CLEAN ENERGY ASSOCIATION OF B.C.

(CEABC)

FINAL WRITTEN SUBMISSION TO

THE B.C. UTILITIES COMMISSION

2017 INQUIRY RESPECTING

THE SITE C PROJECT

OCTOBER 11, 2017

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1. INTRODUCTION

CEABC acknowledges that BC Hydro has done an exceptionally thorough job of presenting the economic side of the Site C project in the best possible light. However, CEABC is obliged to point out that, very often within this presentation, BC Hydro makes use of assumptions and economic values that are more theoretical and hypothetical than they are certain and real.

These assumptions and values always have a plausible basis in some real physical situation – a situation that can occur at certain times and under certain conditions. However, they push the boundaries of reasonableness when they exaggerate the amounts, and make them appear as if they are certain, constant and permanent, rather than merely allowances for the possible and plausible.

By exploring many of these assumptions and values, CEABC will show that, more often than not, the values are exaggerated in such a way as to introduce biases which tend to positively affect the net benefits from the Site C project, and adversely impact the costs and benefits of the alternative renewable projects.

In general, these biased assumptions and values fall into four categories:

1. Capital, operating and financing costs for Site C that are kept artificially low.
2. The costs for renewable energy alternatives are artificially inflated.
3. Exaggerated estimates of sunk costs, termination and remediation costs.
4. Estimated savings from the termination or suspension of Site C are being minimized.

CEABC asserts that, while this practice does represent aggressive advocacy at its finest, the net result is a biased or "tilted playing field", and this is not an effective way to reach optimal economic investment decisions for the benefit of the people of British Columbia.

2. SITE C COSTS ARE KEPT ARTIFICIALLY LOW

Site C costs are kept artificially low while the costs of renewable energy alternative are artificially inflated.

When estimates are made of Site C's financing, capital or operating costs, they tend to arrive at the best case scenarios. Serious or significant risks are being ignored or minimized. Contingency allowances are inadequate to realistically cover the risks. Realistic outcomes are only addressed in sensitivity analyses, where they draw less attention, while the base case assumes an unrealistically optimistic scenario.

The nature of the values and assumptions being used in the Site C analysis range from incorporating taxpayer subsidies into the financing costs, to overestimating the values for certain attributes like capacity or flexibility, to underestimating the contingency amounts needed to cover construction risks, to overestimating the future electricity demand, to underestimating the cost of future maintenance and sustaining capital:

A. Enormous taxpayer subsidies are being incorporated into Site C's cost of capital

In its August 30 submission, CEABC pointed out that the Site C financial analysis has incorporated not one but two enormous taxpayer subsidies. Both of these are the result of policy changes negotiated between BC Hydro and the Government in the 10 Year Rates Plan approved in November 2014, namely:

(a) The Government has pledged to increase the taxpayers' equity investment in all BC Hydro capital projects up to 40%. Furthermore, the Government also pledged not to ask for any rate of return on this investment. For the Site C project alone, it amounts to a $3.5 billion interest free grant, requiring no principal or interest payments. It has been incorporated into the Site C financial analysis for the full 70 year life of the project. Based on the equity rate of return approved by the BCUC to simulate what a private investor would expect from a similar private utility, this amounts to a saving to the Site C project analysis of over $400 million per year for 70 years.

(b) The Government also guarantees any debt of BC Hydro, which allows BC Hydro to borrow at the low Government interest rate – a rate only made possible because of the taxpayers guarantee on the debt. This means that the taxpayers are granting BC Hydro, and the Site C project in particular, an enormous insurance policy and receiving no premiums for it. They will be on the hook for all the risks, but receive no compensation for taking that risk. This amounts to a second enormous taxpayer subsidy.

Initially, CEABC took BC Hydro's statements at their face value and assumed that Hydro had used a 5% weighted average cost of capital (WACC) for Site C and a 7% WACC for the alternative renewable energy projects. That would have meant a 2% differential in the cost of capital, which is already an egregious "tilting" of the playing field when it comes to evaluating the economic consequences of the alternative projects – especially when you consider that a large, complex, long-term project like Site C will actually face far more risks than the smaller, shorter-term alternatives.

Subsequently we discovered that, in some of the analyses, the situation is far worse. In its presentation of the ratepayer impacts of Site (in Appendix R of its August 30 submission, Exhibit F1-1), it is revealed that BC Hydro is actually

assuming that Site C will be financed using 100% debt at a rate of 3.4%, fixed for 77 years (until 2094). On the other hand, the alternative projects are assumed to pay 8.5%, and to have to completely rebuild themselves every 25 years. So in the ratepayer impact analysis, at least, BC Hydro has imposed a 5 percentage point differential in cost of capital.

In its August 30 submission (Exhibit F18-3), CEABC pointed out that modern financial theory and practice completely rejects this sort of differential in cost-of-capital as entirely inappropriate for making efficient economic investment decisions, and it offered a Commentary from the C.D. Howe Institute, in support.

(c) **In response to the Panel's request for clarifications regarding the cost of capital issues, CEABC has commissioned the lead author, Dr. Marcel Boyer**, to provide a paper aimed more specifically at the issues surrounding the Site C financial analysis as presented by BC Hydro. That paper is attached hereto as Appendix 1.

In this targeted paper, Dr. Boyer points out several problems in the Site C analysis, along the same lines as he outlined in his C.D. Howe paper.

Dr. Boyer comments specifically on the "pretense" of 100% debt financing, and on how it is an artificial illusion, potentially saddling both ratepayers and taxpayers with huge risks for which they are uncompensated.

> *"These errors expose BC citizens to potentially large losses of value, possibly hundreds of millions of dollars, if not more, without any compensation for the risks they are being asked to bear."*

He derives a more realistic weighted average cost of capital (WACC) at around 8.8%, which employs risk premiums on both the debt and the government's 40% equity share, in order to compensate for the risks inherent in such a large, lengthy and complex project as Site C.

He also comments on the use of a 70 year amortization period and gives guidelines for reference periods used in other jurisdictions. He points out the difficulties that can arise in properly reflecting the renewal costs of shorter-term projects in order to arrive at useful apples to apples comparisons.

(d) **A caveat on the matter of subsidies:** It is perfectly understandable if the Government may wish to subsidize the electricity consumers -- rates are definitely rising, and the more capital BC Hydro spends, the higher the rates must go. However, any subsidy the Government does undertake should not be done in such a way that it interferes with an economically efficient investment decision process. It would be better to subsidize consumers directly, than to artificially

depress BC Hydro's perceived cost of capital (and also Site C's unit energy cost) and cause it to make unwise investment decisions. (Specific subsidies could be directed based on need – seniors, low income, export industries, etc. – rather than on electricity consumption.)

(e) **One further caveat:** Any subsidy to electricity consumers that is in proportion to their electricity consumption would constitute a very confusing and contradictory public policy choice. For at least the past 10 years, the Government has been openly encouraging BC Hydro to use new rate structures, like the Residential Inclined Block pricing, to give incentives to customers to conserve and to invest in energy efficiency and energy saving technologies.

Does it really make good public policy sense to then turn around and directly subsidize electricity consumption – which will incent people to consume more and discourage them from investing in conservation and efficiency measures? One policy would be directly opposing the other.

Not only does this "cost-of-capital" subsidy policy induce BC Hydro into making unwise investments, it also discourages consumers from making wise choices.

3. CAPACITY, FIRMING, SHAPING, AND STORAGE

The following discussion of Capacity, and its closely allied attributes, Firming, Shaping, and Storage is but one example of how the value of certain attributes can be exaggerated and used to depress the apparent unit energy cost (UEC) of Site C, or elevate the UECs of the alternative projects.

It is, however one of the most significant examples because, as pointed out in our August 30 submission, the $11/MWh "capacity credit" being granted to the Site C project is effectively assuming a revenue stream of some $56 million per year can be achieved, without any substantiation as to where this will come from.

In BCUC's Preliminary Report to the Government of B.C.[1] ("**Preliminary Report**") the BCUC stated that it adopts definitions of firming, shaping and storage for the purposes of the section 3(b)(iv) of Order in Council 244 ("**OIC 244**")[2]:

> *"Firming capability is the ability of a resource to quickly change output in response to changes in customer demand and output from variable generation resources that fluctuate within the hour (e.g. wind or solar). The best resource for this capability is large hydro, but it can also be supplied by pumped storage and gas-fired generation. Variable resources like wind, solar and run-of-river hydro, the output of which depends on environmental factors do not have this capability;*

[1] Dated September 20, 2017
[2] Preliminary Report, pages 75 and 76

The BCUC then goes on to say:

"We have made the following assumptions with regard to additional terms in the questions posed above:

> *1. Commercially feasible means full-scale technology demonstrated in an industrial (i.e. not R&D) environment for a defined period of time. Publicly verifiable data exists on technical and financial performance. Regulatory challenges (e.g. safety certifications, lack of standards) have been addressed in multiple jurisdictions…*
>
> *2. Maintenance or reduction of 2016/2017 greenhouse gas emission levels means that the alternative portfolio must not increase the greenhouse gas intensity of BC Hydro's greenhouse gas emissions, as measured in CO2 tonnes equivalent per GWh generated…"*

The Panel invites comment on the interpretations above."

Section 3(b)(iv) of this inquiry's mandate, as defined in OIC 244 says:

> *"Given the energy objectives set out in the Clean Energy Act, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage, grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?"*

The CEABC's comments on the interpretations are organized as follows:

(a) What firming, shaping and storage capability, often referred to in general terms as "capacity" can Site C provide?

(b) How much firming, shaping and storage does BCH require?

(c) Is transmission available to market excess firming, shaping and storage?

(d) What is the value of firming, shaping and storage?

(e) Is single cycle generation a viable capacity option in the context of the *Clean Energy Act* (B.C.)?

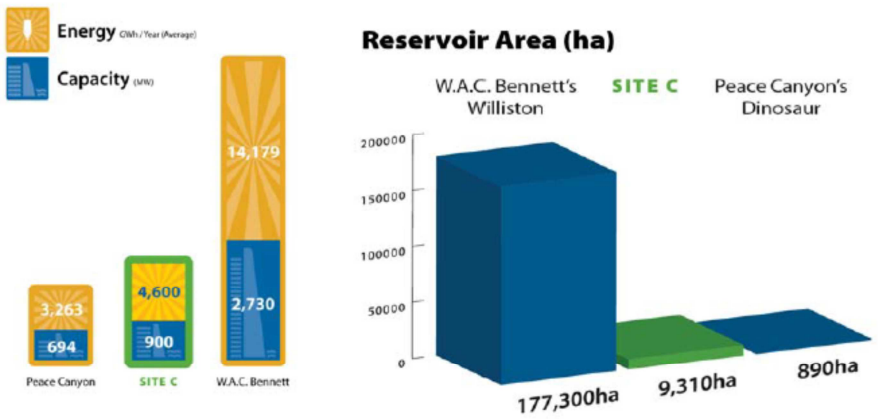
(f) Is the proposed definition of commercially feasible adequate in the context of the Site C project.

As noted elsewhere in this Final Submission, Site C will not come into commercial operation until 2024 at the earliest and as currently proposed, won't be fully paid for until 2094. This time frame creates enormous difficulties in allowing for a proper analysis of Site C, and the alternatives. The farther out in time, the less likely any analysis will have any meaning whatsoever.

