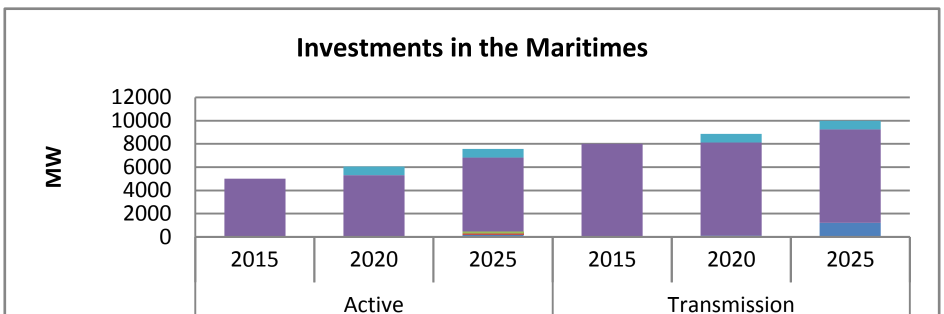
	Costs
New Brunswick <=> Boston + 1,500 MW, HVDC (600 km)	-1.05
New Brunswick <=> Nova Scotia, + 1,000 MW, 345 kV AC (100 km)	-0.15
New Brunswick <=> Northern Maine, + 600 MW, 345 kV AC (100 km)	-0.15
New Brunswick <=> PEI, + 600 MW, 345 kV AC, (100 km)	-0.15
Sum	-1.5

Table 10: Estimated cost of extending the transmission system (bnCAD). Costs of the interconnectors are accounted for in period 2010-2025 and discounted to Net Present Value using a discount rate of 6 percent p.a. An economic life time of 30 years is assumed for the investments in the transmission system.

The cost-benefit analysis does not value potential additional benefits to the security of supply or synergies related to the acquisition of ancillary services between system areas.

5.3.1 Investments in new generation resources

Figure 41 shows the investments in the Maritimes in the Transmission scenario compared to the Active scenario.

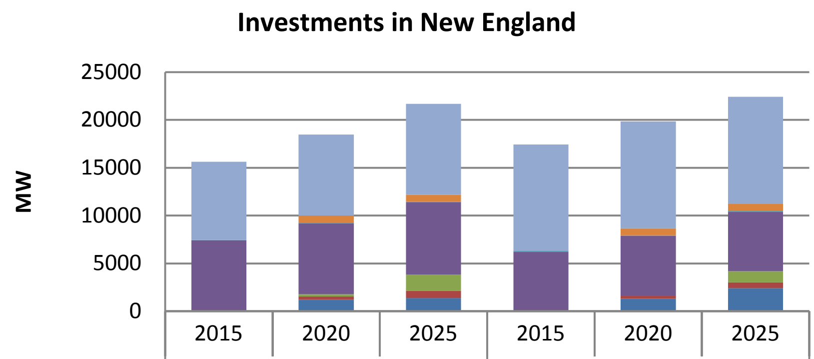


	Active 2015	Active 2020	Active 2025	Transmission 2015	Transmission 2020	Transmission 2025
Hydro		740	740		740	740
Wind	5.005	5.320	6.347	8.018	8.018	8.058
Natural gas			182			
Coal			136			
Nuclear			162		100	1.200

Figure 41: Cumulated investments in the Maritimes in the Active and Transmission Scenario.

Compared to the Active scenarios, the investments in both wind power and natural gas facilities are higher in the Transmission scenario. The reason for this is that larger amounts of electricity can be transferred out of the Maritimes in this scenario, and also that the wind resources in the Maritimes and the gas price make it more attractive to establish these facilities here than in New England.

Figure 42 shows the investments in New England in the Transmission scenario compared to the Active scenario.



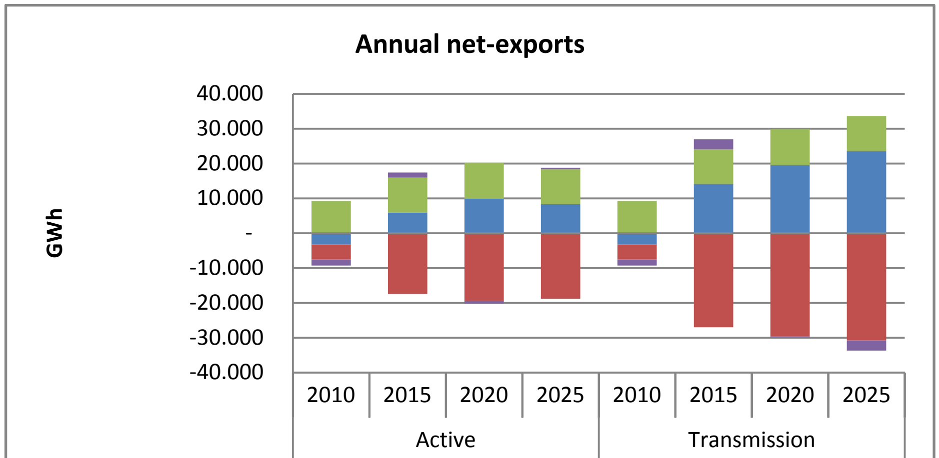
	Active 2015	Active 2020	Active 2025	Transmission 2015	Transmission 2020	Transmission 2025
Wind	8.154	8.469	9.496	11.167	11.167	11.207
Hydro		740	740		740	740
Landfill gas	54	54	54	54	54	54
Natural gas	7.418	7.418	7.600	6.231	6.231	6.231
Coal w CCS		231	1.676			1.151
Coal		354	764		354	628
Nuclear		1.200	1.362		1.300	2.400

Figure 42: Cumulated investments in the New England in the Active and Transmission Scenario.

It appears from the figure that in the Transmission scenario investments in New England decreases compared to the Active scenario, which is because the increased transmission capacity allows new production facilities to be installed in the Maritimes where wind resources are better and the gas price lower.

5.3.2 Production and transmission

Figure 43 shows the annual net export in the Transmission scenarios compared to the Active scenario.



	Active 2010	Active 2015	Active 2020	Active 2025	Transmission 2010	Transmission 2015	Transmission 2020	Transmission 2025
Nova Scotia	-1.754	1.450	-717	332	-1.754	2.885	-260	-2.892
Quebec	9.300	10.008	10.308	10.108	9.300	9.999	10.324	10.103
New England	-4.348	-17.43	-19.49	-18.81	-4.348	-26.99	-29.60	-30.77
New Brunswick & PEI	-3.198	5.973	9.900	8.372	-3.198	14.114	19.544	23.560

Figure 43: Annual net-exports in the Active Scenario and the Transmission Scenario.

It appears that in the Transmission scenario, the "volume of trade" is much higher than in the Active scenario, in particular in 2025.

5.3.3 Electricity prices

Figure 44 shows the electricity price in the Transmission scenario.

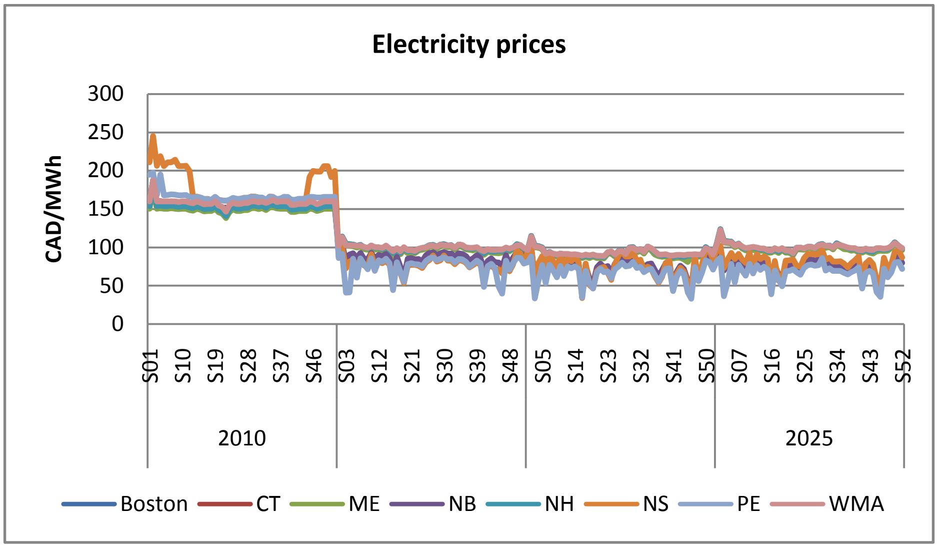


Figure 44: Electricity prices for eight selected regions - weekly variation.

