

**Vancouver Island Electricity Supply Alternatives:  
Natural Gas South Island versus  
Low Emission North Island**

**Final Report**

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# Executive Summary

## Introduction

A decision is going to be made within the next six months that will determine whether or not a natural gas-based generation strategy is implemented to supply power needs on Vancouver Island starting in 2007. This decision is key because the natural gas strategy will likely preclude other, more environmentally benign alternatives for decades to come. It is expected that if this path is chosen, natural gas generation will dominate supply expansion in the province as a whole.

Older High Voltage Direct Current (HVDC) transmission lines linking the south part of the Island to the mainland are reaching the end of their reliable life. This situation, combined with significant residential development occurring south of Nanaimo means that BC Hydro must identify new dependable capacity to meet power demands.

BC Hydro has put forward a strategy for meeting future power needs that involves building a combined cycle gas turbine (CCGT) plant on Vancouver Island, referred to as the Vancouver Island Generation Project (VIGP). The Georgia Strait Crossing (GSX) pipeline would be built to supply this facility with natural gas. During the summer of 2003, the British Columbia Utilities Commission (BCUC) conducted an extensive hearing on VIGP and denied a Certificate of Public Convenience and Necessity to build the plant. BC Hydro is now conducting a Call for Tenders (CFT) to determine the most cost-effective option for new dependable capacity.

As a result of this process, one alternative to natural gas-fired generation that has emerged is a strategy of developing low emission generation resources north of Nanaimo on Vancouver Island. Projects could involve biomass plants, pulp mill cogeneration, wind power, curtailable load projects and small hydro. To deliver power to the load concentrated in the South, upgrades to the existing north-south power line infrastructure on the Island would be necessary.

The importance of upcoming decisions, coupled with the complexity of objectives involved, indicates that the provision of additional power supply to Vancouver Island (as well as to BC as a whole) should be addressed using Multi-Attribute Trade-Off Analysis (MATA). This type of analysis evaluates alternative generation and end-use efficiency investments in terms of their financial, environmental and social attributes. Public values are critical to the evaluation; therefore direct public involvement is required, usually in the form of stakeholder consultative processes. Explicit consideration of uncertainty about key input assumptions should be included. The electricity industry has played a prominent role over the last two decades in the development of transparent processes that show how decision makers trade off competing objectives. The common electricity industry name for its application of MATA is Integrated Resource Planning (IRP).

The purpose of this study is to perform a MATA comparing natural gas-fired generation with an alternative portfolio of low emission independent power producer (IPP) projects located north of Nanaimo on Vancouver Island. These portfolios are referred to as Natural Gas South Island and Low Emission North Island. The MATA considers financial, environmental and social attributes: unit electricity costs, impact on rates, GHG

emissions, other environmental impacts and socio-economic impacts. The impact of uncertainty on the financial aspect will also be estimated.

### **Base Case Assumptions**

The best available information is used to assemble a set of base case assumptions describing the Natural Gas South Island and Low Emission North Island portfolios. Because these values are uncertain, alternative assumptions are tested in a sensitivity analysis and then a probabilistic uncertainty analysis. The base case parameters describing Natural Gas South Island were based for the most part on the CFT Benchmark suggested by the BCUC in their decision on the VIGP. Input assumptions describing the Low Emission North Island portfolio were supplied by Willis Energy Services Ltd. based on information submitted by interveners at the VIGP hearing, other data supplied by various project proponents, and information made public by BC Hydro and the BCTC.

The financial analysis included GHG liability costs of \$49/tonne CO<sub>2</sub>e in the base case. This is higher than the cost suggested by the BCUC in its decision on VIGP, which was equivalent to \$10 per tonne. The higher cost reflects the belief of many GHG policy analysts that GHG charges in most countries will rise over time in order to reflect increasing reduction targets and to allow for gradual capital stock turnover. Existing policies in other developed countries, including state-level initiatives in the US also support the assumption of higher GHG charges.

### **Base Case Results and Sensitivity Analysis**

Unit electricity costs were estimated at 9.08 ¢/kWh for Natural Gas South Island and 7.58 ¢/kWh for Low Emission North Island under base case assumptions. The unit costs indicate only the cost of the electricity generated under each of the portfolios; they do not apply to the province-wide electricity system.

The information on unit electricity costs can be used to estimate residential rates that would apply to customers within the BC Hydro service area under each portfolio. In the base case, these are estimated as 6.26 ¢/kWh for Natural Gas South Island and 6.22 ¢/kWh for Low Emission North Island. In both cases the rate is higher than the current rate of 6.11 ¢/kWh, reflecting a higher cost of new supply relative to the supply cost from existing sources, including hydropower dams. The difference between the two portfolios is much less pronounced when it comes to rates, because the increase in supply is small relative to the total system. According to these numbers, if the Natural Gas South Island portfolio is pursued, BC Hydro customers will actually pay slightly more for a new electricity supply with higher GHG emissions.

The finding that unit costs and rates are lower under Low Emission North Island was robust to sensitivity tests performed on the capital cost of VIGP, the GHG cost and the discount rate.

Estimated annual GHG emissions from the Natural Gas South Island portfolio are 721 kilotonnes CO<sub>2</sub>e over the lifetime of VIGP, more than three times greater than emissions from the Low Emission North Island resource package at 214 kilotonnes.

Implementation of the Natural Gas South Island portfolio would lead to an increase in annual emissions of about 36% over BC Hydro's 1997-2001 average GHG emission level of 2 Mt CO<sub>2</sub>e.

No other major environmental impacts were found to be associated with either portfolio, if appropriate mitigation measures are implemented. A preliminary socio-economic assessment conducted by Willis Energy found that Low Emission North Island keeps more money in BC and creates more jobs – although the relevance of increased employment is questionable in this type of analysis.

### **Impact of Uncertainty**

BC Hydro has not conducted (or at least made public) a comprehensive uncertainty analysis of the major alternatives facing it for meeting increased demand and for replacing retired generation and transmission facilities. Uncertainty analysis requires the portrayal of uncertainty in a way that helps decision makers (government, the utility, the regulator, consumers, taxpayers) assess the relative risks of alternatives with respect to objectives that are important to them – and ultimately to make trade-offs between these risks. A comprehensive analysis should involve different stakeholders so that their risk preferences can be taken into account. Only BC Hydro has the resources for this desired level of evaluation.

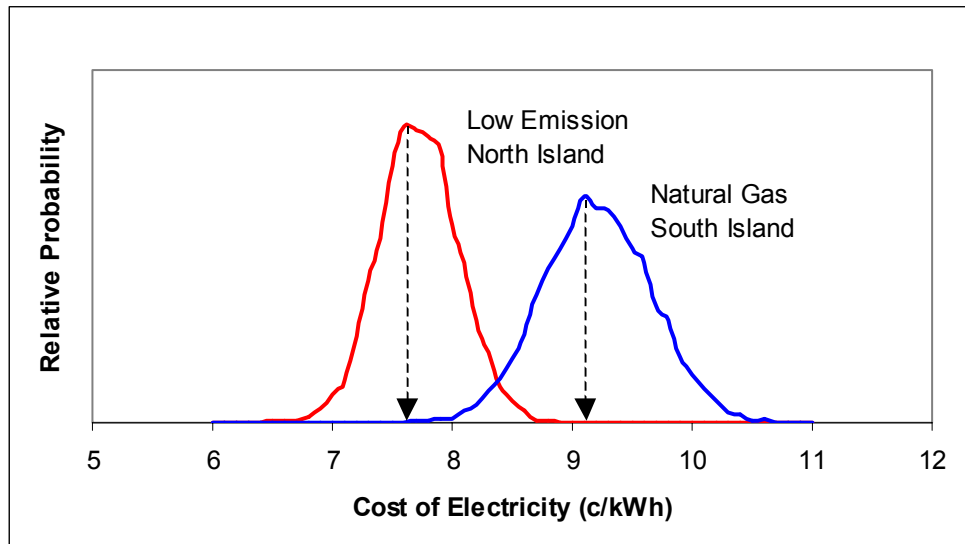
The uncertainty analysis conducted here focused on the impact of uncertainty on unit electricity costs. The uncertain parameters that were considered are: the capital cost of the VIGP, the price of natural gas, the capital cost of GSX, the weighted average cost of generation for Low Emission North Island, the cost of the Vancouver Island transmission upgrade, and the financial liabilities associated with GHG emissions. Other variables were also uncertain and a more comprehensive uncertainty analysis would address these as well in a full-scale MATA comparing electricity supply options for Vancouver Island.

