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The Voluntary Approach to GHG Reduction: A Case Study of BC Hydro

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Abstract

Voluntary programs for environmental protection are increasingly popular with governments, but it is difficult to assess the extent to which such programs change the behaviour of firms. We conduct a hindsight decision analysis of the electricity supply strategy that BC Hydro chose in the late 1990s while it participated in a Canadian government program for voluntary greenhouse gas (GHG) reduction. The electric utility chose an electricity generation strategy for 2000 – 2010 that under its own input assumptions provides negligible financial advantage relative to a strategy that dramatically lowers GHG emissions. If BC Hydro's decision is indicative of other industries during the 1990s, this may explain in part the continued increase in Canadian industrial GHG emissions in the decade since the launching of the voluntary program, and Canada's inability to achieve its 1992 target of reducing emissions back to 1990 levels by 2000.

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1. Introduction

Over the past decade, governments have shown a growing interest in a voluntary approach to environmental protection by industry (Carraro and Levesque, 1999; OECD, 1999; Khanna, 2001; Karamanos, 2001). In contrast with other environmental policy approaches (command-and-control regulations, economic instruments), voluntary programs cast government in the role of information provider, facilitator, role model, and cheerleader, while allowing individual firms to determine their level of effort for environmental protection and improvement.

Various arguments have been offered in support of the voluntary approach. First, command-and-control regulation is a crude policy instrument that can cause unnecessarily high costs for attaining a given level of environmental improvement (Khanna, 2001). Second, the compulsory nature of regulation fosters an uncooperative, cat-and-mouse relationship between government and industry, with no incentives to develop innovations that go beyond minimal compliance (Nash and Ehrenfeld, 1997). Third, some analysts argue that once firms are better informed of the cost reduction and marketing benefits associated with environmental improvements, they will pursue environmental improvement of their own accord. Popular new catchphrases, such as *the natural step, eco-efficiency* and *triple bottom line*, suggest that firms can increase profits by adopting technologies that are more efficient in their use of energy and materials, and hence less polluting (Hawken, Lovins and Lovins, 1999). Finally, to the extent that economic policy instruments (environmental taxes, tradable emission permits) increase the prices of goods and services, they are difficult to sell politically.

However, while the growth of voluntary programs has been dramatic, and participating industries offer much anecdotal evidence of voluntary actions to improve the environment, we know little about the aggregate effectiveness of such programs (Harrison, 1999). Effectiveness is difficult to determine. Without the benefit of a real-world, controlled experiment, researchers must resort to comparing program participants with non-participants, or comparing industry environmental performance under an environmental program with a counterfactual forecast of how firms might otherwise have performed in the absence of the program. Indeed, achievement of a given voluntary environmental target does not confirm the effectiveness of the policy, for it could be that even without the voluntary program an industry would have evolved toward the desired environmental improvement. In a recent survey of empirical studies into voluntary approaches to environmental protection, Khanna (2001, p.311) noted that, "relatively few have examined the impact of voluntary initiatives taken by firms on their environmental performance."

In one effort to control for non-program factors, Khanna and Damon (1999) used a two-stage estimation technique to assess the impact of participation in the 33/50 program of the U.S. Environmental Protection Agency for reducing industrial toxic releases in the period 1991 – 93. They found that only 28% of reductions could be attributed to the program. King and Lenox (2000) analyzed the impact of the Responsible Care program of the U.S. chemical industry on environmental performance of firms over the period 1991 – 96. Their empirical study could not find a significant effect of program participation on environmental performance.

While these aggregate empirical studies may provide some indication of the effectiveness or ineffectiveness of voluntary programs, policy makers might also benefit from a detailed examination of the investment options available to firms while participating in such programs, and the decisions that they then actually make. This approach may reveal the extent to which a program shifts the investment strategy of the firm from the path that it might otherwise have taken. We explore this approach in this paper by conducting a hindsight decision analysis of the investment strategy of an individual firm while it participated in a voluntary environmental program.

Our case study focuses on the major investment strategy of BC Hydro – a publicly-owned electric utility that dominates the British Columbia electricity market – while it participated in the Canadian government's voluntary program to reduce greenhouse gas (GHG) emissions. In its 2000 Integrated Electricity Plan (IEP), developed during the period 1998 – 2000, BC Hydro presented its 10-year electricity supply investment strategy. The 2000 IEP identifies the alternatives facing the company in 2000, and notes that these alternatives have changed little from those detailed in the publicly-available documents produced by BC Hydro in the mid-1990s as part of its earlier investment planning process. This wealth of information about resource options makes BC Hydro, like other regulated electric utilities, an ideal case study for the hindsight decision analysis approach that we are proposing for assessing the effectiveness of voluntary programs.

In 1992, Canada signed the United Nations Framework Convention on Climate Change and set a target to reduce its GHG emissions back to their 1990 level by the year 2000. To this end, Canada launched in 1993 the National Action Program on Climate Change, which included the Voluntary Challenge and Registry (VCR). In the VCR, firms submit an action plan for GHG reduction and provide regular progress reports, all on a voluntary basis. By 2000, the VCR had 757 action plans from firms covering 75% of all industrial GHG emissions.[1]

The impact of the VCR is in dispute. During the period 1993 – 2000, emissions of several industrial sectors increased only slightly, although those of the fossil fuel production and electricity generation sectors grew significantly. In a recent report, the Analysis and Modelling Group (1999) – an entity of the National Climate

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[1] VCR Website www.vcr-mvr.ca.