Compared to Figure 37, it appears how the largest price peaks have now been removed due to the increased transmission capacity.

Figure 45 below shows the marginal area prices weighted by consumption in 2025.

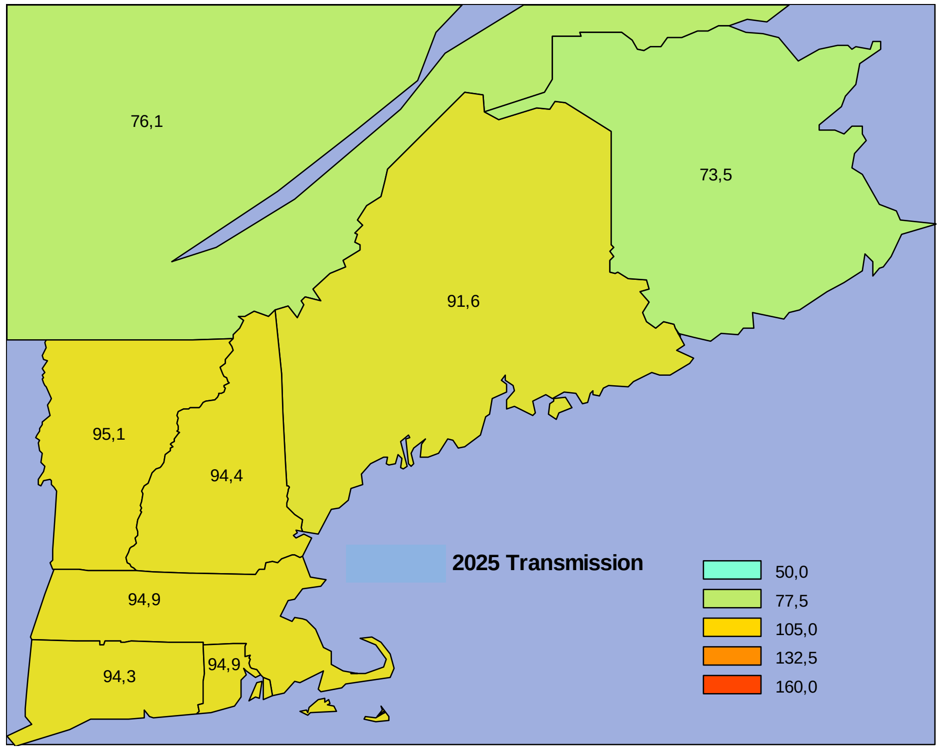


Figure 45: Marginal area prices weighted by consumption (CAD/MWh) in 2025 of the Transmission Scenario

The price levels are very resembling to the Active scenario. What happens from the Active to Transmission scenario is additional wind power is installed in the Maritimes until the prices are depressed to the same level. This is logical since it will be profitable to install wind until the competition drives the prices to a level where additional profits are not made from additional installations.

5.3.4 Costs and Benefits

In Table 11 the costs and benefits in the Transmission scenario are shown in relation to the Passive scenario.

Table 11: Costs and Benefits of the Transmission scenario relative to the Passive Scenario (bnCAD)

	New Brunswick & PEI	Nova Scotia	Quebec	New England	Total
Saved costs	-11.0	0.6	0.0	16.9	6.6
- fuel	0.0	2.1	0.0	12.2	14.3
- variable costs	-0.5	0.0	0.0	0.4	-0.1
- fixed costs	-1.0	0.0	0.0	0.7	-0.2
- capital costs	-9.5	-1.4	0.0	3.5	-7.4
Trade balance	13.0	1.0	0.2	-14.5	-0.3
Sum	2.1	1.7	0.2	2.4	6.3
Investment transmission					**-1.5**
Total					**4.8**

This time the extra capital costs amount to 7.4 bnCAD whereas the saved fuel costs amounts to 14.3 bnCAD. The total benefit sums up to 6.3 bnCAD, whereof the benefit to New Brunswick and PEI is 2.1 bnCAD. This does not however account for the costs of investing in the additional infrastructure and as such this cost should be subtracted from the total benefit.

5.3.5 Emissions and CO2/RE shadow prices

Figure 46 shows the RPS credit value in the Transmission scenario compared to the Passive and Active scenario.

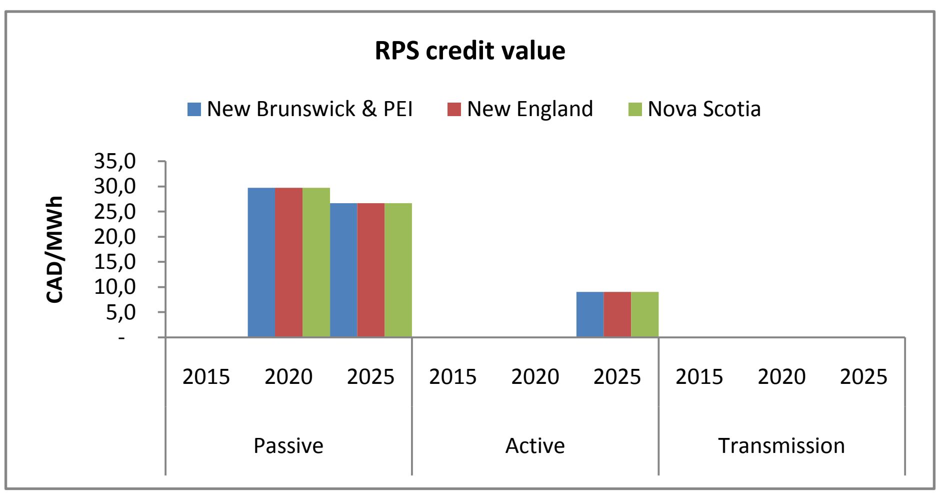


Figure 46: Price of RPS credits in the Transmission scenario compared with the Passive and Active scenario

In the Transmission scenario, the RPS credit value is zero in all regions in 2015, 2020 and 2025. The reason for this is that it is feasible to make investments in wind power and the RPS system does not make up any binding constraint. The driver for wind power development is the fuel prices and this is more than sufficient.

5.3.6 Summary of key findings from the Transmission scenario

From **Active** to the **Transmission** scenario the key developments are:

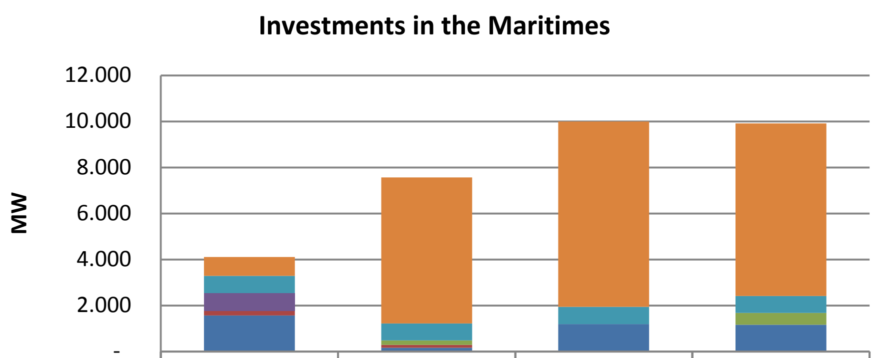
- A number of investments in transmission capacity are assumed to be undertaken specifically between New Brunswick and respectively PEI, Nova Scotia, Northern Maine most importantly to New England all the way to Boston.
- The scenario substantially increases the exports from the Maritimes to the New England market from roughly 8 TWh/year to 20 TWh/year.
- An additional 1.7 GW of wind power is established in the Maritimes as a result of better access to the New England market.
- Additionally, the Lepreau 2 nuclear plant is established.
- The benefit of the **Transmission** scenario in relation to the **Active** scenario *without taking account of the investment cost of the new transmission capacity* is estimated to be an additional 2.3 bnCAD. This benefit must of course be seen in relation to the cost of the transmission infrastructure which is estimated at 1.5 bnCAD.