Figure ES-1 presents the results of the uncertainty analysis. A Monte Carlo simulation methodology was used to generate a single probability distribution for the unit cost of electricity with each portfolio. The graph indicates the relative probabilities of various unit electricity cost outcomes. The base case unit electricity cost estimates are indicated with dashed arrows. The base case estimates have the highest probability of occurrence.<sup>1</sup>

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<sup>1</sup> Values are not given on the y-axis because the probabilities are dependent on the size of the interval chosen on the x-axis. The total area under each of the two curves is equal to 100%.

**Figure ES-1 Unit Electricity Cost Probability Distributions**



The probability distribution for Natural Gas South Island is wider than the distribution for Low Emission North Island because this portfolio is more heavily influenced by the parameters around which there is greater uncertainty – natural gas prices and GHG liability costs. The probability distributions only overlap slightly, indicating that it is quite unlikely that Low Emission North Island will have a higher unit cost of electricity than Natural Gas South Island.

Uncertainty around key input parameters affecting costs means that there are financial risks associated with each of the portfolios. The Natural Gas South Island portfolio has greater cost risks than Low Emission North Island because there is more uncertainty associated with this portfolio. Because this portfolio is also the more expensive option in the base case, there is no trade-off between cheaper base case cost and less risk. Therefore, even if Natural Gas South Island does prove cheaper under some outcomes, it is very important to see what kind of weighting stakeholders might put on these various risks. It is difficult to have BC Hydro making this decision without getting trade-off and risk-preference input from those who must pay the bills or taxes.

### **Multi-Attribute Trade-Off Analysis**

The results of this analysis are summarized in Table ES-1 in the form of a multi-attribute trade-off matrix. Although a comprehensive MATA was not carried out, the attributes listed in the table below are representative of the basic considerations that should be taken into account when making electricity supply decisions. There is not a common unit across all attributes, so decision makers must weigh the importance of the various attributes when choosing between alternative portfolios.

**Table ES-1 Multi-Attribute Trade-Off Matrix**

	Natural Gas South Island	Low Emission North Island
Financial		
Unit Electricity Cost	Significantly higher cost (9.08 ¢/kWh). Uncertainty analysis shows very low probability that this portfolio will be lower cost.	Lower cost (7.58 ¢/kWh).
Rate Impact	Higher rate (6.26 ¢/kWh).	Lower rate (6.22 ¢/kWh).
Environmental		
GHG Emissions	Higher emissions (721 kt).	Lower emissions (214 kt).
Other Impacts	No major impacts with mitigation.	No major impacts with mitigation.
Socio-Economic	Further assessment required. May result in less money kept in BC and lower job creation.	Further assessment required. May result in more money kept in BC and higher job creation.
Financial Risk	Electricity cost risk somewhat greater because more heavily impacted by uncertain natural gas prices and GHG costs.	Lower electricity cost risk.

Decisions like this often imply difficult trade-offs, such as a choice between an alternative that is less harmful to the environment or has less financial risk and one in which costs are lower in the base case. Table ES-1 does not reveal these kinds of trade-offs; Low Emission North Island performed equally well or better than Natural Gas South Island in terms of all the attributes tested.

The financial risk associated with Natural Gas South Island indicates that there is value in deferring any decision to go down the gas-fired generation path until greater certainty exists around key variables that impact the cost of electricity supply to Vancouver Island. Low Emission North Island has the advantage of avoiding large capital investments that could lock BC into an undesirable electricity future. The low emission portfolio could be followed by similar electricity sector investments in BC, or might act simply as a bridge to implementing Natural Gas South Island at some point in the future, should that strategy be revealed as the best option.

New information could change the results that have been presented in this report, as could methodological refinements. This analysis was of limited scope and there may be additional factors in the decision of how to supply electricity to Vancouver Island that were not included here.

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# **Vancouver Island Electricity Supply Alternatives: Natural Gas South Island versus Low Emission North Island**

## **1 Introduction**

### **1.1 Background**

A decision is going to be made within the next six months that will determine whether or not a natural gas-based generation strategy is implemented to supply power needs on Vancouver Island starting in 2007. This decision is key because the natural gas strategy will likely preclude other, more environmentally benign alternatives for decades to come. It is expected that if this path is chosen, natural gas generation will dominate supply expansion in the province as a whole.

Older High Voltage Direct Current (HVDC) transmission lines linking the south part of the Island to the mainland are reaching the end of their reliable life. This situation, combined with significant residential development occurring south of Nanaimo means that BC Hydro must identify new dependable capacity to meet power demands.

BC Hydro has put forward a strategy for meeting future power needs that involves building a combined cycle gas turbine (CCGT) plant on Vancouver Island, referred to as the Vancouver Island Generation Project (VIGP). The Georgia Strait Crossing (GSX) pipeline would be built to supply this facility with natural gas. During the summer of 2003, the British Columbia Utilities Commission (BCUC) conducted an extensive hearing on VIGP and denied a Certificate of Public Convenience and Necessity to build the plant (BCUC, 2003). The Commission concluded it had not been established that VIGP is the most cost-effective means to reliably meet Vancouver Island's power needs. The BCUC suggested that BC Hydro conduct a Call for Tenders (CFT) to determine the most cost-effective option for new dependable capacity. This process is currently underway. Proposals may be submitted to build gas-fired power projects or other alternative power generation projects.

As a result of this process, one alternative to natural gas-fired generation that has emerged is a strategy of developing low emission generation resources north of Nanaimo on Vancouver Island. Projects could involve biomass plants, pulp mill cogeneration, wind power, curtailable load projects and small hydro. To deliver power to the load concentrated in the South, upgrades to the existing north-south power line infrastructure on the Island would be necessary. All of the projects located in the North would have lower greenhouse gas (GHG) emissions and usually lower local air emissions than natural gas-fired generation.

There is concern that BC Hydro's CFT process will not lead to a supply strategy that is optimal for the people of BC. The Net Present Value (NPV) model used to assess proposals under the CFT is complicated and not available to the public. There is concern that BC Hydro ratepayers and taxpayers will absorb the natural gas price risk associated with gas-fired power projects, whereas other types of projects must guarantee supply at a firm price. The CFT applies to new generation only and does not allow bids for peak

shaving or load curtailment. BC Hydro's NPV model does not take into account a GHG cost as advised by the Utilities Commission, nor does it consider social aspects of the decision at hand. Risk and uncertainty are not addressed in the model.

## **1.2 Objectives**

The outcome of the Vancouver Island CFT process will have major implications for British Columbia. The importance of upcoming decisions, coupled with the complexity of objectives involved, indicates that the provision of additional power supply to Vancouver Island (as well as to BC as a whole) should be addressed using Multi-Attribute Trade-Off Analysis (MATA). This type of analysis evaluates alternative generation and end-use efficiency investments in terms of their financial, environmental and social attributes. Public values are critical to the evaluation; therefore direct public involvement is required, usually in the form of stakeholder consultative processes. Explicit consideration of uncertainty about key input assumptions should be included. The electricity industry has played a prominent role over the last two decades in the development of transparent processes that show how decision makers trade off competing objectives. The common electricity industry name for its application of MATA is Integrated Resource Planning (IRP).

In June 1994, BC Hydro issued its Resource Acquisition Policy, which indicated that BC Hydro intended to use a Multiple Account Evaluation process in ranking alternative demand-side and supply-side resources. The current Energy Plan issued by the Provincial government also emphasized the importance of considering environmental concerns and private sector opportunities (BC Ministry of Energy and Mines, 2002).