A. What Firming, Shaping and Storage Capability, Often Referred to in General Terms as "Capacity" Can Site C Provide?

In a document previously prepared for BCH[3] there is the following graphic that puts the Site C reservoir area into context in relation to the two upstream projects:

Figure 3: Site C in Comparison to Other BC Hydro Facilities on the Peace River



This graphic was prepared at a time when the expected energy production of Site C was expected to be 4,600 GWh per year and the capacity 900 megawatts. These values have increased to 5,286 GWh and 1,145 megawatts despite the fact the amount of water available for generation has not changed nor the available head. The CEABC is not aware of any material that explains why the energy and capacity output were increased to 5,100 GWh and 1,100 megawatts[4]. A BCH response to a BCUC Information Request (or "IR")[5] explains the increase from 5,100 to 5,196 and finally 5,286 GWh/year and from 1,100 to 1,145 megawatts per year. The increase in capacity and part of the increase in energy are attributed to higher turbine efficiency however field performance may not be the same as model testing.

Without access to the Site C financial models, the CEABC does not know whether there is any provision for any degradation as the turbines and generators age, major maintenance when they and other equipment need to be replaced at the end of its useful life and what assumptions are made about the value of capacity nor energy. Most of the equipment including transmission will need to be replaced well before 2094.

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[3] "Peace River Site C Hydro Project – Stage 2 – Review of Potential Downstream Changes from Site C Operations – Preliminary Findings" ("October 2019 Review") BC Hydro, October 2009, Page 11 of 27. **https://www.sitecproject.com/sites/default/files/05-021%2020091000%20Peace%20River%20Site%20C%20Hydro%20Project%20Stage%202%20Review%20of%20Potential%20Downstream%20Changes%20from%20Site%20C%20Operations%20-%20Preliminary%20Findings%20-%20BCH.pdf**

[4] BC Hydro Fact Sheet, September 12, 2016

[5] BCUC IR 2.23.0

The graphic shows that Site C is essentially a very large run of river project and the October 2109 Review confirms this as follows[6]:

> *"Like the Peace Canyon Dam, Site C would take advantage of the regulation of the Peace River by the W.A.C. Bennett Dam, generating additional electricity from water that has already flowed through the two upstream generating stations. Most of the inflow into the reservoir would come from Peace Canyon, but the Halfway River and, to a lesser extent, the Moberly River, would also contribute some flows. Similar to Peace Canyon, Site C as currently conceived would have a relatively stable reservoir with limited daily storage and would typically operate in approximate hydraulic balance over any given day, meaning that water flowing into the project would be approximately equal to the water flowing out of the project."*

This statement is reinforced by[7]:

> *"The operation of the Project reservoir would be predominantly determined by the size and characteristics of the Project generating station in comparison to other generation facilities within the BC Hydro system and by the operation of the GM Shrum and Peace Canyon facilities. The existing Peace facilities are typically operated as a base loaded system, while the Columbia system, with its comparably lower energy content but comparably greater capacity capability, is used to manage the load and market opportunity fluctuations on hourly, daily and weekly basis. With the addition of units in the Columbia system, this pattern would be further reinforced and would not change with the addition of the Project.*
>
> *The Project generating units are expected to have approximately 25% more hydraulic discharge capability than the GM Shrum and Peace Canyon generating units, providing for some ability of generation shaping for load and market opportunities at Site C. However, its high sensitivity of generation to hydraulic head (water pressure) would lead to the Project being used for shaping in lower preference over other facilities."*

Once water from Williston Lake passes through the GM Shrum powerhouse soon thereafter it will have to pass through the turbines at Peace Canyon and Site C. The reservoirs for these projects have at best some daily storage capability. Site C should not be viewed as a standalone project that can be independently operated from its upstream neighbors and in most instances will be operated in tandem with them. It becomes a must run, or run of river facility.

For the purposes of the definitions that the BCUC has adopted and OIC 244 Site C has firming capability and shaping capability subject to the operating restrictions set out in BCH's response to BCUC IR 2.22.10. There will be additional constraints because the inflows from the Halfway and the West Moberly during the spring freshet can't be stored in the Site C reservoir. This water must be used for generation as it is available or spilled i.e. the corresponding generation is must run. Like almost all hydro generation in B.C., the Site C generation can't simply be turned off or on.

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[6] Page 10 of 27

[7] BCH Undertaking No. 18, Site C Joint Review Panel hearing process
http://www.ceaa.bc.ca/050/documents/p63919/97913E.pdf

By comparison, single cycle natural gas fired generation has firming and shaping capability. If situated in proximity to a gas field it also has storage capability. The gas resource is a form of storage just as inventoried coal is at a coal fired thermal plant. Natural gas fired generation is constrained by the greenhouse gas measures in the *Clean Energy Act* (B.C.).

While the CEABC appreciates all the effort that BCH has gone to provide information in the form of responses to BCUC IRs about the potential export opportunities created by the additional capacity and flexibility that Site C brings, the reality is that in physical terms Site C is not going to add appreciably to BCH's export ability.

B. Is Transmission Available to Market Excess Firming, Shaping and Storage?

The CEABC is one of the entities that raised the matter of transmission constraints that BCH responded to as follows[8]:

> *"Some participants in the Commission inquiry have expressed concerns over BC Hydro's ability to export Site C energy due to transmission constraints. These concerns are unfounded."*

The concerns that the CEABC raised were in relation to marketing excess capacity[9] but also apply to BCH's ability to market excess energy. As well as marketing BC Hydro's surplus capacity and energy, BCH also markets the Downstream Benefits under the Columbia River Treaty ("DSBs") on behalf of the Province of B.C. When analyzing transmission availability, these benefits for approximately 1,300 MW of capacity and 4,500 GWh of energy have to be taken into account as if they were surplus BCH energy and capacity. In particular, transmission capacity to the California market. At least insofar the Columbia Treaty isn't terminated or renegotiated.

As has been previously expressed by the CEABC in this and other submissions, we are attempting to analyze a matter, in this case transmission access, until 2094. We are merely projecting what we know today until this date, knowing that there will be major interrupters that are going to materially change the generation and delivery of electricity as we know it.

In IR 2.21.1 BCH says[10]:

> *"In addition to transmission to export power out of B.C. Powerex has long-term U.S. transmission agreements for about 2,500 MW of transmission rights between the Pacific Northwest and California, allowing it to pursue market opportunities throughout the west."*

At first glance, this appears to be a large amount of transmission capacity. In reality it isn't exclusively available for Site C. As noted under the heading "How Much Firming, Shaping and

[8] BCH's response to BCUC IR 2.22., page 5 of 14
[9] See also BCH's response to BCUC IR 2.76.0
[10] Page 6 of 14

Storage Does BC Hydro Require" BCH already has a large amount of surplus capacity throughout almost all of the year. The DSBs require transmission capacity. Site C merely adds to an already full stable of capacity that needs space on the wires to access the California markets. Insofar as surplus BCH energy is being sold it also requires transmission capacity.

There are also transmission constraints with respect to the Alberta market assuming a market for capacity exists in Alberta. Most of BCH's exports go to California. As noted in BCH's response to BCUC IR 2.22.8 the business case can't be made to increase the existing intertie capacity or build a new one without assistance from the Federal Government. The case for expanded intertie capacity between neighboring jurisdictions is normally predicated on security of supply with the generating assets in the neighboring jurisdictions being available to meet a system emergency in the other jurisdiction. Without long term firm energy contracts that fill the wires on year round basis it is very difficult to make a business case on the basis of non-firm electricity trade.

For example the proposal to build a new $3 billion, 1,000 mile, 3,000 megawatt capacity intertie to carry electricity from new generation in B.C. and the U.S. Pacific Northwest to California was[11]:

> *"abandoned by the proponents in 2011 due to the expense of the facilities and the inability to reach a commercial agreement."*

Expansion of transmission systems is very expensive and also faces competition from generation and storage in the load centres. E.g. rooftop solar generation combined with battery storage in California.

C. How Much Firming, Shaping and Storage Does BC Hydro Require?

BCH's planning criteria are not described in terms of firming, shaping and storage. Rather the generic term used is capacity. According to a BCH response to a BCUC IR[12]:

"BC Hydro builds the system to meet peak needs, resulting in the system having surplus capacity and flexibility in most hours of the year when loads are lower than peak loads. This planning requirement is expected to continue going forward."

The peak demand is defined as the average of the 4 highest demand days of the year. These are always the four coldest days of the winter.

Most other electrical systems that BCH is interconnected to have the same or similar planning criteria. It is a matter of security of supply and economic development. According to BCH[13]:

[11] BCH's response to BCUC IR 2.22.8
[12] BCUC IR 2.22.1, page 1of 14
[13] BCH response to BCUC IR 2.22.1, page 5 of 14

> *"…For example, public power utilities, as well as local government agencies generally want to support the building of their own resources within their own state or province to support local jobs. Independently owned, state-regulated, investor-owned utilities also prefer to build and own their own resources in order to earn a return on their associated capital investments."*

The entire capacity of Site C would not be needed in 2024 for domestic purposes. However, there are two types of surplus capacity from this project - capacity in excess of BCH's peak domestic demand and capacity that is available throughout the remainder of the year. The later will be in addition to the existing surplus capacity that is already available throughout most of the year. Simply put when an electrical system is built to meet peak demand there is surplus capacity other than during peak demand.

There are times when there are markets for both types of surplus capacity but in absence of firm contracts, they are not dependable. In its response to BCUC IR 2.22.1 BCH describes some of these markets and potential markets for surplus capacity and energy. Realistically because of the available volume of surplus capacity from all the electric utilities that BCH is interconnected to and transmission constraints, BCH's ability to sell surplus capacity from Site C and its other assets is limited. BCH/Powerex are not the sole participants in the markets and a geographically remote project like Site C is not ideally situated with respect to the urban load centres. According to BCH's response to BCUC IR 2.36.0, line losses from the Peace projects to the Lower Mainland average about 14%. Additional line losses will be incurred beyond the borders of B.C. The concept of "flexibility" that BCH uses to describe as one of the benefits of Site C is highly subjective and is not supported by financial analysis. As noted above Site C is essentially a very large run of river project and is not a very flexible generating resource.

D. What is the Value of Capacity – Firming, Shaping and Storage?

Unless BCH is short capacity for domestic purposes or there is an accessible export market, surplus capacity has no value.

In its response to BCUC IR 2.22.1, BCH catalogues the potential export markets for capacity including the factors that could create growth[14]. It also provides some material that is redacted apparently because it contains price information. Certainly there may be potential markets and growth but they have to materialize by 2024 and remain in existence for a number of years before they can be reasonably included in any projected Site C revenue stream. Similarly they must not be included in any revenue stream to 2094 without adequate supporting material.

The problem is compounded when also trying to value firming, shaping and storage or as sometimes described by BCH, "flexibility". There are two "proxies" that can be used for this valuation exercise. The first is the revenue the Province of British Columbia receives for the sale

[14] E.g. page 2 of 14

of the DSBs through Powerex. The annual revenue from the combined sale of the approximately 1,300 MW of capacity and 4,500 GWh of energy is as follows:

Year	Revenue to the Province[15] ($millions)
2015/16	116
2014/15	130
2013/14	170
2012/13	89
2011/12	110
2010/11	136
2009/10	168
2008/09	231
2007/08	246
2006/07	223

In 2015/2016 the revenue from the combined sale of this energy and capacity is approximately $26/Mwh.[16] This illustrates that, although capacity and energy are sold together, external markets don't recognize a high value for capacity. Unless there is a material change in circumstances, past revenue from the sale of DSBs indicates that the value of capacity is very low. There is nothing in BCH's responses to BCUC IRs that indicates this will change in the foreseeable future and in particular in the period when Site C capacity will be surplus to BCH's peak demand requirements. This represents only a few days in winter and this surplus will only exist until such time as BCH's peak demand catches up with the capacity of Site C. As noted above, Site C's capacity will always be surplus outside this period unless BCH's system becomes a summer peaking system.

