A CAPITAL BUDGETING ANALYSIS OF THE PROPOSED SITE C DAM

by

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ABSTRACT

This paper looks at the issues surrounding BC Hydro's the capital budgeting decision for the proposed Site C Dam on the Peace River in northeast British Columbia, Canada. The project is compared with a potential combined cycle natural gas-fired thermal electricity generating facility. Techniques such as net present value, internal rate of return, modified internal rate of return, profitability index, payback period, modified payback period, and equivalent annual annuity are used to evaluate six scenarios. These scenarios have varying values for weighted average costs of capital and carbon tax rates. A sensitivity analysis addressing changes to weighted average cost of capital, inflation rate, electricity price, annual electricity output, capital cost, carbon tax rate, and the price of natural gas identifies the largest uncertainties faced by the project and compares them with the natural gas alternative.

TABLE OF CONTENTS

Abstract		ii
Table of Contents		iii
List of Tables		v
List of Figures		vi
Acknowledgement		vii
Introduction	Introduction	1
	The problem – We need more electricity	3
	BC Hydro Crown Corporation	6
	The Clean Energy Act	7
Section 1	Project Descriptions	10
	Site C Description	10
	Benefits of Site C	12
	Costs of Site C	12
	Natural Gas Combine Cycle Gas Thermal	13
	Costs of the CCGT	14
	Benefits and capabilities of CCGT	15
Section 2	Factors to Consider in Capital Budgeting Decisions	16
	The Supply of Natural Gas	16
	Carbon Tax	17
	Weighted Average Cost of Capital	19
	Price of Electricity	22
	Inflation	24
Section 3	Project Comparisons	28
	Comparison Methods	28
	Comparison Introduction	31
	Scenario 1	33
	Scenario 2	34
	Scenario 3	35
	Scenario 4	36
	Scenario 5	37
	Scenario 6	38

Section 4	Sensitivity Analysis	39
	Weighted Average Cost of Capital Sensitivity	39
	Electricity Price Sensitivity	40
	Annual Electricity Output Sensitivity	41
	Inflation Rate Sensitivity	43
	Capital Cost Sensitivity	44
	Natural Gas Price Sensitivity	45
	Carbon Tax Sensitivity	46
Section 5	Conclusion	48
Bibliography		51
Appendices		55
	Appendix A - Scenario 1, Site C Cashflow	56
	Appendix B - Scenario 1, CCGT Cashflow	57
	Appendix C - Scenario 2, Site C Cashflow	58
	Appendix D - Scenario 2, CCGT Cashflow	59
	Appendix E - Scenario 3, Site C Cashflow	60
	Appendix F - Scenario 3, CCGT Cashflow	61
	Appendix G - Scenario 4, Site C Cashflow	62
	Appendix H - Scenario 4, CCGT Cashflow	63
	Appendix I - Scenario 5, Site C Cashflow	64
	Appendix J - Scenario 5, CCGT Cashflow	65
	Appendix K - Scenario 6, Site C Cashflow	66
	Appendix L - Scenario 6, CCGT Cashflow	67

LIST OF TABLES

Table 1	Energy Deficit/Surplus (GWh) with Demand Side Management Target and Revelstoke Unit 6 (No LNG)	5
Table 2	Capacity Deficit/Surplus (MW) with Demand Side Management Target and Revelstoke Unit 6 (No LNG)	6
Table 3	Future Electricity Prices	23
Table 4	Geometric Mean Inflation	25
Table 5	Weighted Average Cost of Capital Sensitivity	40
Table 6	Electricity Price Sensitivity	41
Table 7	Annual Electricity Output Sensitivity	42
Table 8	Inflation Rate Sensitivity	43
Table 9	Capital Cost Sensitivity	44
Table 10	Natural Gas Price Sensitivity	45
Table 11	Carbon Tax Sensitivity	46

LIST OF FIGURES

Figure 1	Scenario 1	33
Figure 2	Scenario 2	34
Figure 3	Scenario 3	35
Figure 4	Scenario 4	36
Figure 5	Scenario 5	37
Figure 6	Scenario 6	38

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Introduction

British Columbia currently enjoys some of the lowest electricity rates in North America. Cheap and abundant electricity has been a cornerstone of our provinces economic development and continues to be a competitive advantage. Most of our electricity comes from hydroelectric dams constructed in the 1960's, 70's, and 80's. Demand for this electricity has grown as the province has grown. In 1971 the provincial population was approximately 2.24 million and today it is estimated to be over 4.60 million. (Statistics Canada 2010) Economic growth has also developed along with population growth fueled largely by the natural resource industries: forestry, mining, and oil and gas. These same factors will continue to grow the Province's economy and spur new demand for electricity in the future. In fact, at the forecast rate of growth, there is a shortfall of electricity by the year 2024. Action must be taken to ensure the province has sufficient supply to service the population and support the economy.

Part of the solution is to moderate the demand for electricity through demand side management. This will require all electricity users to shift their consumption patterns and adjust habits but will also require innovative thinking and investments in new, more efficient technologies. In addition to demand side management, new investments to retrofit existing generation facilities will help to bridge the gap but these measures alone will not be enough.

BC Hydro, the Crown corporation charged with producing, transmitting, and selling British Columbia's electricity is assessing new potential projects to generate the electricity needed in the future. The Crown corporation is guided by legislation such as the Hydro and Power Authority Act and the Clean Energy Act, regulated by the British Columbia Utilities

Commission, and ultimately answers to the Government of British Columbia. It is within this framework that BC Hydro chooses which projects to pursue.

British Columbia's successful policy of building large hydroelectric projects has brought the province to where it is today. Looking forward, BC Hydro must find the solution which balances economic, social, and environmental values. To do this BC Hydro has proposed the construction of a new dam project named Site C. Other projects were considered to meet British Columbia's future needs but Site C has been chosen as the best option.

Although Site C has many positive attributes, is the project the best option? As mentioned above, the Government of British Columbia enacts the legislation that BC Hydro works under and also sets policies which influence or direct the way new sources of electricity supply are procured. An example of this is the Clean Energy Act, which sets out the requirement that ninety-three per cent of British Columbia's electricity must be obtained from clean sources and prohibits the use of nuclear power generation. Interestingly, the Act prohibits large hydroelectric projects but specifically excludes Site C from the prohibition. The Act also specifies that new energy sources must be clean or renewable but in regulations subsequently produced under the Act, the production of electricity to serve potential liquefied natural gas (LNG) exportation was exempt, leaving the door open for exporters to burn natural gas to power the facilities.

With all of this direction from the provincial government, it is clear that Site C is the clear choice to meet future demand but does it stand up to scrutiny without the constraints placed on the decision by the Province? This paper examines the Site C project from a capital budgeting stand point and compares it against a Combined Cycle Gas Thermal plan fired with natural gas. Factors such as the weighted cost of capital, inflation, price of electricity, annual electricity output, capital cost, operation cost, carbon tax rate, and natural gas prices are all taken into account. Methods such as net present value, internal rate of return, and payback period are all employed to compare the two projects in six different scenarios. A sensitivity analysis is also performed to understand how unforeseen changes could affect each project. All of this information will be brought together to better understand the tradeoffs between the two projects and to make recommendations about future energy planning and policy in British Columbia.

The problem – We need more electricity

Domestic electricity consumption in British Columbia is divided between three main customer groups: residential users account for thirty-five per cent of demand, commercial customers account for thirty one per cent, and industrial customers account for thirty thirty-two per cent of the demand.[1] The forecast demand for residential customers is forecast to increase by 1.8 per cent over five year, 2.0 per cent over ten years, and 1.9 per cent over twenty years.[2] Residential demand is forecast using population and housing start projections. BC Hydro projects an average of 26,000 housing starts per year[3], and the provincial population is expected to grow between one and two million people by 2035.[4] Commercial demand is driven by projections of retail sales, employment, and commercial output. Commercial demand is expected to grow by 2.0 per cent over five years, 1.9 per

[1]BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Sec 5.2.1.1
[2] BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Sec 5.2.1.1
[3] BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Sec 5.2.1.1
[4] Statistics Canada, *Catalogue no. 91-520-X*, Table 2-11 and 7-11

cent over ten years, and 1.8 per cent over twenty years.[5] Industrial demand is made up of three key industries. The sawmills, pulp, and paper industry accounts for almost sixty per cent of industrial users. Demand from this industry is expected to decline by 2.4 per cent over five years, 1.2 per cent over ten years and 0.6 per cent over twenty years.[6] The expected decline is due to lower demand for paper and attrition of saw mills unable to find an economic fiber supply. The oil and gas sector which makes up ten per cent of industrial demand is expected to experience significant growth. Demand is expected to grow 19.0 per cent over five years, 14.3 per cent over ten years and 7.5 per cent over twenty years. This expected growth is in response to increased natural gas production in areas served by BC Hydro infrastructure between Dawson Creek and Chetwynd. The final significant industrial sector is mining. Demand from mining is expected to grow by 11.8 per cent over five years, 7.1 per cent over ten years, and 2.8 per cent over twenty years. The forecasts for mining demand are based largely prices of commodity such as copper, gold, molybdenum, and coal. The potential LNG industry on British Columbia's north coast is not considered in future demand forecasts. The demand for electricity in the LNG industry could reach between 2000 and 4000 MW of electricity capacity between 2015 and 2025. (Lewis 2013)

BC Hydro actively attempts to lessen demand through demand side management in order to ensure that demand for electricity does not outstrip available supply. This is done through a variety of initiatives such as codes and standards, rate structures (but not increases), load displacement projects, and other programs such as public awareness campaigns and technology improvements. BC Hydro's demand side management target is a reduction in yearly consumption of 7,800 GWh and an associated capacity savings of 1,400 MW by

[5] BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Sec 5.2.1.1
[6] BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Sec 5.2.1.1

2021.[7] Even if the corporation is successful at achieving its goal, there will be a supply gap by the year 2014 which widens each year after that.

Table 1 - Energy Deficit/Surplus (GWh) with Demand Side Management Target and Revelstoke Unit 6 (No LNG)[8]

Year	Load-resource Balances without DSM and Rev 6	DSM	Revelstoke Unit 6	LRB with DSM and Rev 6
F2012	(1,100)	900	0	(2,100)
F2013	(4,000)	1,200	0	(5,200)
F2014	(2,000)	2,000	0	(4,000)
F2015	(2,400)	3,000	0	(5,500)
F2016	(800)	3,900	0	(4,700)
F2017	100	4,800	0	(4,700)
F2018	2,300	5,700	0	(3,400)
F2019	4,300	6,500	0	(2,200)
F2020	5,400	7,200	0	(1,900)
F2021	6,400	7,800	0	(1,400)
F2022	7,200	8,200	0	(1,000)
F2023	8,200	8,400	0	(200)
F2024	9,100	8,900	0	200
F2025	9,900	9,200	0	700
F2026	10,400	9,600	0	800
F2027	11,000	9,800	0	1,200
F2028	12,100	10,200	0	1,800
F2029	13,000	10,600	0	2,400
F2030	14,000	10,900	0	3,100
F2031	15,000	11,200	0	3,800

[7] BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Sec 5.2.2.2
[8] BC Hydro, BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Sec 5.2.1.1, Table 5.8. Revelstoke 6 refers to a proposed sixth turbine planned to be added to the Revelstoke Dam in 2020.

Table 2 - Capacity Deficit/Surplus (MW) with Demand Side Management Target and Revelstoke Unit 6 (No LNG)[9]

Year	Load-resource Balances without DSM and Rev 6	DSM	Revelstoke Unit 6 (after Reserves)	LRB with DSM and Rev 6
F2012	(800)	150	0	(950)
F2013	(850)	150	0	(1,000)
F2014	(550)	350	0	(900)
F2015	(250)	500	0	(700)
F2016	400	650	0	(250)
F2017	600	800	0	(200)
F2018	850	950	0	(100)
F2019	1,150	1,100	400	(400)
F2020	1,300	1,250	400	(350)
F2021	1,500	1,350	400	(250)
F2022	1,650	1,450	400	(250)
F2023	1,850	1,500	400	(100)
F2024	2,000	1,600	400	–
F2025	2,200	1,650	400	100
F2026	2,350	1,750	400	200
F2027	2,500	1,800	400	300
F2028	2,700	1,850	400	450
F2029	2,950	1,900	400	600
F2030	3,200	2,000	400	800
F2031	3,400	2,050	400	950

BC Hydro Crown Corporation

The British Columbia Hydro and Power Authority, commonly known as BC Hydro, was created in 1961 through the purchase of BC Electric and its subsequent amalgamation with the Power Commission. This Crown corporation was responsible for building one of the

[9] BC Hydro, BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Sec 5.2.1.1, Table 5.9.

world's most ambitious hydroelectric systems in the 1960's and 70's.[10] From that time to present, the corporation has seen many changes and re-structuring but the core mandate: to generate, purchase, distribute, and sell electricity has remained intact[11]. The Utilities Commission Act, RSBC 1996, gives the British Columbia Utilities Commission the responsibility to regulate utilities including BC Hydro. The act also sets out the role of the Lieutenant Governor in Council in providing direction and delegating power to the Commission. This structure ensures BC Hydro operates to achieve the goals of the currently elected provincial government.