The purpose of this study is to perform a MATA comparing natural gas-fired generation with an alternative portfolio of low emission independent power producer (IPP) projects located north of Nanaimo on Vancouver Island. These portfolios are referred to as Natural Gas South Island and Low Emission North Island. The MATA considers financial, environmental and social attributes: unit electricity costs, impact on rates, GHG emissions, other environmental impacts and socio-economic impacts. The impact of uncertainty on the financial aspect will be estimated. The analysis is conducted primarily from a social perspective, addressing the impacts of the power supply decision on BC Hydro ratepayers, as well as on those who live and pay taxes in this province.

## **1.3 Outline**

Section 2 describes some of the electricity supply resource options available in BC. Section 3 presents two electricity supply portfolios constructed from these options: Natural Gas South Island and Low Emission North Island. Section 4 describes the two portfolios in terms of a series of base case assumptions. This is followed in section 5 by a description of the methodology used to conduct a financial comparison of the alternatives. Section 6 presents results and section 7 conclusions and recommendations.

## **2 Power Supply Options**

To provide context for the analysis to follow, this section describes some of the options for power supply in BC.

### **2.1 Biomass**

Biomass is defined as organic material derived from plants. Biomass is produced through photosynthesis as plants convert the sun's energy into chemical energy. The chemical energy in biomass can be extracted through combustion to produce heat or power. Sustainably managed biomass resources are environmentally desirable because they are renewable and do not contribute to global warming. Carbon dioxide (CO<sub>2</sub>) is absorbed during the growth cycle of the biomass resources; therefore, the net contribution to the atmosphere that results from combustion is zero, as long as the resource is sustainably managed (for example, through replanting). Using wood residue in energy projects can also reduce the amount incinerated in beehive burners, greatly reducing particulate emissions. Because biomass projects are generally situated in developed and populated areas, they offer some additional advantages. They do not require long transmission line extensions, although transmission or distribution may require system upgrades. As well, biomass projects can contribute to economic development through employment and encouragement of industry.

### **2.2 Combined Cycle Gas Turbine Plants**

A Combined Cycle Gas Turbine (CCGT) uses the exhaust gases from a turbine to turn a generator directly and to heat water into steam that turns a second generator. These two steps explain the term combined cycle. Although the turbine could burn various fuels, natural gas is the dominant energy source.

### **2.3 Pulp Mill Cogeneration**

This is the simultaneous production of heat and electricity using a single fuel such as biomass or hog fuel in pulp mills, although other fuels can be used. The heat produced from the electricity generating process (for example from the exhaust system of a turbine) is captured and utilized to produce steam. The heat by-product is available for use without the need for further burning of primary fuel. The use of cogeneration in pulp mills across BC has reduced the use of beehive burners to dispose of biomass.

### **2.4 Small Scale Cogeneration**

While power generated from a CCGT is produced at 50% efficiency, power from cogeneration facilities can be produced at 70% to 90% efficiency when the steam use is included. This means that the fuel cost for cogeneration is generally 2/3 that of the fuel cost for a CCGT. The non-fuel operating and maintenance cost is greater for small cogeneration plants than for large CCGTs, but the combined fuel and non-fuel operating and maintenance cost is approximately 15% lower. The capital costs for small cogeneration projects vary from site to site but the average cost on a \$/installed kW basis is approximately the same as that of a CCGT. Accordingly, small cogeneration projects are competitive with large CCGT projects.

## **2.5 Wind**

Wind energy is usually considered a green energy resource because it is renewable and does not produce GHG emissions or other pollutants. Due to its intermittent nature, wind is not a firm energy source, but it is a good source of green energy in concert with firm electricity generation resources. Use of wind power is increasingly dramatically in most developed countries. Estimating production costs at a site requires monitoring for at least one year. Wind development has a number of potential environmental, cultural, and socio-economic issues. The most commonly identified are visual impacts and impacts on birds. These can generally be avoided or mitigated through careful siting of the wind turbines. First Nations' interests have also been identified at some sites.

## **2.6 Small Hydro**

BC Hydro defines small hydro resources as installations with installed capacities between 2 and 50 MW. These projects are often run-of-river projects, which means that the water passing through the powerhouse is essentially the flow that naturally occurs in the stream. This implies that there is no (or minimal) storage reservoir, and the flow quantity and profile downstream of the powerhouse is virtually identical to the pre-development flow. The relative density of potential projects in BC, combined with the relative sparseness of transmission and distribution lines, makes it sensible to consider clustered projects that can share infrastructure. Issues that may be associated with small hydro development include environmental impacts, development challenges and social concerns. Small hydro projects have well-established technologies and development processes.

## **2.7 Energy Conservation Programs (Power Smart)**

Energy conservation programs attempt to convince consumers and businesses to reduce electricity and/or natural gas consumption during all or significant portions of the year through improved energy efficiency. Energy conservation programs administered by utilities are referred to as demand-side management (DSM). BC Hydro's demand-side management program is called Power Smart.

## **2.8 Peak Shaving Programs**

Peak shaving programs are energy conservation programs directed at reducing customers' peak demand. While there may be limited potential for peak shaving among BC Hydro's large industrial customers, a review of efficiency potential suggested that smaller industrial customers offer some possibilities.

## **2.9 Curtailable Load**

At certain electricity cost thresholds, it is more economical to reduce production than to continue to buy power. The concept of curtailable load can be controversial because it results in reduced production – a disadvantage from a macro-economic standpoint. The effectiveness and practicality of this option depends on the curtailment time involved. For example, if BC Hydro can avoid building a capacity addition costing hundreds of millions of dollars by having two pulp mills prepared to shut down for two weeks every five years, it may be a reasonable economic alternative for society as a whole. Pulp and paper mills, mines, electro-chemical facilities and large sawmills all have shutdowns or

plant turndowns for market and equipment maintenance reasons. It would be possible for these facilities to take into consideration BC Hydro's peak capacity requirements in scheduling these activities.

### 3 Supply Alternatives for Vancouver Island

Both portfolios in this study feature on-Island generation, as opposed to transmission from the mainland. In its decision on the VIGP, the BCUC concluded that on-Island generation was the appropriate next resource addition.<sup>2</sup>

The Natural Gas South Island portfolio is based on the Call For Tenders (CFT) Benchmark suggested by the BCUC in its decision. The Benchmark is the Vancouver Island Generation Project (VIGP) – a natural gas-fired generation plant at Duke Point near Nanaimo – fed by the Georgia Strait Crossing Pipeline (GSX).

The VIGP is capable of providing 295 MW of capacity if direct duct firing is used. The analysis therefore provides for consideration of two alternatives that are each capable of delivering 295 MW of dependable capacity. This target more than compensates for the anticipated loss of 240 MW of transmission from the mainland in 2007 associated with derating the aging high voltage direct current (HVDC) submarine transmission cable system. Both alternatives also meet the high end of BC Hydro’s acquisition target under the Vancouver Island CFT – Hydro has said it will acquire 150 to 300 MW of new supply through this process.

In addition to matching each other in terms of capacity, both portfolios will provide significant electrical energy. All resources are brought on-line in the year 2007 to compensate for the loss of transmission capacity from the HVDC system and to meet increasing demand for power on Vancouver Island. The analysis covers the period 2007-2031 to reflect the 25-year expected lifetime of VIGP.

Low Emission North Island is a portfolio of low emission IPP projects located north of Nanaimo on Vancouver Island. Table 1 below describes the resource composition of this portfolio. The northern part of Vancouver Island has a significant amount of power generation potential in addition to the resources illustrated in Table 1. Appendix A, prepared by Willis Energy Services Ltd., identifies over 2100 MW of projects in north and central Vancouver Island.

**Table 1 Resource Composition of Low Emission North Island**

Resource	Capacity (MW)	Share of Total
Biomass	80	27%
Energy Conservation	28	9%
Natural Gas Cogeneration	104	35%
Small Hydro	25	8%
Wind	58	20%
Total	295	

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<sup>2</sup> The BCUC’s suggestion that cost-effective generation resources be considered before demand-side resources such as energy conservation, peak shaving and curtailable load is behind the exclusion of these options from the BC Hydro CFT.

