Atlantic Energy Gateway

Resource Development Modelling Study

A Study of Potential Savings for the Combined Resource Planning of Atlantic Canadian Utilities

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Atlantic Energy Gateway Resource Development Modelling Study Report

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Executive Summary

The Atlantic Energy Gateway (AEG) project is a regional initiative of the federal government, the Atlantic provincial governments, electric utilities of Atlantic Canada and the system operators in New Brunswick and Nova Scotia. The objective of the AEG project is to contribute to the development of Atlantic Canada's clean energy resources by identifying the opportunities and assisting in evaluating the advantages of the region's substantial and diversified renewable energy potential for wind, tidal, biomass/biofuels, and hydro.

The AEG is focused on contributing to identifying greater regional cooperation, benefits, and efficiencies among the various participants in the electricity and clean renewable energy sectors. This particular study was conducted by ABB Technology Ltd (Ventyx) under the direction of the Resource Development Modelling Committee of the AEG. It was undertaken at the request of the AEG Steering Committee and has involved collaborative efforts by the Governments of Canada, the Atlantic Provinces and the Atlantic region electric utilities. This document is the final report of the AEG - Resource Development Modelling Committee.

The fundamental hypothesis behind this study is that benefits can be achieved by regional planning of future electric generating resources rather than planning separately as is done today. Each of the Atlantic utilities currently develops an integrated resource plan (IRP) for its medium and long term future generation development. The objective in this study was to model a more integrated view of the region and determine the economic and environmental benefits compared to the individual provincial models.

Resource development planning identifies the long term optimization of power system supply, demand and transmission resources to meet projected reliability, environmental and economic targets. To achieve the study results, an optimization computer simulation tool called *Strategist*® was used. NB Power, NS Power and NL Hydro currently utilize *Strategist*® and had developed a partial Atlantic simulation model to evaluate the Muskrat Falls portion of the Lower Churchill hydro development entering the region, including the transmission links from Labrador to Newfoundland and from Newfoundland to Nova Scotia. By adding PEI and Northern Maine to this existing model plus revised representations of the Hydro Québec and ISO New England markets, a more detailed expansion simulation was developed for Atlantic Canada.

Study parameters and assumptions were developed by the Resource Development Modelling Committee with assistance from Ventyx. Commercially sensitive confidential utility data was

supplied directly to Ventyx and protected via non-disclosure agreements. Ventyx executed the *Strategist®* model to recreate the proposed IRPs of the four provincial utilities and then compared the sum of their costs against the costs of operating the combined Atlantic region. All of the resource development options particular to each utility's IRP were available in the analysis which included the renewable energy potential for wind, tidal, biomass, and hydro plus nuclear and natural gas options. Several environmental regulations were included as development constraints. These included: renewable energy standards, SO_2 and NO_x requirements for each province, CO_2 emission reduction to 5 Mte by 2020 in Nova Scotia and the federal requirement for coal fired power plants to emit CO_2 equivalent to a combined cycle natural gas plant or better or retire after a 45 year life. In this study, coal fired power plant retirement was assumed for New Brunswick but an equivalent cap of 5 Mte by 2030 and 4.5 Mte by 2040 was assumed by Nova Scotia. While this does not exactly match the profile of the CO_2 emission cap of the proposed equivalency agreement between the province of Nova Scotia and the federal government related to the GHG Regulations (as these limits were still under negotiation during this study work), this assumption is sufficiently close to give confidence in the results.

The systems were simulated in detail for the study period of 2015 through 2040 with the capital costs of each new generation resource charged at its escalating economic carrying cost. This approach treated projects of differing lives within the study period on a level playing field and eliminated the need to conduct an end effects analysis beyond 2040. Analysis was completed to determine Least Cost resource model results for a reasonable forecast of future conditions (Base Case scenario), for a High Natural Gas Price future, for a Low Load future and a scenario with Limited Transmission Expansion between NB and NS. In each of these cases (except for the Limited Transmission Expansion), expansion of the NB-PEI and NB-NS interconnections was assumed to be increased significantly above current transfer levels and the cost of the assumed transmission expansion is not included in the resource models. In addition to Least Cost model results several "Plans of Interest" were selected to reflect development strategies that focused on Natural Gas, Nuclear in NB and High Renewable Penetration if these were not part of the least cost model. These resulting models were subsequently simulated in greater detail to determine annual energy sources and emission levels. The results of the net present value (NPV) analysis of resources options are provided in Figure 1.

A number of resource options (Lower Churchill project for NL Hydro, Lower Churchill participation for NS Power and Grand Falls Redevelopment and Coleson Cove units 1 and 3 conversion to natural gas) are committed in the provincial base case as part of their IRP's and by such their costs and benefits relative to existing resources today are not captured in these model results.