5.4 Proactive scenario and overall scenario comparison

This section presents the results of the proactive scenario and compares them with the results of the other scenarios.

5.4.1 Investments in new generation resources

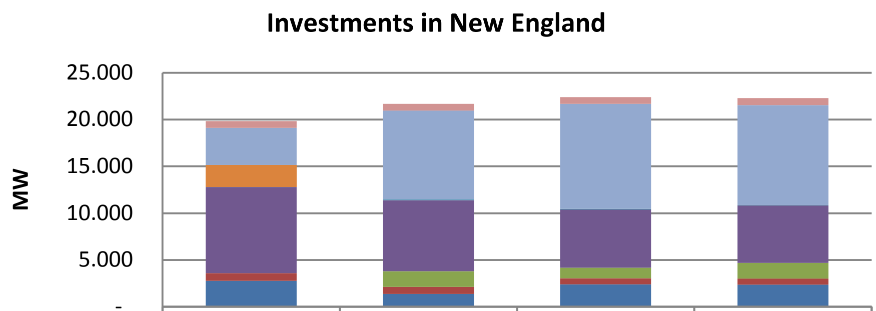
Figure 47 and Figure 48 show the investments in the Proactive scenario compared to the other scenarios by 2025.



	2025 Passive	2025 Active	2025 Transmission	2025 Proactive
Wind	819	6.347	8.058	7.500
Hydro	740	740	740	740
Biomass	773			
Natural gas		182		513
Coal	201	136		
Nuclear	1.573	162	1.200	1.169

Figure 47: Cumulated investments in the Maritimes in all scenarios.

Regarding the Maritimes, the investments in the Proactive scenario are quite similar to the investments in the Transmission scenario. Wind power, however, is a bit less. This is because that in the transmission scenario, the CO2 targets were binding in 2015 resulting in a price of CO2 making it more feasible to invest in wind power. Also, some thermal investments are now moved to the Maritimes, since a level playing field with respect to environmental regulation will now allow for more advantageous gas prices in the Maritimes to be exploited.



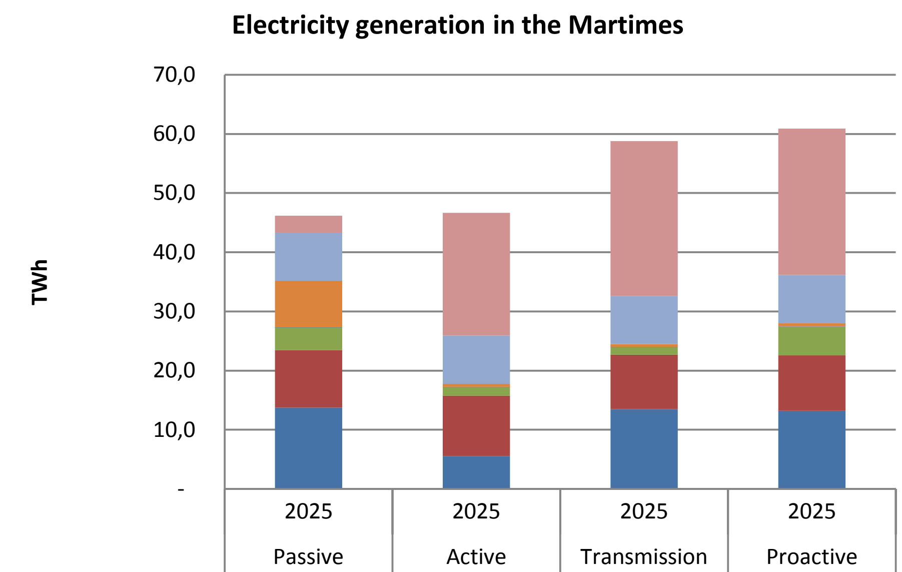
	2025 Passive	2025 Active	2025 Transmission	2025 Proactive
Hydro	740	740	740	740
Wind	3.968	9.496	11.207	10.649
Biomass	2.311			
Landfill gas	54	54	54	54
Natural gas	9.173	7.600	6.231	6.165
Coal w CCS		1.676	1.151	1.676
Coal	829	764	628	628
Nuclear	2.773	1.362	2.400	2.369

Figure 48: Cumulated investments in New England in all scenarios

It appears from the figure that in New England, the amount of investments is coal power with CCS is higher in the Proactive scenario than in the Transmission scenario. For natural gas it is opposite.

5.4.2 Production and transmission

Figure 49 shows the electricity generation in the Maritimes in the Proactive scenario as well as the other scenarios.

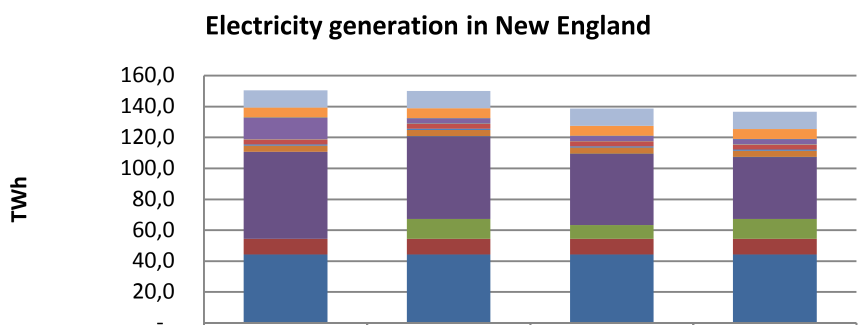


	2025 Passive	2025 Active	2025 Transmission	2025 Proactive
Wind	2,8	20,7	26,2	24,8
Hydro	8,2	8,2	8,2	8,2
Biomass	7,8	0,5	0,5	0,5
Diesel	0,0	0,0		
Residual fuel oil	0,0	0,0	0,0	0,0
Natural gas	3,9	1,5	1,3	4,9
Coal	9,7	10,2	9,2	9,3
Nuclear	13,7	5,5	13,5	13,2

Figure 49: Electricity generation in the Maritimes in all 4 Scenarios by 2025.

As for the investments, the generation from wind power is a bit lower in the Proactive scenario than in the Transmission scenario, whereas the generation from gas is a bit higher.

Figure 50 shows the electricity generation in New England in the Proactive scenario as well as the other scenarios.



	2025 Passive	2025 Active	2025 Transmission	2025 Proactive
Wind	11,2	11,2	11,2	11,2
Hydro	6,4	6,4	6,4	6,4
Biogas	0,1	0,1	0,1	0,1
Biomass	14,0	3,4	3,4	3,4
Tires	0,2	0,2	0,2	0,2
MSW	3,2	3,2	3,2	3,2
Landfill gas	0,7	0,7	0,7	0,7
Waste oil	3,9	3,9	3,9	3,9
Residual fuel oil		0,0	0,0	0,0
Natural gas	56,3	53,7	46,2	40,2
Coal w CCS		12,8	8,8	12,7
Coal	10,2	10,2	10,2	10,2
Nuclear	44,3	44,3	44,3	44,3

Figure 50: Electricity generation in the Maritimes in all 4 Scenarios by 2025.

Compared to the Transmission scenario, the generation at gas facilities is a bit lower and the generation at CCS technologies a bit higher in the Proactive scenario.

Figure 51 shows the net export in the different scenarios.