The Low Emission North Island Portfolio was constructed by Willis Energy. The biomass resource referred to in Table 1 is based on a plan by Green Island Energy Ltd. to adapt facilities at an inactive pulp mill at Gold River. The energy conservation project is based on a proposal by NorskeCanada to install a new thermomechanical pulp (TMP) refiner plant at their Elk Falls operation near Campbell River. The natural gas cogeneration project is also being proposed by Norske at Elk Falls. Two different proponents are proposing to develop a small hydro facility with a capacity of about 25 MW on the Kokish River near Port McNeill. A number of companies are investigating the development of wind power projects on northern Vancouver Island. The 58 MW of wind power included in the Low Emission North Island portfolio will require the construction of approximately 20 wind turbines. All of the resources in Table 1 provide dependable capacity except for the wind projects. In order to provide 295 MW of dependable capacity with this portfolio, 58 MW of curtailable load from Norske's pulp mill operations are also included.

An advantage of Natural Gas South Island over Low Emission North Island is that VIGP is located where the additional power is needed. Most load growth, in terms of MW of peak demand, is forecast to occur on the southern part of Vancouver Island. BC Hydro does have existing hydro generation in the North of the Island at approximately 400 MW, which comes close to matching the load on the north part of the Island.

Low Emission North Island will require upgrades to the transmission system on Vancouver Island to deliver power to the load in the South. All of the dependable power transmission from the Lower Mainland after 2007 is going to be by means of two 500 kV transmission lines that terminate at the Dunsmuir sub-station a few miles north of Qualicum Beach. Since the north part of the Island is almost self-sufficient, most of this power, once it is on the Island, has to be transmitted south. Due to the load growth in the South, the British Columbia Transmission Corporation's (BCTC) transmission lines running north to south have reached their capacity. BCTC has provided estimates of what it will cost to increase the capacity of on-Island transmission.

## 4 Base Case Assumptions

The best available information is used to assemble a set of base case assumptions describing the Natural Gas South Island and Low Emission North Island portfolios. Because these values are uncertain, alternative assumptions are tested in a sensitivity analysis and then a probabilistic uncertainty analysis. These exercises are described in later sections. Wherever possible, taxes have been removed from monetary inputs. This methodology reflects the social perspective of the analysis. Unless otherwise indicated, all cost estimates presented below are in real Canadian dollars.

### 4.1 Natural Gas South Island

The parameters describing this alternative were based for the most part on the CFT Benchmark suggested by the BCUC in their decision on the VIGP. Key parameters are listed below.

- Capacity factor (utilization rate) for VIGP: 77.5%.
- Heat rate for VIGP: 0.0073 GJ/kWh.
- Capital cost of VIGP: \$355 million.

As directed by the BCUC, the average of two cost estimates provided by the Vancouver Island Energy Corporation (VIEC) was used to derive the capital cost of \$355 million. The BCUC also specified that VIGP sunk costs of \$51 million should be deducted. For proper social cost comparison, the \$51 million is not deducted in the base case, but is in a sensitivity analysis.

- Operating, maintenance and administration (OMA) costs for VIGP: \$12.4 million/year.

The BCUC accepted an OMA cost of \$17 million nominal dollars in 2010/11 for VIGP. This estimate does not include fuel costs. Once property taxes estimated at \$3 million/year were deleted and an inflation rate of 2% per year was included, the resulting \$12.4 million was applied over the entire period of the analysis (2007-2031).

- Natural gas price: \$5.575/GJ.

The BCUC suggested that the CFT Benchmark should use a natural gas price that is the average of BC Hydro's reference and high forecast gas prices. BC Hydro has provided an updated levelized price for its reference case of \$4.55 \$Cdn/GJ. Their high gas price is \$6.60/GJ.

- Capital cost of GSX: \$296.5 million. To reflect GSX tolls that would apply for gas transportation to the plant, 50% of this cost is allocated to VIGP.

The allocation of 50% of GSX costs to the VIGP suggested by the BCUC is very close to the 55% allocation applied by the authors in a previous analysis (Jaccard and Murphy, 2002b).<sup>3</sup>

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<sup>3</sup> For additional work on this topic by the same authors, see Jaccard and Murphy, 2002a and Murphy and Jaccard, 2003.

- Terasen Gas Vancouver Island charge to transport gas from GSX to VIGP (on-Island charge): \$0.6/GJ.
- Emission factor for VIGP: 360 tonnes CO<sub>2</sub>e/GWh.

#### 4.2 Low Emission North Island

Input assumptions describing this portfolio were supplied by Willis Energy based on information submitted by interveners at the VIGP hearing, other data supplied by various project proponents, and information made public by BC Hydro and the BCTC.

Capacity factors for the Low Emission North Island resources are shown in Table 2. A 100% capacity factor is applied to energy conservation, which is equivalent to simply deducting from demand in an integrated resource plan (IRP).

**Table 2 Capacity Factors for Low Emission North Island Resources**

<b>Resource</b>	<b>Capacity Factor</b>
Biomass	90%
Energy Conservation	100%
Natural Gas Cogeneration	95%
Small Hydro	59%
Wind	35%

The generation costs assumed for the Low Emission North Island resources are shown in Table 3. These costs are based on consultations with experts and were informed by BC Hydro's 2004 Integrated Electricity Plan (BC Hydro, 2004). The cost associated with cogeneration was based on evidence provided by Norske Skog Canada Limited to the BCUC Hearing on VIGP (Norske Skog Canada Ltd., 2003). The natural gas price associated with cogeneration was the same as that described above for VIGP. Additional costs associated with upgrades to the existing Terasen Gas pipeline to Vancouver Island to accommodate cogeneration by Norske are not included in the cost of cogeneration estimate provided in Table 3, but are added as capital costs later on in the unit electricity cost calculation. Based on the amount of electricity generated using each type of resource, the weighted average cost of generation for the Low Emission North Island portfolio is 5.95 ¢/kWh.

**Table 3 Generation Costs for Low Emission North Island Resources**

<b>Resource</b>	<b>Generation Cost (¢/kWh)</b>
Biomass	6.5
Energy Conservation	6.5
Natural Gas Cogeneration	4.9
Small Hydro	6.5
Wind	8.0

The cost associated with installing additional pulp storage and refining capacity to accommodate 58 MW of curtailable load by Norske is estimated at \$26.1 million. This value is based on confidential discussions with experts in BC and other jurisdictions.

The overall cost associated with transmission upgrades on Vancouver Island was estimated at \$98 million for Low Emission North Island. This cost may be broken down as follows.

- Transmission interconnection costs, or direct assignment costs – costs of the actual line and connection to the IPP facility: \$7 million.
- Interconnection network costs – costs that the BCTC has to incur to accommodate the IPP load up to (in general) the first sub-station: \$16 million.
- System network costs – upgrades to the entire system that are required as a result of the increased generation capacity in the northern part of the Island: \$75 million.

These transmission costs were estimated based on the methodology outlined by the BCTC (BCTC, 2003; BCTC, 2004).

In order to accommodate natural gas cogeneration by Norske, the capacity of the existing Terasen Gas pipeline to Vancouver Island must be increased. A stream of costs (in real dollars) for providing additional natural gas transportation to VI was assumed: \$35 million in 2005, \$43 million in 2007, \$17 million in 2012, \$20 million in 2017, \$23 million in 2018 and \$25 million in 2023. These cost estimates were provided by Terasen and are specific to an upgrade sufficient to accommodate 256 MW of cogeneration by Norske (Terasen Gas, 2003). Applying these costs to a portfolio that only calls for 104 MW of cogeneration is therefore likely to overstate the cost.

Based on the evidence provided by Norske to the BCUC Hearing, the cogeneration resource is associated with an emission factor of 247 tonnes CO<sub>2</sub>e/GWh. GHG emissions are not attributed to any of the other resources in the Low Emission North Island portfolio. Emissions are not associated with biomass combustion because CO<sub>2</sub>e is absorbed during the growth cycle of the biomass resources. This approach is consistent with Intergovernmental Panel on Climate Change (IPCC) methodology.

For projects located in the North of the Island, there will be additional transmission losses compared to projects located in the South. Calculations to precisely determine such

losses are complicated, but this study includes a 1% loss to electricity generated from the Low Emission North Island resources. The total transmission loss on BC Hydro’s system is 6%, with the majority of power being transmitted from Fort St. John and Revelstoke to Vancouver. The distance over which electricity is being transmitted on Vancouver Island is considerably less than the distances over which transmission occurs at the system level.