Figure 1
NPV Costs of Different Resource Development Plans
($Millions)

	Sum of Standalone Provincial Systems with Existing Transmission			Combined Regional System with Expanded Transmission			Combined Regional
Scenarios:	Base Case	High Gas Price	Low Load	Base Case	High Gas Price	Low Load	Limited Transmission
Plans of Interest:							
Nuclear (least Cost)	**$22,395**	**$24,228**	**$17,730**	**$21,516**	**$23,199**	**$17,146**	**$21,608**
Natural Gas	**$22,453**	**$24,465**	**$17,769**	**$21,624**	**$23,534**	**$17,232**	**$21,710**
High Renewable	**$22,408**	**$24,475**	**$17,769**	**$21,635**	**$23,541**	**$17,249**	**$21,718**

In viewing these modeled potential resource results the reader is cautioned that they are indicative and directional in nature. Simulation of power system expansion over a period of 30 years is an approximate exercise subject to many assumptions. The optimization model results were derived from the assumption set and hold true only to the extent that the assumptions are accurate. It is important to understand that the results are not the total revenue requirement for the region but only the costs of fuel, optional new generation O&M and capital, and new generator interconnection capital. There is no consideration of any existing or future costs for in province distribution and transmission and there is no consideration of capital for existing generation resources. It is generally accepted that these will be common across the Cases and net-out of the comparative analysis. Finally, the opportunity to achieve NPV benefits resulting from combined regional planning have not been segregated by province. Opportunities are shown from an Atlantic region perspective only.

Comparison of the different resource scenarios and development plans provided the following findings:

> The Nuclear in NB plan, based on cost assumptions, is the least cost expansion for the Base Case scenario and the combined regional resource plan is $879 million less cost than the sum of the separate provincial plans. This resource benefit is sufficient to pay the cost of the transmission expansions estimated at $565 million in 2015 and provide a net benefit to the ratepayers of the region of $314 million. The primary development components, other than Nuclear in NB in 2038, are 114 MW of wind in NS in 2015, three small hydro projects in NL in 2019, 2021 and 2023, a 250 MW combined cycle gas unit in NS in 2030, a 400 MW combined cycle gas unit in NB in 2032 and a 130 MW combined cycle gas unit in PEI in 2033. The higher gas price in the High Natural Gas Price scenario makes the nuclear plan even more economic than the Base Case Scenario and the regional plan has a NPV benefit of $1029 million (net benefit of $464 million) compared to the High Gas stand-alone provincial plans. Other than installation of 100 MW of wind in each of NS in 2035 and NL in 2039, this High Gas Scenario has the same combined regional resource expansion plan as the Base Case.
>
> In the Low Load Scenario the least cost plan is still the nuclear expansion but with the combined regional resource NPV benefits reduced to $584 million (net benefit of $19 million). The Low Load Scenario development plan is similar to the Base Case except that a 400 MW combined cycle gas unit in NB was deferred from 2032 to 2039.
>
> The Limited Transmission sensitivity reduces transfer capabilities from the Expanded Transmission Cases and increases the NPV cost of supply resources by $92 million compared to the combined regional system Base Case. The expansion plan is the same as the High Gas plan except that the 100 MW of wind in NL is delayed from 2039 to 2040. The wind in NS and NL occurs because the limited interconnection reduces the opportunity for economy transfers from NB to NS so it is needed to enable NS to operate within its CO_2 cap.

The value of any development plan is not just measured in financial differences. Given the global concerns regarding climate change and associated policies to reduce greenhouse gas (GHG) emissions, the amount of emissions from a particular plan is extremely important. Under the Expanded Transmission Base Case, overall regional emissions are reduced by 64% from 2005 levels.

The relative energy mix in a resource development plan is also of interest, not just because of its influence on emissions, but also from the perspective of diversity of fuel source risk and fuel price volatility. Fuel sources of coal and oil are imported and depend on world markets for cost and availability while wind and hydro are local and natural gas is currently an indigenous resource (though subject to international market pricing). In the Expanded Transmission Base Case the large increase in hydro by 2020 combined with natural gas and a large nuclear after 2030 reduces coal and oil generation from its 49% share in 2005 to only 6% by 2040.

Preliminary estimates have determined that the cost of the two transmission expansions between NB-PEI and NB-NS is $565 million in 2015. With an Expanded Transmission Base Case resource benefit of $879 million the transmission can be paid for and still provide $314 million of benefit for regional ratepayers. However, the Limited Transmission Sensitivity suggests a benefit of $787 million. These preliminary estimates require further analysis and would need to be confirmed through a comprehensive transmission study. While this particular Sensitivity assumed no expansion of the existing transmission interties, based on current system operating conditions transmission expenditures will be necessary to maintain the present transfer limits into the future. Accordingly, the benefit of the Limited Transmission Sensitivity is somewhat inflated. Regardless, the resource benefits derived in this study are only one component of total benefit of transmission and the other considerations (reliability) need to be analysed and understood prior to any commitment to expand the interconnections. In short, more detailed transmission analysis work is required and it must be integrated with additional resource analysis in order to determine an optimum expansion plan for the region.