The Clean Energy Act

Another critical piece of legislation governing BC Hydro's policy is the Clean Energy Act, 2010. When assessing potential sources of electricity, BC Hydro works within the parameters outlined by the Clean Energy Act. There are a total of sixteen named energy objectives in the Act which outline the government's vision for British Columbia's electricity generation needs. At the time Premier Gordon Campbell said "our goal is to build on our unique competitive advantages with record investments in our historic 'two rivers' public power system and with new clean and renewable electricity investments and partnerships," and "we want British Columbia to become a leading North American supplier of clean, reliable, low-carbon electricity and technologies that reduce greenhouse gas emissions while strengthening our economy in every region."[12] The three priorities of the act are to: provide low cost, self-sufficient power generation; create jobs through a clean power

[10] BC Hydro, *https://www.bchydro.com/about/who_we_are/history.html*
[11] BC Hydro, *https://www.bchydro.com/about.html*
[12] Office of the Premier, *News Release 2010PREM0090-00048*, 1.

industry in each region of the province; and reduce greenhouse gas emissions and ensure environmental stewardship.[13]

In practice, the Act narrows the focus of BC Hydro in planning for the province's future energy needs through outright bans on use of certain methods of power generation such as the prohibition of nuclear power[14] and various potential large scale hydroelectric projects.[15] The Act further directs that 'two-rivers' projects are exempt from the prohibition and specifically states that the proposed Site C project falls under this exemption.[16] Other objectives of the Act include: a requirement that ninety-three per cent of British Columbia's power must come from clean sources, encouraging economic development and jobs creation, and maximization of British Columbia's power infrastructure.[17] In addition to the Clean Energy Act, the 2007 Energy Plan Policy Actions are important when considering alternative sources of power. Policy Action No. 18 under this plan mandates that all future natural gas-fired generation must have zero net carbon emissions. This would require the development of an emissions offset plan[18].

In December 2013 Harry Swain, the chairman of the Environmental Review Panel reviewing Site C was quoted as saying "it seems to me that your choices have been substantially narrowed by public policy in the province, by the Clean Energy Act and so on." (The Canadian Press 2013) Furthermore it is clear that the provincial government has no qualms about making changes to the regulatory framework in order to further broader goals such as attracting global companies to invest in liquefied natural gas facilities in

[13] Office of the Premier, *News Release 2010PREM0090-00048*, 2.
[14] Province of British Columbia, *Bill 17 -2010 Clean Energy Act*, Part 1 - Section 2 (o).
[15] Province of British Columbia, *Bill 17 -2010 Clean Energy Act*, Part 2 - Section 10.
[16] Province of British Columbia, *Bill 17 -2010 Clean Energy Act*, Part 2 - Section 10.
[17] BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Table 5.15
[18] BC Hydro, *Site C Clean Energy Project Environmental Impact Statement (EIS)*, Vol 1, Section 5.5.2.8

British Columbia by allowing natural gas to be considered a clean fuel so long as the electricity produced from it is in support of LNG exports. (Bailey and Stueck 2012) The duly elected government of the day has the right and responsibility to pursue the policies for which it was elected and it is clear that politics figure strongly in the Site C site decision. However, in the absence of political influence, would the project proceed based on its own merits?

This paper seeks to evaluate the Site C project against an alternative thermal, natural gas fired generation plant assuming the restrictions of the Clean Energy Act are not in force, examining the value of Swain's estimation. A legitimate argument can be made to prove the possibility of offsetting the ill-effects of greenhouse gas emissions by placing a price on those emissions and using market forces to choose winning projects. Furthermore, this approach could be used to evaluate all other aspects of the project. This includes, but is not limited to examining the cost of flooding the 83km long reservoir or the impact that natural gas exploration and production, with the associated wellsites, roads, pipelines and facilities, has on the land base. However, these considerations are beyond the scope of this project. This paper will consider the cost of carbon emissions through the operations phase of the natural gas alternative but will not attempt to quantify the cost of carbon emissions created during the construction phase of the proposed dam. It is very possible the decision as to how British Columbia will meet its future energy demands carries significant impacts to local residents and society; established or asserted aboriginal rights and title; the environment including fish and wildlife; and human health but the solutions are well beyond the scope of this paper.

Section 1 - Project descriptions

Site C Description

The 'Two Rivers" policy was envisioned in the 1950s and led to the construction of two dams on the Peace River in northern British Columbia: the WAC Bennett Dam in 1967, and the Peace Canyon Dam in 1980.[19] During this time the potential for a third dam on the Peace River was identified. In the 1970's planning and engineering work began for the proposed third dam known as Site C.[20] These efforts culminated in an unsuccessful application for an Energy Project Certificate in the early 1980's.[21] After the initial rejection more work was done between 1989 -1991 and again from 2009 to present date in order to optimize the Site C design.[22]

The latest incarnation of the project would see an earthfill dam spanning 1,050 metres across the river valley. The dam itself would be sixty metres high. The generating facility would have six 183 MW vertical axis Francis turbines for a combined installed capacity of 1,100-megawatts.[23] It is expected that the project, if built, would supply 5,100 gigawatt hours of electricity per year; enough energy to power more than 450,000 homes. Other works associated with the project would include realignment of four sections of road and four

[19] BC Hydro, *Site C Clean Energy Project: Business Case Summary*, A2.
[20] BC Hydro, *Project Description: Site C Clean Energy Project*, i.
[21] BC Hydro, *Project Description: Site C Clean Energy Project*,10.
[22] BC Hydro, *Project Description: Site C Clean Energy Project*, i.
[23] BC Hydro, *Site C Clean Energy Project: Business Case SUMMARY*,39-40, Table 6.1

bridges along Highway 29, two seventy seven kilometer long transmission lines, and a host of ancillary projects such as access roads and work camps.[24]

BC Hydro has assessed many options to expand its supply of electricity. The potential project options have been evaluated based on resource potential, volume and quality of incremental energy and capacity, price, environmental and social impacts and the outcome of these evaluations led BC Hydro to again favour the option building Site C. The dam site is planned to be situated downstream of the existing W.A.C. Bennett and Peace Canyon dams, just seven kilometers south west of the city of Fort St John at latitude N 56°11′40.44″, and longitude W 120°54′44.83″[25], in order to take advantage of the Williston Lake reservoir's multi-year capacity without impacting a new river system. This use of existing reservoirs will allow Site C to generate approximately thirty-five per cent of the energy produced at the W.A.C. Bennett Dam with only five per cent of the reservoir area.[26] Site C has a large upfront capital cost of $7.9 billon ($2011) that will be spent over the seven year construction period but enjoys low operating costs over the seventy year planning period. The dam has been designed to allow for repairs and replacement of infrastructure and components, ensuring the longevity of the project. These replacements will require additional funding not captured in the current budgeted costs of the Site C project, however the replacements will enable the dam's usable life to be extended to more than one-hundred years.[27]

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[24] BC Hydro, *Project Description: Site C Clean Energy Project*, 10.
[25] BC Hydro, *Project Description: Site C Clean Energy Project*, 11.
[26] BC Hydro, *Project Description: Site C Clean Energy Project*, 20.
[27] BC Hydro, *Information Sheet: Cost Estimate for Site C*, and *Site C Clean Energy Project Environmental Impact Statement.*

Benefits of Site C

British Columbia currently enjoys relatively inexpensive electricity because of past investments in its hydroelectric infrastructure. The initial capital costs of hydroelectric projects are typically quite high but benefits from low future operating costs. Another attribute of hydroelectric power is its dependable capacity. Although there is seasonality in power production, the release of water behind the dam can be timed to coincide with peak loads during the day and avoid the need for less efficient resources such as pumped storage. The timing of water releases can also be aligned to coincide with demand peaks throughout the year. Hydroelectric dams can have a symbiotic relationship with alternative sources of electricity generation, using the dam's existing turbines and connections to infrastructure. This can include solar energy, using the stored water behind the dam to capture the sun's energy, or utilizing wind turbines when weather permits. When optimal conditions do not exist for solar and wind energy production, the water can be release from the dam to again power the turbines, maintaining a consistent supply of electricity.

Costs of Site C

As mentioned above, the projected capital cost of the Site C dam is $7.9 billion, in 2011 dollars. The main capital costs of the dam are broken into four components; the first is the dam and associated structures will cost $1,790 million. This component is comprised of the earthfill dam; approach channels and buttress; spillway, intakes and penstock; north back stabilization; cofferdams, dikes and diversion tunnels. The second group of works, with a cost of $990 million, is the power facilities which include the power house and switchgear building, and stations and transmission. Representing a cost of $530 million, the third component is offsite works such as the Highway 29 relocates, land and rights, access roads, and clearing. The final component is construction management and services, and worker accommodation. This is expected to carry a price tag of $515 million. In addition to those direct construction costs, there is $1,005 million of expected indirect costs such as development, regulatory, construction insurance, project management and engineering, and mitigation and compensation costs. The remainder of the budget is taken up by a contingency at $730 million, inflation at $790 million and interest during construction at $1,550 million.

Annualized variable costs of the dam would include water rentals of $40.2 million, grants-in-lieu and school taxes of $2.6 million, operating and maintenance costs of $7.5 million and annualized sustaining capital of $9.3 million. All of these variable costs are also reported in 2011 dollars.[28]

Natural Gas Combine Cycle Gas Thermal

BC Hydro has studied a range of options for power generation in its 2010 Resource Options Report. One of the most plausible alternatives to Site C is natural gas-fired generation. In particular, combined cycle gas turbines (CCGT) are attractive given they are a proven technology with energy conversion efficiencies of between fifty and sixty per cent.[29] Even greater efficiency can be gained if the generating station is combined with a cogeneration facility. CCGT technology is also attractive because of the range of sizes and capacities for

[28] BC Hydro, *EIS*, Volume 1, Figure3.1 and BC Hydro, *Business Case Summary*, 25
[29] BC Hydro, *2013 Resource Options Report Update*, 5-66.

providing large-scale, dependable energy; they can be sited close to load centers so as to minimize the need for electricity transmission infrastructure (as long as there is a natural gas supply); and production of electricity can be displaced by alternative energy sources such as run or river hydro or wind when available.[30] However, there are also disadvantages to this method of power generation when considering the emission of greenhouse gases and other air pollution; as well as the reliance on non-renewable fossil fuels.[31]

Currently, BC Hydro owns two natural gas thermal generation plants which are connected to the provincial power grid, the Burrard and Prince Rupert facilities; and one that is operated without connection to the rest of the province, Fort Nelson. The Burrard station, which is by far the largest thermal facility of the three, boasting an installed capacity of 900MW is set to be retired in incremental stages beginning in 2014 and ending in 2016 as upgrades to the Mica hydro project are completed.[32]

Costs of the CCGT

For the purposes of this comparison, a potential project identified in the BC Hydro Resource Options Database (RODAT)[33] has been used. This project as proposed has an installed 500MW Combined Cycle Gas Turbine (CCGT) and would produce a 3776.4 GWh/year of firm energy. In order to make the comparison with the Site C project, the costs associated with the project have been scaled by roughly one-third to match the expected yearly output for Site C of 5100 GWh. The scaled \$2011 capital cost of the project is \$818.3 million, the

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[30] BC Hydro, *2013 Resource Options Report Update*, 5-66.
[31] BC Hydro, *2013 Resource Options Report Update*, 5-66.
[32] BC Hydro, *Integrated Resource Plan*
[33] BC Hydro, *2010 Resource Options Report, Appendix 3 - Resource Options Database (RODAT) Summary Sheets*, 825.

fixed operating and maintenance cost is $5.3 million, the fixed taxes are $622,580 and the variable operating and maintenance costs remain the same at $4.6/MWh. The United States Energy Information Administration produces long term forecasts for the Henry Hub price of natural gas. In a projection extending to 2040, the average annual nominal increase in the Henry Hub spot price was 5.6 per cent.[34] This small increase is attributable to the continued production of North American shale and tight gas plays.

