CLEAN ENERGY ASSOCIATION OF B.C.

SUBMISSION TO

THE B.C. UTILITIES COMMISSION

2017 INQUIRY

RESPECTING THE SITE C PROJECT

August 30, 2017

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1. INTRODUCTION

In Part 1 of its Submission to the British Columbia Utilities Commission in relation to the Site C project, the Clean Energy Association of B.C. ("CEABC") set out some due diligence questions that should be asked about BC Hydro's Site C model(s) ("Model"). The premise being that this Model will produce the Site C plant gate energy cost from 2024 to 2094 which would then be compared to the plant gate prices of other forms of renewable generation, primarily wind over the same term (collectively the "Term"). If there are any abnormal assumptions or figures in the Model they need to be corrected before the next step in the process can be properly undertaken.

In this Part 2, a comparison of the plant gate prices, or as they are often described, unit energy costs, or "UECs", will be described and discussed ("Comparative Analysis" or "Analyses"). The CEABC's main concern is that the Comparative Analysis be done on a level playing field basis over the Term. Including where applicable delivered costs to the Lower Mainland.

Each type of generation has some different characteristics such as the block nature of the Site C project generation coming into service all at once and the intermittency of wind and solar generation. These types of differences need to be adjusted or accounted for.

BC Hydro has done some Comparative Analyses in other forums but as with the Model, it is necessary to perform due diligence to determine whether it contains any abnormalities including omissions. This is no different than when a buyer conducts due diligence on the books and records being provided by a seller of a business. If there are any abnormalities in the Comparative Analyses they need to be corrected so the playing field isn't tilted.

The information available from these other processes isn't complete and in some cases assumptions and extrapolations have to be made or deficiencies noted. Ideally the CEABC would have been given access to the information it requested in its letter to the BCUC dated August 17, 2017 but in the absence of this information it must work with the information that is publicly available.

A senior Government official presented a comparative analysis of unit energy costs ("UECs" or "UEC") to the CEABC Board of Directors[1] which will also be discussed in this Part 2.

Performing due diligence on various aspects of the Model and the different Comparative Analyses and providing meaningful comments on each is very difficult because of the extraordinary length of the Term. The period from 2024 to 2094 spans generations. A person born today will be 77 years old before the Site C project debt is paid off. The CEABC has provided more detailed comments about this topic under the heading elsewhere in this

[1] January 26, 2015

submission.[2] In summary it is an exercise in wild speculation to produce certain forecasts, primarily numerical, over the Term. For example, is there any credibility in forecasting the price or revenue that BC Hydro will receive for the electricity produced from the Site C project from 2024 to 2094? With technological change causing the price of wind and solar generation to steeply decline and the cost of storage such as batteries headed in the same direction, there is a very high probability that users of electricity will have a choice as to where their electricity comes from.

No regulatory compact between a regulator and a utility or Government direction is going to be able to stem the advance. Just as it is not possible to stem the advance of online shopping or ride sharing. The accounting life of a shopping mall may be 50 years but its technological life is a lot less. The Term should be 40 and not 70 years to recognize the futility of making ultra-long forecasts in an era of technological change in the electricity industry. Making a 70 year forecast today is the equivalent of making a prediction at the end of World War II about 2017. Things change. The revolutions that hit the computer and communications industries were unforeseen. So, too, will be the revolution that is coming in the electricity industry.

The CEABC's comments about the Model and the Comparative Analyses are primarily intended to assist the BCUC in advising the Lieutenant Governor in relation to the following Term of Reference:

> "*(iv) 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 2016/2017 greenhouse gas emission levels) to ratepayers at similar or lower unit energy costs as the Site C project?"*

Because of time constraints, the CEABC will not be making any comments on demand-side management in this Submission.

In addition to the commentary on the Comparative Analyses, comments are being provided on the length of the Term, and on the value of the capacity and energy produced by the Site C project which is applicable to the Model and the Comparative Analysis.[3]

Also included is a summary of the report prepared by Power Advisory LLC for the Clean Energy Association of B.C. and the Canadian Wind Energy Association of B.C. entitled: "*Independent Assessment of the Renewable Generation Costs and the Relative Risks and Benefits of These Projects Compared to Site C.*" ("CanWEA and CEABC Report") which is attached as Appendix 1 of this submission. This report was separately filed by these parties and is an attachment and reference in this Submission for the convenience of the reader. It contains market based and modeling derived pricing data.

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[2] Under the heading: "the Use of a 70 Year Term for Site C in the Model and Comparative Evaluations"
[3] See Appendix 5

2. A FUNDAMENTAL ISSUE – GOVERNMENT SUBSIDIES AND BC HYDRO'S COST OF CAPITAL

When making financial comparisons between the Site C project and the competing alternatives, BC Hydro invokes at least two separate B.C. government ("Government") subsidies, neither of which is appropriate for a fair and "level playing field" comparative evaluation.

In the order they were invoked, these taxpayer subsidies are namely:

1. **A 2% differential in the cost of capital is utilized when evaluating the Site C project vs. the potential alternative projects, such as wind, solar or run-of-river.** This differential is supposedly rationalized on the basis that BC Hydro can borrow at the Government's low borrowing cost. Finance theory, however, completely rejects the use of such a subsidized rate in investment decision making. The risk of developing a long and complex project like Site C is actually much higher than developing the competing alternative projects but the cost of capital, which ought to reflect that higher risk, is actually lower.

   This subsidy was inherent in all of the financial evaluation material presented during the Joint Review Panel's review of the Site C Environmental Impact Statement ("JRP" or "JRP Review").