Change Process created after the Kyoto Protocol of 1997 – estimated that the VCR and related initiatives had reduced national GHG emissions by 35 megatonnes (Mt) CO_2e from what they otherwise would have been on an annual basis over the period 1993 – 98 (a 5% decrease).[2] The method used to estimate this effect was not explained. In contrast, the Pembina Institute (Bramley, 2002) suggested that the VCR had little effect, a conclusion based on the evolution of aggregate industrial emissions (24% increase in the period 1990 – 2000), lack of program coverage (less than 55% of total industrial emissions), and case studies of the target setting and emission accounting practices of some individual firms.

BC Hydro has been an early and ongoing participant in the VCR. Although it is not a private firm – the normal focus of voluntary programs – the provincially-owned corporation should be less constrained than a typical private firm to take voluntary actions, given that it is a monopoly and does not have private shareholders to answer to.[3] Moreover, BC Hydro proudly highlights its willingness to voluntarily pursue environmental objectives. Its 2001 Triple Bottom Line report stated: "Last year, BC Hydro recognized sustainability as the core of our business, becoming one of only a handful of companies and organizations on this planet who have actively committed to balancing social, economic and environmental considerations in everything they do." (BC Hydro, 2001, p.5). In the same report, Hydro noted that: "We are committed to limiting the growth of GHG emissions from our electrical system, wherever economically feasible." (p.50).

BC Hydro is not explicit about how it balances these two statements. By saying "wherever economically feasible", does Hydro mean that financial considerations override other factors? If so, the balancing of social, economic and environmental considerations would have little meaning. If, however, Hydro is willing to incur some level of financial costs in order to pursue environmental (and social) objectives, what does this mean in practice? What level of such costs would BC Hydro be willing to trade off against an environmental objective? How would it make that determination? What does participation in the VCR mean to BC Hydro in terms of the choices it makes with respect to GHG emission reduction versus other objectives?

In this paper, we explore these questions by conducting a hindsight decision analysis of BC Hydro's electricity generation strategy for the period 2000 – 2010, and by comparing this to an alternative strategy based on Hydro's own data. This provides an opportunity to assess how BC Hydro balances economic and

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[2] CO_2e is short for CO_2 equivalence, a measure that converts all GHGs into equivalent units of CO_2 in terms of their GHG effect.

[3] This is not to suggest that public shareholders are not also worried about financial returns.

environmental considerations and how it interprets a voluntary commitment to reduce GHG emissions. The outcome of this analysis supplies some evidence for the general assessment of voluntary programs, as well as possible insights into the relative merits of alternative policy instruments for GHG emission reduction.

The paper is organized as follows. Section 2 describes BC Hydro's electricity planning process and its electricity supply strategy for the period 2000 – 2010. Section 3 presents an alternative strategy that emphasizes minimizing GHGs and other emissions. Section 4 provides key inputs for the contrasting investment strategies so that they can be compared as mutually exclusive alternatives. Section 5 compares the two strategies in a hindsight decision analysis that estimates their relative financial and environmental performance under base case assumptions. Section 6 incorporates uncertainty about key assumptions into the decision analysis. Section 7 presents the results in a multi-attribute trade-off framework. In Section 8, the conclusion, we reflect on the role of the VCR in BC Hydro's electricity planning process and speculate on the lessons of this hindsight decision analysis approach for assessing the effectiveness of voluntary industry environmental programs.

2. BC Hydro's Electricity Supply Strategy: 2000 – 2010

BC Hydro supplies 90% of British Columbia's electricity consumption, generating most of its power at hydroelectric plants. Because of growing public concern over large hydropower projects, BC Hydro now considers these along with alternative sources to meet load growth. Its principal options include stand-alone natural gas plants (combined cycle gas turbines – CCGT),[4] cogenerated electricity,[5] coal plants, large hydroelectric plants and renewable resources such as wood waste, small-scale hydropower, wind, tidal, wave, geothermal and solar. Future generation facilities may be owned by BC Hydro or independent power producers (IPPs), or as a partnership between Hydro and another private or public entity. A key assumption

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[4] A 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.

[5] Cogeneration is the combined production of useful heat and electricity. Cogeneration can produce more useful energy (useful heat plus electricity) per unit energy input than a combination of stand-alone heating systems and stand-alone thermal electricity generators. By increasing energy efficiency in this way, cogeneration decreases air emissions from what they otherwise would be. Cogeneration units may burn natural gas or some other fuel.

of the 2000 IEP, however, is that BC Hydro in some form would continue to dominate the provincial electricity market.

In the late 1990s, while participating in the VCR, BC Hydro undertook an internal resource planning exercise culminating in the release of its 2000 IEP, covering the period 2000 – 2010 (BC Hydro, 2000). This 40-page document provides a brief rationale for Hydro's resource investment strategy, but refers to the company's earlier, multi-volume 1995 IEP for details on the quantities, costs and other attributes of competing resource options (BC Hydro, 1995).

In its 2000 IEP, Hydro presented a supply expansion of 900 MW for the period 2001 – 2010 of which 83% would be developed by itself (alone or in partnership with an IPP) or the Columbia Power Corporation (another state-owned entity) and the remainder (180 MW) by IPPs focused on renewable energy sources (Jaccard, 2001). Hydro's IEP is dominated by a CCGT plant on Vancouver Island (VI), fed by a new natural gas pipeline called the Georgia Strait Crossing (GSX). The proposed pipeline would connect with the existing Centra Gas transmission system on VI. For convenience, we refer to Hydro's electricity supply plan as GSX-CCGT.

The 2000 IEP justifies Hydro's electricity supply strategy as the result of a two-step analysis. In the first step, a comparison of natural gas with renewable resources such as wood waste and small-medium hydro finds natural gas to be cheaper (BC Hydro, 2000, p.24). This raises the issue of where to locate the natural gas facilities. In the second step, a review of locations finds VI to be cheaper because this avoids the cost of renewing the aging undersea transmission lines to VI (p.28), whose renewal is expected to be more expensive than building a natural gas pipeline to the island.