Benefits and capabilities of CCGT

Like large hydroelectric projects, CCGT plants produce dispatchable electricity, meaning they can respond quickly to changes in demand. This is a key characteristic when considering peak load situations. Much of the electricity purchased from independent power producers generated from wind or run of river cannot be does not have this characteristic which is so important when considering the overall supply mix. Unlike a dam, CCGT plants are not affected by droughts. Although BC Hydro has modeled many low precipitation scenarios and is confident about the level of output generated by Site C this variability creates uncertainty, a CCGT plant is not affected in this way. Another key benefit of a CCGT plant is the smaller foot print on the land. Much of the best farm land in the Peace River Regional District will be flooded by the dam but \ a CCGT facility would have a drastically smaller impact on the landscape. Finally, a CCGT plant has a lot more flexibility in siting decisions. As with the Burrard facility, the CCGT plants can be sited close to load centers to reduce energy loss in transmission. Chief among the concerns about the use of CCGT technology are the variations in the price and supply of natural gas and the cost of greenhouse gas emissions.

[34] Energy Information Administration, *Annual Energy Outlook 2014*, Table A3

Section 2 – Factors to Consider in Capital Budgeting Decisions

The Supply of Natural Gas

British Columbia is awash with natural gas. The Province's remaining gas reserves are estimated to be 1,138.5 x 10^9 m^3 (Okuszko 2013) and in 2011, Canada was the third largest producer of natural gas in the world[35]. (Canadian Association of Petroleum Producers 2012) British Columbia's shale gas plays: the Montney and the Horn River Basin, are among the most prolific in the world and have allowed the province to produce over 113.3 x 10^6 m^3 per day in 2013.[36] With such a large supply of gas, some commenters have asked why there is a need to flood more of the Peace River Valley. Arguments have been made that natural gas is a clean, economical option that will protect the most productive and highest capability rated farm land in the Peace region. (Gibbard 2013) Environmental and first nations groups (Treaty 8 Tribal Council 2013) are saying that we can't afford and don't want either the Site C or large scale oil and gas development. (Andersen 2013)

Natural gas is the cleanest burning fossil fuel, and is fifty per cent cleaner than coal.[37] (Canadian Association of Petroleum Producers 2012) The International Energy Agency has studied the rise in the use of natural gas to offset consumption of oil and coal. One scenario studied shows the use of natural gas increasing fifty per cent between 2010 and 2035 to

[35] Canadian Association of Petroleum Producers, *Upstream Dialogue, The Facts On: Natural Gas*, 23
[36] British Columbia Oil and Gas Commission, *Hydrocarbon and By-Product Reserves in British Columbia*, 9
[37] Canadian Association of Petroleum Producers, *Upstream Dialogue, The Facts On: Natural Gas*, 7

account for more than one-quarter of world energy demand. This increase of natural gas, which offsets the use of dirtier fuels, is a positive factor in combating climate change.[38]

Carbon Tax

The Intergovernmental Panel on Climate Change's (IPCC) recently released report "Climate Change 2013: The Physical Science Basis" reaffirms previous assessments reporting our climate is warming at an unprecedented rate. It further explains the prominent role that carbon dioxide and other greenhouse gasses are playing in that warming.[39] The United Nations held a Framework Convention on Climate Change in at the end of 2010 in Cancun, Mexico. At this convention, the parties to the agreement affirmed climate change as one of the greatest challenges of our time and that nations need to work together to prevent and mitigate its effects.[40] In addition to identifying it generally as an issue, the parties also agreed that urgent action was needed to hold the increase in temperature to two degrees Celsius above pre-industrial levels.[41]

In the 2008 Climate Action Plan, then Premier of British Columbia, Gordon Campbell acknowledged climate change is the "challenge of our generation"[42] In support of the plan to reduce greenhouse gas emissions, the government passed Bill 44, the Greenhouse Gas Reduction Targets Act. The act, among other things, set the emission target levels at 33% less than the 2007 emissions by 2020 and 80% less than the 2007 emissions by 2050.[43]

[38] International Energy Agency, *FAQs: Natural Gas*
[39] Highlighted bullets on page 2 and page 13 of the IPCC "Summary for Policymakers"
[40] United Nations, *Cancun Framework Convention on Climate Change*, Paragraph 1
[41] United Nations, *Cancun Framework Convention on Climate Change*, Paragraph 4
[42] Campbell and Penner, *Climate Action Plan 2008*
[43] Legislative Assembly of British Columbia, *Greenhouse Gas Reduction Targets Act*, Part 1, Section 2

Subsequently, the BC government passed the Carbon Tax Act in May of 2008. The current Carbon tax rate in BC is thirty dollars per tonne. This translates into 5.70 ¢/cubic meter of Natural Gas burned (British Columbia Ministry of Finance 2012). For its part, BC Hydro uses a lower limit of thirty dollars per tonne and an upper limit of $177.72 per tonne ($2014) [44] for project comparison purposes.[45]

British Columbia was widely praised for the plan but there has been very little adoption of carbon taxes by other governments. One notable exception is the Republic of Ireland. Section 67 of the Irish Finance Act of 2010 sets the carbon tax of €3.07 per megawatt hour for electricity generated through thermal Nat Gas generation (Office of the Attorney General of the Government of Ireland 2010). Other jurisdictions have setup cap and trade systems allowing those industries who are able to reduce their emissions to sell credits to other industries for which reductions would be more costly. The most prominent example of such a system is the European Emissions Auction. So far in 2014, emissions contracts have been sold in a range in price from 4.45 to 6.93€/tCO2 (European Energy Exchange (EEX) 2014).

One may debate about the relative merits of a tax or a cap and trade scheme to pay for greenhouse gas emissions but the important issue is what the price of the emissions should be. Bowen discusses the need to maintain an atmospheric concentration of carbon dioxide and carbon dioxide equivalent of 450 PPM in order to avoid a global temperature increase of over 2°C (Bowen 2011). He draws on the UK Committee on Climate Change which says that "a price of £30 per tonne of carbon-dioxide-equivalent in 2020, rising to £70 in 2030" (Committee on Climate Change 2011) is required. Another study which analyzes various

[44] BC Hydro, *Environmental Impact Statement,* Vol 1,Page 5-56. The statement quotes a $2013 value of $173/tonne.
[45] BC Hydro, *Site C Clean Energy Project Environmental Impact Statement*

models finds that the price of carbon in 2020 derived from eight different models was from US$15 per tonne to US$263 per tonne in 2005 US dollars. (Clarke, et al. 2009). This wide range of potential prices makes planning for governments and corporations very difficult.

Weighted Average Cost of Capital

The province of British Columbia enjoys an "Aaa" credit rating from Moody's rating agency. (Shea and Hess 2013) The main driver for this rating is that BC Hydro's debt is guaranteed or owned by the Province of British Columbia. Other factors in this rating were BC Hydro's ability to support its debt and make payments (such as water rentals), and the corporations liquidity and access to capital. In April of 2013, the Standard and Poor's rating service rated the BC Government and BC Hydro both as "AAA". (Judson and Angastiniotis 2013)

BC Hydro does not have publicly sold bonds so we have to use proxies must be used in order to determine the cost of Hydro's debt. In the Moody's report, a debt interest rate of 3.3% was used to calculate BC Hydro's debt service rate. British Columbia's bond maturing in 2037 has a yield to maturity of 3.76%. Hydro Quebec's bond maturing in 2045 has a yield to maturity of 4.01%. The Government of Canada's bond, which matures in 2041, has a yield to maturity of 2.98% which can be used as the risk free rate of the market. Of these, the Government of British Columbia bond is the best estimate for the cost of debt because BC Hydro borrows directly from the province. The downside to this choice is the relatively short maturity period. A provincial 30 year bond would be a better estimate if one were available.

In order to determine an appropriate beta for BC Hydro, I have chosen Fortis Inc. as a proxy. I chose Fortis because they are a large, stable publically traded utility. Google finance reports a beta for Fortis of 0.27 (Google 2014) and I have calculated the same figure by looking at the monthly share price against the Toronto Stock Exchange from January 2009 to March 2014.

Risk premium is the additional return demanded by investors based on the riskiness of a particular investment. Instead, the best way to determine a reasonable risk premium is to look back at the history of the Toronto Stock Exchange. From 1926 to 2005, the geometric mean has been 3.8 per cent (Brigham, et al. 2011). Damordaran found that from the period from 1900 to 2012 the Canadian geometric mean risk premium was 3.40 per cent.

Using the capital asset pricing model we can determine BC Hydro's cost of equity. Using a risk-free rate of 3.76 per cent, a beta of 0.27, and a risk premium of 3.40 per cent, means BC Hydro's calculated cost of equity would be 4.68 per cent.

$$r_s = r_{RF} + (RP_m)\, b_i$$

Where r_{RF} is the risk-free rate, RP_m is the market risk premium, and b_i is the stock's beta.

$$r_s = 3.76 + (3.40)0.27$$

$$r_s = 4.68\%$$

BC Hydro's overall weighted cost of capital is found by combining the cost of debt and the cost of equity weighted by the debt to equity ratio of seventy to thirty.[46] Doing so produces a weighted average cost of capital for BC Hydro of 4.04 per cent (see Figure ##).

$$WACC = w_d r_d + w_{ce} r_s$$

Where w_d and w_{ce} are weights used for debt and common equity respectively.

$$WACC = (0.7)(3.76\%) + (0.3)(4.68\%)$$ [47]

$$WACC = 4.04\%$$

An alternative method to determine BC Hydro's weighted cost of capital comes from the British Columbia Utilities Commission. In a letter sent to natural gas utility companies in order to set utility rates, the commission proposed a risk free rate of 3.8 per cent, a market risk premium of 6.4 per cent and a beta of 0.6 which leads to a cost of equity of 7.64 per cent as shown below. (Hamilton 2013)

$$r_s = r_{RF} + (RP_m)\, b_i$$

$$r_s = 3.8 + (6.4)0.6$$

$$r_s = 7.64\%$$

Calculating the weighted cost of capital as above:

$$WACC = w_d r_d + w_{ce} r_s$$

$$WACC = (0.7)(3.76\%) + (0.3)(7.64\%)$$

[46] BC Hydro, *BC Hydro Service Plan 2014/15 - 2016/17*, See the Performance Measures box on page 15

[47] Note that the formula would usually show a tax advantage of debt. BC Hydro is a crown corporation and pays most of its net income to the Province instead of paying tax as a regular company would.

WACC = 4.92%

BC Hydro uses a six per cent weighted average cost of capital in the January 2013 Business Case Summary and later a five per cent weighted average cost of capital in the August 2013 Cost Estimate for Site C. The Energy Information Administration's Levelized Cost of New Generation Resources in the Annual Energy Outlook 2011 suggests a WACC of 7.4 per cent for new power plants in the United States.[48] In the 2013 release of the same publication, the weighted average cost of capital was reduced to of 6.6 per cent.[49] The difference between BC Hydro and the US Energy Information Administration is reasonable given that BC Hydro is a Crown corporation and has access to credit at the same rate as the Province of British Columbia. The value derived from the information provided by the British Columbia Utilities Commission yields a weighted cost of capital very similar to the five per cent noted in the Site C cost estimate so for the purposes of this exercise, the later value of five per cent has been accepted as given.

Price of Electricity

British Columbia currently enjoys the third lowest electricity rates in North America, behind only Manitoba and Québec. The Province and BC Hydro have worked to create the so called Ten Year Plan. This plan will allow significant refurbishments and upgrades to existing infrastructure over the coming years. The projects will be funded partially by a reduction in the dividends collected from BC Hydro by the Province and also through rate increases. The plan allows for staged increases in the first five years starting in 2015. In 2015 the rate

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[48] Energy Information Administration, *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2011*

[49] Energy Information Administration, *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013*

increase will be nine per cent, in 2016 by six per cent, in 2017 by four per cent, in 2018, by 3.5 per cent, and in 2019 by three per cent. After 2019, the price of electricity will be permitted to rise at a rate necessary to ensure a return on deemed equity (ROE) of 11.84 per cent. The plan will also see the debt to equity ratio change from the current eighty to twenty to the preferred sixty to forty over time.[50] The British Columbia Utilities Commission (BCUC) is in place to prevent unfair rates being charged and would normally set the price of electricity. In the case of the Ten Year Plan, the Provincial government has mandated that it be implemented by the BCUC.

Table 3 - Future Electricity Prices

Year	$/GWh (nominal)	Description
2012	71804.89	Actuals
2013	70371.15	
2014	70371.15	Assumed
2015	76704.55	Increases as per the first five years of the ten year plan
2016	81306.83	
2017	84559.10	
2018	87518.67	
2019	90144.23	
2020	92605.17	Increases tied to Inflation
2021	95133.29	
2022	97730.43	
2032	127938.92	
2042	167484.86	
2052	219254.46	
2062	287026.05	
2072	375745.85	
2082	491888.96	
2092	643931.93	

[50] BC Hydro, *BC Hydro Service Plan 2014/15 - 2016/17*

Inflation

Inflation plays a strong role in capital budgeting decisions especially when considering projects with extended life spans. BC Hydro uses an inflation rate of two per cent in its calculations for the dam. This is based on consumer price index figures released in the Province of BC 2012 Budget and Fiscal Plan.[51] For this paper, the Consumer Price Index compiled by Statistics Canada dating back to 1920 is used in order to approximate the historical levels of inflation in Canada. Most forecasts for inflation attempt only to predict a short distance into the future, commonly one or two years, but for projects spanning thirty to seventy years, the best method for accounting for inflation is to take the geometric mean of the longest possible historical sample. Using a broad historical period accounts for unforeseen swings such as the deflation in the early 1930s and the inflation of the early 1980's. Using the geometric mean of the past data results in a calculated an inflation rate of 2.73 per cent.