The second proxy is shown on the following slide which was presented by a representative of the Ministry of Energy Mines and Petroleum resources to the CEABC:

[15] From Government of B.C. Budget Documents, Revenue by Source, Columbia River Treaty
[16] ($116mm/4,500,000MWh=$25.70/MWh)

BRITISH COLUMBIA

Comparing Unit Energy Costs of Site C and IPPs

Unit Energy Cost (UEC) at Point of Interconnection:	Site C	IPPs *BCH 2013 IRP*	IPPs *CEBC 2014*
Before Rates Plan changes	**$83/MW.h**	**$96/MW.h**	**$85/MW.h**
Impact of equity return and dividend changes	Subtract $26		
Remove Tier 3 Water Rentals	Subtract $1		
Rates Plan UEC at Point of Interconnection	**$56/MW.h**	**$96/MW.h**	**$85/MW.h**
Sunk Costs	Subtract $4		
Line Losses	Adds $6	Adds $10	Adds $10
Area Transmission	$0	Adds $6	Adds $6
Cost of Firm Transmission	Adds $6	Adds $2	Adds $2
Foregone exports	Not Applicable	Adds $9	Adds $5
Firm Energy Adjustment (seasonal shape)	Subtract $2	Subtract $2	Subtract $2
EA, permitting, FN and community benefit costs	Included	Adds $5	Included
Cost of Capacity Backup		Adds $5	Adds $5
UEC Delivered to Lower Mainland:	**$62/MW.h**	**$130/MW.h**	**$110/MW.h**
UEC with PST/Delay - Reserve	**$64-67/MW.h**		

In relation to "Cost of Capacity Backup" which is to account for the intermittency of renewable generation such as wind and solar, the Province has assigned a value of $5/MW.h. On the basis of the CEABC's two proxies, surplus capacity from Site C does not have a very high value over the period for the above unit energy cost calculation.

E. Is Single Cycle Generation a Viable Capacity Option in the Context of the Clean Energy Act (B.C.)?

One of the options for backing the intermittency of renewable generation is single cycle natural gas fired turbines. In terms of capital cost per megawatt they are relatively inexpensive (BC Hydro's 2012 Resource Options Database lists a 100 MW Simple Cycle Gas Turbine plant at between $80 and $95 million, i.e. less than $1 million per MW) and can be installed relatively quickly as demand requires. Their drawback is their greenhouse gas emissions in the context of the Clean Energy Act (B.C.) which says[17]:

> *"The following comprise British Columbia' energy objectives:*
>
> *(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;"*
>
> *(g) to reduce BC greenhouse gas emissions…"*

OIC 244 states:

> *"Given the energy objectives set out in the Clean Energy Act, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage, grid reliability; and*

[17] Section 2.

maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?"

This lead the BCUC to assume[18]:

> *3. Maintenance or reduction of 2016/2017 greenhouse gas emission levels means that the alternative portfolio must not increase the greenhouse gas intensity of BC Hydro's greenhouse gas emissions, as measured in CO2 tonnes equivalent per GWh generated…"*

The CEABC does not agree with this assumption primarily because it is not consistent with the wording of the objectives in the Clean Energy Act. The CEABC's interpretation of this act allows for 7% of the electricity generated in B.C. to be from non-clean or non-renewable resources as calculated on a floating basis. The Clean Energy Act is specific with respect to electricity generation and in terms of statutory interpretation, a specific provision will always override a general provision which in this case is Clean Energy Act section 2(g).

The CEABC agrees with BCH[19] that OIC 244 is predicated on emission and not intensity levels. It is not correct to impute intensity as the BCUC has in its assumption.

CEABC does not agree with BCH's conclusion:

"… that we have no room for the addition of any new gas fired generation…"

OIC 244 is not specific about: "maintenance or reduction of 2016/17 greenhouse gas emission levels" and the CEABC interprets this to mean Provincial greenhouse gas emission levels and not BCH's 2016/17 levels which are totally dependent on how BCH decides to manage its system including its own and third party natural gas fired thermal generation.

In almost all respects the BCUC's, the CEABC's and BCH's views must be subject to a reality check.

BCH states[20]:

"BC Hydro owns or has electricity purchase agreements with a few non-clean generating resources including Prince Rupert generating station, Island Generation facility, McMahon co-generation facility and Fort Nelson generating station. The total firm energy contribution from these facilities is approximately 3,500 GWh."

On paper the total firm energy capability may be 3,500 GWh but the actual contribution is far less, including the associate greenhouse gas emissions. The reasons can be found in BCH's

[18] Interim Report, pages 75 and 76
[19] BCH response to BCUC IR 2.70.0
[20] BCH response to BCUC IR 2.70.0

response to BCUC IR 2.69.0 with respect to the 275 MW natural gas fired Island Generation ("IG") facility:

> *"There are two reasons that BC Hydro would not run IG to its full output. The first is to absorb high energy inflows from either the Heritage Hydro system or from IPPs in years with high water inflows. The second is as a result of the provincial carbon tax. The carbon tax results in a cost of 11 $MWh at the current value of the tax, and will increase as the tax increases. This frequently makes the plant non-competitive with other resources in the Pacific Northwest that do not face a similar tax. BC Hydro rarely makes use of IGs firm energy contribution, instead favouring cheaper electricity imports; it is a valuable insurance policy should BC Hydro face circumstances where energy supplies are limited."*

Assuming a capacity factor of 90%, IG is capable of producing about 2,200 GWh annually or about 60% of 3,500 GWh of the natural gas fired thermal generation. For the period January 2014 through September 2017 actual production was about 260 GWh[21] - about 70 GWh per year or 3% of potential annual output.

Effectively IG has become a peaking plant which produces very little in the way of greenhouse gas emissions because other than for testing and occasional use for capacity it is hardly ever used. The unused greenhouse "cap space" could be applied to single cycle peaker turbines.

Any single cycle natural gas fired turbines used to backup renewable generation would also hardly ever be used. At current rates the carbon tax payable would be about $20 per MWh because they are less efficient than IG. In order of dispatch of BCH's capacity resources single cycle turbines would be at or near the bottom of the list. Looked at from another perspective a peaking facility is required for very few hours in a year and some years not at all. BCH's peak demand in winter is for only a few hours on the 4 coldest days. The hours required for monthly testing could exceed the hours when it is used for capacity.

BCH maintains that:

> *"New gas generation relied upon for dependable capacity is expected to operate around 18 per cent of the time. This means that a 100 MW gas turbine would operate 160 GWh/year."*

The IG reality test does not support this conclusion. The 18 per cent figure should be in the order of 2-3%.

BCH 's second largest available natural gas fired thermal resource is the McMahon 120 megawatt cogeneration facility which went into operation in 1993. The CEABC understands that this generation facility isn't being fully utilized and the existing electricity purchase agreement expires in 2023. Given that it is near the end of its useful life, it is possible that this agreement

[21] BCH response to BCUC IR 2.69.0, page 2

may not be renewed, extended or amended. Any used greenhouse gas emission "cap space" could be applied to single cycle peakers.

If the CEABC is incorrect in its interpretation of the Clean Energy Act and OIC 244 and there is no room for the addition of any new gas fired generation even to replace existing generation, there remains the option of acquiring offsets or carbon credits to reduce the emission from single cycle peakers to zero.

The Clean Energy Act or OIC 244 does not preclude the use of offsets, or carbon credits to reduce greenhouse gas emissions. There are two examples where the B.C. Government has looked to use carbon offsets to help reduce greenhouse gas emissions.

First, under British Columbia's Carbon Neutral Government Program[22], the *Greenhouse Gas Reduction Targets Act* (GGRTA) and the Carbon Neutral Government Regulation, all public sector organizations (PSOs) seek to achieve carbon neutrality. Those PSOs which are not carbon neutral in their operations must purchase carbon offsets to bring their carbon quotient to zero.

Since 2010, B.C.'s carbon offset portfolio has resulted in total emissions reductions of approximately 4.9 million tonnes carbon dioxide equivalent (CO2e). In any single year, B.C. has between 14 and 25 projects in the portfolio[23]. A number of B.C.'s carbon offset projects are owned by First Nations.

Second, the Greenhouse Gas Industrial Reporting and Control Act (GGIRCA) which seeks to limit greenhouse gas emissions from, among others, LNG facilities. Under the GGIRCA, LNG facilities which emit more than the legislated emissions "cap" must purchase carbon offsets from a qualifying emission offset project or pay a prescribed amount into a technology fund.

Given the very low amount of time single cycle peakers would be in operation and corresponding minimal greenhouse gas emissions, purchasing offsets would not be a material expense. It is a proven viable option to reduce greenhouse gas emissions to zero.

F. Is the Proposed Definition of Commercially Feasible Adequate in the Context of the Site C Project?

The BCUC's assumption that:

> *"Commercially feasible means full-scale technology demonstrated in an industrial (i.e. not R&D) environment for a defined period of time."*

needs to be modified because it is far too restrictive. For example, wind, solar and battery technology are evolving. Advancements in each of these classes of technology would be

[22] www2.gov.bc.ca/gov/content/environment/climate-change/public-sector/carbon-neutral
[23] www2.gov.bc.ca/gov/content/environment/climate-change/public-sector/offset-portfolio

excluded including decreases in prices for the period between now the 2024, the earliest date for the commercial operation of Site C, and thereafter. The assumption should read:

> *"Commercially feasible means full-scale technology demonstrated in an industrial (i.e. not R&D) environment for a defined period of time or technological advances in full-scale technology that are reasonably foreseeable."*

The time horizon created by the insertion of the words "reasonably foreseeable" is probably too short. The Site C debt won't be repaid until 2094. We are assuming what we know or what is reasonably foreseeable today will be useful when comparing Site C to the alternatives over a 77 year period. Forty years from now electrical infrastructure could be radically different than it is today.

4. BC HYDRO'S LOAD FORECAST AND SURPLUS

BC Hydro's Load Forecast shows a surplus of energy, once Site C is operating, of 3,000-4,000 GWh/year. This surplus will have to be sold into a depressed market. However, that is an optimistic forecast of demand. If anything, the surplus is likely to be greater.

The following table is taken from BC Hydro's August 30, 2017 submission (Exhibit F1-1, Appendix. K). It shows the amount of the surplus in the bottom line.