While much of this discussion has been focussed on the benefits derived in the model, important areas for policy consideration which establish the winning conditions for renewables described in the modeling are as follows:

- <u>Natural Gas Supply and Infrastructure</u> - This resource modeling study shows increased use of natural gas for electricity generation in all scenarios examined. Development of a long-term regional plan focussed on security of natural gas supply and pipeline infrastructure needs would help ensure that the region could enjoy the forecasted cost and the air emission benefits of natural gas generation.

- <u>Enhanced Transmission Interties</u> - Transmission transfer capacity within the region promotes the sharing of renewable resources and is an important enabler of regional cooperation. There are significant transmission expansion decisions to be made in the near- to mid-term. A finding of this resource modeling study is that additional transmission analysis is required by the utilities in order to determine an optimal plan for transmission intertie expansion within the region.

- <u>Hydroelectric Power</u> - Hydroelectric generation grows to approximately 45% of the region’s electricity supply by 2040. Hydro provides renewable energy but, equally important, it can supply valuable regulation and load following capacity which is a critical enabler of wind and tidal generation. Efforts to promote new and protect existing hydro generating resources are important to allow the progress of other renewables in the region.

Background

The Atlantic Energy Gateway ("AEG") is an Atlantic Canada electricity and clean renewable energy project funded and coordinated by the Federal Government Department of Natural Resources Canada ("NRCan") and The Atlantic Canada Opportunities Agency ("ACOA"), with participation from the Governments of New Brunswick ("NB"), Prince Edward Island ("PEI"), Nova Scotia ("NS"), and Newfoundland and Labrador ("NL"); four of the region's major electrical utilities: New Brunswick Power Group of Companies ("NB Power"), Maritime Electric Company Limited ("MECL"), Nova Scotia Power/Emera Inc. ("NS Power"), and Nalcor/Newfoundland and Labrador Hydro Corporation ("NL Hydro"); and the region's two system operators, New Brunswick System Operator ("NBSO") and Nova Scotia Power System Operator ("NSPSO").

The AEG is focused on contributing to identifying greater regional cooperation, benefits, and efficiencies among the various participants in the electricity and clean renewable energy sectors through increased collaboration, discussion and analysis of existing utility assets, and future requirements including additional clean and renewable energy resources for regional and export purposes.

The AEG participants have worked collaboratively over the past two years sharing existing information pertaining to the electricity systems, development of Atlantic Canada's clean and renewable energy resources, and where necessary, undertaking new analysis to improve the understanding of the region's electricity industry.

Some of the major components of the AEG work included: workshops on individual energy components in each of the four Atlantic Provinces; working committees on functional sectors such as transmission, resource generation, system operations; meetings and conference calls; participation by industry experts; and a number of professional external studies designed to provide a strategic and factual foundation on topics such as renewable energy financing, renewable energy R&D, supply chain development, and a study of the Eastern Canada and Northeast United States marketplace for electricity.

This ***Resource Development Modelling Study*** is one of those professional external studies with the purpose of determining if there are long term economic and environmental benefits arising from the coordination of planning the development of regional generating assets compared to planning within the utilities current provincial jurisdiction. Resource development planning is a complex iterative process that needs technical skill sets supported with specialized computer simulation models to determine optimization of power system supply, energy demand profiles and transmission infrastructure. The operational requirements are established by the market rules, procedures and tariffs applicable to the operation of the systems under study. The issues of reliability, environmental emission targets and economic targets influence the rules established by government policy and regulators.

A Resource Development Modelling Technical Committee (comprised of modelling experts from the modeling consultant Ventyx, the Atlantic utilities, and independent consultants) provided advice to the Steering Committee of government officials. The committee selected technical support from Ventyx through consultation with utilities, consultants and experts because of their current role of providing similar services to the regional utilities and professional reputation. This Technical Committee developed terms of reference for the study implementation and provided necessary data and technical support to Ventyx for the modelling work. Each utility entered Non-Disclosure Agreements with Ventyx to protect data and detailed study results deemed to be commercially sensitive.

Study Approach

Overview

Each of the regional utilities currently develops an integrated resource plan (IRP) for its medium- and long- term future generation and transmission development. These IRPs are often reviewed by provincial regulators and, although the results are made public through the regulatory process, confidential data is withheld from public scrutiny. The approach in this study was to develop a potential regional IRP and determine the economic and environmental savings from taking a regional planning and development approach.

To do so required that a regional simulation model be developed so that its IRP profile could be compared to the sum of the individual utility IRPs. The terms of reference sought a model that would determine the least cost base case plan as well as plans that integrate increasing amounts of clean, renewable and non-emitting energy sources for varying domestic and export loads. The modelling approach followed three steps as follows:

- Simulation Model Development and Database Adaptation
- Base Case Analysis
- Sensitivity Analysis

Progress and results were reported by Ventyx to the Technical Committee on a continuous basis and updates were provided to the Steering Committee at the conclusion of each phase.