[51] BC Hydro, *Environmental Impact Statement*, Vol 1, section 5.5.3.4

Table 4 – Geometric Mean Inflation

Canadian Annual Inflation Rate Year on Year

Year	Inflation %	Decimal	Decimal +1	Calculation
1920	16.3	0.1630	1.1630	
1921	-12.3	-0.1230	0.8770	1.0200
1922	-8.0	-0.0800	0.9200	0.9384
1923	0.0	0.0001	1.0001	0.9384
1924	-2.2	-0.0220	0.9780	0.9178
1925	1.1	0.0110	1.0110	0.9279
1926	1.1	0.0110	1.0110	0.9381
1927	-1.1	-0.0110	0.9890	0.9278
1928	0.0	0.0000	1.0000	0.9278
1929	1.1	0.0110	1.0110	0.9380
1930	-1.1	-0.0110	0.9890	0.9277
1931	-9.9	-0.0990	0.9010	0.8358
1932	-8.5	-0.0850	0.9150	0.7648
1933	-5.3	-0.0530	0.9470	0.7243
1934	1.4	0.0140	1.0140	0.7344
1935	1.4	0.0140	1.0140	0.7447
1936	1.4	0.0140	1.0140	0.7551
1937	4.1	0.0410	1.0410	0.7861
1938	0.0	0.0000	1.0000	0.7861
1939	0.0	0.0000	1.0000	0.7861
1940	3.9	0.0390	1.0390	0.8167
1941	6.3	0.0630	1.0630	0.8682
1942	3.5	0.0350	1.0350	0.8986
1943	2.3	0.0230	1.0230	0.9192
1944	1.1	0.0110	1.0110	0.9293
1945	1.1	0.0110	1.0110	0.9396
1946	2.2	0.0220	1.0220	0.9602
1947	9.6	0.0960	1.0960	1.0524
1948	14.6	0.1460	1.1460	1.2061
1949	3.4	0.0340	1.0340	1.2471
1950	2.5	0.0250	1.0250	1.2782
1951	10.4	0.1040	1.1040	1.4112
1952	2.9	0.0290	1.0290	1.4521
1953	-1.4	-0.0140	0.9860	1.4318
1954	0.7	0.0070	1.0070	1.4418
1955	0.0	0.0000	1.0000	1.4418
1956	1.4	0.0140	1.0140	1.4620
1957	3.5	0.0350	1.0350	1.5132

1958	2.7	0.0270	1.0270	1.5540
1959	0.7	0.0070	1.0070	1.5649
1960	1.3	0.0130	1.0130	1.5852
1961	1.3	0.0130	1.0130	1.6058
1962	1.3	0.0130	1.0130	1.6267
1963	1.3	0.0130	1.0130	1.6479
1964	1.9	0.0190	1.0190	1.6792
1965	2.4	0.0240	1.0240	1.7195
1966	4.2	0.0420	1.0420	1.7917
1967	3.4	0.0340	1.0340	1.8526
1968	3.9	0.0390	1.0390	1.9249
1969	4.8	0.0480	1.0480	2.0172
1970	3.0	0.0300	1.0300	2.0778
1971	3.0	0.0300	1.0300	2.1401
1972	4.8	0.0480	1.0480	2.2428
1973	7.8	0.0780	1.0780	2.4178
1974	11.0	0.1100	1.1100	2.6837
1975	10.7	0.1070	1.1070	2.9709
1976	7.2	0.0720	1.0720	3.1848
1977	8.0	0.0800	1.0800	3.4396
1978	8.9	0.0890	1.0890	3.7457
1979	9.3	0.0930	1.0930	4.0940
1980	10.0	0.1000	1.1000	4.5034
1981	12.5	0.1250	1.1250	5.0664
1982	10.9	0.1090	1.1090	5.6186
1983	5.8	0.0580	1.0580	5.9445
1984	4.3	0.0430	1.0430	6.2001
1985	4.0	0.0400	1.0400	6.4481
1986	4.1	0.0410	1.0410	6.7125
1987	4.4	0.0440	1.0440	7.0078
1988	3.9	0.0390	1.0390	7.2811
1989	5.1	0.0510	1.0510	7.6525
1990	4.8	0.0480	1.0480	8.0198
1991	5.6	0.0560	1.0560	8.4689
1992	1.4	0.0140	1.0140	8.5874
1993	1.9	0.0190	1.0190	8.7506
1994	0.1	0.0010	1.0010	8.7594
1995	2.2	0.0220	1.0220	8.9521
1996	1.5	0.0150	1.0150	9.0863
1997	1.7	0.0170	1.0170	9.2408
1998	1.0	0.0100	1.0100	9.3332
1999	1.8	0.0180	1.0180	9.5012
2000	2.7	0.0270	1.0270	9.7578

2001	2.5	0.0250	1.0250	10.0017
2002	2.2	0.0220	1.0220	10.2217
2003	2.8	0.0280	1.0280	10.5079
2004	1.8	0.0180	1.0180	10.6971
2005	2.2	0.0220	1.0220	10.9324
2006	2.0	0.0200	1.0200	11.1511
2007	2.2	0.0220	1.0220	11.3964
2008	2.3	0.0230	1.0230	11.6585
2009	0.3	0.0030	1.0030	11.6935
2010	1.8	0.0180	1.0180	11.9040
2011	2.9	0.0290	1.0290	12.2492
2012	1.5	0.0150	1.0150	12.4329
2013	0.9	0.0090	1.0090	12.5448
				1.0273
			Geo Mean	2.73%

Section 3 - Project Comparisons

Comparison Methods

An important consideration to make for the purposes of this paper is the possibility of building both the Site C earthfill dam and natural gas fired generation project, or if the project demands for electricity are only large enough to support one of the two options. It is economically feasible to build both projects if both are shown to be profitable, but the forecasted levels of electricity demand indicate building both would lead to an oversupply of electricity in the province. The excess electricity would have to be sold to the United States. It is probable the proliferation of natural gas production in the United States will allow a portion of BC Hydro's customers in the United States to build their own CCGT plants closer to market which would mean that the oversupply would have to be sold at below market prices. For this reason, the two projects are considered to be mutually exclusive.

The most prominent method used to choose between two mutually exclusive projects is the net present value method as returns are the most consistent of capital budgeting techniques. This is because the technique assumes the free cash flows will be re-invested at the projects weighted average cost of capital as opposed to the rate of return of the project. The net present value method allows us to take the time value of future cash flows into account and convert them into a total, in today's dollars. The project with the highest net present value should be selected as it is a summation of all future cash flows. (Brigham, et al. 2011)

The internal rate of return allows decision makers and investors to see the percentage return they will receive from a particular investment. As long as the internal rate of return is greater than the weighted average cost of capital, the investors will enjoy a profit. The internal rate of return method runs into challenges when dealing with projects of different lengths and scales. The fundamental assumption in this method is that the cash flows generated will be reinvested at the internal rate or return and not the weighted average cost of capital. The net present value method assumes that the cash flows will be re-invested at the cost of capital while the internal rate of return which is a more reasonable assumption for the long run. Another concern while using the internal rate of return method is when multiple internal rate of return values are created by non-normal cash flows. In the case of these two projects, this is not an issue because the cash outflows are then followed by steady cash inflows. This could become an issue if additional costs to upgrade the dam and generating facility were evaluated after the 70 year planning period. However, these potential additional costs are outside the scope of this paper and therefore will not impact the analysis. (Brigham, et al. 2011)

The modified internal rate of return method can also be used to evaluate projects. This method improves upon the internal rate of return method by allowing the cash flows to be re-invested at the cost of capital and not the internal rate of return. This eliminates one of the largest problems with the internal rate of return method but there can still be discrepancies between the net present value method and the modified internal rate of return method when evaluating mutually exclusive projects with different life spans and scales, which is the case between Site C and a CCGT project. The problem of multiple rates of return is also solved by the modified internal rate of return method. The modified internal rate of return is valuable because it is easily understood and is intuitive in nature. The net present value remains a better choice however because the modified internal rate of return can still be unreliable when evaluating mutually exclusive projects with different lifespans and scales. (Brigham, et al. 2011)

The profitability index of the project is another way to make capital investment decisions. The profitability index is calculated by dividing the net present value of the project by the initial investment. If the profitability index value is greater than one, the project will generate a positive return. (Brigham, et al. 2011)

The payback period method determines the length of time it will take for a project to be fully paid off. After which time, all of the free cash flows would be profit. This method is intuitive and easily understood by all stakeholders to an investment but it does suffer flaws. The method does not take the time value of money into account. That is, a dollar generated in year six for example is given the same weight as a dollar generated in the first year of operation. Another issue occurs as the method does not account for any cash flows after the payback term. This means that two projects with the same payback period would be ranked the same regardless of what happens after each project is paid off. If one project had profits of one million dollars after the initial investment was recovered, while another profited only one thousand dollars, no discernable difference would be noted by this method. The final concern with the payback period method is it does not account for investor wealth maximization. The method simply illustrates when the investors will see their money back. Potential profits investors may receive are not calculated and remain unknown. (Brigham, et al. 2011)

The payback method has been improved upon in the form of the discounted payback period. This method takes the time value of money into account, thus solving one of the largest issues with the standard payback method but it still fails to address cash flows generated after the payback period and does not comment on investor wealth maximization. (Brigham, et al. 2011)

The dissimilar scale and life span of the Site C and CCGT project make a direct comparison challenging. The Site C project has a planning lifespan of seventy years and BC Hydro has stated that it is likely that the life of the project will be extended to continue to generate power past the one-hundred year mark. This means that if the CCGT plant was built instead, several plants would need to be constructed and become operational over the same time frame as the Site C Dam in order to continue generating a comparable amount of power. The equivalent annual annuity method can be utilized to assist in mitigating the issue. This method converts the net present value of a project into a constant annual cash flow stream which can be directly compared to that of competing projects. While helpful, the equivalent annual annuity method does have particular challenges of its own. Any future changes in inflation or the capital costs of the projects are not considered. It is also very difficult to predict one long term project, and therefore is increasingly challenging to address a series of projects spanning over 100 years.

Comparison Introduction

For this comparison, the Site C project will be evaluated against a CCGT plant in three different taxation scenarios for GHG emissions and two different funding situations, which would lead to a different cost of capital for the CCGT project. The three different tax rates are: the current tax rate in BC of thirty dollars per tonne of CO2 equivalent; the point at which the two projects have roughly equal net present vales; and at the upper limit of the carbon price expected by BC Hydro, of $177.73/tonne of CO2 equivalent. The projects have also been evaluated in two different weighted average cost of capital situations. First, the weighted average cost of capital is set to five per cent for Site C and seven per cent for the CCGT plant as outlined by BC Hydro. Secondly, the five per cent rate has been used for both projects. This case assumes that BC Hydro would be building or at least funding the CCGT plant. In each case, inflation is set at 2.73 per cent as mentioned above. The current inflation rate is lower than the 2.73 per cent geometric average but this rate is the most suitable for the long run forecasts. Both plants are planned to have an annual electricity output of 5100 GWh. For the purposes of this comparison, the estimates are based on the point of interconnection with the grid. This means that the CCGT plant benefits from not having to build transmission infrastructure as extensively as in the Site C case. This comparison also does not take the GHG emissions produced by the construction phases of these projects and only the emissions produced during the operational phases of the projects are considered. Sunk costs for these projects are not considered. See Appendices A to L for scenario cash flow calculations.

BC Hydro has identified many social impacts of the Site C Dam. They include positive benefits such as jobs and negative impacts such as the loss of First Nations traditional territory. In addition, there are costs and benefits associated with the exploration, production, and transmission of natural gas which also impact the land base and society. These costs and benefits are difficult to quantify and are subjective in nature. Because of this and because there are effects of both projects, this paper does not considered social costs.

Scenario 1

In Scenario 1, the carbon tax rate is set to the current rate of thirty dollars per tonne of CO2 equivalent. See the comparison factors below in Figure 1. At current GHG tax levels, the CCGT plant is a more viable option than Site C. The net present value of the CCGT plant is over $387 million greater than that of Site C. Site C's modified internal rate of return exceeds the hurdle rate but only by 0.48 per cent whereas the CCGT exceeds its hurdle rate by 5.09 per cent. The CCGT plant is also more profitable than Site C with a PI of 4.85 compared to Site C's 1.49. The CCGT plant will be paid off in just 8.70 year while Site C will take a further 36.87 years. Considering the equivalent annual annuity the CCGT plant again comes out on top with an annual payment 1.54 times larger than Site C at $260.6 million. Using each of aforementioned comparisons, the CCGT plant is the distinct frontrunner in this first scenario.