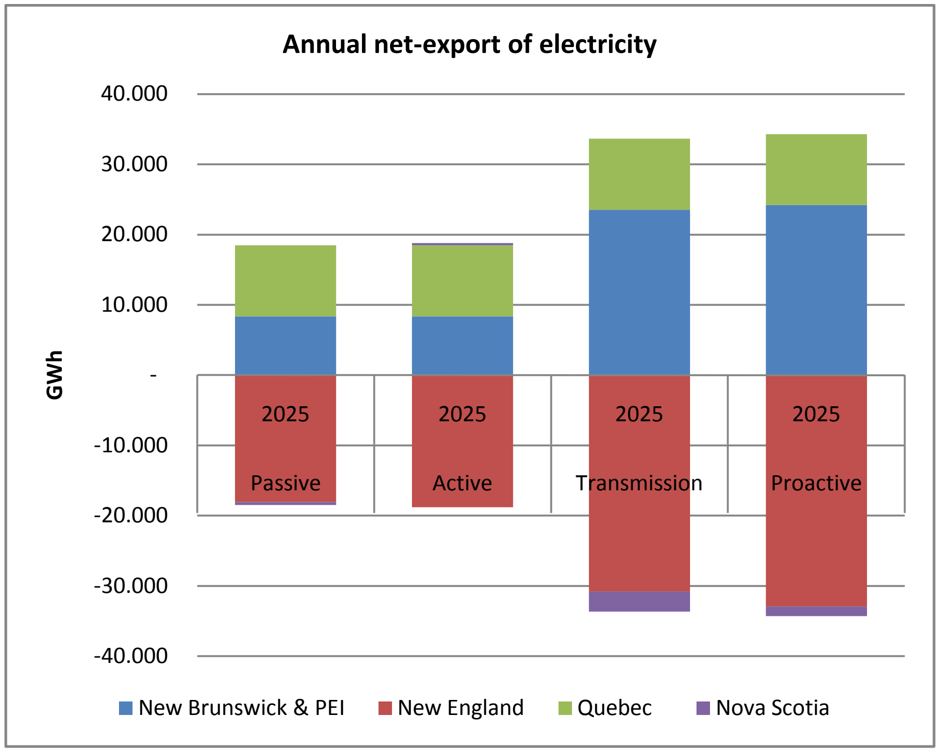


Figure 51: Annual net-export of electricity in all scenarios by 2025.

Similar to the Transmission scenario, the "volume of trade" is also very high in the Proactive scenario. However, the traded volume is not much higher even though the transmission tariffs have been removed, which is because the transmission capacities are fully used even in the Transmission scenarios despite of the transmission tariffs.

5.4.3 Electricity prices

Figure 52 shows the electricity prices in the Proactive scenario. The most notable difference in comparison with the Transmission scenario in prices is the more frequent dips in the electricity price in the especially Prince Edward Island. The removal of transmission tariffs makes it profitable to move more wind power to where the wind resource is the better. This creates local pressure on the electricity price in some hours of the year leading to lower prices and a higher average capacity factor.

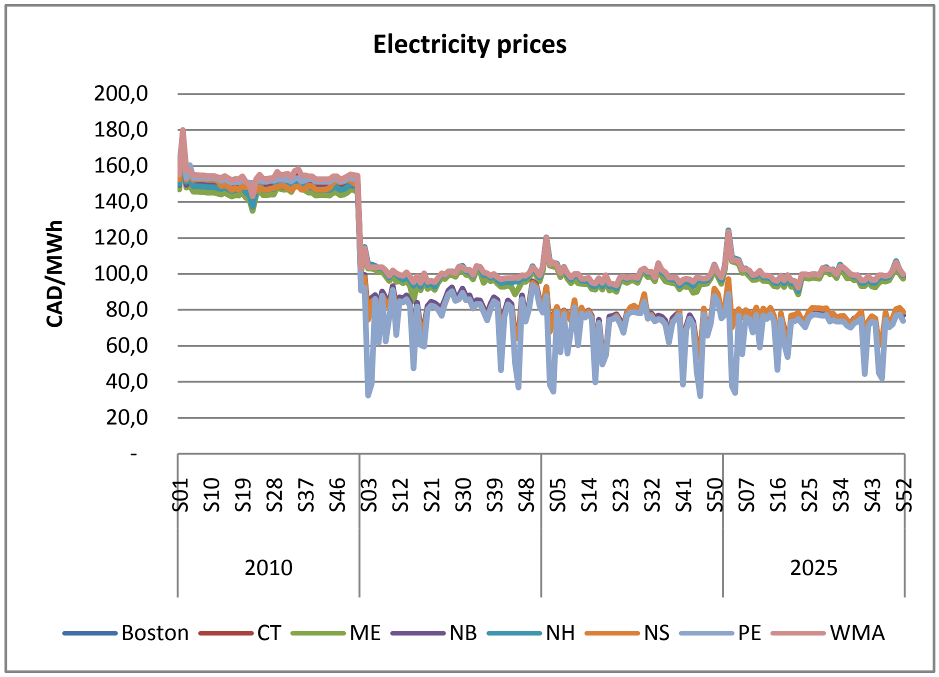


Figure 52: Electricity prices for eight selected regions - weekly variation in the Proactive Scenario.

Figure 53 below shows the marginal area prices weighted by consumption in 2025. The trend is very much the same as in Active and transmission scenarios. This is evidence that the model invests in wind power until it reaches a tipping point, i.e. until the long run costs of additional wind power would no longer be covered by electricity prices as they are continually depressed by increasing installed capacity. Since the exports to New England are the same as in the transmission scenario, and there is no CO_2 or RPS credit value by 2025, prices in New England are also the same.

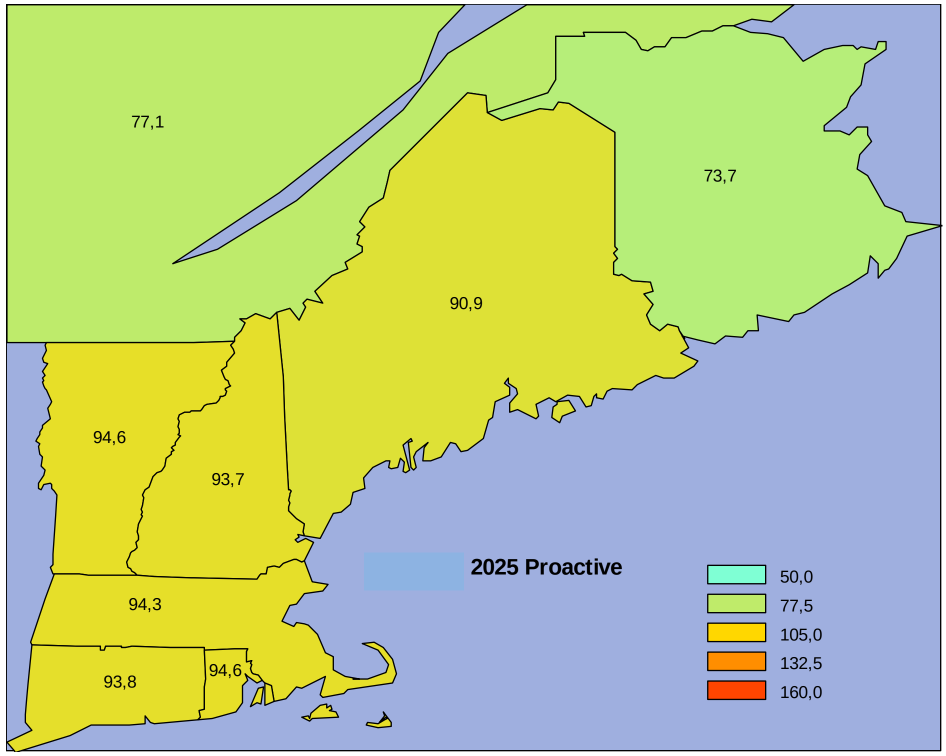


Figure 53: Marginal area prices weighted by consumption (CAD/MWh) in 2025 of the Proactive Scenario

5.4.4 Costs and Benefits

In Figure 18 the costs and benefits in the Proactive scenario are shown in relation to the Passive scenario.