Table K-3 Energy Load Resource Balance after Planned Resources with Site C

(GWh)		F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031
Existing and Committed Heritage Resources															
Heritage Resources		46,895	46,014	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491
Site-C								366	3,892	5,286	5,286	5,286	5,286	5,286	5,286
Heritage Resources (including Site C)	(a)	46,895	46,014	48,491	48,491	48,491	48,491	48,857	52,383	53,777	53,777	53,777	53,777	53,777	53,777
Existing and Committed IPP Resources	(b)	14,592	14,337	14,364	14,097	13,782	13,547	13,210	12,814	12,414	12,307	11,983	11,467	10,720	10,259
Planned Supply-Side Resources															
IPP Renewals		280	571	647	779	936	1,114	1,349	1,628	1,951	2,032	2,223	2,617	3,328	3,788
Standing Offer Program		130	291	419	546	674	801	929	1,056	1,184	1,311	1,439	1,566	1,694	1,821
Revelstoke 6															
Sub-total	(c)	410	862	1,066	1,325	1,609	1,916	2,278	2,684	3,135	3,344	3,662	4,183	5,022	5,609
Total Supply (Operational View) **	(d) = a + b + c	61,897	61,213	63,922	63,913	63,883	63,954	64,345	67,881	69,327	69,428	69,423	69,427	69,519	69,646
Demand - Integrated System Total Gross Requirements															
2016 May Mid Load Forecast Before DSM*		-59,013	-60,413	-61,371	-62,309	-63,675	-64,836	-66,008	-67,109	-68,310	-69,267	-70,256	-71,222	-72,296	-73,374
Expected LNG Load		-148	-148	-252	-1,265	-2,299	-2,721	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848
Sub-total	(e)	-59,162	-60,561	-61,624	-63,574	-65,974	-67,557	-68,856	-69,957	-71,158	-72,115	-73,104	-74,070	-75,144	-76,222
Existing and Committed Demand Side Management & Others Measures															
SMI Theft Reduction		83	83	83	83	83	83	83	83	83	83	83	83	83	83
Voltage and VAR Optimization		152	171	188	219	240	254	259	263	268	285	290	295	300	305
2016 DSM Plan F16 savings		970	939	940	935	926	923	917	912	885	863	855	848	844	807
Planned Demand Side Management Measures															
2016 DSM Plan F17 to F19 savings		988	1,679	1,896	1,931	1,969	1,956	1,935	1,917	1,908	1,896	1,853	1,787	1,694	1,613
2016 DSM Plan F20+ savings		0	0	292	904	1,454	1,897	2,310	2,637	2,946	3,229	3,500	3,758	4,006	4,248
Sub-total	(f)	2,192	2,873	3,399	4,072	4,672	5,112	5,502	5,811	6,089	6,356	6,581	6,770	6,927	7,055
		F2018	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**
Surplus / (Deficit) (Operational View) **	(g) = d + e + f	**4,928**	**3,524**	**5,697**	**4,411**	**2,582**	**1,509**	**991**	**3,735**	**4,257**	**3,669**	**2,900**	**2,128**	**1,302**	**480**

We note that included in this forecast is 2,848 GWh/year of "Expected LNG Load". However, at this point in time, two of the larger projects have been cancelled, a fate that is likely in store for most of the remaining North Coast projects. The only project that seems firmly certain to be built is a very small one for FortisBC, that will, at its peak, require only about 132 GWh, as shown in the table below (from F1-1, Appendix J).

The table below compares the revised sales projection recently provided by FortisBC Tilbury LNG to BC Hydro against the sales projection assumed in the Current Load Forecast.

Table J-8 Fortis Tilbury Change for Current Load Forecast

GWh/year	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027
FortisBC Tilbury LNG Revised	22	64	92	97	92	110	132	132	132	132
FortisBC Tilbury LNG Current Load Forecast	139	139	139	139	139	139	139	139	139	139
Difference (GWh)	(116)	(75)	(47)	(42)	(47)	(29)	(7)	(7)	(7)	(7)

That will mean that the surpluses currently being forecast by BC Hydro are likely to be on the optimistic side (i.e. low) by around 2,700 GWh, and are likely to persist for at least 10 years after Site C is online.

Here, once again, there is some plausibility to BC Hydro's forecast, it's simply that it is optimistically biased to favour Site C's economic future.

Still on the topic of selling the surplus energy produced by Site C, the price for those sales also seems optimistic.

The following table (from F1-1, Appendix R) shows what BC Hydro is forecasting for the lost sales revenue in 2025 to 2029 if Site C is terminated.

BC Hydro
Rate Impact Analysis

Rate Impact Model - Ratepayer Impact - Terminate & 10 Yr Recovery.xlsx

Revenue Requirement (Ratepayer Costs) Summary
($ million)

Line	Fiscal Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	Column Reference	1	2	3	4	5	6	7	8	9	10	11	12
	Change in Revenue Requirement (Ratepayer Costs):												
1	Domestic Energy Costs	(5.3)	(10.0)	(16.2)	(27.3)	(45.1)	(72.4)	(118.3)	238.4	343.1	355.0	205.4	216.9

If we combine the lost sales revenue information from this table and the GWh of surplus energy from Table K3 above, we can calculate the implied price for those surplus energy sales.

	Surplus to Sell GWh	Sales Revenue $ millions	Implied Price $/MWh
2025	3,735	238.4	$ 63.83
2026	4,257	343.1	$ 80.60
2027	3,669	355.0	$ 96.76
2028	2,900	205.4	$ 70.83
2029	2,128	216.9	$ 101.93

Prices of $64 to $102 seem high for forced sales into a market that BC Hydro will be flooding with an extra 6,000 to 7,000 GWh/year – especially when you consider that a considerable portion of Site C's production must occur during the freshet when it operates, essentially, as a run-of-river facility. Of course, BC Hydro can reduce the forced sale during the freshet, by

"backing down" the generation at its storage dams, which is what they must be doing to rationalize the above forecast of Mid-C prices. But how much capability does BC Hydro have to do this especially during freshet?

5. USING THE CAPABILITIES OF STORAGE TO ALTER GENERATION PROFILE

BC Hydro is Using the Capabilities of its Storage System to Alter the Natural Generation Profile of the Site C Project, Especially During the Freshet.

This is not an unconscionable thing to do, but they have repeatedly told IPPs that it is not possible. The message to IPPs has always been that any generation during the freshet is not needed and must be sold into that depressed Mid-C market. Accordingly any such generation by IPPs is always downgraded to "non-firm energy" and paid at the very low forecast of Mid-C freshet prices. However, apparently the same doctrine is not applied to energy from the Site C project.

The Commission Panel asked BC Hydro to "Please provide in table form the percentage of annual generation expected from Site C in each month of the year."[24]

BC Hydro responded as follows:

RESPONSE:

The following table provides the incremental system energy from the addition of Site C to the BC Hydro system.

	Incremental System Energy from the addition of Site C (GWh)	Incremental System Energy (%)
January	659	12
February	765	14
March	118	2
April	322	6
May	230	4
June	-80	-2
July	511	10
August	702	13
September	911	17
October	343	6
November	483	9
December	322	6
Total	5286	100

This response is not untrue, but it is decidedly slanted to camouflage the run-of-river nature of Site C during the freshet period. The key phrase in the response is "*incremental system energy from the addition of Site C*." This means that BC Hydro has gotten around the awkwardness of the question by giving the change in the system's total energy production, rather than the actual generation from Site C, as asked for in the Panel's question. Which simply means they

[24] Exhibit F1-08, BC Hydro's response to IR 2.22.6

have employed other system resources to shift Site C's generation into other time periods. Note that in June, when Mid-C prices are traditionally at their lowest, and Site C is probably generating at its 1100 MW capacity, this table is showing no production at all, in fact it is negative. That indicates a very great system capability to shift energy generation throughout the year.

The Good News is that this response demonstrates that BC Hydro does have, in its system resources, the capability to absorb all of the energy production from Site C during the freshet, which is probably close to its capacity of almost 1200 MW, and store that energy and divert to other time periods during the year. This is a very important fact for the future integration of more small-scale renewables.

The total freshet energy generation from all operating IPPs is currently around 1200 MW, and it doesn't really change much from dry years to wet years, because all the run-of-river facilities are operating at their design capacity during the freshet months of every year. It is good to know that BC Hydro's system has the capability to absorb another 1100 to 1200 MW of freshet energy generation.

The Bad News is that Site C would be absorbing this valuable system capability and paying no penalty for it.

6. SITE C IS NOT CHARGED WITH ANY PENALTY FOR ITS FRESHET GENERATION

The Site C Project is not Being Charged With any Penalty for its Freshet Generation. In Fact it is Given a $2 Credit for the Profile of its Energy Generation[25]. If it Were Treated the Same as Run-of River IPPs, it Could be Charged With a $20 to $25 Penalty.

Since BC Hydro has refrained from providing the actual generation profile for Site C, CEABC will make some modest assumptions in order to illustrate this point. (If we are far wrong, BC Hydro can then provide the actual forecasts by way of response.)

During the freshet months (May to July), its anticipated that the local inflows to the Peace Canyon and Site C watersheds will be sufficient to keep the Site C dam operating at close to capacity in order to avoid spilling. The generation at the GMS station (Bennett dam) will essentially be turned off to avoid adding more water flow.

If Site C generates at 1100 MW for 92 days during the freshet period, it will produce about 2,400 GWh. That means that it only generates 2,700 GWh in the rest of the year. Under the rules applied to run-of river IPPs, it can only produce as much Firm energy in the freshet period as the average of the other 3 quarters of the year. All the rest must be classified as Non-Firm, and paid at the forecast Mid-C price.

[25] This is referred to as a "Firm Energy Adjustment" see Exhibit F18-3, page 7

The average for the other 3 quarters is 900 GWh, so 1,500 GWh of Site C's generation would be classified as Non-Firm. If the unadjusted Firm Energy price is $95, and the assumed Non-Firm price is only $45/MWh, that's a penalty of $50 on 1,500 GWh, or $75 million per year. This $75 million cost must be made up by raising the price of the 3,600 GWh of Firm Energy by approximately $21. So the "adjusted" Firm Energy price for Site C would be raised to $116.

This is the rule that would apply to an IPP project with that kind of generation profile. Rather than being dropped by $2/MWh, its Firm Energy price would be penalized by $21/MWh, due to this freshet generation penalty. However, apparently, when evaluating Site C, BC Hydro is permitted to use its other system resources to smooth and shape the generation profile so that Site C looks more cost effective.

One might ask, why can't this same smoothing, shaping and time shifting be done for the other alternative renewable projects? Why only for Site C?

7. COST OF SYSTEM TRANSMISSION ENHANCEMENTS

The Cost of System Transmission Enhancements is Another Area in Which the Economic Playing Field is Being Dramatically Tilted in Favour of Site C. Alternative Renewable Projects are Being Charged for Fictional Additions to the Bulk Transmission System.

The responses to IR 2.26 (in F1-4) and 2.36 (in F1-8) give explanations of the calculation of a cost adder known as CIFT (Cost of Incremental Firm Transmission). The theory behind this charge is plausible. If a project is going to require additional capacity in the bulk transmission system (the 500kv backbone of the system), so that its energy can serve the peak loads in the Lower Mainland on the coldest days of winter, then it will be allocated a share of the costs of that transmission expansion or reinforcement.

While the charge is plausible in concept, there are a few assumptions being made that are of a questionable nature.

One assumption is that intermittent projects should be charged for having dependable capacity. Both wind and small hydro projects are allocated an attribute known as ELLC (Effective Load Carrying Capacity). It is established by looking at the probabilities that a project will be able to deliver its energy at the times of the peak loads. A wind project might be given an ELCC of 26%. It's a capacity that is considered statistically reliable, but it is still not considered "dependable". A CIFT charge is assessed on the basis of that ELCC, but the project is never given any capacity credit for having "dependable" capacity.

Another questionable assumption has to do with the need to always transmit power to the Lower Mainland. With growing load centres around the province, it is more and more likely that new renewable generators will be located much closer to those regional load centres – thus saving on line losses as well as the need for new transmission to Vancouver.

Still a third assumption is even more questionable. The response to IR 2.26 gives a reference to the BC Transmission documents that established the cost coefficients for assessing these charges. These reference documents are dated from 2006 to 2010 and all rely on studies that were done prior to the crash of 2008/9. As such, they rely on load growth forecasts and the projections of transmission capacity enhancements that were thought to be needed at that time. They take the present value cost of those projected transmission enhancements and divide it by the present value of the projected capacity increases on the various lines to get a quotient which represents a cost per year per kw of expansion.