Figure - Scenario 1

Variables	
Inflation Rate	2.73%
WACC (Site C)	5.00%
WACC (Combined Cycle Gas Thermal)	7.00%
Carbon Tax Rate 2014$/tonne of CO2	$30.00
Annual Electricity Generation (GWh)	5100

	Site C	**CCGT**
Net Present Value (NPV)	$2,986,580,942.59	$3,374,049,144.56
Internal Rate of Return (IRR)	6.29%	24.28%
Modified Internal Rate of Return (MIRR)	5.48%	12.09%
Profitability Index (PI)	1.49	4.85
Payback period (years)	25.22	7.78
Discounted Payback period (years)	45.57	8.70
Equivalent Annual Annuities (EAA)	$152,561,181.57	$260,591,175.48

Scenario 2

In Scenario 2, the carbon tax rate is set to $44.44/tonne of CO2 equivalent. In this scenario, the net present value of both projects is roughly equivalent at $2.987 billion. Although the net present values are approximately equivalent at this point, the modified internal rate of return for the CCGT plant continues to be much more lucrative when compared to Site C at 4.77 per cent above its hurdle rate as opposed to Site C's 0.48 per cent above hurdle. The profitability of the CCGT plant is considerably greater with a profitability index of 4.41 versus Site C's 1.49. The CCGT project's initial investment will also be recovered 36.87 years faster than Site C. The equivalent annual annuity calculation shows the contrast between the projects while considering the differences in the life spans. In fact, the equivalent annual annuity is 70 per cent greater for the CCGT project. Figure 2 below shows the comparison figures for Scenario 2.

Figure 2 - Scenario 2

Variables	
Inflation Rate	2.73%
WACC (Site C)	5.00%
WACC (Combined Cycle Gas Thermal)	7.00%
Carbon Tax Rate 2014$/tonne of CO2	$44.44
Annual Electricity Generation (GWh)	5100

	Site C	CCGT
Net Present Value (NPV)	$2,986,580,942.59	$2,986,508,683.04
Internal Rate of Return (IRR)	6.29%	22.86%
Modified Internal Rate of Return (MIRR)	5.48%	11.77%
Profitability Index (PI)	1.49	4.41
Payback period (years)	25.22	8.04
Discounted Payback period (years)	45.57	9.09
Equivalent Annual Annuities (EAA)	$152,561,181.57	$230,659,891.12

Scenario 3

In Scenario 3, the carbon tax rate is set to \$177.73/tonne of CO2 equivalent. This is the upper limit of what BC Hydro anticipates as possible. In this scenario, the net present value of the CCGT project is a deficit of more than \$590 million and the CCGT plant falls 1.92 per cent below its hurdle rate. The profitability index of the CCGT plant is 0.33, which is expected as it is not possible for the project to be profitable at such a high carbon tax rate. In this scenario, the project is cannot be paid off before it reaching the end of its expected life span, with the annual annuity totaling a loss of more than \$45 million per year. Figure 3 below shows the comparison figures for Scenario 3.

Figure 3 - Scenario 3

Variables	
Inflation Rate	2.73%
WACC (Site C)	5.00%
WACC (Combined Cycle Gas Thermal)	7.00%
Carbon Tax Rate 2014\$/tonne of CO2	\$177.73
Annual Electricity Generation (GWh)	5100

	Site C	CCGT
Net Present Value (NPV)	\$2,986,580,942.59	(\$590,725,951.08)
Internal Rate of Return (IRR)	6.29%	(2.95%)
Modified Internal Rate of Return (MIRR)	5.48%	3.55%
Profitability Index (PI)	1.49	0.33
Payback period (years)	25.22	N/A
Discounted Payback period (years)	45.57	N/A
Equivalent Annual Annuities (EAA)	\$152,561,181.57	(\$45,624,104.27)

Scenario 4

If BC Hydro chose to construct the CCGT project or merely finance it, the cost of capital would be the same as for Site C at five per cent. This would cause a tremendous difference in the comparison of the two projects. Factoring in the variables of Scenario 1 where the cost of CO2 was thirty dollars per tonne but re-evaluating with the cost of capital for both projects set at five per cent, the net present value of the CCGT project is now $4,952,372,120.30 which is $1.966 billion greater than that of Site C. The percentage return for the CCGT project is more rewarding than in Scenario 1 with the modified internal rate of return 5.97 per cent above the hurdle rate. The profitability index is 6.55 and the project will be paid back within 8.33 years. The equivalent annual annuity is $302.4 million which is twice that of Site C's. Figure 4 below shows the comparison figures for Scenario 4.

Figure 4 - Scenario 4

Variables	
Inflation Rate	2.73%
WACC (Site C)	5.00%
WACC (Combined Cycle Gas Thermal)	5.00%
Carbon Tax Rate 2014$/tonne of CO2	$30.00
Annual Electricity Generation (GWh)	5100

	Site C	CCGT
Net Present Value (NPV)	$2,986,580,942.59	$4,952,372,120.30
Internal Rate of Return (IRR)	6.29%	24.58%
Modified Internal Rate of Return (MIRR)	5.48%	10.97%
Profitability Index (PI)	1.49	6.55
Payback period (years)	25.22	7.73
Discounted Payback period (years)	45.57	8.33
Equivalent Annual Annuities (EAA)	$152,561,181.57	$302,449,820.23

Scenario 5

In Scenario 5, the carbon tax rate is set to \$82.95/tonne of CO_2 equivalent. At this tax rate, the net present values of the projects are roughly equal at \$2.987 billion. The change in the cost of capital for the CCGT project has allowed it to maintain the same net present value as Site C at a tax rate that is almost \$53/ tonne of CO_2 equivalent higher than in Scenario 2. Although the differences in the comparisons, other than the net present value, show smaller gaps between the two projects as compared to Scenario 2, they remain significantly better for the CCGT project. Figure 5 below shows the comparison figures for Scenario 5.

Figure 5 - Scenario 5

Variables	
Inflation Rate	2.73%
WACC (Site C)	5.00%
WACC (Combined Cycle Gas Thermal)	5.00%
Carbon Tax Rate 2014\$/tonne of CO2	\$82.95
Annual Electricity Generation (GWh)	5100

	Site C	**CCGT**
Net Present Value (NPV)	\$2,986,580,942.59	\$2,986,752,726.02
Internal Rate of Return (IRR)	6.29%	18.89%
Modified Internal Rate of Return (MIRR)	5.48%	9.64%
Profitability Index (PI)	1.49	4.35
Payback period (years)	25.22	8.97
Discounted Payback period (years)	45.57	10.01
Equivalent Annual Annuities (EAA)	\$152,561,181.57	\$182,406,088.05

Scenario 6

Scenario 6 has both projects at a five per cent cost of capital and a tax of $177.73/ tonne of CO2 equivalent. The comparisons indicate the same decision as in Scenario 3 but the gaps between the projects have lessened. In this case the CCGT project is in a net present value deficit of $531.7 million which is improved by about $59 million from Scenario 3. Figure 6 below shows the comparison figures for Scenario 6.

Figure 6 - Scenario 6

Variables	
Inflation Rate	2.73%
WACC (Site C)	5.00%
WACC (Combined Cycle Gas Thermal)	5.00%
Carbon Tax Rate 2014$/tonne of CO2	$177.73
Annual Electricity Generation (GWh)	5100

	Site C	**CCGT**
Net Present Value (NPV)	$2,986,580,942.59	($531,687,428.65)
Internal Rate of Return (IRR)	6.29%	(2.81%)
Modified Internal Rate of Return (MIRR)	5.48%	2.27%
Profitability Index (PI)	1.49	0.40
Payback period (years)	25.22	N/A
Discounted Payback period (years)	45.57	N/A
Equivalent Annual Annuities (EAA)	$152,561,181.57	($32,471,058.98)

Section 4 – Sensitivity Analysis

Decision makers evaluating long term, capital intensive projects such as the two this paper examines must consider the impact changing variables have on the outcome and ultimate profitability/affordability. In the case of the two power projects being discussed, the factors which will have the most significant impact on project success are: the long term inflation rate, the weighted average cost of capital, the tax rate for CO2 and equivalent emissions, the cost of electricity, the price of natural gas, and cost overruns during the construction phase.

Weighted Average Cost of Capital Sensitivity

The most important factor to the Site C Dam is the impact from a change in the weighted average cost of capital. The net present value of the project is inversely related to the weighted average cost of capital. The increase of one per cent of the cost of capital (from five per cent to 5.05) decreases Site C's net present value by almost $152 million which is a 5.08 per cent decrease. The increase causes the discounted payback period for the dam increases by a further 0.55 years. The change in the weighted average cost of capital for the CCGT plant also produces a significant difference but the impact is not as pronounced. The increase of one per cent (from seven per cent to 7.07 per cent) translates to a loss of over $44 million in net present value but the payback is only marginally delayed. But as seen above in Scenario 5, the decrease of two per cent in the net present value of the CCGT plant allows the plant to remain profitable at a much higher carbon tax rate than is currently in force.

Table 5 - Weighted Average Cost of Capital Sensitivity

	Site C		CCGT	
Increase 1% Weighted Average Cost of Capital				
	Δ	Δ%	Δ	Δ%
Net Present Value (NPV)	($151,672,693.48)	(5.08%)	($44,262,219.78)	(1.31%)
Internal Rate of Return (IRR)	0.00%	NA	(0.01%)	NA
Modified Internal Rate of Return (MIRR)	0.03%	NA	0.04%	NA
Profitability Index (PI)	(0.02)	(1.41%)	(0.05)	(0.99%)
Payback period (years)	0.00	0.00%	0.00	0.02%
Discounted Payback period (years)	0.55	1.21%	0.01	0.16%
Equivalent Annual Annuities (EAA)	($6,416,403.00)	(4.21%)	($1,452,843.10)	(0.56%)

Electricity Price Sensitivity

An increase in the price of electricity is positively correlated with the net present value of the projects. In the case of Site C, when the price rises by one per cent, the net present value increases by four per cent or about $120 million. An upsurge in the price of electricity unsurprisingly benefits the CCGT plant as well but to a lesser extent. When the price of electricity increases by one per cent, the net present value grows by 1.72 per cent or $58 million.

Table 6 - Electricity Price Sensitivity

Increase 1% Price of Electricity	Site C Δ	Site C Δ%	CCGT Δ	CCGT Δ%
Net Present Value (NPV)	$119,610,140.28	4.00%	$57,930,660.31	1.72%
Internal Rate of Return (IRR)	0.05%	NA	0.21%	NA
Modified Internal Rate of Return (MIRR)	0.02%	NA	0.04%	NA
Profitability Index (PI)	0.02	1.19%	0.07	1.36%
Payback period (years)	(0.15)	(0.61%)	(0.04)	(0.45%)
Discounted Payback period (years)	(0.66)	(1.44%)	(0.05)	(0.59%)
Equivalent Annual Annuities (EAA)	$6,109,951.37	4.00%	$4,474,214.28	1.72%

Annual Electricity Output Sensitivity

The annual amount of electricity sold is positively correlated with the success of the project. The greater the volume of electricity sold, the more the revenue generated by the facility. In the case of Site C, a one per cent increase in the amount of electricity sold yields a four per cent increase in the net present value and also of the equivalent annual annuity. This sensitivity is potentially an important issue for Site C due to the possibility of a prolonged drought. The dam is expected to generate 5,100GWh in an average year but in a scenario investigating a three-year sequence of low precipitation levels BC Hydro predicted the average output during this time could be as low as 4700 GWh.[52] When considering the CCGT plant, the impact of the change is less at only a 1.29 per cent in the net present value.

[52] BC Hydro, *Environmental Impact Statement,* Volume1, Table 7.1

This is an important factor because it means that the projections about demand must be accurate. The International Energy Agency suggests that this factor can be more important than the costs associated with the project.[53]

Table 7 - Annual Electricity Output Sensitivity

	Site C		CCGT	
Increase 1% Annual Electricity Generation				
	Δ	Δ%	Δ	Δ%
Net Present Value (NPV)	$119,610,140.28	4.00%	$43,426,855.81	1.29%
Internal Rate of Return (IRR)	0.05%	NA	0.16%	NA
Modified Internal Rate of Return (MIRR)	0.02%	NA	0.03%	NA
Profitability Index (PI)	0.02	1.19%	0.05	1.02%
Payback period (years)	(0.15)	(0.61%)	(0.03)	(0.35%)
Discounted Payback period (years)	(0.66)	(1.44%)	(0.04)	(0.46%)
Equivalent Annual Annuities (EAA)	$6,109,951.37	4.00%	$3,354,028.03	1.29%

[53] International Energy Agency, *2012 Technology Roadmap: Hydropower*, 38

Inflation Rate Sensitivity

Inflation is also a significant factor affecting the two projects. When the inflation rate climbs from 2.73 per cent to 2.76 per cent, the Site C project gains $87 million in net present value which is 2.91 per cent of the base case value. The project's discounted payback period is extended by 0.48 years. The CCGT plant is impacted more by the change than Site C. The net present value of the project goes down by $107 million which accounts for 3.19 per cent of the base case shown in Scenario 1. The inverse change between the two projects is due to the large costs of fuel in the production of electricity in the case of the CCGT plant. The forecast price increase for natural gas is 5.6 per cent but this would increase with inflation. Site C benefits from an increase in inflation because the increases in the price of electricity would be greater than the increase costs of operations.