Currently, electricity generated on VI accounts for only 20% of the island's needs. The remaining 80% is delivered from the mainland by three submarine cable transmission systems: two 500 kV circuits, a high-voltage direct current (HVDC) system and two 138 kV circuits. These systems are aging: the 138 kV cables are no longer in use and the HVDC link is slated for retirement in 2007.

The 2000 IEP indicates that Hydro's GSX-CCGT strategy is driven by economics. Natural gas is cheaper than the alternatives for electricity generation and a natural gas pipeline to VI is cheaper than undersea electricity cables. However, it is unclear the extent to which other, non-financial factors were incorporated – if at all – into the decision-making process, especially BC Hydro's commitment in the VCR program to take voluntary actions to reduce GHG emissions.

While the natural gas strategy will lead to substantial increases in GHG emissions, other elements of BC Hydro's 10-year strategy can have an effect on emissions. In the 2000 IEP, BC Hydro commits to allocate to renewable sources of electricity a minimum 10% share of new generation. It does not, however, provide a specific estimate of the expected cost of this undertaking. BC Hydro also has an energy efficiency program (Power Smart) and a program for upgrading existing hydropower facilities (Resource Smart). However, in the 2000 IEP neither of these is treated as a variable that can be increased or decreased depending on the balancing of financial, environmental and social considerations; their quantities are presented as fixed under alternative resource scenarios. Finally, BC Hydro also commits to pursue GHG offsets – paying others to decrease GHG emissions in other sectors, whether inside or outside of the province. Again, however, the 2000 IEP provides no indication of how the financial cost and effectiveness of offsets compare to an approach in which BC Hydro pursues a resource investment strategy with much lower GHG emissions. In any case, the biggest impact on GHG emissions is BC Hydro's decision to pursue natural gas for meeting most of the province's growth in electricity generation requirements over the period 2000 – 2010. We, therefore, focus our hindsight decision analysis on this question.

The 2000 IEP does not indicate how BC Hydro considered environmental and social objectives in setting its electricity investment strategy. This is unfortunate because 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. As concerns mounted in the 1970s and 1980s about the environmental threats posed by electricity generation technologies, utility regulators responded by requiring utilities to conduct multi-attribute trade-off analysis (MATA) to evaluate alternative generation and end-use efficiency investments in terms of their financial, environmental and social attributes. Because public values are critical in such evaluations, the MATA included direct public involvement, usually in stakeholder consultative processes. Increasingly, these processes also included an explicit consideration of uncertainty about key input assumptions. The common electricity industry name for its application of MATA is integrated resource planning (IRP). The overall impact of IRP has been to increase utility investment in energy efficiency and environmentally desirable generation technologies like cogeneration, wind, small hydro, biomass and solar, especially where these have only marginally higher financial costs relative to conventional large-scale generation.

Hydro's 2000 IEP, and the process of producing it, differs significantly from the conventional IRP process. Hydro produced the IEP in-house, with virtually no public involvement. Hydro does not explain how it traded-off competing economic, environmental and social objectives in arriving at its GSX-CCGT strategy. Hydro appears to have ignored cogeneration and end-use efficiency as resources that might be increased from their current levels. Hydro does not assess the effect of input uncertainty in its consideration of GSX or alternative strategies.

BC Hydro's 1995 IEP, however, does include detailed information on key attributes of the GSX-CCGT strategy as well as the alternative, renewable and cogeneration resources. Some of this information has recently been updated by research within and outside of BC Hydro. With this information, we have constructed an alternative, contrasting strategy to GSX-CCGT, one that keeps GHG emissions virtually stable. We conduct a MATA analysis, and consider input uncertainties, in assessing how this strategy performs relative to GSX-CCGT, thus generating an indication of BC Hydro's GHG-related decision making as it participated in the VCR program. A more detailed description of our assumptions and analysis is found in Jaccard and Murphy (2002).[6]

3. An Alternative, Low-Emission Electricity Supply Strategy

We developed an alternative to GSX-CCGT that we refer to as the Low Emission IPP (LOW-EM-IPP) portfolio. LOW-EM-IPP involves replacing and increasing undersea electricity transmission capacity to VI, and encouraging IPPs to develop low emission resources such as cogeneration,[7] woodwaste[8] and small-medium hydro[9] throughout the province. These resources have positive environmental attributes and are low in cost relative to other environmentally desirable technologies.[10]

GSX-CCGT and LOW-EM-IPP differ in two fundamental respects.

1. Energy transmission: Under GSX-CCGT, energy is delivered to VI in the form of natural gas through a new pipeline, while under LOW-EM-IPP energy is

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6 The report is available on the website of the Energy and Materials Research Group in the School of Resource and Environmental Management at Simon Fraser University www.emrg.sfu.ca.

7 In describing the LOW-EM-IPP alternative, we use the term cogeneration to refer to retrofits to systems that already burn natural gas (or other fossil fuels) to generate heat. Once a retrofit has occurred, the additional fuel needed to generate electricity is small relative to what was already required by the heating system. This means that the air emissions associated with the electricity production are quite low. Heating systems that could be targeted for cogeneration retrofits include those in hospitals, universities, commercial buildings, industry and institutional buildings.

8 Because trees absorb CO_2 during their growing cycles, net CO_2 (and greenhouse gas) emissions are considered to be zero when woodwaste is burnt to generate electricity. The impact of woodwaste combustion on local air pollution varies by project. In cases where the wood residue was previously disposed of in beehive burners, local air quality will improve substantially with diversion to a modern biomass electricity generation plant.