Simulation Model Development and Database Adaption

An IRP involves a computer optimization simulation tool that selects a set of generation expansion options at future years that will result in the least net present value (NPV) cost for the selected time period. This requires detailed modelling of projected generation construction and operation and associated costs for the study period (2015 to 2040 for this study). It also requires consideration of the economic value of the model results beyond the study period because power system generators have very long and differing length lives (in this study the economic carrying charge method was used to deal with this issue). The generation related options available (wind, biomass, tidal, natural gas, nuclear, demand side management, etc.) can be numerous with varying sizes.

The foundation for the simulation model was established using the base model for each utility including the existing systems and the commitments already made respecting future generation sources. This enabled the optimization simulation to operate efficiently and produce feasible model results for generation development in the region. For this study screening was done collaboratively by the Technical Committee and the detailed development plan modelling was completed by Ventyx with its *Strategist*® IRP optimization tool for plan development.

The existing data sets from the three regional utilities that license *Strategist*® (NS Power, NB Power & NL Hydro) formed the basis of the regional model, and were supplemented with data for PEI. Market data for Quebec, New England and Northern Maine were included as well. The Technical Committee reviewed common data and adjusted where necessary to create a consistent dataset for the region. Confidential data (such as heat rates of existing units, unique parameters of a new option, etc.) were provided directly to Ventyx by each utility and protected via the non-disclosure agreements. Ventyx reviewed this confidential data and provided assurance to the Technical Committee that it was reasonable and consistent. Adjustments to necessary items were made by Ventyx in confidence through discussions with the utility owning such data.

It should be noted that *Strategist®* is not a transmission optimization model. Accordingly the Technical Committee made assumptions about existing and expanded transmission capability, particularly related to transmission interties between companies. These assumptions were evaluated in relation to utility import and export outputs from the model.

The *Strategist®* database was used to conduct PROVIEW module optimization runs that generated multiple resource development models and their associated NPV costs. Because PROVIEW does not store all the information of interest for every plan that it produces greater detail on specific models were generated by the Generation And Fuel (GAF) module to provide annual generation, cost and emissions results.

<u>Base Case Analysis</u>

The Base Case was based on the projected load, fuel and market prices, and generator cost and performance parameter updates deemed necessary by the participating provincial utilities. The following assumptions were also included:

- 45 year retirement of coal plants in New Brunswick
- CO_2 emission hard caps to 2030 and beyond for Nova Scotia in alignment with the assumed provisions of an equivalence agreement with Environment Canada
- Natural gas prices based on current futures and the US Energy Information Agency outlooks with appropriate tolls applied (forecast derived with information available in December 2011)
- Load forecasts and generating options
- For the combined system, 500/250 MW transfer capability between NL-NS, 800 MW between NS-NB and 350 MW between NB-PEI
- For the individual system runs the existing intertie transfer capabilities were used for NB-NS and NB-PEI (although the NS import from NB was reduced to 100 MW to better reflect the limitations that have emerged on this interface)

Running the Base Case required five separate PROVIEW optimization runs: one for each of the four provincial models with plan optimality and rankings selected on the basis of what is best for a single province and a final combined optimization model with the plans optimized across the entire region. For the individual provincial models it was necessary to “fix” the future resource plans for the remaining three provinces. The “fixed” plans used were the same models that resulted from the separate databases before combining them.

The Base Case output from PROVIEW produced numerous potential generation development scenarios from which was identified the models most in line with the development strategies of – least cost plan, natural gas expansion, high renewable expansion and nuclear expansion. Once these models were selected, GAF runs of each model were completed to determine more detailed energy utilization, cost and emission impacts by year.

<u>Sensitivity Analysis</u>

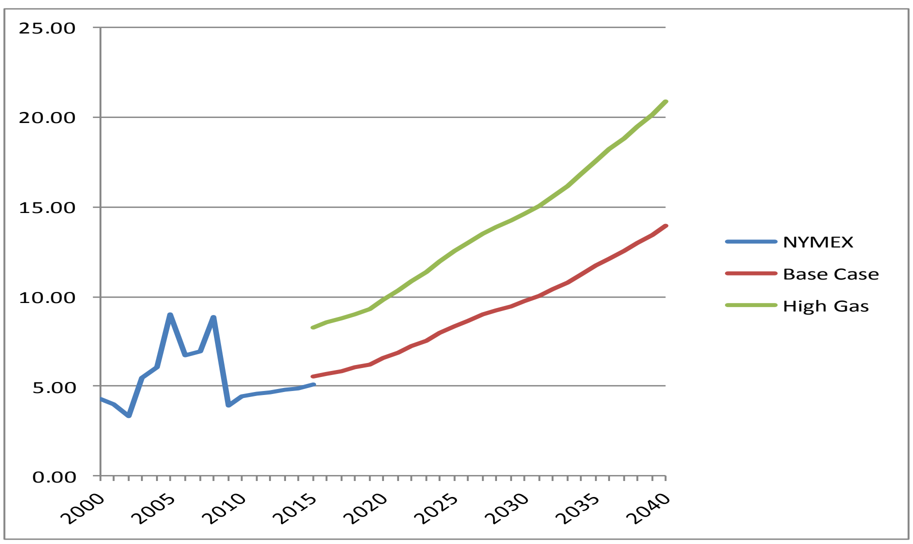
A sensitivity analysis was conducted against the Base Case Scenario to produce a High Natural Gas Price Scenario and a Low Load Growth Scenario for both individual provinces and combined regional system models. A separate model of a Limited Transmission Scenario was undertaken for the combined regional model to assess the impact of transmission restrictions. The primary focus in the sensitivity analysis was to determine the least cost plans for all scenarios and compare resulting NPV costs to the base case. The computer simulation runs required for the various scenarios are provided in Figure 2.