Table 8 - Inflation Rate Sensitivity

Increase 1% Inflation Rate	**Site C**		**CCGT**	
	Δ	Δ%	Δ	Δ%
Net Present Value (NPV)	$87,018,742.70	2.91%	($107,514,747.96)	(3.19%)
Internal Rate of Return (IRR)	0.03%	0.52%	(0.13%)	(0.53%)
Modified Internal Rate of Return (MIRR)	0.01%	0.20%	(0.09%)	(0.73%)
Profitability Index (PI)	0.01	0.81%	(0.13)	(2.63%)
Payback period (years)	(0.12)	(0.46%)	0.01	0.11%
Discounted Payback period (years)	(0.48)	(1.05%)	0.01	0.13%
Equivalent Annual Annuities (EAA)	$4,445,110.47	2.91%	($8,303,789.71)	(3.19%)

Capital Cost Sensitivity

Budget overruns are a common concern for large projects. The increase of one per cent to the capital budget of the dam would mean a loss of 2.36% in net present value of about $71 million. It would also extend the discounted payback of the dam by 0.56 years. The modified rate of return is not significantly affected by the overruns and only decreases by 0.01 per cent. This is due to the large upfront cost and the long back end cash flows experienced with the Site C project. A similar increase in construction costs has lesser of an impact on the CCGT than Site C, with the net present value being decreased by $8.7 million or 0.26 per cent.

Table 9 - Capital Cost Sensitivity

Increase 1% Project Capital Cost	**Site C**		**CCGT**	
	Δ	Δ%	Δ	Δ%
Net Present Value (NPV)	($70,509,673.09)	(2.36%)	($8,764,633.07)	(0.26%)
Internal Rate of Return (IRR)	(0.04%)	NA	(0.16%)	NA
Modified Internal Rate of Return (MIRR)	(0.01%)	NA	(0.03%)	NA
Profitability Index (PI)	(0.01)	(0.99%)	(0.05)	(0.99%)
Payback period (years)	0.13	0.52%	0.03	0.35%
Discounted Payback period (years)	0.56	1.23%	0.04	0.46%
Equivalent Annual Annuities (EAA)	($3,601,790.56)	(2.36%)	($676,927.32)	(0.26%)

Natural Gas Price Sensitivity

If the price of natural gas were to increase by one per cent, the net present value of the CCGT project would decrease by about $148 million or 4.38 per cent. The modified internal rate of return would see a reduction of 0.12 per cent and there would be only negligible change to the discounted payback period. The cost of natural gas does not affect the Site C project.

Table 10 - Natural Gas Price Sensitivity

Increase 1% Price of Natural Gas	**Site C**		**CCGT**	
	Δ	Δ%	Δ	Δ%
Net Present Value (NPV)	$0.00	0.00%	($147,681,759.66)	(4.38%)
Internal Rate of Return (IRR)	0.00%	NA	(0.26%)	NA
Modified Internal Rate of Return (MIRR)	0.00%	NA	(0.12%)	NA
Profitability Index (PI)	0.00	0.00%	(0.17)	(3.47%)
Payback period (years)	0.00	0.00%	0.03	0.33%
Discounted Payback period (years)	0.00	0.00%	0.04	0.46%
Equivalent Annual Annuities (EAA)	$0.00	0.00%	($11,406,047.07)	(4.38%)

Carbon Tax Sensitivity

The carbon tax rate will also have an impact on the decision. When the carbon tax rate is increased by one per cent per tonne of CO2 equivalent, it affects the net present value of the CCGT project by decreasing the value by $8 million, or 0.24 per cent, down from the base case. Although this appears to be a small change, there is much uncertainty about the price of carbon. As noted previously, BC Hydro has estimated that the price could be between $30 and $177 per tonne of CO2 equivalent. Also as mentioned previously, the dam is assumed not to produce any carbon emissions so there is no impact to the Site C project.

Table 11 - Carbon Tax Sensitivity

	Site C		CCGT	
Increase 1% Carbon Tax	Δ	Δ%	Δ	Δ%
Net Present Value (NPV)	$0.00	0.00%	($8,051,394.63)	(0.24%)
Internal Rate of Return (IRR)	0.00%	NA	(0.03%)	NA
Modified Internal Rate of Return (MIRR)	0.00%	NA	(0.01%)	NA
Profitability Index (PI)	0.00	0.00%	(0.01)	(0.19%)
Payback period (years)	0.00	0.00%	0.00	0.06%
Discounted Payback period (years)	0.00	0.00%	0.01	0.08%
Equivalent Annual Annuities (EAA)	$0.00	0.00%	($621,841.09)	(0.24%)

The overall sensitivity analysis shows several trends and common themes. Each of the changes, excluding the inflation, price of natural gas, and the carbon tax, have a much larger effect on the Site C project. This is due to the timing and size of the cash flows for this project. The high upfront capital costs (eighty-five per cent of the overall cost) combined with the extended period of modest cash inflows means that this project will have a high level of sensitivity. Conversely, the CCGT project with its low upfront costs (construction and development is twenty per cent of the total cost, the operation costs are eighty per cent)[54] and strong positive cash flows is better able to cope with unforeseen changes in the market place and external environment.

[54]BC Hydro, *Environmental Impact Statement,* Section 5.5.2.8

Section 5 – Conclusion

British Columbia currently enjoys the third lowest electricity prices in North America due to BC Hydro's heritage dams built in the 1960's, 70's, and 80's. This cheap and plentiful supply of electricity has allowed British Columbia to expand its industries and has become a cornerstone of the province's economic success. In the past, the parts of the forest industry such as saw and pulp mills have relied heavily on cheap and plentiful electricity and in the future, the oil and gas industry seems certain to take a larger share of the supply as the natural gas fields are developed and mature. Continued access to electricity is also a key factor in investment decisions for mining companies who often have competing projects around the world in which to invest.

As our economy continues to grow, the demand for electricity will outpace supply. British Columbia's population is set to increase by between one and two million people by 2035. This population growth and associated consumption of consumer goods and housing will mean more electricity will be required. Although BC Hydro actively advances demand side management programs, this will not be enough to ensure adequate supply. The potential for a LNG industry on British Columbia's north coast also looms in the near future. It seems unlikely that even if Site C is built that there will be enough energy produced to satisfy the LNG's demand.

BC Hydro must fulfill its mandate to supply electricity to the province and it must do so within the framework constructed by the provincial government in an economically, socially, and environmentally responsible manner. This means that the province must be energy self-sufficient and may only choose clean energy sources for ninety-three per cent of its electricity. Within this frame work, the Site C Dam is the only possible choice for BC

Hydro to proceed with. It seems certain that the dam will be built and the river valley flooded as long as it is approved by the environmental review process. But this doesn't mean that the project is necessarily the best choice for British Columbia. There are valid alternatives which if considered through an objective lens could be of more benefit to the environment, residents, and rate payers.

A natural gas-fired CCGT plant could be such an alternative. This paper has shown once a CCGT plant is considered on equal footing with Site C, there are many potential benefits. Using the same five per cent cost of capital allows for a carbon price of up to $82.95 / tonne of CO2 univalent emissions to be paid while maintaining the same net present value as Site C. In this scenario, the sensitivity to unforeseen factors is much less for the CCGT project than is for Site C because low upfront capital cost of the dam and the shorter commitment period. The carbon tax collected from the CCGT project, which is 2.77 times higher than the current rate, could be used to offset the effects of carbon emissions.

This exercise shows there is potential to develop other sources of electricity supply while considering social, environmental, and economic factors. Much of the current policy setting the course toward Site C has been developed over the last three decades and has slowly marched to a seemingly pre-determined conclusion. Government policy should not point so obviously in one direction. Instead, a framework which allows for objective study and decisions based on the tools of capital budgeting should prevail. Natural gas and nuclear technologies should be considered in a meaningful exercise to truly weight the trade-offs. Even efficient coal generating systems should be examined at such time as carbon capture and sequestration technologies become viable. In the end, British Columbia's energy policies will be dictated by political considerations and not by net present value, modified rate of return, or equivalent annual annuities.

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APPENDICES

APPENDIX A

Scenario 1

Variables

Inflation Rate	2.73%
WACC	5.00%

Site C	Engineering, Approvals, and Construction									Operation						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2032	2042	2052	2062	2072	2082	2092
Development, regulatory, project management and Eng.	227.49															
Known Construction Costs From Business Case																
Dam, generating station, and spillways (approximation)	27.52	135.69	139.39	143.20	147.10	151.12	155.25	159.48	163.84							
Reservoir clearing (approximation)	27.81	137.12	140.87	144.71	0.00	0.00	0.00	0.00	0.00							
Quarried and excavated construction materials (approximation)	12.38	61.03	62.70	64.41	66.17	67.97	69.83	71.74	0.00							
Worker accommodation	14.62	72.07	74.04	76.06	78.14	80.27	82.46	84.71	65.27							
Access roads and rail, and Highway 29 realignment	20.09	90.81	101.77	104.55	107.41	110.34	94.46	0.00	0.00							
Powerhouse and transmission lines to Peace Canyon Dam	40.97	67.34	0.00	88.83	219.01	224.98	173.35	237.44	182.94							
Remaining costs including contingency, inflation, and interest during construction	84.48	416.56	427.93	439.61	451.61	463.94	476.61	489.62	502.98							
Total Construction Costs	**455.35**	**980.62**	**946.69**	**1,061.37**	**1,069.43**	**1,098.63**	**1,051.95**	**1,042.99**	**915.03**							
Annualized Operating Costs																
Water Rentals										70.77	92.65	121.29	158.78	207.86	272.10	356.21
Grants-in-Lieu and School Taxes										4.58	5.99	7.84	10.27	13.44	17.60	23.04
Operations and Maintenance Costs										13.20	17.29	22.63	29.62	38.78	50.77	66.46
Annualized Sustaining Capital										16.37	21.43	28.06	36.73	48.09	62.95	82.41
Total Annual Operating Costs	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**104.93**	**137.36**	**179.82**	**235.40**	**308.16**	**403.42**	**528.11**
Total Cost	**455.35**	**980.62**	**946.69**	**1,061.37**	**1,069.43**	**1,098.63**	**1,051.95**	**1,042.99**	**915.03**	**104.93**	**137.36**	**179.82**	**235.40**	**308.16**	**403.42**	**528.11**
Revenue	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**652.49**	**854.17**	**1,118.20**	**1,463.83**	**1,916.30**	**2,508.63**	**3,284.05**
Net Cash Flow	**(455.35)**	**(980.62)**	**(946.69)**	**(1,061.37)**	**(1,069.43)**	**(1,098.63)**	**(1,051.95)**	**(1,042.99)**	**(915.03)**	**547.56**	**716.81**	**938.38**	**1,228.43**	**1,608.14**	**2,105.22**	**2,755.94**

Notes:
All construction and operating costs taken from the Site-C Business Case Summary. Timing of individual cash flows taken from Volume 1, Figure 3.1, of the Site C Clean Energy Project Environmental Impact Statement (2013).
All values shown in Millions of Canadian Dollars.
Carbon emissions during construction are not considered.
Development, regulatory, project management and engineering expenses prior to 2014 are sunk costs and are not considered.
The cost estimate shows the dam construction, reservoir clearing, and quarries all as one cost. I have approximated the individual breakdown to more accurately time the cash flows
Payback periods calculated from the start of construction.