It's a nice idea, but the studies are hopelessly out of date. The load forecast is no longer anything close to what it was in 2008, and any planned transmission enhancements have either already been built, and are providing the needed capacity, or they are no longer needed in view of the static load forecast. These ancient studies cannot be relied upon to produce any kind of accurate present day costs. The CIFT charge is theoretical and hypothetical to the point of being fictional.

8. SITE C IS GIVEN A FREE RIDE FOR OVER $1.4 BILLION OF UPGRADES

On the Other Hand, Site C is Quite Directly Responsible for Certain Specific Transmission Enhancements, yet it is Given a Free Ride for Over $1.4 Billion of These Upgrades.

The following two tables are taken from the BCUC Preliminary Report (Exhibit A-13, page 95 of 121):

Table 33: BC Mid load forecast with current DSM plan transitioning to IRP DSM. Site C completed on current schedule

UECs and UCCs are shown for energy and capacity resources respectively. The UEC/UCC shown includes wind integration costs and network upgrade costs where applicable.

Resources Selected

			Capacity - MW		Energy - GWh		UEC / UCC
Year	Zone	Resource	Installed	Dependable	Firm	Total	$/MWh or $/kW-year
2023	BCH_PR	Site C	1145	1,145	5,286	5,286	34
2025	BCH_REV	Revelstoke Unit 6	500	488	26	26	46
2027	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2034	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2035	BCH_PR	Wind_PC20	156	41	594	594	92
2037	BCH_NC	Wind_NC09	333	87	1,074	1,074	101

Table 34: Mid Load forecast with IRP DSM plan. Site C construction suspended until 2024.

UECs and UCCs are shown for energy and capacity resources respectively. The UEC/UCC shown includes wind integration costs and network upgrade costs where applicable.

Resources Selected

			Capacity - MW		Energy - GWh		UEC / UCC
Year	Zone	Resource	Installed	Dependable	Firm	Total	$/MWh or $/kW-year
2024	BCH_LM	Pumped_Storage_LM	1000	1,000			124
2027	BCH_REV	Revelstoke Unit 6	500	488	26	26	46
2029	BCH_PR	Wind_PC18	138	36	524	524	92
2029	BCH_LM	2017 Load Curtailment	85	85			77
2031	BCH_PR	Site C	1145	1,145	5,286	5,286	34+Suspension Costs
2036	BCH_LM	Pumped_Storage_LM	1000	1,000			124
2037	BCH_PR	Wind_PC14	144	37	570	570	92
2038	BCH_PR	Wind_PC20	156	41	594	594	92
2039	BCH_PR	Wind_PC28	153	40	641	641	94
2039	BCH_PR	Wind_PC48	150	39	538	538	95
2040	BCH_PR	Wind_PC13	135	35	577	577	98
2041	BCH_NC	Wind_NC09	333	87	1,074	1,074	101

Transmission Expansion

Year	Project Description	Between	Capacity - MW
2027	Nicola-Vaseux Lake Compensation (NVLC)	SEL to KN	147
2031	Increase series compensation of 5L1, 5L2, 5L7 from GMS to WS	PR to CI	360
2031	Increase series compensation of 5L11, 5L12, 5L13 from WSN to	CI to KN	390
2031	Static VAr compensation at WSN	PR to KN	650
2034	Shunt compensation at NIC and MDN	KN to LM	570

Table 33 shows Site C being completed and operating by 2023, while Table 34 has Site C postponed to 2031. It should be noted that the CIFT charge is not assessed against any projects in these tables, because the System Optimizer schedules the transmission enhancements as needed. This is a good thing, because it avoids attempting to attach fictional costs to specific projects.

One thing, however, is made crystal clear by comparing these two tables, and the schedule of transmission expansions at the bottom of each table. Three large transmission projects, totally $1.4 billion are simply moved by the Optimizer to coincide with the startup of Site C. It is Site C that is responsible for the need for those transmission enhancements (at least in the mind of the Optimizer, it is). Yet, that $1.4 billion does not appear anywhere in Site C's $8.9 billion capital cost estimates. Since it is an incremental cost made necessary by the operation of Site C, it should be included in the capital cost estimates. It is not a sensitivity. It is a reality.

To treat that $1.4 billion as it would be treated for an IPP requiring it, we would first convert it to carrying cost of about $110 million per year (if spread over 25 years at 6%). Then we would divide that by the 5,100 MWh of annual generation to get a UEC cost "adder" of $21/MWh. If we were to assess that cost to Site C in the same way as CIFT is assessed to a wind project, it would produce a cost adder of $21/MWh.

With this cost adder, plus the previous $21 for the freshet penalty, the Site C UEC has moved up to $137/MWh, when compared on an apples to apples basis to smaller renewable energy projects that are in the range of $80 to $90.

9. RENEWABLE ENERGY CREDITS

In its comparative analysis of Site C, wind and solar alternatives, BCH overlooks the potential revenue from the sale of renewable energy credits or certificates ("**RECs**") associated with the electricity produced from these alternatives. The result is the price of wind and solar appears higher than it should.

The CEABC's initial comments on this topic are set out in Exhibit F18-3[26]. In addition the CEABC would like to draw the BCUC's attention to the following extract from energy trade publication[27] to demonstrate that REC markets exist in the U.S. and in particular California where most of the exports from the BC Hydro system go[28].

RENEWABLE ENERGY CERTIFICATE MARKETS SEP 28 ($/MWh)

	Low	High	Mid
Class I/Tier I RECs*			
Connecticut	16.25	16.25	16.750
Maryland	2.50	3.50	3.000
Massachusetts	16.25	16.25	16.750
New Jersey	2.50	3.50	3.000
Ohio	2.50	3.00	2.750
Pennsylvania	2.50	3.50	3.000
Texas	0.28	0.38	0.320
Solar RECs*			
Maryland	3.75	5.75	4.750
Massachusetts	317.00	323.00	320.000
New Jersey	181.50	188.50	185.000
Ohio	2.75	4.75	3.750
Pennsylvania	3.00	5.00	4.000
California RPS*			
California Bundled REC (Bucket 1)	14.00	18.00	16.000
California Bundled REC (Bucket 2)	6.00	7.00	6.000
California Tradable REC (Bucket 3)	0.75	1.25	1.000
Voluntary RECs*			
National voluntary, any technology	0.28	0.32	0.300
National voluntary, wind	0.28	0.32	0.300

*Prices are for the value of the environment attribute of the renewable energy certificate only and do not include energy. Bundled transactions are normalized by subtracting the market price of electricity.

To achieve the Bucket 1 price, the electricity and RECs have to be delivered to California as generated. Just as BCH discloses opportunities to market Site C capacity and flexibility to California it should also disclose opportunities that accompany the development of wind and solar generation in B.C.[29] and include them in the comparative analysis as between Site C and these alternatives. This is not to say all these opportunities will be realized and in particular because of the lack of transmission access/cost and the desire of State and Provincial governments to have electrical infrastructure built within their boundaries. However, it is expected that markets for Renewable Energy Credits from generation projects such as wind and solar will continue to develop and prices will increase over time. Large Hydro will not qualify for these markets.

10. CONCLUSIONS

In this submission, CEABC has described a number of the many ways in which the Site C project is being artificially "enhanced" to appear economically superior to an alternative portfolio of renewable energy projects.

[26] Page 16.
[27] S&P Global, Platts, Megawatt Daily, Friday September 29, 2017.
[28] BCH response to BCUC IR 2.22.3, page 2 of 4
[29] Hydro-electric generation is not REC eligible.

Chief among these many ways is the cost-of-capital subsidy from the Government. Both this Panel and the Government need to be educated to see through that "mirage" so that alternative investments can be evaluated on an apples to apples basis. In an effort to do so, we provide in Appendix 1 a paper by Dr. Marcel Boyer specifically addressing these issues.

Other artificial measures that have we have observed being used to tilt the playing field and create apples to oranges comparisons include:

- An excessive value is being placed on the capacity and "flexibility" of Site C, when its actual flexibility is highly limited and its capacity will simply add to an already surplus situation.

- Penalty costs are assessed on the alternative projects for fictional costs, like CIFT, or for freshet energy production, when Site C is escapes any mention of such penalties even though it will produce a tremendous amount of freshet energy and it is responsible for over $1.4 billion in transmission system enhancements.

The availability of Site C's capacity and flexibility is very constrained by its physical attribute. The generation is highly sensitive to hydraulic head which, along with other reasons, means the drawdown range of its reservoir is very limited.

The Site C project will actually detract from the existing system's flexibility. For instance, during the freshet season, Site C will be generating so much energy that it will require the rest of the system to be used to compensate for its excessive generation.

All of which is respectfully submitted,

CLEAN ENERGY ASSOCIATION OF B.C.

APPENDIX 1

FINANCIAL ISSUES REGARDING BC HYDRO'S SITE C PROJECT

Marcel Boyer Ph.D., O.C., FRSC
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October 11, 2017

1. INTRODUCTION AND SUMMARY

1.1 The Clean Energy Association of British Columbia (CEABC) asked me to comment on specific aspects of the British Columbia Utilities Commission's (BCUC) Preliminary Report dated September 20, 2017 regarding the Site C review. More specifically, I was asked by the CEABC to prepare a summary report that identifies and comments on the following financial issues raised in the CEABC submission to the BCUC; namely I was asked to:

1. Provide comment on the use of **100% debt financing** for a public project with specific reference to Section 6.3.1.2 of the BCUC preliminary report.

2. Provide comment on the use of a **70 year amortization period**, with specific reference to Section 6.4.1.3.1 of the BCUC preliminary report, to calculate the Unit Energy Cost (UEC) and the extent of the potential interest rate risk this can have on Site C's economics.

3. Provide comment on the application of **different discount rates** when comparing multiple project economics with specific reference to Section 6.4.1.3.3 of the BCUC preliminary report.

1.2 BC Hydro's financial analysis of Site C makes a major error in assuming that ratepayers and taxpayers need not be compensated for bearing project risk. With the current Site C financial model there is, in effect, no (or zero) equity with which to provide a return on Site C, and the low unit energy cost follows from a significant downward biased miscalculation of the effective or real costs of the project.

1.3 This error opens the door to significant distortions in investment evaluation, especially when comparing the alternative options, with potentially hundreds of millions of dollars, even billions of dollars of value at stake of being destroyed through a misleading evaluation methodology. The remedy to this error is the application of a proper risk premium either in the form of a large portion of equity and risk adjusted equity return or a larger contingency, or a combination of both. There are industry examples of utility-water projects with debt equity ratios of 43% (i.e. 30% debt/70% equity). However, given the equity risk, size, complexity and longevity of a non-recourse project like Site C, the

BC Government should require BC hydro to evaluate Site C on the basis of at least 40% equity.

1.4 BC Hydro uses an 11.84% return on equity for all projects except for Site C. The Provincial Government allowed them to do that by announcing a new policy just before they approved Site C.[30] The Government should require BC Hydro to use at least 11.84% return for the equity investment in Site C.

1.5 Seventy years is a very long term for Site C or any project's financial analysis. Combining that very long investment term with important risks from diverse factors such as market demand risks, technological innovation risks, stranded assets risks, climate change risks, and political risks (exportation) necessitates a rate of return for Site C between 10% to 13% (and possibly higher).