9 These are mostly under 20 MW in size with negligible disruption of the river flow regime.

10 In this study we have not considered renewables such as wind, tidal, solar and geothermal, which appear to be higher cost in British Columbia relative to wood waste and small hydro.

delivered in the form of electricity through an upgraded submarine cable system.

2. Generation technology, location and ownership: Under GSX-CCGT, electricity is generated on VI by BC Hydro and perhaps a private partner using CCGT technology, while under LOW-EM-IPP electricity is generated throughout BC using low emission resources developed by IPPs.

We specified key attributes by which to compare GSX-CCGT and LOW-EM-IPP. These included two financial attributes, unit electricity cost and impact on residential electricity rates, and two environmental attributes, CO_2e and NO_X emissions. The cost of CO_2e emission reduction was also calculated by comparing the financial and environmental performance of LOW-EM-IPP relative to GSX-CCGT. Finally, we considered the share of electricity generated on VI under each option.

In order to conduct our analysis, we required financial and technical information to the year 2025. We used the available data from BC Hydro and independent experts to construct a set of most likely assumptions. We refer to these as our base case assumptions.

The assumptions for both GSX-CCGT and LOW-EM-IPP have considerable uncertainty. The first natural gas pipeline to VI, built 10 years ago, had a substantial construction cost overrun. Improving electricity transmission capacity to VI may also prove more expensive than expected. Natural gas prices have fluctuated substantially over the past 24 months, as have long-term price forecasts. The costs of a significant expansion of renewable sources of electricity are not well known. We provide a rudimentary portrayal of these uncertainties in a comparison of the two options.

4. Key Inputs for Comparing the Alternative Investment Strategies

The GSX pipeline is expected to be in-service in October 2004 and has been designed to initially deliver 99 TJ of natural gas per day (GSCPL, 2001, V.II, p.2-1).[11] This is enough gas to power at least three 220 MW CCGTs on VI, producing a total of 5,280 GWh per year.[12] In our base case, three such facilities are built in stages, with the first one in-service in fiscal year 04/05, the second in 06/07 and the third in 09/10. Each CCGT produces 1,760 GWh per year. We assume the

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[11] With extra compression, capacity could be increased to 150-200 TJ per day. Therefore, the GSX pipeline could ultimately contribute to much more natural gas-based electricity generation on VI than we are assuming here, with greater impacts in terms of plant siting and cumulative emissions.

[12] We assume that the CCGTs are 52.5% efficient and operate at a capacity factor of 92.4%.

plant-gate, levelized cost of electricity from the CCGTs at 5.3 ¢/kWh, a value BC Hydro uses. The cost of the pipeline has been estimated at $340 million by BC Hydro. Table 1 summarizes the base case assumptions for this option and the low emission alternative.

Table 1: Summary of GSX-CCGT and LOW-EM-IPP Base Case Assumptions

	04/05	06/07	09/10
GSX-CCGT			
Number of CCGTs on VI	1	2	3
Total CCGT Capacity (MW)	220	440	660[1]
Generation (GWh)	1,760	3,520	5,280
CCGT Generation Cost (¢/kWh)	5.3	5.3	5.3
Capital Cost of GSX (million 2001 Cdn $, undiscounted)	340		
LOW-EM-IPP			
Generation (GWh) (7% added for transmission losses)			
Cogeneration	628	1,255	1,883
Woodwaste	628	1,255	1,883
Small-Medium Hydro	628	1,255	1,883
Total	1,883	3,766	5,649
Average Generation Cost (¢/kWh)	5.5	5.5	5.5
Capital Cost of Transmission (million 2001 Cdn $, undiscounted)			
Seventh Cable	168		
D-S Reinforcements	56		
New Substation			78[2]

[1] To put this number in perspective, the generation capacity of the BC system used for meeting domestic demand is 12,000 MW.
[2] This investment occurs in 08/09 but is shown in 09/10 for simplicity

Although we initially tested a case in which Hydro builds only one 240 MW CCGT on VI, this was a higher cost option because of underutilization of the remaining pipeline capacity. As both a pipeline developer and a potential pipeline customer, BC Hydro will be motivated to bias its evaluation of subsequent electricity generation investments in favour of ensuring full utilization of the pipeline. Without additional plants, there is considerable evidence to suggest that the pipeline will be underutilized.

First, new sources of natural gas demand will grow relatively slowly given that forest sector restructuring and a wave of provincial government downsizing should hit VI particularly hard. Second, much of the easiest retrofit of existing buildings on VI to natural gas occurred in the period immediately after completion of the first pipeline in 1991. Further conversions are more costly and require action by people who are less willing to make the switch because of: (1) a stronger preference for electric, wood or oil heating, (2) higher than average costs for gas connection, (3) the reduction of subsidy programs for conversions to natural gas, and (4) the phase-out of price guarantees for VI natural gas customers combined with wariness due to recent natural gas price volatility.

Under our LOW-EM-IPP alternative strategy, retrofit cogeneration, woodwaste and small-medium hydro resources are developed and utilized throughout BC to a level that allows the same amount of electricity to be provided to VI as under GSX-CCGT. This results in more capacity being installed than under GSX-CCGT because a CCGT has a higher capacity utilization rate than does small hydro (although this latter is only a part of the LOW-EM-IPP portfolio). Also, GSX-CCGT generates electricity on VI, while LOW-EM-IPP requires large-scale transmission from the mainland; transmission losses must therefore be included in the LOW-EM-IPP portfolio. We assume an overall loss of 7%, meaning that 7% more electricity must be generated under this portfolio than under GSX-CCGT (some LOW-EM-IPP electricity will be generated on VI).