Scenario 1

Variables

Inflation Rate	2.73%
WACC	7.00%
Carbon Tax Rate 2014$/tonne of CO_2	30.00

Combined Cycle Natural Gas

	Construction					Operation		
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2028**	**2038**	**2048**
Annualized Capital Cost	**177,432.40**	**182,276.30**	**187,252.44**	**192,364.44**	**197,615.98**			
Interest during Construction	12,420.27	12,759.34	13,107.67	13,465.51	13,833.12			
Fixed Taxes						984.12	1,288.31	1,686.52
Fixed Operating & Maintenance Cost						8,337.25	10,914.29	14,287.90
Variable Operating & Maintenance Cost						59,239.94	102,153.63	176,154.19
Cost of Carbon						81,422.86	106,590.67	139,537.87
Total Operating Costs						**149,984.16**	**220,946.90**	**331,666.49**
Total Cost	**189,852.66**	**195,035.64**	**200,360.12**	**205,829.95**	**211,449.10**	**149,984.16**	**220,946.90**	**331,666.49**
Revenue						**585,846.30**	**766,931.50**	**1,003,990.16**
Net Cash Flow	**(189,852.66)**	**(195,035.64)**	**(200,360.12)**	**(205,829.95)**	**(211,449.10)**	**435,862.14**	**545,984.59**	**672,323.67**

Notes:
All construction and operating costs taken from the 2010 Resource Options Report. These figures are based on the 500 MW Combined Cycle Gas Turbine project shown on page 825 of Appendix 3.
All costs have been scaled to meet the annual output of the Site C Dam (5100 GWh)
Monetary values shown are in Thousands of Canadian dollars
Carbon emissions during construction are not considered
Variable costs increase by 5.6% according to the forecast rise in natural gas prices shown in the U.S. Energy Information Administration Annual Energy Outlook (2014)
Payback periods calculated from the start of construction.

Scenario 2

Variables

Inflation Rate	2.73%
WACC	5.00%

Site C

	Engineering, Approvals, and Construction									Operation						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2032	2042	2052	2062	2072	2082	2092
Development, regulatory, project management and Eng.	227.49															
Known Construction Costs From Business Case																
Dam, generating station, and spillways (approximation)	27.52	135.69	139.39	143.20	147.10	151.12	155.25	159.48	163.84							
Reservoir clearing (approximation)	27.81	137.12	140.87	144.71	0.00	0.00	0.00	0.00	0.00							
Quarried and excavated construction materials (approximation)	12.38	61.03	62.70	64.41	66.17	67.97	69.83	71.74	0.00							
Worker accommodation	14.62	72.07	74.04	76.06	78.14	80.27	82.46	84.71	65.27							
Access roads and rail, and Highway 29 realignment	20.09	90.81	101.77	104.55	107.41	110.34	94.46	0.00	0.00							
Powerhouse and transmission lines to Peace Canyon Dam	40.97	67.34	0.00	88.83	219.01	224.98	173.35	237.44	182.94							
Remaining costs including contingency, inflation, and interest during construction	84.48	416.56	427.93	439.61	451.61	463.94	476.61	489.62	502.98							
Total Construction Costs	455.35	980.62	946.69	1,061.37	1,069.43	1,098.63	1,051.95	1,042.99	915.03							
Annualized Operating Costs																
Water Rentals										70.77	92.65	121.29	158.78	207.86	272.10	356.21
Grants-in-Lieu and School Taxes										4.58	5.99	7.84	10.27	13.44	17.60	23.04
Operations and Maintenance Costs										13.20	17.29	22.63	29.62	38.78	50.77	66.46
Annualized Sustaining Capital										16.37	21.43	28.06	36.73	48.09	62.95	82.41
Total Annual Operating Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	104.93	137.36	179.82	235.40	308.16	403.42	528.11
Total Cost	455.35	980.62	946.69	1,061.37	1,069.43	1,098.63	1,051.95	1,042.99	915.03	104.93	137.36	179.82	235.40	308.16	403.42	528.11
Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	652.49	854.17	1,118.20	1,463.83	1,916.30	2,508.63	3,284.05
Net Cash Flow	(455.35)	(980.62)	(946.69)	(1,061.37)	(1,069.43)	(1,098.63)	(1,051.95)	(1,042.99)	(915.03)	547.56	716.81	938.38	1,228.43	1,608.14	2,105.22	2,755.94

Notes:
All construction and operating costs taken from the Site-C Business Case Summary. Timing of individual cash flows taken from Volume 1, Figure 3.1, of the Site C Clean Energy Project Environmental Impact Statement (2013).
All values shown in Millions of Canadian Dollars.
Carbon emissions during construction are not considered.
Development, regulatory, project management and engineering expenses prior to 2014 are sunk costs and are not considered.
The cost estimate shows the dam construction, reservoir clearing, and quarries all as one cost. I have approximated the individual breakdown to more accurately time the cash flows
Payback periods calculated from the start of construction.

Scenario 2

Variables

Inflation Rate	2.73%
WACC	7.00%
Carbon Tax Rate 2014$/tonne of CO2	44.44

Combined Cycle Natural Gas

	Construction					Operation		
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2028**	**2038**	**2048**
Annualized Capital Cost	177,432.40	182,276.30	187,252.44	192,364.44	197,615.98			
Interest during Construction	12,420.27	12,759.34	13,107.67	13,465.51	13,833.12			
Fixed Taxes						984.12	1,288.31	1,686.52
Fixed Operating & Maintenance Cost						8,337.25	10,914.29	14,287.90
Variable Operating & Maintenance Cost						59,239.94	102,153.63	176,154.19
Cost of Carbon						120,614.39	157,896.32	206,702.10
Total Operating Costs						189,175.70	272,252.55	398,830.72
Total Cost	189,852.66	195,035.64	200,360.12	205,829.95	211,449.10	189,175.70	272,252.55	398,830.72
Revenue						585,846.30	766,931.50	1,003,990.16
Net Cash Flow	(189,852.66)	(195,035.64)	(200,360.12)	(205,829.95)	(211,449.10)	396,670.61	494,678.95	605,159.44

Notes:
All construction and operating costs taken from the 2010 Resource Options Report. These figures are based on the 500 MW Combined Cycle Gas Turbine project shown on page 825 of Appendix 3.
All costs have been scaled to meet the annual output of the Site C Dam (5100 GWh)
Monetary values shown are in Thousands of Canadian dollars
Carbon emissions during construction are not considered
Variable costs increase by 5.6% according to the forecast rise in natural gas prices shown in the U.S. Energy Information Administration Annual Energy Outlook (2014)
Payback periods calculated from the start of construction.

Scenario 3

Variables

Inflation Rate	2.73%
WACC	5.00%

Site C	Engineering, Approvals, and Construction									Operation						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2032	2042	2052	2062	2072	2082	2092
Development, regulatory, project management and Eng.	227.49															
Known Construction Costs From Business Case																
Dam, generating station, and spillways (approximation)	27.52	135.69	139.39	143.20	147.10	151.12	155.25	159.48	163.84							
Reservoir clearing (approximation)	27.81	137.12	140.87	144.71	0.00	0.00	0.00	0.00	0.00							
Quarried and excavated construction materials (approximation)	12.38	61.03	62.70	64.41	66.17	67.97	69.83	71.74	0.00							
Worker accommodation	14.62	72.07	74.04	76.06	78.14	80.27	82.46	84.71	65.27							
Access roads and rail, and Highway 29 realignment	20.09	90.81	101.77	104.55	107.41	110.34	94.46	0.00	0.00							
Powerhouse and transmission lines to Peace Canyon Dam	40.97	67.34	0.00	88.83	219.01	224.98	173.35	237.44	182.94							
Remaining costs including contingency, inflation, and interest during construction	84.48	416.56	427.93	439.61	451.61	463.94	476.61	489.62	502.98							
Total Construction Costs	455.35	980.62	946.69	1,061.37	1,069.43	1,098.63	1,051.95	1,042.99	915.03							
Annualized Operating Costs																
Water Rentals										70.77	92.65	121.29	158.78	207.86	272.10	356.21
Grants-in-Lieu and School Taxes										4.58	5.99	7.84	10.27	13.44	17.60	23.04
Operations and Maintenance Costs										13.20	17.29	22.63	29.62	38.78	50.77	66.46
Annualized Sustaining Capital										16.37	21.43	28.06	36.73	48.09	62.95	82.41
Total Annual Operating Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	104.93	137.36	179.82	235.40	308.16	403.42	528.11
Total Cost	455.35	980.62	946.69	1,061.37	1,069.43	1,098.63	1,051.95	1,042.99	915.03	104.93	137.36	179.82	235.40	308.16	403.42	528.11
Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	652.49	854.17	1,118.20	1,463.83	1,916.30	2,508.63	3,284.05
Net Cash Flow	(455.35)	(980.62)	(946.69)	(1,061.37)	(1,069.43)	(1,098.63)	(1,051.95)	(1,042.99)	(915.03)	547.56	716.81	938.38	1,228.43	1,608.14	2,105.22	2,755.94

Notes:
All construction and operating costs taken from the Site-C Business Case Summary. Timing of individual cash flows taken from Volume 1, Figure 3.1, of the Site C Clean Energy Project Environmental Impact Statement (2013).
All values shown in Millions of Canadian Dollars.
Carbon emissions during construction are not considered.
Development, regulatory, project management and engineering expenses prior to 2014 are sunk costs and are not considered.
The cost estimate shows the dam construction, reservoir clearing, and quarries all as one cost. I have approximated the individual breakdown to more accurately time the cash flows
Payback periods calculated from the start of construction.

Scenario 3

Variables

Inflation Rate	2.73%
WACC	7.00%
Carbon Tax Rate 2014$/tonne of CO_2	177.73

Combined Cycle Natural Gas

	Construction					Operation		
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2028**	**2038**	**2048**
Annualized Capital Cost	177,432.40	182,276.30	187,252.44	192,364.44	197,615.98			
Interest during Construction	12,420.27	12,759.34	13,107.67	13,465.51	13,833.12			
Fixed Taxes						984.12	1,288.31	1,686.52
Fixed Operating & Maintenance Cost						8,337.25	10,914.29	14,287.90
Variable Operating & Maintenance Cost						59,239.94	102,153.63	176,154.19
Cost of Carbon						482,376.14	631,478.69	826,668.86
Total Operating Costs						550,937.44	745,834.92	1,018,797.48
Total Cost	189,852.66	195,035.64	200,360.12	205,829.95	211,449.10	550,937.44	745,834.92	1,018,797.48
Revenue						585,846.30	766,931.50	1,003,990.16
Net Cash Flow	(189,852.66)	(195,035.64)	(200,360.12)	(205,829.95)	(211,449.10)	34,908.86	21,096.58	(14,807.32)

Notes:
All construction and operating costs taken from the 2010 Resource Options Report. These figures are based on the 500 MW Combined Cycle Gas Turbine project shown on page 825 of Appendix 3.
All costs have been scaled to meet the the annual output of the Site C Dam (5100 GWh)
Monetary values shown are in Thousands of Canadian dollars
Carbon emissions during construction are not considered
Variable costs increase by 5.6% according to the forecast rise in natural gas prices shown in the U.S. Energy Information Administration Annual Energy Outlook (2014)
Payback periods calculated from the start of construction.

Scenario 4

Variables

Inflation Rate	2.73%
WACC	5.00%

Site C	Engineering, Approvals, and Construction									Operation						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2032	2042	2052	2062	2072	2082	2092
Development, regulatory, project management and Eng.	227.49															
Known Construction Costs From Business Case																
Dam, generating station, and spillways (approximation)	27.52	135.69	139.39	143.20	147.10	151.12	155.25	159.48	163.84							
Reservoir clearing (approximation)	27.81	137.12	140.87	144.71	0.00	0.00	0.00	0.00	0.00							
Quarried and excavated construction materials (approximation)	12.38	61.03	62.70	64.41	66.17	67.97	69.83	71.74	0.00							
Worker accommodation	14.62	72.07	74.04	76.06	78.14	80.27	82.46	84.71	65.27							
Access roads and rail, and Highway 29 realignment	20.09	90.81	101.77	104.55	107.41	110.34	94.46	0.00	0.00							
Powerhouse and transmission lines to Peace Canyon Dam	40.97	67.34	0.00	88.83	219.01	224.98	173.35	237.44	182.94							
Remaining costs including contingency, inflation, and interest during construction	84.48	416.56	427.93	439.61	451.61	463.94	476.61	489.62	502.98							
Total Construction Costs	455.35	980.62	946.69	1,061.37	1,069.43	1,098.63	1,051.95	1,042.99	915.03							
Annualized Operating Costs																
Water Rentals										70.77	92.65	121.29	158.78	207.86	272.10	356.21
Grants-in-Lieu and School Taxes										4.58	5.99	7.84	10.27	13.44	17.60	23.04
Operations and Maintenance Costs										13.20	17.29	22.63	29.62	38.78	50.77	66.46
Annualized Sustaining Capital										16.37	21.43	28.06	36.73	48.09	62.95	82.41
Total Annual Operating Costs	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	104.93	137.36	179.82	235.40	308.16	403.42	528.11
Total Cost	455.35	980.62	946.69	1,061.37	1,069.43	1,098.63	1,051.95	1,042.99	915.03	104.93	137.36	179.82	235.40	308.16	403.42	528.11
Revenue	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	652.49	854.17	1,118.20	1,463.83	1,916.30	2,508.63	3,284.05
Net Cash Flow	(455.35)	(980.62)	(946.69)	(1,061.37)	(1,069.43)	(1,098.63)	(1,051.95)	(1,042.99)	(915.03)	547.56	716.81	938.38	1,228.43	1,608.14	2,105.22	2,755.94

Notes:
All construction and operating costs taken from the Site-C Business Case Summary. Timing of individual cash flows taken from Volume 1, Figure 3.1, of the Site C Clean Energy Project Environmental Impact Statement (2013).
All values shown in Millions of Canadian Dollars.
Carbon emissions during construction are not considered.
Development, regulatory, project management and engineering expenses prior to 2014 are sunk costs and are not considered.
The cost estimate shows the dam construction, reservoir clearing, and quarries all as one cost. I have approximated the individual breakdown to more accurately time the cash flows
Payback periods calculated from the start of construction.