### 4.3 GHG Liability Costs

The BCUC CFT Benchmark included GHG costs of \$3.60/MWh for VIGP, to represent the potential GHG liability associated with this project. This is equivalent to \$10 per tonne CO<sub>2</sub>e. While the GHG charge proposed by the BCUC may represent expected costs in the short term, it is not representative of the much higher costs that are likely to be associated with emitting GHG emissions over the lifetime of VIGP and the GSX pipeline. A pipeline is a commitment for at least two decades beyond the Kyoto Protocol timeframe of 2010.

Many GHG policy analysts believe that GHG charges in most countries will rise over time in order to reflect increasing reduction targets and to allow for gradual capital stock turnover. Looking at policies in other developed countries, including state-level initiatives in the US, it is possible to construct the schedule outlined in Table 4 below. This is equivalent to a levelized cost of \$49/tonne CO<sub>2</sub>e over the 25 year time period,<sup>4</sup> and implies \$49/tonne as a base case GHG cost. A sensitivity analysis based on the \$10/tonne cost suggested by the BCUC is also tested. The GHG cost will be applied to emissions resulting from both the Natural Gas South Island and the Low Emission North Island supply alternatives.

**Table 4 Assumed GHG Costs over the Period 2007-2031**

	2007-2010	2011-2020	2021-2031
GHG Cost (/tonne CO <sub>2</sub> e)	\$10	\$50	\$100

The higher GHG cost that will be applied in the base case is supported by GHG charges that have been implemented in other jurisdictions, especially Europe. For instance, in 2003, Finland's CO<sub>2</sub> tax rate was approximately \$69/tonne CO<sub>2</sub> (43.5 euros/tonne) and Sweden's CO<sub>2</sub> tax rate was \$132/ton CO<sub>2</sub> (83 euros/ton). In practice, carbon taxes are applied in conjunction with other energy taxes so the implicit rate can be higher. Exemptions, rebates and differential rates are applied that change the implicit rate by user (Eurogas, 2003).

Further justification for a higher GHG cost is provided by estimates of the cost of GHG abatement in Canada and in the US obtained using hybrid energy-economic models.<sup>5</sup> For Canada, simulations using the CIMS model suggest that a GHG tradable permit price of \$150/tonne CO<sub>2</sub>e would result from a national emissions cap that achieves the Kyoto Protocol target of an emission reduction of 6% from 1990 levels in 2010 (Jaccard *et al.*, 2003). In the US, researchers at the Energy Information Administration applied the NEMS model to estimate the cost of US compliance with its Kyoto target of a 7%

<sup>4</sup> Based on a discount rate of 8%. See section 5.1 for a discussion of the discount rate.

<sup>5</sup> Hybrid models are costing models that are both technologically explicit and behaviourally realistic.

reduction from 1990 levels, and found that a carbon tax of \$294/t C would be required using domestic actions alone (USEIA, 1998).<sup>6</sup> These cost of abatement estimates focus on targets set under the Kyoto Protocol, which although a step in the right direction does not even bring the world close to the reduction in global emissions of 70% or greater that would be required to stabilize the atmospheric concentration of CO<sub>2</sub>, according to atmospheric scientists (IPCC, 1996).

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<sup>6</sup> The US negotiated a target under the Kyoto Protocol, but has not ratified the treaty.

## **5 Financial Analysis**

### **5.1 Calculating Unit Electricity Costs and Rates**

The financial costs of the two portfolios were evaluated by combining generation, infrastructure and GHG costs into a single unit cost of electricity. Real costs in each year over the period 2007-2031 were evaluated and discounted to 2004 using a real social discount rate of 8% in the base case. A sensitivity was performed using a 10% discount rate. Electricity generation over the same period was used to calculate the unit cost of electricity for each portfolio.

Rate impacts for residential customers in the BC Hydro service area were also estimated. The current rate is 6.11 ¢/kWh (Task Force on Energy Policy, 2002). Of this, about 3 ¢ is associated with generation costs. Rates under Low Emission North Island and Natural Gas South Island were estimated by adding 295 MW of capacity under each portfolio to the 12,000 MW of BC capacity currently used for meeting domestic demand. The generation cost for this 295 MW is set at the unit electricity cost calculated as described above. All costs associated with the two portfolios are evaluated as generation costs, even though some costs are for the transmission of gas and electricity. This is the only way to create a fair comparison and is standard procedure for evaluating new supply alternatives for delivery to a group of customers in a specific location.

### **5.2 Incorporating Uncertainty into the Analysis**

In addition to evaluating the financial performance of Low Emission North Island and Natural Gas South Island under base case assumptions, the impact of uncertainty on unit electricity costs was addressed. BC Hydro has not conducted (or at least made public) a comprehensive uncertainty analysis of the major alternatives facing it for meeting increased demand and for replacing retired generation and transmission facilities. High and low price scenarios for some uncertain parameters were tested for the BCUC hearing on VIGP, but as Grubb (1997, p.167) noted: “A common misconception is that by analysing a number of different scenarios, we have analyzed uncertainty. This is not the case at all.”

Uncertainty analysis requires the portrayal of uncertainty in a way that helps decision makers (government, the utility, the regulator, consumers, taxpayers) assess the relative risks of alternatives with respect to objectives that are important to them – and ultimately to make trade-offs between these risks. This section provides a brief demonstration of elements to include in such an analysis and the way to present the resulting information. A comprehensive analysis should involve different stakeholders so that their risk preferences can be taken into account. Only BC Hydro has the resources for this desired level of evaluation.

The uncertain parameters targeted by the uncertainty analysis were the capital cost of the VIGP, the price of natural gas<sup>7</sup>, the capital cost of GSX (of which 50% is allocated to VIGP), the weighted average cost of generation for Low Emission North Island, the cost of the Vancouver Island transmission upgrade, and the financial liabilities associated with GHG emissions. Other variables were also uncertain and a more comprehensive

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<sup>7</sup> In this analysis, the utilization rate or capacity factor of VIGP did not vary with the natural gas price, as this would require a full systems model approach.

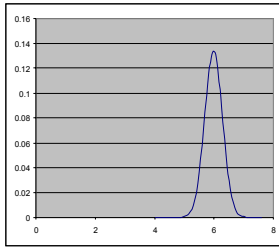
uncertainty analysis would address these as well in a full-scale MATA comparing electricity supply options for Vancouver Island.

Uncertainty was characterized by estimating probability distributions around each of the uncertain parameters. This information is summarized in Table 5. The capital cost of the VIGP, the capital cost of GSX, the weighted average cost of generation for the Low Emission North Island portfolio, and the cost of the Vancouver Island transmission upgrade all have relatively narrow probability distributions, indicating that we have less uncertainty about these parameters. BC Hydro has reached an advanced stage of development in assessing the costs of infrastructure projects. There are precedents in BC for developing the types of resources specified in the Low Emission North Island portfolio, and some of these projects have been analyzed in detail already. Also, assuming that IPP developers will be signing fixed price contracts with BC Hydro to supply power, some of the uncertainty around the cost of generating power is removed from the social perspective (that of BC Hydro ratepayers and BC taxpayers).

The future price of natural gas is more uncertain than the capital costs, and this is reflected in its wider distribution. Some people would argue that the distribution should be skewed to reflect a greater chance that future natural gas prices will be higher rather than lower. However, the distribution is based on historical data, which does not support this hypothesis. Average natural gas prices have changed little during past decades in spite of significant fluctuations over short-time periods, and there is evidence suggesting that synthetic substitutes for natural gas will not be substantially more expensive to produce, should conventional supplies decline.