Figure 2
Resource Development Modelling Study Computer Model Runs

	Standalone Provincial Systems with Existing Transmission Interties			Combined Regional System with Expanded Transmission Interties			Combined System: Limited Trans-mission
Scenarios (Proview Runs)	Base Case	High NG Price	Low Load	Base Case	High NG Price	Low Load	
Plans of Interest: (Devel. Themes)	1A Least Cost	2A Least Cost	3A Least Cost	4A Least Cost	5A Least Cost	6A Least Cost	7A Least Cost
	1B Gas	2B Gas	3B Gas	4B Gas	5B Gas	6B Gas	7B Gas
	1C High Renewable Penetration	2C High Renewable Penetration	3C High Renewable Penetration	4C High Renewable Penetration	5C High Renewable Penetration	6C High Renewable Penetration	7C High Renewable Penetration
	1D New Nuclear in NB	2D New Nuclear in NB	3D New Nuclear in NB	4D New Nuclear in NB	5D New Nuclear in NB	6D New Nuclear in NB	7D New Nuclear in NB

The High Natural Gas Price Scenario applied the same assumptions as the Base Case except that it increased natural gas prices by 50% as shown in Figure 3.

Figure 3
Natural Gas Prices ($/MMBtu)



The objective with this High Natural Gas Price case was to determine the relative impact of low capital cost generation with high fuel risk (gas combined cycle) compared to high capital cost generation options with low fuel risk (wind and nuclear). Figure 3 illustrates the natural gas prices used for the sensitivity (high gas) and base case analyses. Note that historic and projected NYMEX prices at Henry Hub are provided for 2000 through 2015. The prices shown for the Base Case are the annual average natural gas prices from the Annual Energy Outlook 2012 produced by the Energy Information Agency of the US Department of Energy, with a basis differential adder of $0.45/MMBtu for pipeline transportation between Henry Hub and the Maritimes. In the actual modelling these were applied at 95% for summer (April-October) and 110% for winter

(November-March). This seasonal differential reflects both the seasonal nature of NYMEX price variation and especially the seasonal basis differential for pipeline congestion.

The High Gas price was also applied at 95% for summer and 110% for winter. It is worth noting that the natural gas prices applied in the study may seem high considering the current low price of natural gas at Henry Hub (recently in the $2.50/MMBtu range). This current low price is considered an anomaly by industry because of a number of factors (unusually warm winter, high storages, high value of wet gas liquids, locked in discoveries). The forward prices are much higher and consistent with the forecasts of the Energy Information Agency of the US Department of Energy. The High Gas price is not necessarily just a potential price increase at Henry Hub it also could result because of Atlantic Canada supply shortages such that additional basis differential would need to apply to procure natural gas from the Boston area and transport it north.

The Limited Transmission Scenario applied the same data as the Base Case except that the NB-NS interconnection was reduced from 800 MW to the existing interconnection capacities and the NB-PEI interconnection was reduced to the existing 200 MW capacity. The objective here was to determine if less transmission transfer capability (with less cost) may still achieve enough regional benefits to be a more economically attractive approach.

The Low Load Growth Scenario was completed with all the same data as the Base Case except for a lower load for each province. This reflected the potential load impacts of lower economic growth and assuming potential loss of some large industrial loads which would result in reduced energy demand/sales and reduced generation capacity requirements. The impact of higher load growth was also examined but not in detail during the regional analysis.

Summary of Results

The results of the NPV analysis of resources options produced by PROVIEW are provided in Figure 4. Note that a number of resource options (Lower Churchill project for NL Hydro, Lower Churchill participation for NS Power and Grand Falls Redevelopment and Coleson Cove units 1 and 3 conversion to natural gas) are committed in the provincial base case as part of their IRP's or commercial arrangements and as such their costs and benefits relative to existing resources today are not captured in these model results.