Scenario 4

Variables

Inflation Rate	2.73%
WACC	5.00%
Carbon Tax Rate 2014$/tonne of CO2	30.00

Combined Cycle Natural Gas

	Construction					Operation		
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2028**	**2038**	**2048**
Annualized Capital Cost	177,432.40	182,276.30	187,252.44	192,364.44	197,615.98			
Interest during Construction	8,871.62	9,113.82	9,362.62	9,618.22	9,880.80			
Fixed Taxes						984.12	1,288.31	1,686.52
Fixed Operating & Maintenance Cost						8,337.25	10,914.29	14,287.90
Variable Operating & Maintenance Cost						59,239.94	102,153.63	176,154.19
Cost of Carbon						81,422.86	106,590.67	139,537.87
Total Operating Costs						149,984.16	220,946.90	331,666.49
Total Cost	186,304.02	191,390.12	196,615.07	201,982.66	207,496.78	149,984.16	220,946.90	331,666.49
Revenue						585,846.30	766,931.50	1,003,990.16
Net Cash Flow	(186,304.02)	(191,390.12)	(196,615.07)	(201,982.66)	(207,496.78)	435,862.14	545,984.59	672,323.67

Notes:
All construction and operating costs taken from the 2010 Resource Options Report. These figures are based on the 500 MW Combined Cycle Gas Turbine project shown on page 825 of Appendix 3.
All costs have been scaled to meet the annual output of the Site C Dam (5100 GWh)
Monetary values shown are in Thousands of Canadian dollars
Carbon emissions during construction are not considered
Variable costs increase by 5.6% according to the forecast rise in natural gas prices shown in the U.S. Energy Information Administration Annual Energy Outlook (2014)
Payback periods calculated from the start of construction.

Scenario 5

Variables

Inflation Rate	2.73%
WACC	5.00%

Site C

	Engineering, Approvals, and Construction									Operation						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2032	2042	2052	2062	2072	2082	2092
Development, regulatory, project management and Eng.	227.49															
Known Construction Costs From Business Case																
Dam, generating station, and spillways (approximation)	27.52	135.69	139.39	143.20	147.10	151.12	155.25	159.48	163.84							
Reservoir clearing (approximation)	27.81	137.12	140.87	144.71	0.00	0.00	0.00	0.00	0.00							
Quarried and excavated construction materials (approximation)	12.38	61.03	62.70	64.41	66.17	67.97	69.83	71.74	0.00							
Worker accommodation	14.62	72.07	74.04	76.06	78.14	80.27	82.46	84.71	65.27							
Access roads and rail, and Highway 29 realignment	20.09	90.81	101.77	104.55	107.41	110.34	94.46	0.00	0.00							
Powerhouse and transmission lines to Peace Canyon Dam	40.97	67.34	0.00	88.83	219.01	224.98	173.35	237.44	182.94							
Remaining costs including contingency, inflation, and interest during construction	84.48	416.56	427.93	439.61	451.61	463.94	476.61	489.62	502.98							
Total Construction Costs	**455.35**	**980.62**	**946.69**	**1,061.37**	**1,069.43**	**1,098.63**	**1,051.95**	**1,042.99**	**915.03**							
Annualized Operating Costs																
Water Rentals										70.77	92.65	121.29	158.78	207.86	272.10	356.21
Grants-in-Lieu and School Taxes										4.58	5.99	7.84	10.27	13.44	17.60	23.04
Operations and Maintenance Costs										13.20	17.29	22.63	29.62	38.78	50.77	66.46
Annualized Sustaining Capital										16.37	21.43	28.06	36.73	48.09	62.95	82.41
Total Annual Operating Costs	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**104.93**	**137.36**	**179.82**	**235.40**	**308.16**	**403.42**	**528.11**
Total Cost	**455.35**	**980.62**	**946.69**	**1,061.37**	**1,069.43**	**1,098.63**	**1,051.95**	**1,042.99**	**915.03**	**104.93**	**137.36**	**179.82**	**235.40**	**308.16**	**403.42**	**528.11**
Revenue	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**652.49**	**854.17**	**1,118.20**	**1,463.83**	**1,916.30**	**2,508.63**	**3,284.05**
Net Cash Flow	**(455.35)**	**(980.62)**	**(946.69)**	**(1,061.37)**	**(1,069.43)**	**(1,098.63)**	**(1,051.95)**	**(1,042.99)**	**(915.03)**	**547.56**	**716.81**	**938.38**	**1,228.43**	**1,608.14**	**2,105.22**	**2,755.94**

Notes:
All construction and operating costs taken from the Site-C Business Case Summary. Timing of individual cash flows taken from Volume 1, Figure 3.1, of the Site C Clean Energy Project Environmental Impact Statement (2013).
All values shown in Millions of Canadian Dollars.
Carbon emissions during construction are not considered.
Development, regulatory, project management and engineering expenses prior to 2014 are sunk costs and are not considered.
The cost estimate shows the dam construction, reservoir clearing, and quarries all as one cost. I have approximated the individual breakdown to more accurately time the cash flows
Payback periods calculated from the start of construction.

Scenario 5

Variables

Inflation Rate	2.73%
WACC	5.00%
Carbon Tax Rate 2014$/tonne of CO2	82.95

Combined Cycle Natural Gas

	Construction					Operation		
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2028**	**2038**	**2048**
Annualized Capital Cost	**177,432.40**	**182,276.30**	**187,252.44**	**192,364.44**	**197,615.98**			
Interest during Construction	8,871.62	9,113.82	9,362.62	9,618.22	9,880.80			
Fixed Taxes						984.12	1,288.31	1,686.52
Fixed Operating & Maintenance Cost						8,337.25	10,914.29	14,287.90
Variable Operating & Maintenance Cost						59,239.94	102,153.63	176,154.19
Cost of Carbon						225,134.20	294,723.21	385,822.21
Total Operating Costs						**293,695.50**	**409,079.45**	**577,950.83**
Total Cost	**186,304.02**	**191,390.12**	**196,615.07**	**201,982.66**	**207,496.78**	**293,695.50**	**409,079.45**	**577,950.83**
Revenue						**585,846.30**	**766,931.50**	**1,003,990.16**
Net Cash Flow	**(186,304.02)**	**(191,390.12)**	**(196,615.07)**	**(201,982.66)**	**(207,496.78)**	**292,150.80**	**357,852.05**	**426,039.33**

Notes:
All construction and operating costs taken from the 2010 Resource Options Report. These figures are based on the 500 MW Combined Cycle Gas Turbine project shown on page 825 of Appendix 3.
All costs have been scaled to meet the annual output of the Site C Dam (5100 GWh)
Monetary values shown are in Thousands of Canadian dollars
Carbon emissions during construction are not considered
Variable costs increase by 5.6% according to the forecast rise in natural gas prices shown in the U.S. Energy Information Administration Annual Energy Outlook (2014)
Payback periods calculated from the start of construction.

Scenario 6

Variables

Inflation Rate	2.73%
WACC	5.00%

Site C

	Engineering, Approvals, and Construction									Operation						
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2032**	**2042**	**2052**	**2062**	**2072**	**2082**	**2092**
Development, regulatory, project management and Eng.	227.49															
Known Construction Costs From Business Case																
Dam, generating station, and spillways (approximation)	27.52	135.69	139.39	143.20	147.10	151.12	155.25	159.48	163.84							
Reservoir clearing (approximation)	27.81	137.12	140.87	144.71	0.00	0.00	0.00	0.00	0.00							
Quarried and excavated construction materials (approximation)	12.38	61.03	62.70	64.41	66.17	67.97	69.83	71.74	0.00							
Worker accommodation	14.62	72.07	74.04	76.06	78.14	80.27	82.46	84.71	65.27							
Access roads and rail, and Highway 29 realignment	20.09	90.81	101.77	104.55	107.41	110.34	94.46	0.00	0.00							
Powerhouse and transmission lines to Peace Canyon Dam	40.97	67.34	0.00	88.83	219.01	224.98	173.35	237.44	182.94							
Remaining costs including contingency, inflation, and interest during construction	84.48	416.56	427.93	439.61	451.61	463.94	476.61	489.62	502.98							
Total Construction Costs	**455.35**	**980.62**	**946.69**	**1,061.37**	**1,069.43**	**1,098.63**	**1,051.95**	**1,042.99**	**915.03**							
Annualized Operating Costs																
Water Rentals										70.77	92.65	121.29	158.78	207.86	272.10	356.21
Grants-in-Lieu and School Taxes										4.58	5.99	7.84	10.27	13.44	17.60	23.04
Operations and Maintenance Costs										13.20	17.29	22.63	29.62	38.78	50.77	66.46
Annualized Sustaining Capital										16.37	21.43	28.06	36.73	48.09	62.95	82.41
Total Annual Operating Costs	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**104.93**	**137.36**	**179.82**	**235.40**	**308.16**	**403.42**	**528.11**
Total Cost	**455.35**	**980.62**	**946.69**	**1,061.37**	**1,069.43**	**1,098.63**	**1,051.95**	**1,042.99**	**915.03**	**104.93**	**137.36**	**179.82**	**235.40**	**308.16**	**403.42**	**528.11**
Revenue	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**652.49**	**854.17**	**1,118.20**	**1,463.83**	**1,916.30**	**2,508.63**	**3,284.05**
Net Cash Flow	**(455.35)**	**(980.62)**	**(946.69)**	**(1,061.37)**	**(1,069.43)**	**(1,098.63)**	**(1,051.95)**	**(1,042.99)**	**(915.03)**	**547.56**	**716.81**	**938.38**	**1,228.43**	**1,608.14**	**2,105.22**	**2,755.94**

Notes:

All construction and operating costs taken from the Site-C Business Case Summary. Timing of individual cash flows taken from Volume 1, Figure 3.1, of the Site C Clean Energy Project Environmental Impact Statement (2013).
All values shown in Millions of Canadian Dollars.
Carbon emissions during construction are not considered.
Development, regulatory, project management and engineering expenses prior to 2014 are sunk costs and are not considered.
The cost estimate shows the dam construction, reservoir clearing, and quarries all as one cost. I have approximated the individual breakdown to more accurately time the cash flows
Payback periods calculated from the start of construction.

Scenario 6

Variables

Inflation Rate	2.73%
WACC	5.00%
Carbon Tax Rate 2014$/tonne of CO2	177.73

Combined Cycle Natural Gas

	Construction					Operation		
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2028**	**2038**	**2048**
Annualized Capital Cost	177,432.40	182,276.30	187,252.44	192,364.44	197,615.98			
Interest during Construction	8,871.62	9,113.82	9,362.62	9,618.22	9,880.80			
Fixed Taxes						984.12	1,288.31	1,686.52
Fixed Operating & Maintenance Cost						8,337.25	10,914.29	14,287.90
Variable Operating & Maintenance Cost						59,239.94	102,153.63	176,154.19
Cost of Carbon						482,376.14	631,478.69	826,668.86
Total Operating Costs						**550,937.44**	**745,834.92**	**1,018,797.48**
Total Cost	186,304.02	191,390.12	196,615.07	201,982.66	207,496.78	550,937.44	745,834.92	1,018,797.48
Revenue						**585,846.30**	**766,931.50**	**1,003,990.16**
Net Cash Flow	**(186,304.02)**	**(191,390.12)**	**(196,615.07)**	**(201,982.66)**	**(207,496.78)**	**34,908.86**	**21,096.58**	**(14,807.32)**

Notes:
All construction and operating costs taken from the 2010 Resource Options Report. These figures are based on the 500 MW Combined Cycle Gas Turbine project shown on page 825 of Appendix 3.
All costs have been scaled to meet the the annual output of the Site C Dam (5100 GWh)
Monetary values shown are in Thousands of Canadian dollars
Carbon emissions during construction are not considered
Variable costs increase by 5.6% according to the forecast rise in natural gas prices shown in the U.S. Energy Information Administration Annual Energy Outlook (2014)
Payback periods calculated from the start of construction.