Table 12: Costs and Benefits of the Proactive Scenario in relation to the Passive Scenario (bnCAD)

	New Brunswick & PEI	Nova Scotia	Quebec	New England	Total
Saved costs	-12.9	-1.1	0.0	20.9	6.9
- fuel	-3.3	1.5	0.0	16.3	14.4
- variable costs	-0.5	-0.1	0.0	0.4	-0.1
- fixed costs	-0.9	-0.1	0.0	0.8	-0.2
- capital costs	-8.2	-2.4	0.0	3.4	-7.2
Trade balance	15.0	2.9	0.4	-18.8	-0.4
Total	2.1	1.9	0.4	2.1	6.5
Investment transmission					-1.5
Total					**5.0**

In the Proactive scenario the additional capital costs amount to 7.2 bnCAD whereas the saved fuel costs amount to 14.4 bnCAD. The total benefit sums up to 6.5 bnCAD, whereof the benefit to New Brunswick is still 2.1 bn CAD. From this the estimated costs of new Transmission must be subtracted as was done in the transmission scenario. The difference between the Transmission and Proactive scenarios is not very profound. There is some moving around of wind power investments but the wind generation is only 2 TWh less in the Proactive scenario, and this is offset by increased gas fired generation in the Maritimes, as opposed to in New England. The environmental regulation is not very restrictive in light of the fuel prices, which are the key drives for the wind power development.

5.4.5 Fuel consumption and environmental impact

Due to the increased share of renewable energy sources in the Maritimes from year 2015, the fossil fuel consumption decreases in all scenarios. The fossil fuel consumption in the Maritimes and in New England is shown in the figures below.

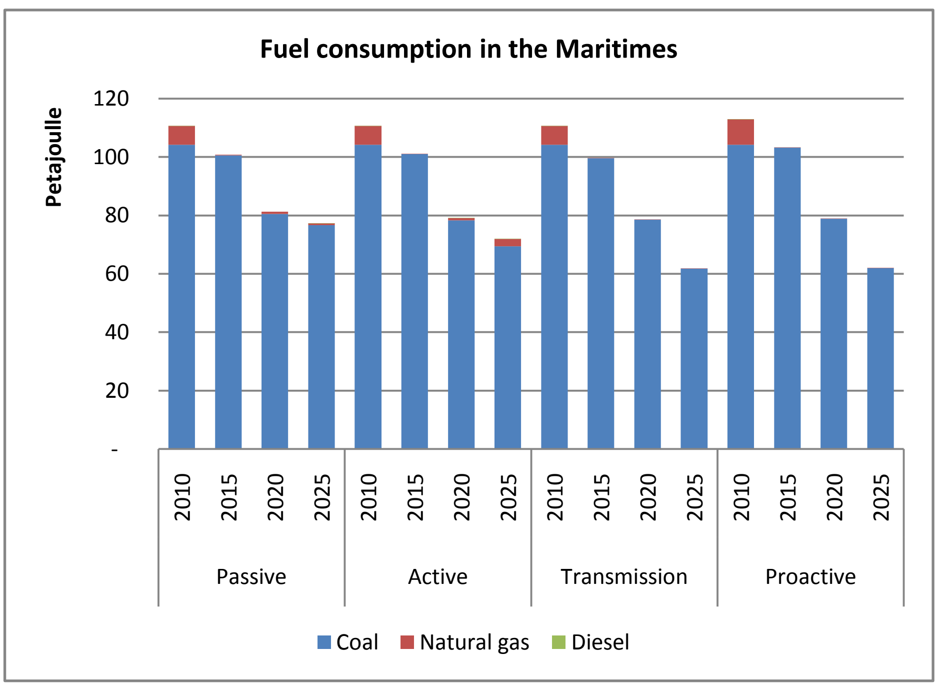


Figure 54: Consumption of fossil fuels in all 4 policy scenarios.

Most notable is the decline in use of oil and gas, but also coal firing decreases, especially after 2015 when the decommissioning of existing plants commences by assumption.

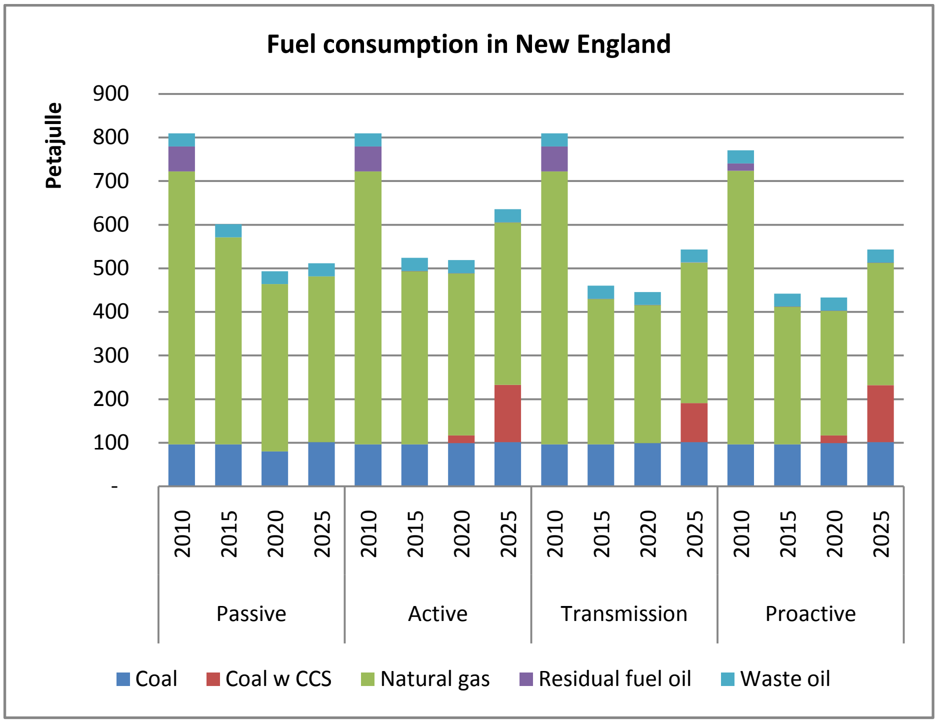
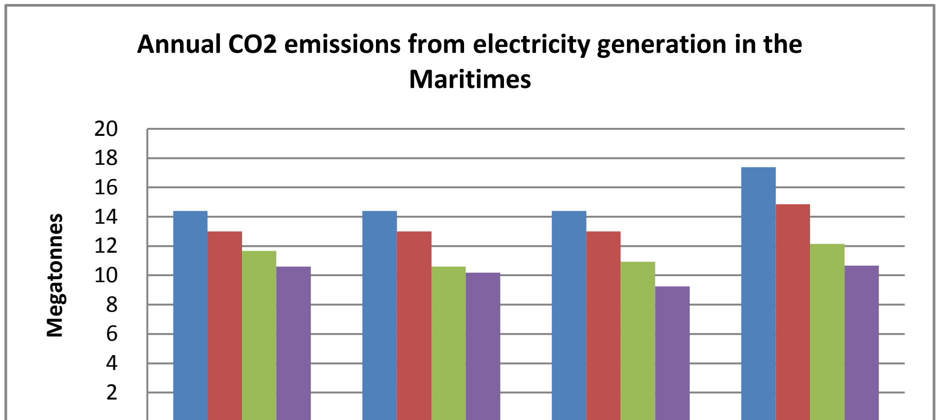


Figure 55: Consumption of fossil fuels in all 4 policy scenarios.

In New England there is a sharp decline in all scenarios in particular in natural gas and oil consumption by 2015. Both decreased generation as well as more efficient generation on new or improved facilities attribute to this. Coal firing stays at the same level, but is augmented with coal w CCS in the all but the passive scenario.

The changes in fossil fuel consumption have a large impact on the emissions including the CO2 emission. The figure below shows the development in the Maritimes.