As with GSX-CCGT, we assume that the generation resources are added in three equal increments, in fiscal years 04/05, 06/07 and 09/10. In each of these years, approximately 1,883 GWh per year are added until the resource totals 5,649 GWh per year in 09/10. Each addition of generation potential is composed of 1/3 cogeneration, 1/3 woodwaste and 1/3 small-medium hydro, giving a total of 1,883 GWh per year for each of the individual resources in 09/10.

We calculated an average generation cost for LOW-EM-IPP resources based on the amount of energy produced in 09/10. For woodwaste and small-medium hydro (3766 GWh in 09/10), we assumed a cost of 5 ¢/kWh for the first 1950 GWh and 5.5 ¢/kWh for the remainder (Marvin Shaffer and Associates, 2001, p.50).[13] For cogeneration (1883 GWh in 09/10), we assumed a cost of 6 ¢/kWh (Hagler Bailly Canada, 2000, p.10, 12).[14] This gives a weighted average cost of generation of approximately 5.5 ¢/kWh in the base case.

In order to continue to meet capacity requirements on VI under LOW-EM-IPP, the electricity transmission link to the mainland is enhanced by adding a seventh,

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[13] The information in the Marvin Shaffer report was compiled primarily from BC Hydro data.

[14] The cogeneration technologies used will be primarily aeroderivative turbines and reciprocating turbines (1 - 6 MW) and gas turbine plants (30 MW) all applied as retrofits to thermal applications in existing facilities. The two studies referenced in this paragraph provide estimates for the quantities of generation resources available at certain price levels.

spare phase cable to the existing Malaspina – Dunsmuir 500 kV circuits.[15] The capital cost is about $300 million and includes the cost of the seventh cable ($168 million), reinforcements to the Dunsmuir to Sahtlam transmission system ($56 million) and a new 500 kV substation in the Nanaimo area ($78 million) (BC Hydro, 1995, Appendix E, p.9-11, Appendix G p.6, 7).[16] We assume that the seventh cable will be in-service in 04/05, the same year that the pipeline is completed under GSX-CCGT. The substation is built four years after the addition of the seventh cable.

The financial costs of the two portfolios were calculated by combining generation and infrastructure (pipeline, transmission improvements) costs into a single unit cost of electricity. Costs in each year out to 2025 were discounted to 2001 using a discount rate of 10%. Electricity generation up to 2025 was used to calculate the unit costs of electricity for each option.

Rate impacts for residential customers in the BC Hydro service area were also estimated. The current rate is 6.5 ¢/kWh. Of this, about 3 ¢ is associated with generation costs. We estimated what rates would be under GSX-CCGT and LOW-EM-IPP by assuming that for each portfolio 660 MW of generation capacity would be added to the 12,000 MW of BC capacity currently used for meeting domestic demand. For a fair comparison, we include the extra generation and transmission costs of the two portfolios.

CO_2e and NO_X emissions were calculated over time for GSX-CCGT and LOW-EM-IPP by applying emission factors (Table 2) to the electricity generated. Emissions associated with pipeline transport of natural gas were not added to the GSX-CCGT portfolio. Our NO_X calculation shows emissions within the Georgia Basin because only this region would experience a significant difference between the two portfolios; wood waste burned outside the Georgia Basin might slightly increase NOx emissions in some localities but these would be more than offset by the reduction of particulates as conventional beehive burners (to incinerate wood waste) are replaced by high efficiency wood burning electricity generators. We calculated NO_X emissions from cogeneration using the emission factor in Table 2, but then subtracted half because we assume that half of the cogeneration retrofits are

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[15] This was the transmission option used for portfolio analysis in BC Hydro's 1995 IEP. We chose to rely on the 1995 IEP because it contains the only publicly available, fully detailed explanation of the transmission options that has been obtained from Hydro. More recently, other strategies for undersea cable upgrades have been presented as being preferable. For example, in a presentation to the Victoria Chamber of Commerce on March 13, 2002, Shawn Thomas, a Senior Vice-President at BC Hydro, suggested repair / replacement of the HVDC cables (at a cost of $230 million), as well as transmission upgrades on the mainland ($50 million). The net present value of this configuration is very similar to that of the seventh 500 kV cable option.

[16] We have converted cost estimates given in BC Hydro's 1995 IEP from $1995 to $2001.

located outside the Georgia Basin.

Table 2: Emission Factors by Generation Resource

	CO_2e (t/GWh)	NO_X (kg/GWh)
CCGT[1]	350	33
Small-Medium Hydro	0	0
Woodwaste	0[2]	NA
Gas Cogeneration Retrofits	100[3]	9[4]

[1] Emission factors for CCGT technology are from BC Hydro (2000, p.23).
[2] Recall that CO_2e is absorbed during the growing cycle of trees.
[3] From Pape (1997, p.59).
[4] We derived our NO_X emission factor for cogeneration by applying the relationship observed between CO_2e emissions for CCGT and cogeneration (about 3 to 1) to NO_X emissions for the two technologies.