1.6 The best way to protect ratepayers from rate increases is to consistently make the right investment and operations decisions. Unfortunately, too many public utilities suffer from the same disease as too many government organisations: they turn out to be political entities with an aversion to rigorous financial principles. The way to achieve an optimal investment portfolio is to follow evaluation methodologies that are rooted in sound economics and finance and to apply them as rigorously as possible. One thing is sure: hiding costs by transferring risks to taxpayers without proper compensation one way or another is not the way to do it.

2. 100% DEBT FINANCING

Regarding subsection 6.3.1.2 of the BC Utilities Commission Preliminary Report:

2.1 The use of debt and equity (there are many classes of debt and equity that I will not address here) in a private firm is basically to save on taxes, as interest on debt is generally deductible from taxable income, as well as take advantage of the lower interest generally associated with the use of debt (from the design of a two class financial structure with higher priority given to debt holders). Insofar as BC Hydro is not taxable, the first reason plays a very limited role in the present context. Moreover, since BC Hydro debt is totally guaranteed by the Government one way or another, the discussion here must be read as applying to a private firm. Later I will discuss the case of BC Hydro as a Crown corporation.

[30] In November 2014 the B.C. government announced the 10 Year Rate Plan which allowed BC Hydro to waive the traditional Return on Equity calculation and the Dividend calculation for Site C, as well as set rate increases of 15% over the ensuing 2 years, That result enabled BC Hydro to artificially and significantly reduce Site C's UEC, and is one of the main reasons why Site C's UEC appears to be much lower than the UEC for the Alternative Clean Energy Block. On December 16, 2014 the provincial cabinet-approved Site C.

2.2 In private firms, the debt/equity (D/E) ratio is used to create two classes of financiers in the project with different priorities as far as compensating payments are concerned. But the inherent project risk is otherwise independent of the D/E ratio. In a sense, there are three different cash flows, and each is subject to its own risks. Some of the risks are determined by the projects inherent risks, and some of the risks are a function of the financial contracting between the financing parties.

2.3 However, this split in the project financing structure between debt and equity is basically a way, a potentially profitable way, to allocate the project's risk between the two groups of financiers who may have different aversion to risk taking. Debt holders have priority over equity holders if available funds are insufficient to adequately compensate both groups. In exchange for this priority, debt holders are entitled to fixed repayment schedule and conditions, while the equity holders are residual claimants and payees and will receive whatever is left after the debt holders are paid. For this reason, debt holders will require a lower return (interest rate) on their investment in the project as their investment in the project is less risky and equity holders a higher return as their investment in the project is more risky. Equity holders face two factors of risk, one from the uncertain cash flows of the project (which affects also debt holders) and one from their lower priority to those cash flows.

2.4 Therefore, a 100% debt financing of an investment project in a private firm is akin to a 100% equity financing of the same project, with the same financing cost in both cases. In the case of a public firm, the situation is more complex because the debt is nonetheless shielded from risk by the presence of "hidden equity" in the form of ratepayer and taxpayer guarantees. There is equity bearing all the residual risk, but it has zero investment and zero return. In the case of Site C, however, I understand that it is not really 100% debt financed. It is only 60% debt with the 40% of the funds that are put up by the Government/taxpayers are assumed to receive a zero rate of return.

2.5 If the risk-free rate is 4% and the risk premium is 6%, then an investment with an unlevered beta of 1 (that is, similar to the overall or broad market risk) would require a rate of return of 10%. If the unlevered beta is 1.5 (50% more risky than an investment in a broad market index), then the required rate of return would jump to 13%.

2.6 For a very long term investment such as BC Hydro's Site C project, a required rate of return and discount rate of between 10% and 13% (and possibly more) would be warranted given the important risks involved coming from diverse factors, among which the following are non-negligible: market demand risks, technological innovation risks, stranded assets risks, climate change risks, and political risks (exportation).

2.7 There are no simple methodologies to estimate and quantify those risks. Two main methodologies can be used: First, simulation studies based on relevant stochastic processes capturing the essential elements of uncertainty as parameters of trend and

volatility, where the parameters of interest are varied in sensitivity analyses. Second, the identification of the market risk attached to the traded stock of firms whose portfolio of assets matches as closely as possible the characteristics of BC Hydro Site C, in particular their very long term amortization period. But it would be challenging for obvious reasons to find such firms. Both methodologies are complex and challenging but nevertheless possible and necessary. The first methodology seems more promising.[31]

2.8 In a Crown corporation like BC Hydro, for which all debt is fully backed by the Government, the distinction between debt and equity is rather blurred. Actually, the ratepayers are acting as the first line of equity holders. They are the first line of defence that protects the debt holders from any project cost overruns, schedule delays, future interest rate increases, or underperformance risks of all kinds (including operating, maintenance, and capital replacement costs, and even climate change or water supply, as well as technological and stranded asset risks). The ratepayers are the first recourse if the project does not meet its expectations in any way.

2.9 After the first recourse to the ratepayers, the second recourse is to taxpayers through the intervention of the Government if it looks like the burden on the ratepayers might exceed a politically acceptable level. The ratepayers and taxpayers are then supporting the total risk of the project, not the lenders or debt holders. In other words, ratepayers and taxpayers are holding a significant level of "hidden equity" for which they are not compensated.

2.10 Properly defending the interests of ratepayers and taxpayers, which is arguably the major role of Governments, requires that the risk or risks of the project be correctly evaluated and priced into the project. The standard methodology used for the evaluation of public projects suffers from serious flaws, particularly with respect to the use of a discount rate corresponding to the government's cost of financing.

2.11 My analysis suggests that the underlying rationale for the approach BC Hydro and the BC Government appear to adopt stems from the analytical illusion that the cost of capital incurred by the private sector to undertake a project is higher than the cost of capital incurred by the public sector to undertake the same project.

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[31] See Boyer, M., et alii, *Méthodes avancées d'évaluation d'investissement / Advanced Methods of Investment Evaluation*, Monographie CIRANO Monograph (2 tomes / volumes), Hiver/Winter 2017, 601 pages, in particular chap.8 Fundamentals of Real Options Valuation; chap.12 Identifying, Creating and Managing Real Options; chap.15 Application de la théorie d'options réelles pour l'évaluation économique d'une interconnexion entre deux marchés d'électricité; chap.18 Prise en compte de la volatilité dans les questions de valorisation long terme deux marchés d'électricité; chap.18 Prise en compte de la volatilité dans les questions de valorisation long terme des actifs physiques. **http://cirano.qc.ca/files/publications/2017MO-03.pdf** (Tome 1) and **http://cirano.qc.ca/files/publications/2017MO-04.pdf** (Tome 2)

2.12 This analytical illusion is due to the fact that a significant portion of the government's cost of capital is not recognized and not accounted for, namely the implicit option granted by taxpayers to their government to require additional funds in order to meet the commitments made to the lenders if and when a project does not meet the expected level of profitability. Discounting at an essentially quasi risk-free rate is often rationalized by "the virtually unlimited taxing power of the Crown": the project may appear quasi risk-free to lenders, but is obviously not risk-free for "ratepaying and taxpaying" citizens.

2.13 If the Government has no interest other than that of the citizens it represents, the allocation of public funds to investments should follow the same principles used in the allocation of private funds. Although the government does not usually relate its borrowing to the funding of specific projects, it remains true that regardless of the project, loan or subsidy, the implicit guarantee taxpayers grant the government allows it to offer the lender an essentially risk-free investment. Taxpayers do not get the same deal.

2.14 For a private firm, the lower the share of a project financed by debt through a lower D/E ratio, the lower the project risk supported or incurred by debt holders will be, the higher the rating of the debt will be, the lower the interest rate required by lenders will be.

2.15 Conversely, the larger the share of a project financed by equity through a low D/E ratio, the lower the (given) project risk supported or incurred by equity holders will be, as those equity holders are better protected (have a higher priority on the cash flows of the project), the lower the return required by equity holders will be.

2.16 Similarly, as the D/E ratio increases from 50% to 100% to 200%, the higher the share of the project financed by debt is, and the riskier the debt becomes, translating into a higher interest rate required by lenders.

2.17 The important lesson one must keep in mind is that, for private firms, debt and equity are communicating vessels. In fine, if a private firm project is financed 100% by debt, there is "no debt" in the usual sense as there are no other residual claimants than lenders and the debt holders support 100% of the risk of the project. Debt becomes equity. More precisely, debt is assuming the role of equity, unless those debt holders are contractually protected by some form of guarantee from a credit-worthy party, like a parent corporation, or even an implicit guarantee from the customers (i.e. that they agree to pay higher prices to protect the debt holders from any loss).

2.18 If BC Hydro were a private firm, BC Hydro would appear to be making the error of assuming that a 100% debt-financed project could benefit from a constant and low cost of debt. Since as I discussed above the cost of debt is commensurate to the risk supported by the lenders, the higher the D/E ratio, the riskier the debt becomes and the

higher the interest rate on the debt will be. If the financing of the project is 100% debt, then debt support 100% of the project risk; and similarly, if the financing of the project is 100% equity, then equity supports 100% of the project risk. In both case, the required return is the same, whether it takes the form of or is called interest on debt or return on equity.

2.19 Given that BC Hydro is a Crown corporation whose debt is totally guaranteed by the BC Government, the debt holders are not supporting the BC Hydro project risk even if the project appears to be financed 100% by debt. The reason is that the project risk is being transferred to ratepayers and taxpayers.

2.20 The way by which Site C is being evaluated assumes that ratepayers and taxpayers need not be compensated for bearing the project risk. This error opens the door to significant distortions. The only sensible way to evaluate such public sector investments without making the major error mentioned above is to include in the cost of public projects, such as BC Hydro's Site C project, a proper compensation of the risk supported by ratepayers and taxpayers. It could be done through different channels: by assuming a proper risk premium on the financing charge, by explicitly including a large portion of equity and a risk adjusted equity return, by adding more and larger contingency allowances, or by some combination of these as well as some other equivalent measures.

2.21 The statement by PRWMFN to the effect that "[w]ithout a requirement to provide any financial return - because there is no equity with which to provide a return - the unit energy cost can be decreased, but this is the equivalent of a mirage" is completely in line with this result. It is indeed a "mirage", as the lower unit energy cost follows from a significant downward biased miscalculation of the effective or real costs of the project as an important share of the risk of the project; the share supported by taxpayers, is hidden and not compensated.

2.22 My second comment pertains to the observed D/E ratios across firms and industries. There is no uniquely or simplistically determined D/E ratio for a given firm or a given industry. The ratio affects incentives for exerting efforts (moral hazard) in managing risks and for putting more competent managers (adverse selection) on risk management tasks. Equity holders will in general be more sensitive to and interested in risk management than debt holders given their lower priority in the distribution of cash flows generated by the project or the firm. The ratio affects also the rating of the firm's debt by rating agencies. Indeed, riskier projects usually require more equity, and more equity allows a better rating of debt by rating agencies, hence a lower interest on debt.