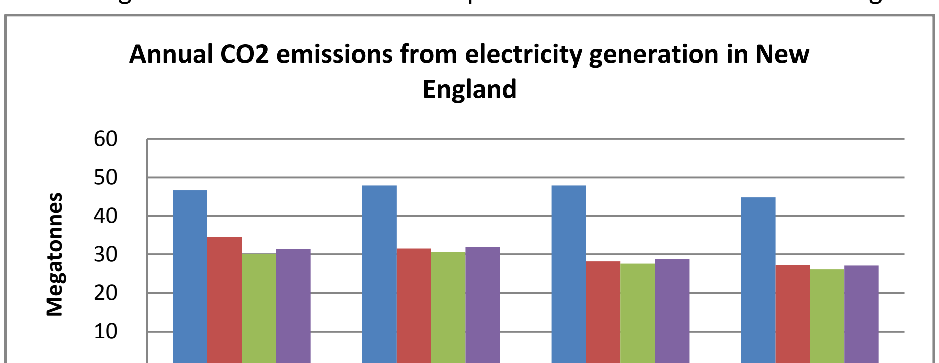


	Passive	Active	Transmission	Proactive
2010	14	14	14	17
2015	13	13	13	15
2020	12	11	11	12
2025	11	10	9	11

Figure 56: Annual CO2 emissions in the Maritimes in all 4 policy scenarios.

In the all scenarios, the CO2 emission decrease in the Maritimes year by year, but interestingly the proactive scenario has generally higher levels of emissions in all scenarios. This is due to the harmonisation of CO2 regimes, enabling the Maritimes area to generate more power on fossil fuels for export to New England.

The figure below shows the development in CO2 emission in New England.



	Passive	Active	Transmission	Proactive
2010	47	48	48	45
2015	35	32	28	27
2020	30	31	28	26
2025	31	32	29	27

Figure 57: Annual CO2 emissions in New England in all 4 policy scenarios.

The CO_2 emissions drop is very profound in 2015 in all scenarios, but in line with fossil fuel consumption as was demonstrated on Figure 55. The total final emissions of CO_2 are highest in the Passive scenario totalling 42 mega tonnes annually by 2025 for New England and the Maritimes. Emissions are lowest in the Transmission and Proactive scenarios.

5.5 More detailed operational analyses

The simulations described so far have used an aggregated representation of time and seasonal variations, which could potentially result in an overestimation of the favourability of wind power. In order to verify, that if managed efficiently, the electricity system and market will be able to handle the variability of the installed wind power, we have supplemented the capacity expansion simulations with some more detailed simulations on the operational side.

5.5.1 Operational aspects

In the operational simulations we look at the Proactive scenario in 2025 including the investments resulting from the capacity expansion model as exogenous capacity. Simulations are performed on a week by week basis with an hourly time resolution. Water values generated from the Proactive scenario run are used to calibrate consumption of storable hydro. Aside from the added time resolution the following detail elements for thermal plant operation is added:

- Unit commitment
- Minimum production levels
- Ramp rates
- Start-up and shutdown sequences
- Minimum uptime and downtime

The data for these aspects are described in the data report.

5.5.2 Operational results

Simulation results are presented in the following for 3 sample weeks throughout the year. The three weeks represent three different times where the integration of wind could be challenging:

- Week 2 is selected to look at a cold winter week with high demand in the Maritimes.
- Week 18 is selected to consider the effects of the spring flood.
- Week 36 is selected to consider the effects of low demand in the Maritimes.

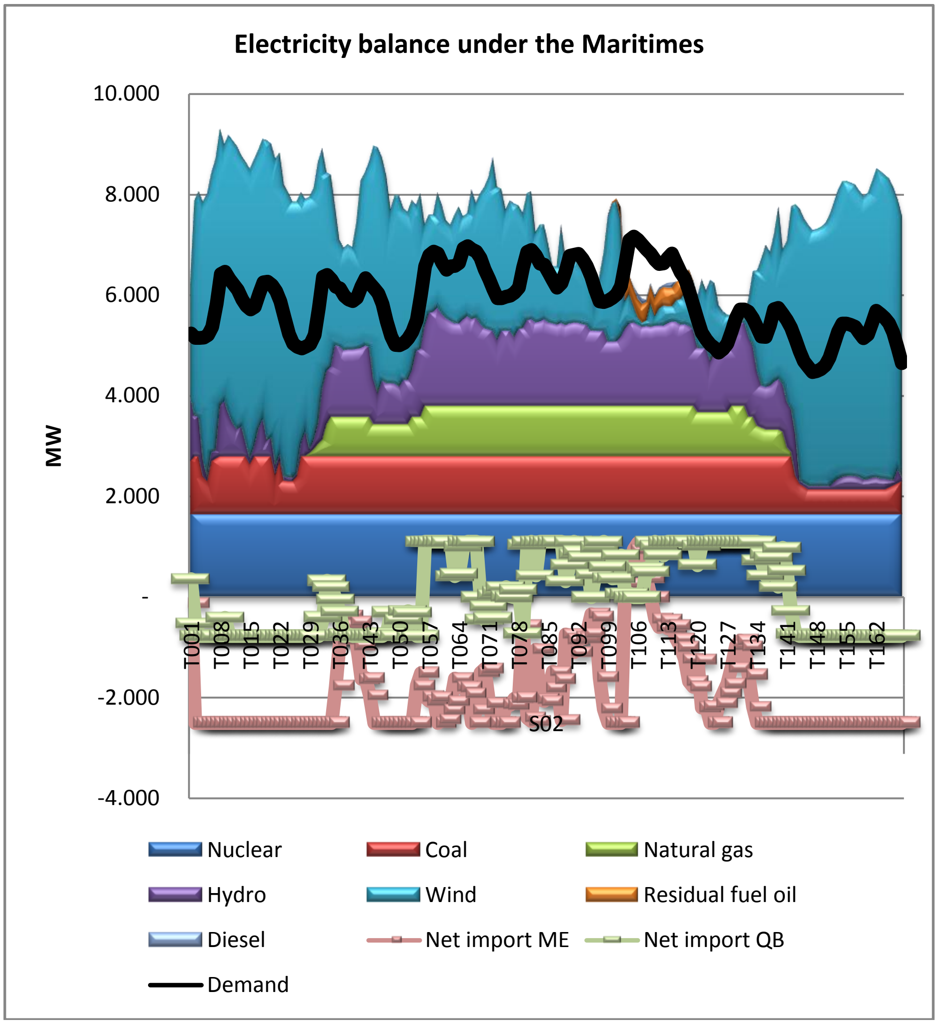


Figure 58: Electricity balance in the Maritimes during peak demand.

The results shown on Figure 58 demonstrate the hourly balance between electricity generation, net exports and consumption in the Maritimes. The peak demand this week is also the annual demand peak. Interestingly, this demand peak falls at a time where there is negligible wind, causing a worst case scenario in terms of balancing wind. The balance is achieved by through lower exports, and simultaneously activation a high level of hydro generation, coal, gas, and a bit of oil based generation to cover the peak in demand.