Figure 4
NPV Costs of Different Resource Development Plans
($Millions)

	Sum of Standalone Provincial Systems with Existing Transmission			Combined Regional System with Expanded Transmission			Combined Regional Limited Transmission
Scenarios:	**Base Case**	**High Gas Price**	**Low Load**	**Base Case**	**High Gas Price**	**Low Load**	
Plans of Interest:							
Nuclear (least Cost)	**$22,395**	**$24,228**	**$17,730**	**$21,516**	**$23,199**	**$17,146**	**$21,608**
Natural Gas	**$22,453**	**$24,465**	**$17,769**	**$21,624**	**$23,534**	**$17,232**	**$21,710**
High Renewable	**$22,408**	**$24,475**	**$17,769**	**$21,635**	**$23,541**	**$17,249**	**$21,718**

In viewing these results the reader is cautioned that these are indicative and directional in nature. Modelling of power system demand, costs and expansion needs 30 years into the future is an approximate exercise subject to many assumptions. It is also important to understand that the results are not the total revenue requirement for the region but only the costs of fuel, generation Operations and Maintenance (O&M), new generation capital cost funding and new interconnection capital cost funding. Therefore these model outcomes are best used for comparative purposes, case to case, rather than as expressions of total system costs. Additionally, it must be noted that there is no consideration of any existing or future costs for in province distribution and transmission and there is no consideration of capital for existing generation resources. These exclusions are considered appropriate as they would be largely common across the cases. Finally, the opportunity to achieve NPV benefits resulting from combined regional planning have not been segregated by province. Opportunities are shown from an Atlantic perspective only.

The following sections analyse these results in greater detail.

Base Case Analysis Results

The Base Case analysis projected the sum of Net Present Value (NPV) costs of current standalone provincial IRP implementation compared to a combined regional IRP to determine if there were potential benefits. As shown in Figure 5 the Least Cost regional plan included the Nuclear unit in NB with a 2015 NPV benefit of $879 million. Given that the transmission upgrades to the NB-NS and NB-PEI interconnections that were assumed in the analysis are projected to cost[1] about $565 million, a combined regional plan with the transmission upgrades completed by 2015 can pay for the transmission and still produce $314 million in savings for ratepayers.

Figure 5
Base Case NPV Results
($Millions)

Plans	Standalone Provincial Systems with Existing Transmission Interties	Combined Regional System with Expanded Transmission Interties	Differences
Nuclear in NB (Least Cost)	$ 22,395	$ 21,516	$ 879
Natural Gas	$ 22,453	$ 21,624	$ 829
High Renewable	$ 22,408	$ 21,635	$ 772

The value of an alternative development plan is not just measured in financial differences. Given the global concerns regarding climate change and associated policies to reduce greenhouse gas (GHG) emissions, the amount of emissions from a particular plan is extremely important. Figure 6 plots the annual regional GHG emissions[2] over the study period for the regional Least Cost – Nuclear in NB case and compares them to actual emissions in 2005 and 2010. Overall regional emissions are reduced by 64% from 2005 levels.

[1] The cost estimates for the transmission upgrades are detailed in the "AEG Transmission Modelling Study Report."
[2] GHG emissions in the power sector are composed almost entirely of CO_2 from combustion of fossil fuels and are measured as tonnes of CO_2 equivalent.

Figure 6
Base Case Nuclear Plan Emissions
(Tonnes of CO_2)