5. Hindsight Decision Analysis Under Base Case Assumptions

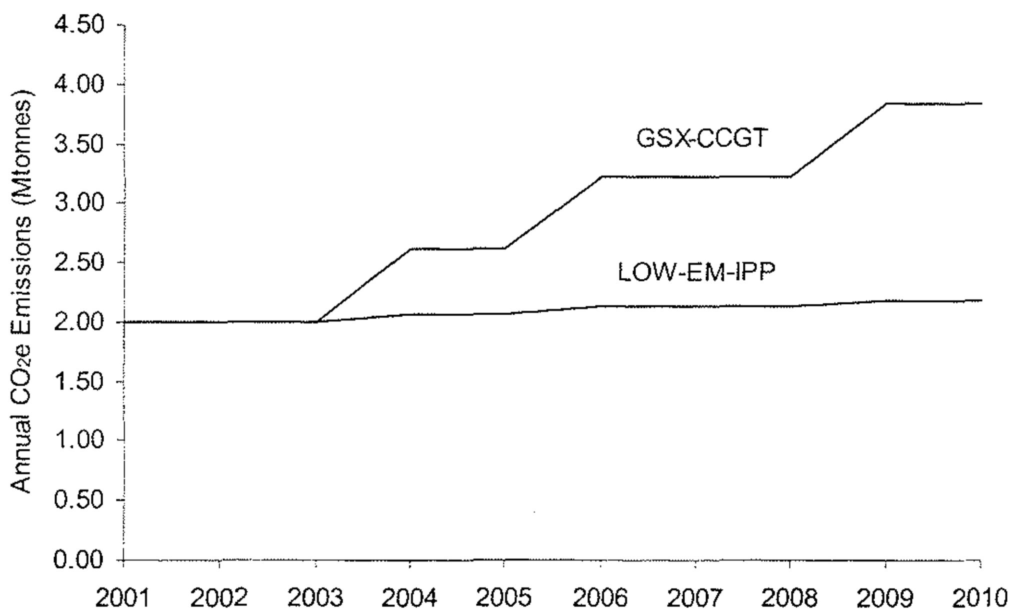
Table 3 summarizes our base case results. Unit electricity costs indicate only the cost of the electricity generated under each of the portfolios; they do not apply to the province-wide electricity system. At 6.57 ¢/kWh, LOW-EM-IPP is 0.43 ¢/kWh more costly than GSX-CCGT, which comes in at 6.14 ¢/kWh in the base case.

Table 3: Summary of GSX-CCGT and LOW-EM-IPP Base Case Results

	GSX-CCGT	LOW-EM-IPP
Unit Electricity Cost (¢/kWh)	6.14	6.57
Residential Rate in BC (¢/kWh)	6.66	6.69
CO_2e Emissions, 2010 (Mt)	1.85	0.19
Cost of CO_2e Reductions ($/t)		14
NO_X Emissions to Georgia Basin, 2010(t)	174	9
VI Capacity Self-Sufficiency, 2010	54%	31%

The estimated residential rates pertain to all customers within the BC Hydro service area. Although unit electricity costs are higher under LOW-EM-IPP, the difference between the two portfolios is barely distinguishable when it comes to residential rates because neither portfolio is significant compared to total system costs. Thus, the LOW-EM-IPP rate of 6.69 ¢/kWh is less than 1% higher than the GSX-CCGT rate of 6.66 ¢/kWh. Compared to GSX-CCGT, LOW-EM-IPP results in an increase in annual electricity costs of about $2.31 for the average residential customer (an extra charge of 19 cents per month).[17] Under GSX-CCGT, the 5,280 GWh of electricity generated on VI in the year 2010 results in 1.85 Mt of additional annual CO_2e emissions, almost a 100% increase over BC Hydro's 1997 – 2001 average GHG emission level of about 2 Mt CO_2e. LOW-EM-IPP delivers the same amount of electricity to the island in 2010 with emissions of only 0.19 Mt. Figure 1 shows approximate CO_2e emissions from electricity generation in BC under the two portfolios. LOW-EM-IPP also performs better in terms of NO_X emissions. Annual emissions in the Georgia Basin are only 9 tonnes (t) in 2010 compared to the 174 t emitted by GSX-CCGT (Table 3).

Figure 1: Comparison of CO^2e Emissions from Electricity in BC to 2010



Dividing the additional costs of LOW-EM-IPP by the (discounted) reductions in GHG emissions results in an estimated emission reduction cost of $14 per t CO_2e.[18] Figure 2 shows a cost curve for emission reductions in Canada estimated as part of the National Climate Change Process. It indicates that under the base case

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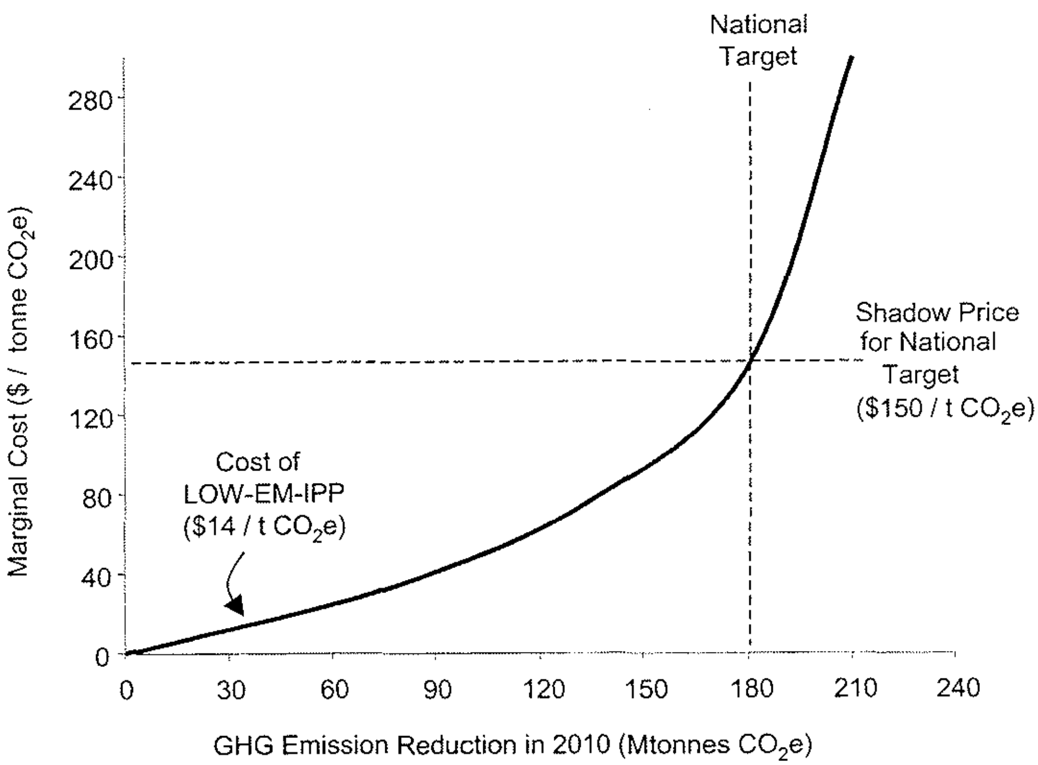
[17] Based on an annual consumption of 10,344 kWh per year for the average residential customer (H. Mak, BC Hydro, personal communication).