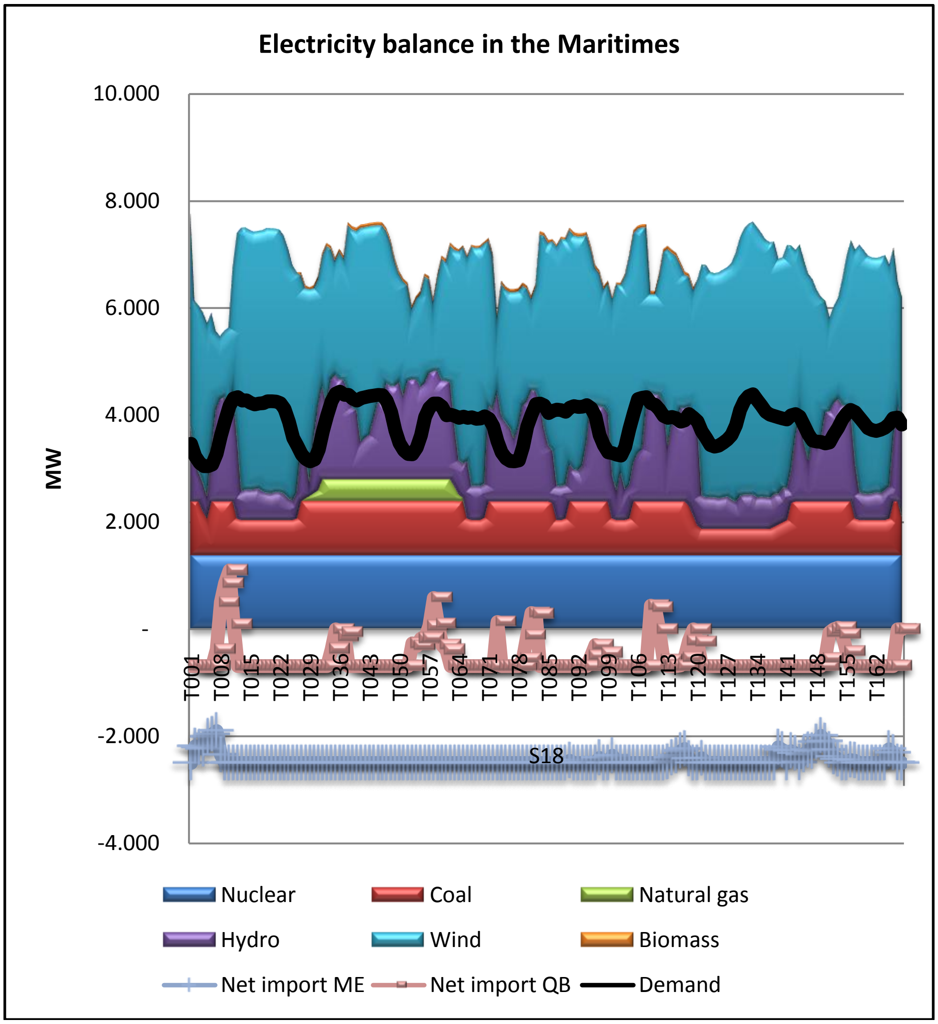


Figure 59: Electricity balance in the Maritimes during spring flood.

During the spring flood generation on New Brunswick's hydro facilities is substantial. In general the levels of exports are high, but a lesser degree of regulation occurs by use of export reductions toward Maine and more towards Quebec. The assumption that there is a full range of regulation options on the hydro coming in from Labrador has a good deal of impact on these results. Even without this, there is still the unexploited option of shutting down coal units.

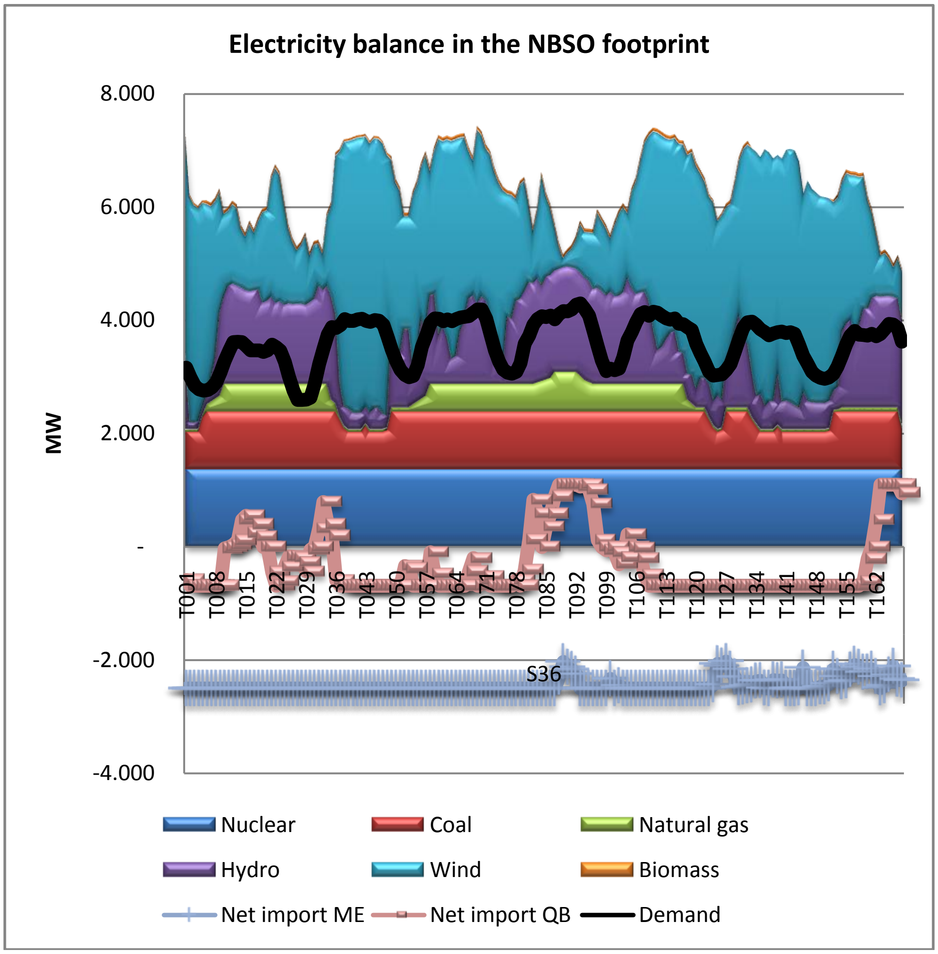
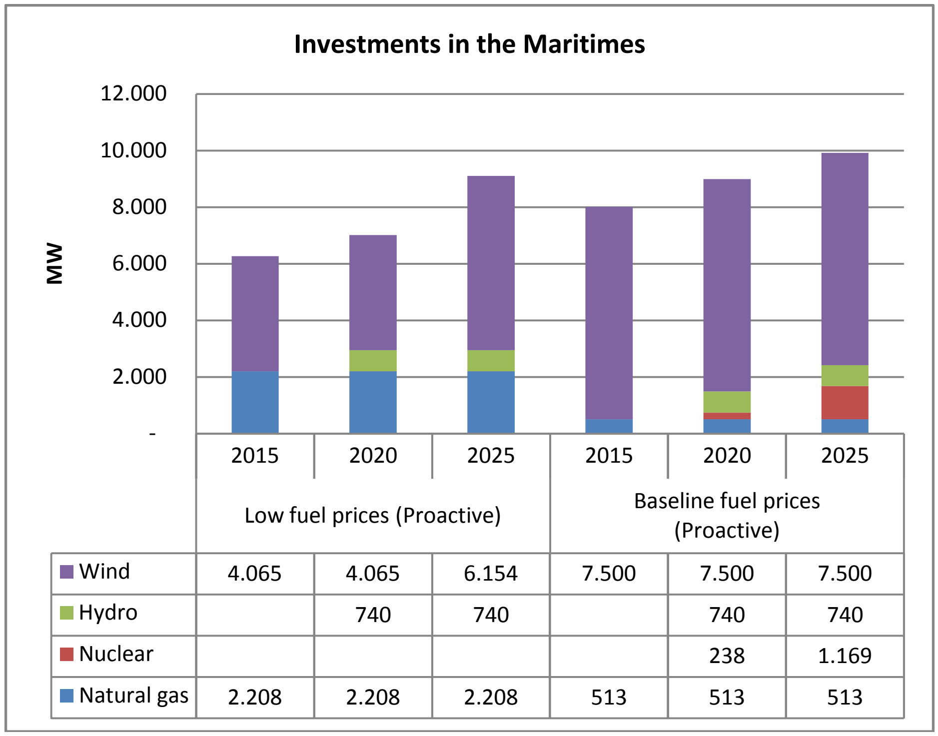


Figure 60: Electricity balance in the Maritimes during a week with low demand.