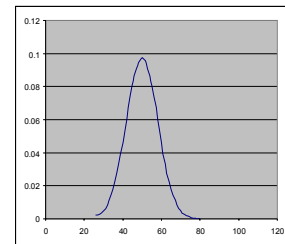
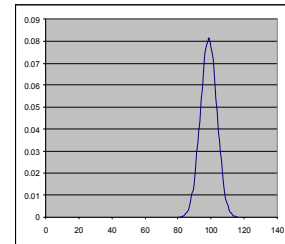
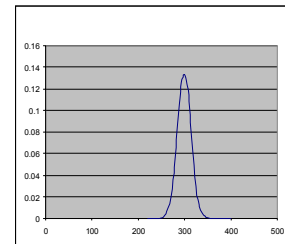
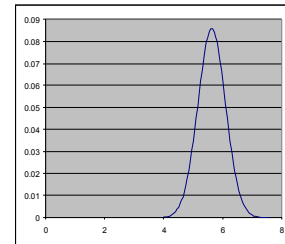
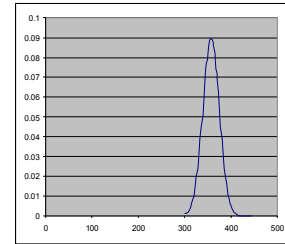
Future financial liabilities for GHG emissions have the greatest uncertainty and therefore the widest range. The future cost of emissions depends on the targets and trading mechanisms of future international agreements, and the cost curves for GHG abatement in different regions of the planet. The base case value and the probability distribution are based primarily on expert judgment as applied in the costing analysis for the Intergovernmental Panel on Climate Change when looking out beyond the Kyoto time period of 2010 (Hourcade *et al.*, 1996).

After specifying probability distributions around the uncertain parameters, a Monte Carlo simulation methodology was used to generate a single probability distribution for the unit cost of electricity with each portfolio. The simulation consisted of 10,000 iterations. For every iteration, a value for each uncertain parameter was selected at random based on the shape of the distribution specified for that parameter, and the resulting electricity cost was recorded for each of the two alternative supply portfolios. The 10,000 observations for each portfolio were then used to plot unit electricity cost probability distributions.



**Table 5 Probability Distributions Associated with Uncertain Parameters**

Uncertain Parameter	Base Case	Probability Distribution
Capital Cost of VIGP (\$ million)	355	Normal distribution; mean = base case; standard deviation 18
Natural gas price (\$/GJ)	5.575	Normal distribution; mean = base case; standard deviation 0.46
Capital cost of GSX (\$ million)	296.5	Normal distribution; mean = base case; standard deviation 14.8
Generation cost for Low Emission North Island (¢/kWh)	5.95	Normal distribution; mean = base case; standard deviation 0.3
Cost of transmission upgrades on VI (\$ million)	98	Normal distribution; mean = base case; standard deviation 5
GHG Cost (\$/tonne CO <sub>2</sub> e)	49	Normal distribution; mean = base case; standard deviation 8



## 6 Results and Discussion

### 6.1 Unit Electricity Costs and Impact on Rates

Unit electricity costs estimated for the two portfolios under base case assumptions, as well as the results of the sensitivity analysis on capital cost of VIGP, GHG cost and discount rate are shown in Table 6 below. Unit costs indicate only the cost of the electricity generated under each of the portfolios; they do not apply to the province-wide electricity system. Under base case assumptions, Natural Gas South Island comes in at 9.08 ¢/kWh, a 1.5 ¢/kWh greater cost than Low Emission North Island, at 7.58 ¢/kWh.

**Table 6 Unit Electricity Costs Under Base Case and Sensitivity Conditions (¢/kWh)**

	<b>Natural Gas South Island</b>	<b>Low Emission North Island</b>
Base Case Assumptions	9.08	7.58
VIGP Capital Cost \$304 million (sunk cost \$51 million removed)	8.86	7.58
GHG Cost of \$10/tonne CO <sub>2</sub> e	7.67	7.17
Discount Rate at 10%	9.29	7.76

Removing \$51 million in sunk costs from the capital cost of VIGP reduces the cost of Natural Gas South Island to 8.86 ¢/kWh. Natural Gas South Island is about 20% more costly than Low Emission North Island under base case assumptions, but is only 17% more costly when sunk costs are removed. Applying a GHG cost of \$10/tonne CO<sub>2</sub>e instead of \$49 over the time period of the analysis decreases the unit electricity cost of both portfolios, with the cost of Natural Gas South Island falling more because this alternative results in greater quantities of GHGs being emitted. At the lower GHG charge, the discrepancy between the two portfolios is only 7%. Applying a 10% discount rate rather than an 8% discount rate raises the costs of both portfolios, but does not impact the percent difference in unit electricity costs between the two alternatives.

Unit electricity cost information can be used to estimate the residential rates that would apply to customers within the BC Hydro service area. In the base case, these are estimated as 6.26 ¢/kWh for Natural Gas South Island and 6.22 ¢/kWh for Low Emission North Island. In both cases the rate is higher than the current rate of 6.11 ¢/kWh, reflecting a higher cost of new supply relative to the supply cost from existing sources, including hydropower dams. The difference between the two portfolios is much less pronounced when it comes to rates, because the increase in supply is small relative to the total system. According to these numbers, if the Natural Gas South Island portfolio is pursued, BC Hydro customers will actually pay slightly more for a new electricity supply with higher GHG emissions.

### 6.2 Greenhouse Gas Emissions

Estimated annual GHG emissions from the Natural Gas South Island portfolio are 721 kilotonnes CO<sub>2</sub>e over the lifetime of VIGP, more than three times greater than emissions from the Low Emission North Island resource package at 214 kilotonnes.

Implementation of the Natural Gas South Island portfolio would lead to an increase in annual emissions of about 36% over BC Hydro's 1997-2001 average GHG emission level of 2 Mt CO<sub>2</sub>e. Implementation of Low Emission North Island would result in only an 11% increase in annual emissions.

Furthermore, Low Emission North Island is an incremental strategy that leaves the door open for more low emission and green generation in the future (see Appendix A). Natural Gas South Island, on the other hand, directs large capital expenditures towards fossil fuel-specific infrastructure. The sunk costs associated with these investments will make it difficult to substitute other forms of generation for natural gas generation before GSX and the VIGP reach the end of their expected lifetimes.

### **6.3 Other Environmental Impacts**

The following environmental indicators were also assessed for Natural Gas South Island and Low Emission North Island by Willis Energy Services Ltd.: air quality; noise; hydrology and storm water run-off; wastewater discharge; fish, wildlife and vegetation; terrain and soils; impacts of transmission line upgrades; and archaeological resources.

#### **6.3.1 Natural Gas South Island**

An environmental impact assessment was completed by the VIEC for its VIGP application and a certificate was granted by the BC Environmental Assessment Office (BCEAO) in November 2003. The comprehensive assessment considered the potential effects of construction and operation of the proposed power plant, natural gas pipeline, power transmission line upgrades<sup>8</sup> and water/wastewater pipelines (BCEAO, 2003). In addition to the provincial process, a Joint Review was carried out by Canada's National Energy Board (NEB) and the Canadian Environmental Assessment Agency (CEAA). This process resulted in an approval of the application for a Certificate of Public Convenience and Necessity for GSX and a recommendation that the project proceed to the next level of decision-making (NEB, 2003a, 2003b). This following section focuses on the BCEAO report, as it includes the impacts of a natural gas pipeline. The report concluded that the proposed project design and construction plans did not cause significant adverse environmental impacts, provided that the recommended mitigation measures and monitoring activities were carried out.

The main findings of the BCEAO report are summarized below.

- Air quality impacts: The project is not expected to have a significant or incremental impact on air quality. VIGP emissions will not exceed existing ambient air quality objectives or standards.
- GHG emissions: VIEC has committed to prepare a GHG mitigation plan, which would include details on BC Hydro's commitment to offset 50% of GHG emissions through 2010. The mitigation plan calls for annual progress reports.
- Health impacts: VIGP does not have a measurable impact given the minimal effect of air quality. A commitment has been made to monitor ambient air quality.

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<sup>8</sup> VIGP also requires a connection and upgrade to the existing on-Island electric transmission grid.

- Water supply: Water for the plant would be obtained through existing water licences. Land and Water BC's view is that the proposed plant would not impact Nanaimo River flows.
- Wastewater quality: The plant's waste process water flows through an appropriate treatment system. The project's wastewater will not have significant impact on quality of wastewater discharged.
- Noise impacts: Mitigation measures include establishing an advisory committee to address any issues.
- Transmission line upgrades: The VIEC plans to undertake a baseline study to determine the effects of the existing transmission line on birds using the area and a post construction bird strike monitoring study to determine any incremental effects from the upgrade.