[18] Had we only discounted costs and not emission reductions – a method sometimes applied in national analyses – the cost per tonne would have been $4.

assumptions LOW-EM-IPP is one of the cheapest options available in Canada for reducing GHG emissions. Thus, if Canada eventually applies policies that result in GHG emission charges of at least $14 per t CO_2e, LOW-EM-IPP becomes the lower cost option. GSX-CCGT commits BC electricity consumers to higher GHG emissions, and possible GHG charges, over at least a 25-year time frame.

Figure 2: Cost Curve for GHG Emission Reductions in Canada, 2010



Source: Jaccard, Nyboer and Sadownik (2002)

Another issue that may be of concern is electricity versus energy self-sufficiency for VI. Under GSX-CCGT, about 54% of the peak capacity demand on VI will be met by generation located on the island by 2010. On-island generation would supply only 31% of peak requirements in 2010 under LOW-EM-IPP. However, GSX-CCGT requires transmission of natural gas from the mainland instead of electricity, meaning that both options are comparable in terms of VI energy self-sufficiency.

6. Adding Uncertainty to the Decision Analysis

We also assessed how the two investment strategies compare when uncertainties around key assumptions are incorporated into the decision analysis. The uncertain assumptions we focus on are the capital cost of the natural gas pipeline, the capital cost of the electricity transmission upgrade, average long-run natural gas prices (affecting CCGT generation cost), and the cost of renewables and cogeneration electricity supply. We present these uncertainties in the form of discrete probabilities associated with alternative states of nature, as shown in Table 4.

Table 4: States of Nature, Probabilities and Cost Estimates for the Uncertainty Analysis

Uncertain Parameter	State of Nature	Probability of State of Nature	Cost Estimate
Capital Cost of GSX	High	20%	\$425 million (25% increase from base case)
	Base Case	60%	\$340 million
	Low	20%	\$289 million (15% decrease from base case)
CCGT Generation Cost	High Natural Gas Prices	20%	5.7 ¢/kWh
	Base Case	60%	5.3 ¢/kWh
	Low Natural Gas Prices	20%	4.9 ¢/kWh
Cost of Electricity Transmission Upgrade	High	25%	\$209 + \$70 + \$98 million (25% increase from base case)
	Base Case	50%	\$168 + \$56 + \$78 million
	Low	25%	\$142 + \$47 + \$66 million (15% decrease from base case)
LOW-EM-IPP Generation Cost	High	25%	5.9 ¢/kWh
	Base Case	50%	5.5 ¢/kWh
	Low	25%	5.1 ¢/kWh

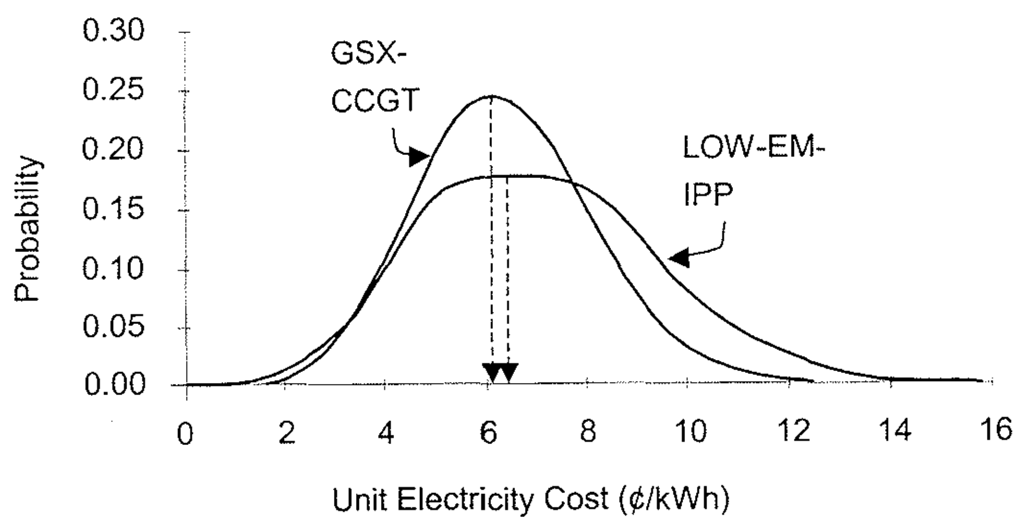
We developed the range of values, and the probabilities associated with these, from discussions with BC Hydro personnel and industry experts.[19] These rudimentary estimates reflect the greater uncertainty associated with the LOW-EM-IPP option because: (1) more detailed engineering analysis has been conducted on GSX relative to the undersea cable option; (2) while the recent volatility of natural

[19] While these discussions were usually confidential, we provide these values so that readers can test their own assumptions about uncertainties associated with key inputs.

gas prices is expected to continue in the future, the long-run average price has not trended upward in real terms for the past 15 years; and (3) there is greater uncertainty about the prospects for renewable electricity given that technological change may drive down the cost of new technologies while exhaustion of the most favourable sites may drive up their cost.