2.23 We observe relatively low industry wide D/E ratios in Oil/Gas-Integrated (17%, that is, 85% equity financed and 15% debt financed), Aerospace and Defense (24%, that is, 81% equity financed and 19% debt financed), Building Materials (27%, that is, 79% equity financed and 21% debt financed), Transportation Railroads (28%, that is, 78% equity

financed and 22% debt financed), Engineering/Construction (32%, that is, 76% equity financed and 24% debt financed); relatively high D/E ratios in Coal and related Energy (139%, that is, 42% equity financed and 58% debt financed), Green and Renewable Energy (174%, that is, 36% equity financed and 64% debt financed), Power (87%, that is, 53% equity financed and 47% debt financed); and relatively medium level D/E ratios in Oil/Gas-Production and Exploration (47%, that is, 68% equity financed and 32% debt financed), and Utility-Water (43%, that is, 70% equity financed and 30% debt financed).[32] For wind power projects, D/E ratio may reach 230% or more: "relatively high gearing in wind projects of about 50%-70% debt financing, where onshore and offshore projects are typically in the upper and lower range, respectively. The difference is due to the larger risk in offshore projects."[33]

Conclusion on 100% debt financing

2.24 I understand that the BC Government has determined that 40% is the amount of Equity they think is appropriate for them to put into BC Hydro. That would give a Debt to Equity ratio of 150%, reasonably in line with industry. One possibility to cut the Gordian knot of Site C project evaluation is to hold them to that proportion for Site C, but require BC Hydro to actually evaluate the Site C project on that basis, with the proper cost of debt and equity, rather than pretend to benefit from a 100% debt mode.

2.25 I understand that BC Utilities Commission determined an appropriate equity rate of return for BC Hydro to be 11.84%, which should be used for all general project evaluations. The Government should require BC Hydro to use no less than this 11.84% for their equity investment, although for such a large, complex and long lasting project as Site C, there should be an additional premium on top of that basic equity rate of return to allow for the additional risks that are somewhat outside the range of BC Hydro's normal business.

2.26 For the rate of interest on the Debt portion, it should be what institutional lenders would require in the private sector for a stand-alone, non-recourse project of the same size, complexity, and longevity as Site C with a 40% equity investment.

2.27 The following table illustrates the implications of the above discussion. The last line represents realistic financial parameters for Site C.

Debt rate	Debt financed	Equity rate	Equity financed	WACC

[32] Aswath Damodaran, New York University Stern School of Business. http://www.damodaran.com

[33] Deloitte, *Establishing the investment case - Wind power*, 2014. Note that a D/E ratio above 230% means more than 70% debt financing and less than 30% equity financing for lower risk onshore wind power projects, while a D/E ratio of 100% means 50% debt financing and 50% equity financing for higher risk offshore wind power projects.

3%	60%	0%	40%	1.80%
3%	70%	0%	30%	2.10%
3%	100%	11.84%	0%	3.00%
3%	70%	11.84%	30%	5.65%
4%	70%	11.84%	30%	6.35%
3%	60%	11.84%	40%	6.54%
4%	60%	11.84%	40%	7.14%
6%	60%	11.84%	40%	8.34%
6%	**60%**	**13%**	**40%**	**8.80%**

3. 70 YEAR AMORTIZATION

3.1 Regarding subsection 6.4.1.3.1 of the BC Utilities Commission Preliminary Report:

3.2 It often appears better to model with an appropriate stochastic process (subject to sensitivity analysis) the residual value of the equipment/project at year thirty or forty than to try to forecast all relevant variables for a period of over 70 years. It may be useful to note here that the European Commission recommends the following maximal reference periods for long term projects:

European Commission's reference periods by sector

Sector	Reference period (years)
Railways	30
Roads	25-30
Ports and airports	25
Urban transport	25-30
Water supply/sanitation	30
Waste management	25-30
Energy	15-25
Research and Innovation	15-25
Business and Infrastructure	10-15
Other sectors	10-15

3.3 A proper comparison of mutually exclusive projects requires that projects (and their replications) must span the same period. The usual way to do this is by replicating projects (replacement chain) up to the point where all projects have the same or similar reference period. Hence if two mutually exclusive projects are considered, with reference periods of respectively 70 years (project 1) and 35 years (project 2), the proper way to compare those projects is to consider the 70 year project 1 and two consecutive 35 year project 2, each option being properly discounted at their respective discount rate.

3.4 The challenge here is to forecast at what conditions the replication of the second project will be made in 35 years and what portion of it will need replacing (not all elements of the 35 year project or equipment would need to be replaced in 35 years, thereby reducing the present value cost of the second option). It may be the case that, due to technological development and innovation, the investment cost required, in real dollar terms, will be significantly lower than the year 0 investment.

3.5 A proper stochastic model (subject to sensitivity analysis) of innovation can and should be developed to ascertain the expected reinvestment level necessary for a replacement project, 35 year from now. The additional flexibility the investor has in considering two 35 year projects (regarding the time to reinvest and whether reinvestment is warranted or not and at which financial and technological conditions) versus one 70 year project has a real option value. In real option valuation (ROV) analysis versus net present value analysis (NPV), the possibility to abandon the reinvestment project (not reinvesting) in 35 years has value and makes more valuable the two 35 year projects option. This value appears to be explicitly ignored by BC Hydro in its comparative evaluation of the Alternatives.

3.6 Finally, the significant uncertainty involved in the evaluation of very long term projects favors the explicit use of properly calibrated stochastic real option models in order to reduce the level of arbitrariness in the estimation of costs and benefits, in particular the end or terminal value of the equipment/project. This can and should be done.

4. DIFFERENT DISCOUNT RATES

Regarding subsection 6.4.1.3.3 of the BC Utilities Commission Preliminary Report:

4.1 <u>My first comment</u> relates to the "commonly held" view and often repeated statement that the private sector is in a good position to manage project costs and meet deadlines, but not, generally, to fund or finance projects. The underlying argument runs as follows: because the interest rate on government borrowings (the government's debt financing cost) is lower than that of the private sector, the cost of goods or services will necessarily be lower if it is funded by government. However, such an argument builds on confusion between the cost of financing and the cost of capital (or discount rate). The analytical error resides in the assessment of the true cost of public funds. This is a subtle but important error that is widespread in both the public and private sectors as well as in academia.

4.2 It is undeniable that the public sector can generally borrow at lower interest rates than the private sector to finance a given project. But this begs the question: Why? Why is the cost of financing lower for a public sector enterprise if that enterprise is involved in the same project or activities and in the same way as a private sector company – same

technology, same inputs, same markets, same prices – and therefore faces the same risk factors?

4.3 The answer is that a government has the power to levy additional fees and taxes to compensate and repay its lenders if the project incurs cost overruns and/or generates lower than expected benefits. The interest rate paid by the public sector reflects the fact that, through its taxation power, it implicitly subscribes a loan insurance wherein taxpayers act as the insurer. This means that lenders to the public sector will require at most a relatively small risk premium regardless of the risk of the project because those lenders are not subject to the risk of the project. This is clearly not the case for the private borrower who does not have such taxation power.

4.4 The risk premium normally required by the lender will depend on several factors: the probability of default, the estimated loss in case of default and an assessment of the systematic (non-diversifiable) risk associated with these two quantities. A lender is not directly interested in the borrower's identity (public versus private) when determining the risk premium, the only important factors being the probability of default and the loss to be incurred in case of default (both the probability and loss being more generally expressed as distributions of probabilities and loss levels).

4.5 The lender will, however, show an indirect interest in the public sponsor if the latter provides a complete risk insurance borne by taxpayers, since this has the effect of reducing to zero the loss in case of default, thereby implying a zero or much reduced risk premium. As such, if a project fails, the public sector can repay the loan by increasing taxes or by reducing the number and/or quality of public services – in effect requiring compensation from the insurer (i.e., the taxpayers).

4.6 For the tax-paying public, the right and power of the state to demand additional contributions as required comes with a cost. This cost is real, but generally not acknowledged and not considered in the evaluation. It corresponds to the value of the financial option (or the insurance policy) granted by taxpayers to their government to obtain from them additional funds to cover a project's possible non-profitability ex post. The lower cost of funding is mainly due to the unaccounted implicit cost of this option or insurance policy held by a government.

4.7 If citizens gave a private company a similar option, i.e., the right to levy a tax if it was in financial distress, the private company could finance its activities at a rate similar to that of a government, public enterprise, or governmental agency.

4.8 All lenders require a premium related to the risk of default and associated potential loss. If the risk is borne by an insurer, represented here by the taxpayers, then the taxpayers as insurer should demand an equivalent risk premium: for a public project proponent, the requirement of a risk premium by the lender or its insurer (the taxpayers) must be

taken into account. The proponent must then evaluate the project, taking into account the risk premium in order to avoid unduly depriving taxpayers of their due return or spoiling their interests.

4.9 In the investment community, there is much confusion between the risk ultimately borne by taxpayers and the cost of government funding which, reflecting the point of view of lenders, does not take into account the cost of the implicit insurance provided by taxpayers to their government. This translates into an error which is surreptitious and hidden, but which is nonetheless undeniable and may be extremely dramatic in its consequences.

4.10 This means that the cost of capital, which is a function of the project risk and which determines the discount rate, should fundamentally be the same whether a given project is public or private. The difference between the public and private sectors rests on their relative blend of competencies and incentives during both the construction phase and the operation phase of the project. This doesn't mean that Site C should be evaluated using the same discount rate assumption as a much smaller, shorter-term, and less complex project, like a wind, solar, or small hydro project. Each similar project should be evaluated the same way with the same cost of capital whether it is a public one or a private one. But two highly dissimilar projects, such as Site C and a much smaller, shorter term and less complex project, will be subject to different financing conditions and therefore different costs of capital. It is not whether the projects are private or public that matters, but rather the risk characteristics of the projects.

4.11 If BC Hydro's cost of debt referred to in BC Hydro statement "the cost to the ratepayer of financing Site C is equal to Hydro's cost of debt" (see BC Utilities Commission Preliminary Report subsection 6.3.1.2) is the firm-wide cost of debt financing of BC Hydro, then relatively riskier projects in BC Hydro portfolio of potential and actual projects will be overvalued, while the other projects, relatively less risky ones, will be undervalued.

4.12 If BC Hydro's cost of debt referred to in the BC Hydro statement is the BC government-backed cost of debt financing of BC Hydro, then the problem is even worse and the portfolio of projects undertaken will be even more biased towards riskier projects with a more important divergence between the actual portfolio of projects selected, and the optimal portfolio of projects.

4.13 BC Hydro is clearly committing this error when it writes: "For purposes of comparing BC Hydro and IPP projects, there should be recognition that BC Hydro will have a lower cost of capital given its access to the Province's high credit rating."[34]

[34] DOC_90351_F1-5_BC Hydro_Site-C-Submission, IR 2.50.2

4.14 This will result in a suboptimal portfolio of actual projects and potentially significant losses of value for BC: billions of dollars are at stake of being wasted.

4.15 In summary, the argument that government funding is less expensive than private funding is not only wrong but also, unfortunately, ubiquitous in debates on public investments, especially for large infrastructure projects. This error is directly related to the determination of the appropriate discount rate for the evaluation of public investments, specifically how the risk of a public project is taken into account in cash flow stream discounting.

4.16 My second comment relates to the second mistake mentioned above regarding the proper use of the weighted average cost of capital (WACC), which averages the cost of debt and the cost of equity, each weighted by its importance in the capital structure of the firm. This is one of the three additional important mistakes identified in the C.D. Howe Institute Commentary #388 mentioned above, which are all just as damaging as the one discussed in my first comment.

4.17 The phenomenon described in the BC Hydro use of WACC and its firm-wide cost of financing, whether based on BC Hydro cost of debt or BC Government cost of debt, has a parallel with respect to large corporations, but to a somewhat lesser extent. When private firms borrow against their corporate balance sheets, and all their diverse sources of income, rather than against a single, perhaps risky project, the lender is not lending to the project specifically, but rather to the corporate entity, with all of its capabilities to pay back the loan, even if the project considered turns out to fail. Accordingly, the debt holder has access to many more assets, and revenue streams, than merely the one project.