Table 7 below summarizes the general environmental impacts associated with Natural Gas South Island.

**Table 7 Natural Gas South Island Environmental Impact Assessment Summary**

Issue	Impact Assessment Indicators				Mitigation	Comments
	SCOPE	MAGNITUDE	DURATION	DIRECTION		
Air Quality	Sub-regional	Very low	Long term	Negative	No	The potential impact of VIGP on air quality in the Nanaimo region was quantified for a 50 km by 50 km area centred at the plant site.
Noise	Sub-regional	Low-medium	Medium/long term	Negative	Yes	Operation noise specification has been developed for VIGP to control the noise emissions from the facility through the use of specific equipment design. Mitigation measures are expected to minimize noise impacts during construction and operation.
Hydrology and Stormwater Run-off	Local	Very low	Medium/long term	Negative-neutral	Yes	After construction of VIGP has been completed, the construction-phase settling pond will be converted to a stormwater detention pond.
Wastewater Discharge	Local	Nil	Long term	Negative-neutral	No	The process water will be largely uncontaminated cooling water containing low concentrations of suspended and dissolved solids. Chlorine will be used to control bacteria, algae growth and compounds present in the raw water.
Fish Wildlife and Vegetation	Local	Low	Long term	Negative	Yes	Construction and operation will result in some habitat loss, but the affected area is small and impacts will be mitigated.
Terrain and Soils	Local	Low	Long term	Neutral	No	Residual effects are expected to be negligible.
Transmission Line Upgrade	Local/Regional	Medium	Medium/long term	Negative	Yes	Existing circuits are to be upgraded by creating a double circuit from Harewood substation to the Duke Point Area. Increased avian mortality issues were raised.
Archaeological Resources	Local	Nil	Long-term	Neutral	No	The archaeological impact assessment determined that much of the VIGP has no archaeological potential.

### 6.3.2 Low Emission North Island

The projects considered in this portfolio are varied in nature. They include small hydro, biomass, wind and natural gas-fired cogeneration projects. In addition to the specific impacts associated with each resource, this portfolio also includes the impacts from the large transmission upgrades that are necessary to integrate the power from northern Vancouver Island to the network. This section describes the potential impacts of an upgraded transmission power line and those of each generation technology in general terms. The severity and significance of each impact would vary according to site conditions. All estimated impacts assume the use of commonly employed mitigation measures.

Environmental issues associated with each of the resources included in the Low Emission North Island portfolio are summarized below.

- **Small Hydro:** The biggest concern with hydropower projects is the impact on fish and fish habitat. The use of flow releases is one technique to ensure that fish habitats are preserved in the area downstream of a hydropower diversion (BC Hydro, 2002). The small hydro project included in the Low Emission North Island portfolio is not a run-of-river project, as it includes storage facilities. Preliminary studies indicate that controlled flooding will have a positive impact by regulating annual flow patterns to effectively increase fish spawning habitat. Noise is created by small hydro projects due to the size and rotation frequency of the generating equipment, though the degree to which a project is isolated will determine if mitigation is needed. Construction impacts, particularly around watercourses, can be minimized by utilizing proper techniques intended to minimize spillages, and by providing a proper cleanup response if spills do occur.
- **Biomass:** Air emissions of  $\text{NO}_x$ ,  $\text{SO}_2$ , and CO are associated with biomass projects. Emissions depend on the exact nature of the fuel used, and the design and controls of each combustion facility. Another air quality concern associated with biomass plants is particulates, although these emissions can be controlled through conventional technologies.
- **Wind:** These projects present the potential for impacts on wildlife, especially through increased avian mortality. Detailed baseline studies will determine the presence of sensitive species, as well as prescribe mitigation measures to minimize injuries to wildlife populations. Modern turbines have a number of design techniques that can be utilized to minimize impacts.
- **Natural Gas Cogeneration:** The primary impact associated with natural gas cogeneration is the emissions of GHGs and other air pollutants. GHG emissions were discussed in the previous section. Most air quality impacts can be addressed through conventional technologies.

Based on the results of this environmental screening assessment, potential adverse environmental impacts associated with Low Emission North Island are believed to be low for most criteria. It should be possible to effectively mitigate impacts to most of the environmental criteria at a reasonable cost. Moderate to high impacts are expected for visual resources, vegetation and wildlife habitat for the wind projects, in the absence of mitigation and baseline monitoring studies. Many of the projects included in Low

Emission North Island are in their design stage, requiring additional environmental studies for permitting and compliance purposes. Table 8 below summarizes the general environmental impacts associated with Low Emission North Island.

**Table 8 Low Emission North Island Environmental Assessment Summary**

Issue	Impact Assessment Indicators				Mitigation	General Comments
	SCOPE	MAGNITUDE	DURATION	DIRECTION		
Air Quality	Local	Very low	Long term	Neutral	Yes	Individual impacts of each project have not been quantified. The natural gas cogeneration project is expected to have some local impacts that can be minimized with proper mitigation measures. Woodwaste projects contribute to closing beehive burners and may lead to air quality improvements. Emissions of air pollutants can be further reduced through the addition of electrostatic precipitators.
Noise	Local	Low	Medium/long term	Neutral	Yes	Noise is a factor in wind power sitings. Mitigation is through zoning ordinances and proper stakeholder involvement.
Hydrology and Stormwater Run-off	Local	Very low	Medium/long term	Negative-neutral	Yes	The small hydro project included in this portfolio includes storage facilities. Hydrology is modified to enhance stream conditions by preventing summer drought. Mitigation measures employed during construction address stormwater run-off issues.
Wastewater Discharge	Local	Nil	Long term	Negative-neutral	Yes	Effects are expected to be negligible.
Fish Wildlife and Vegetation	Local	Low	Long term	Negative	Yes	Wind projects present the largest potential for impacts on wildlife. Siting procedures take into account the presence of sensitive species, and prescribe mitigation measures. New right-of-ways for power lines can be managed to minimize habitat loss.
Terrain and Soils	Local	Nil	Long term	Neutral	Yes	Effects are expected to be negligible.
Archaeological Resources	Local	Nil	Long term	Neutral	Yes	New power line construction and maintenance could damage potential sites. Proper communication and stakeholder involvement would plan an optimal right-of-way.

## 6.4 Socio-Economic Impacts

The VIEC submission to the BCEAO is relevant to assessing the potential socio-economic impacts of Natural Gas South Island, as well as its environmental impacts. The submission addressed impacts including: employment, population, housing, traffic and transportation, emergency services, human health and health care, education, utility infrastructure, land use, visual resources, tourism, recreation, local businesses/industry, culture/heritage and quality of life. From the analysis, it was concluded that no significant adverse social impacts would occur from the project, in the Nanaimo region, as the existing community services are expected to be capable of responding to the needs of the VIGP without difficulty (VIEC, 2002).

The estimated capital cost of VIGP is \$355 million, with expenditures in BC estimated by Willis Energy at approximately \$70 million. A detailed cost breakdown was not available, but it is assumed that the bulk of the expenditures will be dedicated to the cost of the gas and steam turbines, which are not manufactured locally. According to the application submitted to the BCEAO (VIEC, 2002), VIGP is forecast to create approximately 239 person-years of employment during construction and 20 full time operating and support staff positions thereafter.

A full socio-economic assessment is not available for the portfolio of projects making up Low Emission North Island. Willis Energy has estimated up-front costs for the projects included in this portfolio at \$357 million, with approximately \$204 million spent in BC. This alternative includes small projects where a large proportion of the total costs are spent on construction and design activities. According to Willis Energy, Low Emission North Island is expected to create about 1285 person-years of employment during construction and 35 full time operations and support positions thereafter.

The pulp mill closure in Gold River, the shutting down of forestry operations by Western Forest Products and the temporary closure of the pulp mill in Port Alice have had a devastating effect on the economy on the northern half of Vancouver Island. It is recognised that economic diversification is the north Island's key to survival and prosperity. The forestry sector will remain an important component of the region's economy, but coupled with this must be more value-added processing.