If the discrete probabilities are converted into continuous probability distributions, and these are used as inputs for stochastic estimation of the costs of each option, the unit electricity costs of GSX-CCGT and LOW-EM-IPP can be represented with a single continuous probability distribution, as in Figure 3. This graph shows substantial overlap between the unit cost distributions for the two options, even under the relatively modest uncertainty range of Table 4. The base case cost estimates are indicated with dashed arrows. The overlap of the two distributions implies that with just a small shift in base case assumptions, LOW-EM-IPP could become the cheaper financial option as well as being the better environmental performer.

Figure 3: Electricity Cost Probability Distributions, GSX-CCGT and LOW-EM-IPP



7. Multi-Attribute Trade-Off Framework

Table 5 summarizes the results of our analysis in the form of a multi-attribute trade-off matrix. This presentation highlights the advantages and disadvantages that must be weighed in choosing between GSX-CCGT and LOW-EM-IPP.

Table 5: Multi-Attribute Trade-Off Matrix

Attribute \ Portfolio	GSX-CCGT	LOW-EM-IPP
Financial • Unit Electricity Cost • Rate Impact	Slightly better – if no pipeline cost overruns and gas prices low	Slightly poorer – may end up better depending on pipeline and natural gas costs
Environmental • GHG / CO_2e • NO_X	Poorer	Much better
VI Electricity Security	Better	Poorer
Ratepayer Risks	Impacts on rates and / or gov't	Risks to ratepayers less if IPPs

In terms of the financial attribute, electricity costs are slightly lower with GSX-CCGT in the base case. This is consistent with BC Hydro's rationale for choosing this option. However, the degree of overlap in the probability distributions around unit electricity costs for the two portfolios, as revealed by our uncertainty analysis, indicates a substantial possibility that LOW-EM-IPP will be as cheap or cheaper than GSX-CCGT.

With respect to air emissions – our indicators of environmental performance – LOW-EM-IPP performs substantially better. It causes virtually no increases in provincial GHG emissions or in NOx emissions in the Georgia Basin. Although we do not show it in our results, LOW-EM-IPP would also lead to a reduction of particulate emissions in those interior communities that replace beehive burners with low emission wood waste electricity generation units, an air quality improvement that is unlikely to occur without the opportunity to invest in wood waste electricity. In terms of VI electricity security, GSX-CCGT appears to be the superior option because a greater percentage of peak capacity is generated on the island itself. The improved security of this option, however, depends on the assumption that an undersea natural gas pipeline is more secure from failure than an undersea electricity line. We could find no data to support such a claim. The GSX-CCGT option does not, however, result in greater energy self-sufficiency for VI because it simply replaces imported electricity with imported natural gas.

The cost risks associated with GSX-CCGT are borne to a greater extent by provincial ratepayers or taxpayers. If BC Hydro incurs higher than expected costs, it will pass these costs on to its captive customers, or BC taxpayers will bear the costs in the form of lower returns from their publicly-owned utility. If the undersea cable runs over budget, these costs are also borne by Hydro's captive customers or BC taxpayers. But under the LOW-EM-IPP option, some cost risks are borne by individual IPPs as they develop their low emission projects and compete with each other for long-term supply contracts or spot market sales.[20] For example, an IPP usually must have a long-term, fixed-price contract with BC Hydro in order to attract loans but the holders of equity would bear substantial financial risk for construction cost overruns and unforeseen maintenance requirements. Under GSX-CCGT, these types of costs would be borne entirely by BC Hydro's captive customers.

Given that the costs and energy self-sufficiency outcomes of the two options are so similar, the dramatically superior ranking of the LOW-EM-IPP option in terms of GHG and NOx emissions is revealing. One would have to value this environmental advantage at close to zero in order to prefer GSX-CCGT to LOW-EM-IPP. This is a troubling finding given BC Hydro's stated commitment to balancing financial, social and environmental objectives in everything it does, and its participation in the VCR while developing its GSX-CCGT strategy.

8. Conclusion

While governments have recently shown considerable interest in voluntary approaches to environmental improvement, there has been little in the way of empirical analysis of the effectiveness of voluntary programs. In this paper, we test an approach to assessing effectiveness that involves the detailed examination of the investment options available to a given firm in order to estimate the extent to which it considered its voluntary environmental commitment in making critical investment decisions. Our hindsight decision analysis suggests that BC Hydro's participation in Canada's voluntary program to reduce industrial GHG emissions had little impact on its willingness to incur small financial costs in order to reduce these emissions. Moreover, there is no evidence that BC Hydro even calculated the size of the financial sacrifice implied by the environmental objective. Nor did BC Hydro attempt to involve its customers in its decision so that they might express their willingness to incur a slight increase in their rates in order to reduce environmental risks from increasing GHG emissions.

Overall, this analysis suggests that the voluntary program had little effect on those very decisions of the firm that it was presumably intended to influence, decisions that would result in substantial progress toward the environmental objective at minimal cost. In reaching this conclusion, however, we should caution

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[20] These contracts and spot sales would be with BC Hydro, if it remains a monopsonist purchaser of IPP electricity, or with final customers if the industry evolves toward a retail competition model.

that while we rely almost exclusively on BC Hydro's data, there may be additional factors that we are unaware of that had some influence on Hydro's decision to pursue a fossil fuel electricity strategy in a region rich with alternative, low emission resources.

If BC Hydro's decisions in the late 1990s are indicative of decisions made by industry throughout the 1990s, this case study may help explain the continued increase in Canadian industrial greenhouse gas emissions in the seven years since the launching of the voluntary program and Canada's inability to achieve its 1992 target of reducing emissions back to 1990 levels by 2000.

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