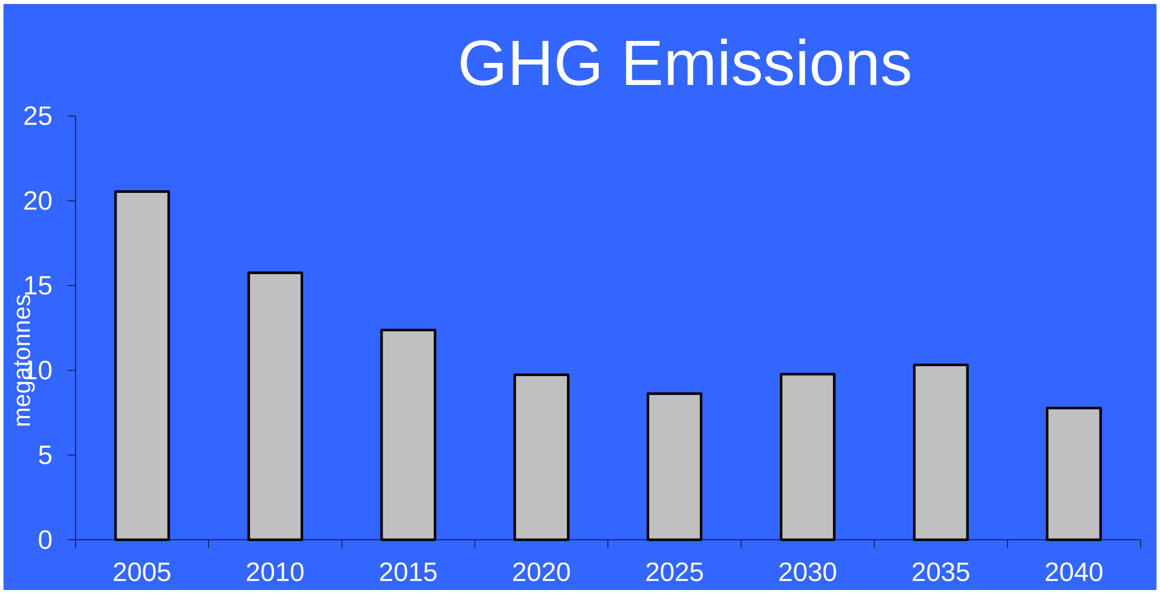
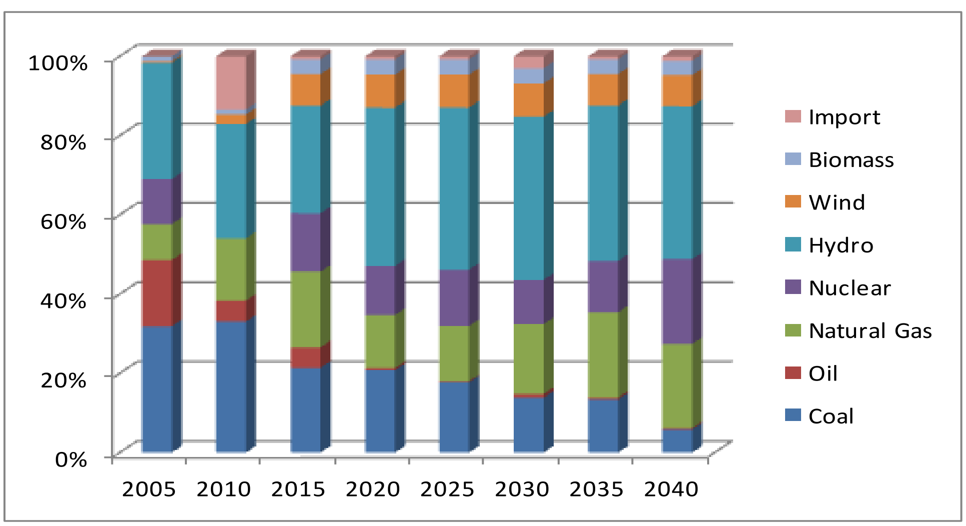


Figure 7
Generation Energy Mix (%GWh)
Base Case Least Cost – Nuclear in NB



The relative energy mix in a resource development plan is of interest, not just because of its influence on emissions, but also from the perspective of diversity of fuel source risk and fuel price volatility. Fuel sources of coal and oil are imported and depend on world markets for cost and availability while wind and hydro are local and natural gas is currently an indigenous resource. Figure 7 provides the relative energy mix for the Base Case Least Cost Plan for the study period and compares them to the actual mix that occurred in 2005 and 2010. Note the large increase in hydro by 2020 as a result of the Muskrat Falls plant and the reduction of coal and oil generation from 49% in 2005 to only 6% by 2040. Also note the amount of imports is small in all years except 2010 when large purchases occurred because of the Point Lepreau outage and low natural gas prices that made ISO-NE imports economic relative to regional oil fired generation.

Additionally, with the region’s current natural gas pipeline infrastructure, it will be important to ensure that the development of natural gas units across the region does not outstrip the capacity of the pipeline facilities to deliver a reliable, secure fuel supply to existing and proposed new gas fired generation. Collaborative planning would be required by the utilities if new gas fired generation is brought on line, in order to understand the risk of generation loss to the region that could result from the interruption of fuel supply from the natural gas transmission pipelines.

Sensitivity Analysis Results

NPV sensitivity results for the High Gas Price Case scenario, the Low Load Growth Scenario and the Limited Transmission Expansion scenario are provided in Figure 8. Note that the Combined Regional System includes expanded transmission for the NB-NS and NB-PEI interconnections in the High Gas and Low Load sensitivities but not in the Limited Transmission sensitivity.

Figure 8
Sensitivity Analysis NPV Results
($Millions)

Plans	Standalone Provincial Systems with Existing Transmission Interties	Combined Regional System	Differences
High Gas Prices	$24,228	$23,199	$1,029
Low Load	$17,730	$17,146	$583
Ltd Transmission	$22,395	$21,608	$787

Comparison of these sensitivity results with the Base Case results in the previous section provides several findings of interest as follows:

- The higher gas price in the High Natural Gas Price scenario makes the nuclear plan even more economic than the Base Case Scenario and the regional plan has a NPV benefit of $1029 million compared to the High Gas stand-alone provincial plans. The stand-alone plan for NL is unchanged from the Base Case while the plans for NB, NS and PEI add wind and tidal rather than combustion turbines. Other than installation of 100 MW of wind in each of NS in 2035 and NL in 2039, this High Gas Scenario has the same combined regional resource expansion plan as the Base Case. But even with this additional wind the regional CO_2 emissions are higher by about 1.5 Mte prior to 2030 before reducing gradually from 0.8 Mte higher in 2030 to 0.4 Mte lower by 2040. This is caused mainly by increased use of coal in NB and NS which is more economic than the higher priced natural gas.