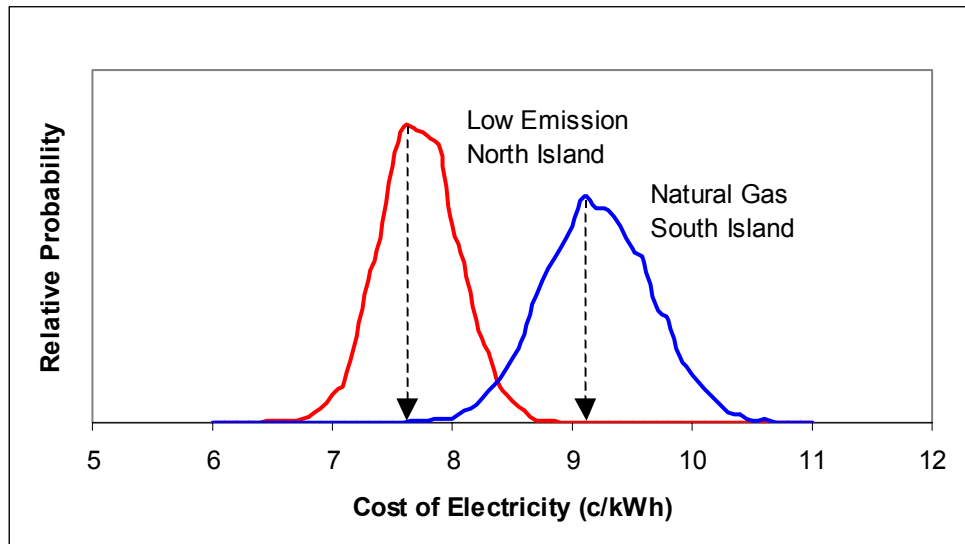
## 6.5 Impact of Uncertainty on Cost Estimates

Figure 1 presents the results of the uncertainty analysis. The graph indicates the relative probabilities of various unit electricity cost outcomes for each portfolio, given probability distributions around uncertain parameters as specified in Table 5 (section 5.2). The base case unit electricity cost estimates are indicated with dashed arrows. The base case estimates have the highest probability of occurrence.<sup>9</sup>

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<sup>9</sup> Values are not given on the y-axis because the probabilities are dependent on the size of the interval chosen on the x-axis. The total area under each of the two curves is equal to 100%.

**Figure 1 Unit Electricity Cost Probability Distributions**



The probability distribution for Natural Gas South Island is wider than the distribution for Low Emission North Island because this portfolio is more heavily influenced by the parameters around which there is greater uncertainty – natural gas prices and GHG liability costs. The probability distributions only overlap slightly, indicating that it is quite unlikely that Low Emission North Island will have a higher unit cost of electricity than Natural Gas South Island.

Uncertainty around key input parameters affecting costs means that there are financial risks associated with each of the portfolios. Under both portfolios, there is a risk that actual costs may be greater than the costs estimated under base case assumptions. (There is also a chance that costs will be lower.) The Natural Gas South Island portfolio has greater cost risks than Low Emission North Island because there is more uncertainty associated with this portfolio. Because this portfolio is also the more expensive option in the base case, there is no trade-off between cheaper base case cost and less risk. Therefore, even if Natural Gas South Island does prove cheaper under some outcomes, it is very important to see what kind of weighting stakeholders might put on these various risks. It is difficult to have BC Hydro making this decision without getting trade-off and risk-preference input from those who must pay the bills or taxes.

## **6.6 Multi-Attribute Trade-Off Analysis**

The results are summarized in Table 9 in the form of a multi-attribute trade-off matrix. Although the analysis reported here did not include a comprehensive MATA, the attributes listed in the table below are representative of the basic considerations that should be taken into account when making electricity supply decisions. There is not a common unit across all attributes, so decision makers must weigh the importance of the various attributes when choosing between alternative portfolios.

**Table 9 Multi-Attribute Trade-Off Matrix**

	Natural Gas South Island	Low Emission North Island
Financial		
Unit Electricity Cost	Significantly higher cost (9.08 ¢/kWh). Uncertainty analysis shows very low probability that this portfolio will be lower cost.	Lower cost (7.58 ¢/kWh).
Rate Impact	Higher rate (6.26 ¢/kWh).	Lower rate (6.22 ¢/kWh).
Environmental		
GHG Emissions	Higher emissions (721 kt).	Lower emissions (214 kt).
Other Impacts	No major impacts with mitigation.	No major impacts with mitigation.
Socio-Economic	Further assessment required. May result in less money kept in BC and lower job creation.	Further assessment required. May result in more money kept in BC and higher job creation.
Financial Risk	Electricity cost risk somewhat greater because more heavily impacted by uncertain natural gas prices and GHG costs.	Lower electricity cost risk.

Decisions like this often imply difficult trade-offs, such as a choice between an alternative that is less harmful to the environment or has less financial risk and one in which costs are lower in the base case. Table 9 does not reveal these kinds of trade-offs; Low Emission North Island performed equally well or better than Natural Gas South Island in terms of all the attributes tested. Natural Gas South Island came in at a 20% higher unit electricity cost than Low Emission North Island, given base case assumptions. Rates were also slightly higher under this portfolio. GHG emissions associated with Low Emission North Island were estimated to be less than one third of those for Natural Gas South Island. No other major environmental impacts were found to be associated with either portfolio, if appropriate mitigation measures are implemented. A preliminary socio-economic assessment conducted by Willis Energy found that Low Emission North Island keeps more money in BC and creates more jobs – although the relevance of increased employment is questionable in this type of analysis. Finally, the uncertainty analysis revealed that electricity cost risk might be somewhat higher under Natural Gas South Island because this portfolio is more heavily impacted by natural gas price and GHG cost liability uncertainties.

## **7 Conclusions and Recommendations**

This analysis of the Vancouver Island electricity supply decision evaluated a portfolio referred to as Natural Gas South Island (planned VIGP supplied by the GSX pipeline) and a portfolio referred to as Low Emission North Island in terms of several key attributes. The best available information was used to assemble a set of base case assumptions describing both portfolios. Because these values are uncertain, alternative assumptions were tested in a sensitivity analysis and then a probabilistic uncertainty analysis.

Decisions like this often imply difficult trade-offs, such as a choice between an alternative that is less harmful to the environment or has less financial risk and one in which costs are lower in the base case. These kinds of trade-offs were not identified in this analysis. Low Emission North Island is lower cost under base case assumptions and has lower rates. This finding was robust to the sensitivity tests performed. Low Emission North Island also results in fewer GHG emissions and exposes the taxpayers and electricity customers of BC to less risk from higher natural gas prices and GHG liabilities.

The financial risk associated with Natural Gas South Island indicates that there is value in deferring any decision to go down the gas-fired generation path until greater certainty exists around key variables that impact the cost of electricity supply to Vancouver Island. Low Emission North Island has the advantage of avoiding large capital investments that could lock BC into an undesirable electricity future. The low emission portfolio could be followed by similar electricity sector investments in BC, or might act simply as a bridge to implementing Natural Gas South Island at some point in the future, should that strategy be revealed as the best option.

New information could change the results that have been presented in this report, as could methodological refinements. There may be additional factors in the decision of how to supply electricity to Vancouver Island that were not included here. This analysis was of limited scope and did not conform to all of the requirements for a comprehensive MATA or Integrated Resource Planning exercise. It does, however, demonstrate the need to perform such an exercise before supply investments are made. Only BC Hydro has the resources for the desired level of evaluation.

## Appendix A: Power Generation Potential in North and Central Vancouver Island

The north part of Vancouver Island has a significant amount of power generation potential based on information provided by various project proponents. Table A-1, prepared by Willis Energy, identifies over 2100 MW of projects.

**Table A-1 Potential Generation Projects: North and Central Vancouver Island**

Type of Project	Estimated Capacity (MW)
Biomass	80
Small Hydro	103.5
Coal	200
Pulp Mill Cogeneration	149
Wind	1568.5
<b>Total</b>	<b>2101</b>

Other proponents have also indicated that there is a potential for coal bed methane projects. Most of these projects are in the north and central parts of the Island where economic development would be welcomed.

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