5.6 Sensitivity analysis with lower fuel prices

As a low fuel price scenario the assumptions pertaining to the IEA's World Energy Outlook 2007 baseline scenario for fuels prices is used. This implies long-term crude prices of 62$/barrel while the medium term prices are below that. An additional run of the Proactive scenario is made using these prices instead of the higher baseline scenario prices.

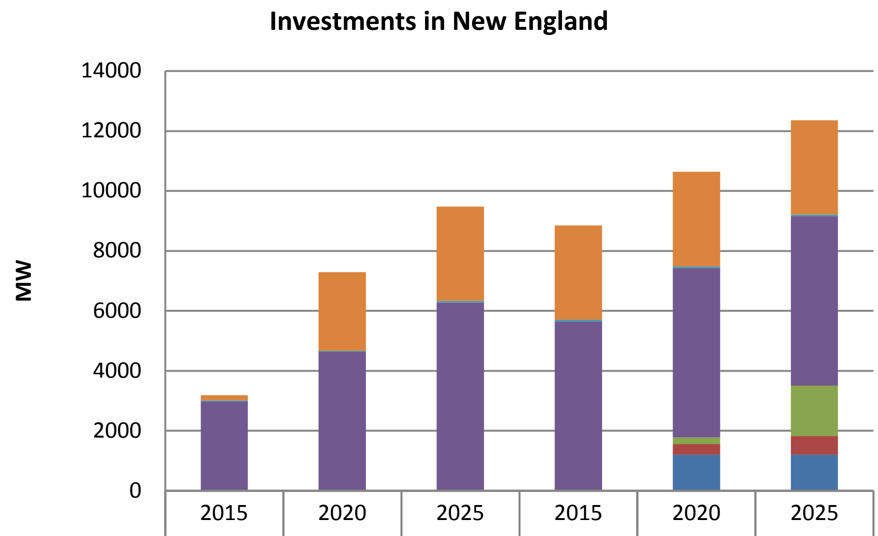


	Low fuel prices (Proactive) 2015	2020	2025	Baseline fuel prices (Proactive) 2015	2020	2025
Wind	4.065	4.065	6.154	7.500	7.500	7.500
Hydro		740	740		740	740
Nuclear					238	1.169
Natural gas	2.208	2.208	2.208	513	513	513

Figure 61: Investments in the Maritimes in the Proactive scenario with low and baseline fuel prices.

The investments shown on Figure 61 are the investments the model undertakes with low fuel prices in comparison with the already discussed baseline fuel prices in the Proactive policy scenario. Interestingly, there are large scale investments undertaken even with the lower fuel prices. Wind power is still economical in light of the targets for renewable and carbon reductions. This gives an indication that if one driver doesn't carry the investments, the other driver will take over.

In New England the same trend is predominant. Wind comes in at a gradual pace rather than initially. This again is an indication that the driver is a gradually tightening of environmental regulations. Less investments are made initially to improve efficiency of natural gas fired generation, but over the long run, more investments are natural gas are made than with baseline fuel prices. This is at the expense of keeping old coal plants online and investing in coal with CCS. The reason is mainly that the spread between gas and coal prices is reduced and therefore gas fired generation is more economical in the long run than coal fired generation.



	2015	2020	2025	2015	2020	2025
	Low_fuelprices			Proactive		
Wind	167	2.622	3.149	3.149	3.149	3.149
Landfill gas	30	30	54	54	54	54
Natural gas	2.987	4.639	6.280	5.652	5.652	5.652
Coal w CCS					229	1.676
Coal					354	628
Nuclear					1.200	1.200

Figure 62: Investments in the New England states in the Proactive scenario with low and baseline fuel prices.

Not surprisingly the overall marginal electricity prices are lower when fuel prices are lower. The still considerable expansion of wind power generation capacity in particular in the Maritimes causes electricity prices in the Maritimes to be lower than in New England, as was the case in the main scenarios.

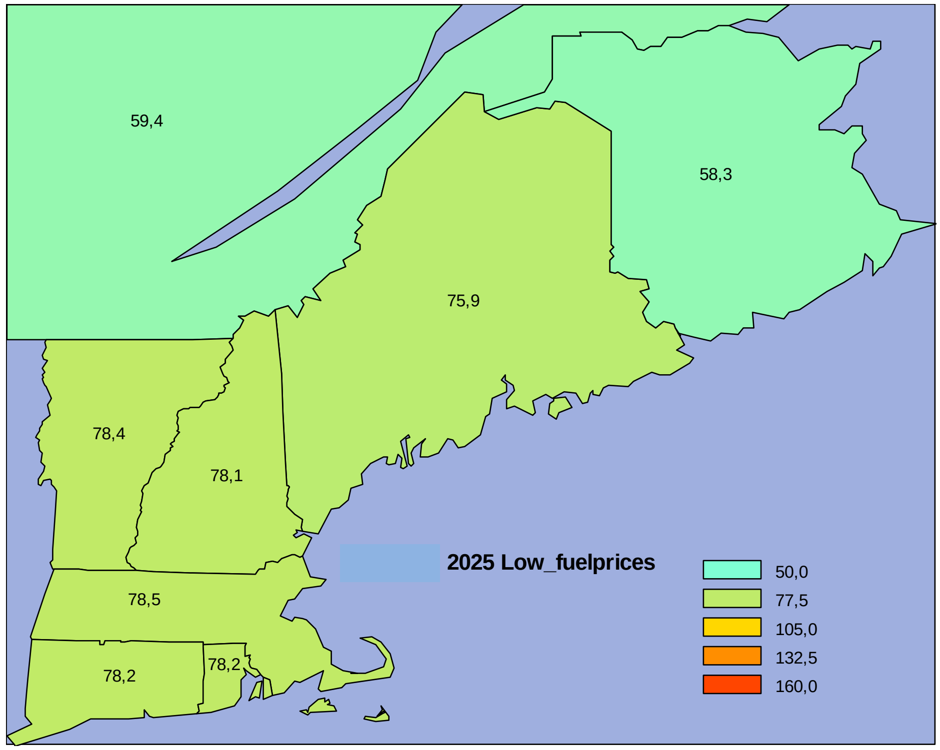


Figure 63: Consumption weighted yearly averaged marginal value of electricity.

5.7 Summing up

In this chapter, the scenario analyses for the electricity markets of the Maritimes and New England to 2025 are presented. The analyses have been carried out for four different policy scenarios with different assumptions on renewable energy, CO2 regulation, psychical planning, market, and transmission. In addition to the "basic analyses" of the four different policy scenarios, also a more detailed operational analyses and a sensitivity analysis with lower fuel prices have been carried out.

The results of the analyses were different scenarios for:

- Investments in new generation resources
- Production and transmission
- Electricity prices or marginal values
- Fuel consumption
- Costs and benefits
- Environmental impact
- Emissions and CO_2/RE credit prices

The policy scenarios were constructed so that they are more and more extensive (in terms of potentials for wind power, power transmission possibilities etc.) with the Passive Scenario as the least extensive scenario and the Proactive Scenario as the most extensive scenario. The results have shown that in each of the three most extensive scenarios, there is a total economic benefit to the society compared to the Passive scenario (baseline), which is in the range of 4 to 6.5 billion CAD. However, in the Transmission Scenario and in the Proactive scenario, the necessary investment costs in increased transmission capacity (of approximately xxx billion CAD) should be deducted from this amount.

The sensitivity analyses with lower fuel prices shows that also in this situation, it is feasible to invest in large amounts of wind power even though the investments in wind power facilities are lower than in the situation with high fuel prices. One reason why there are still large investments in wind power is the presence of the RPS and the CO2 regimes. These two systems ensure that in a situation with lower than expected fuel prices a premium on renewable energy and/or an incentive to reduce carbon emissions make up a "safety net" for the wind power investment.

The main conclusion from the analyses is that it is economically and technically feasible to develop the wind power in the Maritimes area in the order of 5,000-7,500 MW. The few known errors mentioned in the beginning of the report are not expected to compromise this core result. Moreover, exploiting this potential will bring economic benefits to Atlantic Canada as well as to New England.