- In the Low Load Scenario the least cost plan is still the nuclear expansion but with the combined regional resource NPV benefits reduced to $583 million. The 100 MW of wind in NL that appears in both the High Gas Price case and the Limited Transmission case is not included in the Low Load case. As expected CO_2 emissions in this Low Load scenario are lower in all years by about 2 Mte.

- The Limited Transmission sensitivity reduces transfer capabilities from the Base Case and increases the NPV cost of supply resources by $92 million compared to the combined regional system Base Case. The expansion plan is the same as the High Gas Price plan except that the 100 MW of wind in NL slips its in service from 2039 to 2040. The wind in NS and NL occurs because the limited interconnection reduces the opportunity for economy transfers from NB to NS so it is needed to enable NS to operate within its CO_2 cap.

This result for the Limited Transmission is insightful. As was discussed in the Base Case Results section, preliminary estimates have determined that the cost of the two transmission expansions between NB-PEI and NB-NS is estimated at $565 million in 2015. With a Base Case resource benefit of $879 million the transmission expansion can be paid for and still provide $314 million of benefit for regional ratepayers. However, the Limited Transmission Sensitivity, as modeled, provides $787 million of net present benefit. These preliminary estimates require further analysis and would need to be confirmed through a comprehensive transmission study.

While this particular Sensitivity assumed no expansion of the existing transmission interties, the available transfer capacity of the NB to NS interface has diminished in recent years and it would be reasonable to expect that this decay will only continue over time with local load growth leaving negligible capacity available for firm or economy energy transactions. Accordingly, the benefit of the Limited Transmission Sensitivity is somewhat inflated as some level of transmission expenditures will be necessary to maintain the present transfer capacity into the future. Regardless, the resource benefit determined in this study is only one component of total benefit of transmission and the other components need to be analysed and understood prior to any commitment to expand the interconnections. In short, more detailed transmission work is required and it must be integrated with additional resource analysis in order to determine an optimum expansion for the region. However, it is apparent that a reduced amount of transmission expansion expenditure, from that assumed in the base case, can provide necessary transmission transfer capacity for energy resource optimization. Additional drivers like system reliability, inter-system balancing, reserve sharing and others could combine to require tie line capacity expansions similar to those initially assumed.

A supplemental analysis regarding the potential impact of a tidal energy development opportunity was also undertaken. This analysis determined that tidal energy development would displace CO_2, which would be positive in helping enable Nova Scotia to operate within its CO_2 cap. Large scale deployment of tidal generation would be selected if it was cost-competitive with other clean and renewable sources.

Conclusions

Combined regional planning provides an opportunity to achieve NPV savings in the range of $314 to $787 million dependent on the cost and achievable transfer capacity benefit of transmission expansion to the NB-NS and NB-PEI interconnections.

Observations arising from this study for policy consideration or for further work are as follows:

- There are few significant resource decisions to be taken in the coming decade given that many key decisions for that planning window have been already made (not all on a regional basis) before or during the AEG process.

- This resource modeling study shows increased use of natural gas for electricity generation in all scenarios examined. Development of a long-term regional plan focussed on security of natural gas supply and pipeline infrastructure needs would help ensure that the region could enjoy the forecasted cost and the air emission benefits of natural gas generation.

- Follow up to the AEG work is required for further transmission analysis. A finding of this resource modeling study is that additional transmission analysis is required by the utilities in order to determine an optimal transmission intertie expansion within the region. Transmission transfer capacity within the region promotes the sharing of renewable energy resources and is an important enabler of regional cooperation. There are significant transmission expansion decisions to be made in the near term.

- Hydroelectric generation grows to approximately 45% of the region's electricity supply by 2040. Hydro provides renewable energy but, equally important, it also provides valuable regulation and load following capacity which is a critical enabler of wind and tidal generation. Efforts to promote and protect hydro generating resources are important to allow the progress of renewables in the region.

- Further work is needed to determine how much variable generation can be integrated into the regional resource mix. The *Strategist*® simulation program, like most computer simulations of its type, is not capable of a full representation (sub-hour) of the intermittent nature of wind generation. This additional work could focus on the continued availability of existing hydro, the introduction of additional fast acting generation resources to provide for load following, or other integration options like storage, load shifting, and regional dispatch.

- While some of the resource development options identified in this study are triggered to serve load or respond to capacity retirements, compliance with environmental regulations is an equally important driver. Under the Base Plan, the region would see CO_2 emissions reduced from 15 Mte in 2010 to just under 10 Mte in 2030.

- A critical component of the follow up analysis is a determination of how costs and benefits of transmission expansion and resource development should be shared. This resource modeling study did not address this issue and the results shown are totals for the region as a whole.