4.18 Similarly, when BC Hydro or the BC Government borrow against all their diverse sources of income, rather than against a single, perhaps risky project, the lender is not lending to the project specifically, but rather to the government entity, with all of its capabilities to pay back the loan (include raising taxes, or electricity rates) or cutting on other government services. Accordingly, the debt holder has access to many more assets, and revenue streams, than merely the one project.

4.19 However, there is a fallacy in that reasoning, both for public sector and private sector investment evaluations. When using the company's cost of capital as a whole (WACC) in the assessment of its investments, one will overvalue and overinvest in some projects whose level of risk is higher than the average level of risk of the company's project portfolio. Similarly, one will undervalue and underinvest in other projects whose risk level is lower than the average risk of the company's project portfolio. Ultimately, this leads to a suboptimal portfolio of project investments and can cause a potentially large destruction of value in the company.

4.20 When assessing a particular project over another project, one must use a discount rate or cost of capital specific to this project, pegging it to the project's systematic risk level. The justification for using the WACC is that it is simpler to use as compared to estimating a given project's risk and cost of capital. Another reason would be that all projects within the company are of a similar risk profile.

4.21 But that simplification is value destroying.[35] It is the WACC of the project itself that one must use, with its particular D/E capital structure ratio and its own cost of debt and equity, reflecting its particular cost of capital. The overall financing of the firm and the evaluation of investment projects are two different responsibilities in private corporations. Even if holders of additional debt raised to finance a given project have recourse to the whole cash flows of the firm and determine their required interest rate and loan condition accordingly (through rating the company's debt rather than what would be the "project's debt"), it remains that the optimal investment policy of the firm must be linked to each project risk profile and particular cost of capital and discount rate.

4.22 In either case, it might not be a serious problem for a large company making a lot of smaller investments, but it can be a big problem when you throw into the mix one single massive investment, with a complex array of new and long-term risks.

4.23 In using a concept of WACC as the cost of capital in evaluating a Crown corporation project, one must determine the proper "interest rate on the debt" and the "return on equity", which enter into the calculation of the WACC. Those two factors must be evaluated at the project level, hence in relation to the risk of the project being considered and its particular cost of capital and discount rate. If one uses the overall Crown Corporation cost of debt or Government cost of debt financing as the cost of debt, which together with an estimated cost of equity determine the WACC, one makes a second error: besides improperly using the WACC itself directly in investment evaluation (the first error), the WACC used itself would be underestimated (the second error): if the WACC, which should not be used, is nevertheless used, then it must be estimated properly with proper estimates of the cost of debt, the cost of equity, and the proportions of each that are appropriate for a project with that particular risk profile.

4.24 In the overall financing of a private firm, the cost of debt and the cost of equity are both market driven and represents the risk the firm's lenders and stockholders are supporting and facing. Only the error related to using the wrong WACC is made (insofar as the WACC of the firm is used rather than the WACC of the project). In the case of a public firm, which benefits from the fact that the government can raise taxes to repay its debt

[35] Kruger, P., Landier, A., and D. Thesmar, "The WACC Fallacy: The Real Effects of Using a Unique Discount Rate", *The Journal of Finance*, Vol. LXX, No.3, June 2015. The authors verify investment biases empirically and measure the value destruction caused by this fallacy.

obligations, using the interest rate at which the government can finance its debt means that a second error is made namely the error of using an interest rate that hides the significant risk supported by taxpayers. Not only the WACC fallacy is present but the interest rate used in calculating the WACC is underestimated, thereby reducing the WACC and generating further distortions in investments and losses of value.

4.25 My third comment relates to two further mistakes identified in the C.D. Howe Institute Report (Commentary #388) that are also relevant in the present BC Hydro Site C case. Hence a brief comment is warranted.

4.26 The mistake made by using a single cost of capital in assessing a project when it is dependent on several different sources of risk comes from the fact that, in such a case, the net present value (NPV) methodology is at variance with, that is, violates two fundamental principles of value creation in modern finance, namely the principle of additivity[36] and the principle of no arbitrage opportunities.[37] The use of a single discount rate for a project's net cash flows is the main problem, even when the discount rate is risk-adjusted. We cannot avoid considering separately the cash-flow components that are dependent on different sources and levels of risk and assigning them a risk premium of their own.

4.27 The other mistake is related to the fact that when managers may intervene in the development, implementation, and timeline of a project by reacting to a changing and volatile environment, the traditional NPV must be replaced with the real option valuation (ROV) that integrates the value of managerial flexibility in the project's value. This is because traditional NPV implicitly assumes that a company investing in a project passively holds the underlying assets for the life of the project. NPV therefore neglects the value of active management.

4.28 In the presence of managerial flexibility, investments, in particular strategic investments, can be seen as portfolios of real options that managers exercise at the appropriate time. Managers are expected to respond to future events and market developments as well as to changes in the intensity of competitive forces. The NPV methodology does not have the flexibility to account for managers' expected flexibility options. These options are similar to financial options but are generally more complex. However, they can be

[36] The additivity principle states that the value of a portfolio of independent projects must be equal to the sum of its constituent projects. We must, therefore, be able to evaluate a sequence of cash flows broken into several components by the sum of the evaluations of these various components.

[37] An arbitrage opportunity can be defined as an investment strategy at no cost (no net-cash outflow) that promises a positive return in some states of nature while having a zero probability of loss. The principle of no arbitrage states that in developed markets populated by rational agents, arbitrage opportunities for all practical purposes should be rare and of short duration or non-existent. If an arbitrage opportunity arises, the agents would exploit it immediately, and it would quickly disappear. In other words, "there is no free lunch," especially in the world of public or private finance.

evaluated using a similar methodology. Neglecting them produces a bias, usually downwards, in project value.

4.29 In the case of BC Hydro Site C, it is clear that management flexibility in controlling or adapting the development, implementation, and timeline of the project in reaction to a changing and volatile environment will raise the value of the project as well as the value of the alternative projects. Ascertaining these relative flexibility values cannot be neglected. It is complex but can be done in a rigorous manner and should be done.

4.30 My forth comment is that one must remember and keep in mind that there are two broad groups of risks: one group I will call project management risks and one group I will call market risks.

4.31 Project management risks are risks that managers can mitigate through better resource and schedule planning, better inventory management, better surveillance of construction and operations, and more generally through better incentives and incentives alignment fostering proper cooperation and exchange and use of information throughout the chain or network of operators, clients and suppliers, and stakeholders. One example suffices to characterize such project management risks: if the resources dedicated to achieving a given task on time are insufficient in quantity and/or quality, there is a serious risk that the objective will not be met. But this is not really a risk, but a certitude!

4.32 Market risks are different. They relate to the impact of the overall economic outlook on the financial results of the project. The economic outlook, with alternating periods of favorable conditions (expansion) and unfavorable ones (slowdown or recession) will affects more or less severely the benefits and costs of the project. The risk level is typically measured as the beta factor, which measures the relative covariance between the project's financial returns from the net cash flow results and the overall broad market returns over the variance of market returns. This beta factor, which is a measure of the quantity of risk, is combined with the market price of risk or risk premium and the risk free or pure time preference rate to determine the appropriate discount factor to apply to the expected cash flows generated by the project. A project, a firm, and an industry can be characterized by their respective beta factor.[38]

4.33 My fifth comment relates to the seemingly counterintuitive result that riskier costs, discounted at a higher discount rate, will have a present value that is smaller than less risky costs discounted at a lower discount rate. In choosing between two projects with identical revenue or benefit streams and similar expected costs, the Discounted Cash Flow criteria will favor the riskier project.

[38] See for instance **http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/Betas.html**

4.34 It is often claimed that: "The discount rate chosen should match the market risk inherent in cash flows. Since higher risks require higher returns, one could argue for a higher discount rate (i.e., risk-free rate plus risk premium) to capture the riskiness in the project costs. However, this leads to the counterintuitive result of future uncertain costs being heavily discounted leading to a project appearing less costly in present-day dollars as a result of this increased risk." The result may be counterintuitive, but it is nevertheless correct!

4.35 The reason why this so-called counterintuitive result is correct is that risky costs, assuming that the systematic riskiness of costs is properly measured through the costs beta factor (see my fourth comment just above), act as a form of insurance against the fluctuations of the market: if costs are systematically more risky, it means that they are high when market returns are high and low when such returns are low. This makes the riskier project more valuable and should not lead to manipulations to avoid this result.[39]

4.36 BC Hydro falls into this trap as noted in its response to IR 2.50.2[40]: "In contrast, BC Hydro's analysis compares the costs of portfolios of multiple alternative resources and as such uses the discount rate to compare the annual costs of portfolios based on the 'time preference' of ratepayers. If in portfolio PV cost analysis one were to apply a higher discount rate for portfolios of similar cost but higher risk, the distorted outcome would be that a riskier portfolio would result in lower PV costs and appear to be the preferred outcome."

4.37 It appears that the preference of BC Hydro for sensitivity analysis to account for risk is misplaced. Sensitivity analysis allows to illustrate how different factors may affect the value of projects. As such it is a complement illustrative tool but not a substitute for the risk adjusted discount rate in project evaluation. The confusion is clear when BC Hydro writes: "BC Hydro believes that the sensitivity approach provides a more transparent view of the risks to the projects and the impact of each as opposed to a subjective and blanket change in the discount rate."[41]

4.38 BC Hydro fails to properly consider the differential risks of BC Hydro projects and IPP projects when it writes: "The discount rate used for evaluations should be the same for BC Hydro projects and IPP projects. While it is possible to vary discount rates by adding a further project-related risk premium to reflect project-specific risks, the BCUC found that project-specific risks should be assessed through sensitivity analysis and contingencies

[39] Infrastructure Ontario (IO) has for instance developed a methodology to improperly correct the proper result through value-destroying manipulations (or "comprehensive risk assessment" in IO terminology) to "avoid this result." In doing so, IO goes against the lessons of modern finance and contribute to destroy value through improper project choices. See the C.D. Howe Commentary #388 for more on this.
[40] DOC_90351_F1-5_BC Hydro_Site-C-Submission, IR 2.50.2
[41] DOC_90351_F1-5_BC Hydro_Site-C-Submission, IR 2.50.2

as BC Hydro has done in its filing." The only situation where this approach is warranted is when cash flows have been transformed into certainty equivalent cash flows to be discounted at the risk-free rate. This does not appear to be the case here.

5. GENERAL CONCLUDING COMMENTS

5.1 The financial analysis completed for BC Hydro's Site C project shows a number of errors, primarily related to the inappropriate accounting and allocation of risk (in its many forms). While the general financial methodology may be correct, the application and specific values used to complete the financial analysis is seriously flawed. These errors expose BC citizens to potentially large losses of value, possibly hundreds of millions of dollars, if not more, without any compensation for the risks they are being asked to bear.

5.2 For example, given the difference between a 3.4% interest rate currently being applied to Site C and a real world (i.e. risk accounted) WACC of 8.8% as suggested in this submission, the overall effect of this difference, including aforementioned errors, results in a significant present value bias that appears to have led to the selection of Site C as the least cost option. However, a rigorous verification is warranted. Such verification would require a period of three or four months. It would, therefore, be wise for the BC Utilities Commission to ask for such an independent assessment.

APPENDIX A

Statement of Qualifications

My academic CV is available at **http://www.cirano.qc.ca/~boyerm**