2. **Taxpayer equity provided at essentially no cost.** No-one contests that the Government has the right to subsidize whatever industrial, commercial, or residential activities it chooses. However, when subsidized rates are used to make investment decisions, these subsidies can cause both taxpayers and ratepayers to unknowingly assume risks for which they receive zero compensation. They will, consequently, make misguided and unwise investment decisions. Scarce capital will be inappropriately allocated.

   And that is exactly what is happening with respect to the Site C project. Taxpayers and ratepayers are being encouraged to make an unwise investment decision, without being fully informed of all the costs they are assuming. They do not comprehend that they are implicitly providing a premium-free insurance policy to the project. Although they won't receive any premium payments, they will, however, have to pay all the claims.

   A case in point which illustrates the potential extent of this insurance gamble is the situation evolving around the Muskrat Falls project in Labrador. In 2012, this project was promised as a long-term source of low cost power for the people of Newfoundland & Labrador. Today its cost escalations are threatening to double their electricity bills. Such is the nature of providing insurance coverage for a venture of unknown risks.[4]

[4] http://globalnews.ca/news/3551273/muskrat-falls-hydro-project-price-tag-rises-by-another-billion-ceo/

Although this "zero-return-on-equity"[5] subsidy stems from policies which were devised in November of 2013, well before the conclusion of the JRP Review, its impact was never revealed in any comparative financial evaluations until after the decision by the Government, in December of 2014, to move ahead with the Site C project.

This submission will deal with these two subsidies in the reverse order of their being invoked.

3. SUBSIDY #2

40% OF SITE C's CAPITAL IS GIVEN AS FREE EQUITY

New Government policy devised in November, 2013, essentially granted BC Hydro an increase in its taxpayer equity to 40%, and simultaneously ended the linkage between the amount of taxpayer investment and the returns paid to Government.

This Government policy, developed in conjunction with BC Hydro, is known as the 10 Year Rates Plan, and was released in November, 2013. This policy is intended to make life easier for electricity consumers at a time when BC Hydro needs to spend $2 billion a year for a period of approximately 20 years simply to refurbish its capital infrastructure. This was certainly a noble goal (at least from the point of view of BC Hydro ratepayers); however, the consequence is that every dollar saved by the ratepayers is a dollar foregone by the taxpayers. Every dollar of debt not incurred by the electric utility will be incurred instead by the Government.

The financial consequences for the Site C project are described in the following slide, taken from a presentation by a senior Government official to the CEABC[6] a month after the Site C project approval decision was made:

[5] This matter has been the subject of discussion between the CEABC's successor and the Government before. It resulted in Order in Council 028, January 17, 2008. See Appendix 2.
[6] January 26, 2015

The 10 Year Plan Reduces the Rate Impacts of Site C

2013 changes reduce government's 'take'

Item	Previous Policy	10 Yr. Rates Plan	Result
Net Income	Tied to in-service assets. (30% of in-service asset value X 11.8% return) As assets are added or improved, income and rates increase.	Tied to inflation starting in F2018. Investing in assets or adding new assets does not increase net income requirement.	Site C unit energy cost had included an annual return of ~12% ($280M cost in 2024). This is no longer required.
Dividend	BC Hydro pays out 85% of net income, subject to debt to equity cap of 80:20. BC Hydro borrows to pay dividend.	Dividend decreases as of F2018. Stays at $0 until BC Hydro reaches debt to equity ratio of 60:40.	BC Hydro retains more cash. Can be used to finance Site C, reduce borrowing requirements.
Water Rentals	BC Hydro pays Tier 3 rate.	Tier 3 gone in F2018.	$1/MWh reduced cost to Site C.

Slide 6

Prior to the 10 Year Rates Plan being adopted, the previous policy required BC Hydro to set its rates in order to earn an annual income (the amount which is consolidated into Government revenues) that was a percentage of the Government's investment in the crown utility (which investment was "deemed" to be 30% of a certain definition of BC Hydro's long-term capital assets).

To set an appropriate rate of return for this calculation, the BCUC holds periodic reviews to determine a rate that would be comparable to what a private investor would earn, on a pre-tax basis, from an investor owned utility similar to BC Hydro (usually Fortis Inc.). That rate was most recently set at 11.84%.

Accordingly, BC Hydro had made a provision in its Site C project financial projections for $280 million per year (being about 11.84% of 30% of $7.9 billion), described as *"return on equity"*. And this provision was included in all the financial analyses presented during the JRP Review (including all the Comparative Analyses), and right up until the Site C project approval decision was announced.[7]

Under this policy, this return on equity provision was no longer considered necessary (as stated in the top box in column 4 of the slide), since the equity return to Government was no longer tied to the amount of Government investment. Consequently, the $280 million provision was completely removed from the financial projections, and with a single stroke of the pen the levelized UEC dropped by $26/MWh (as described in the following slide):

[7] December 16,2014

The 10 Year Plan Reduces the Rate Impacts of Site C

Site C Cost to Ratepayers (before changes)	$83 / MWh
Net income no longer tied to asset base	**- $26 / MWh**
Reduction in water rental charges for BC Hydro.	**- $1 / MWh**
Updated Site C capital cost (from $7.9 billion to $8.335 billion)	**+ $2.25 / MWh**
Government reserve for higher than forecast inflation or interest rates	**+ $2.50 / MWh (if fully utilized)**
Updated Site C Cost to Ratepayers	**$58 - $61 / MWh**

Slide 7

With that large cost reduction dropping the UEC to $56/MWh, the Government then felt comfortable increasing the budget for the Site C project from $7.9 billion to $8.8 billion, which raised the UEC slightly to $61/MWh (as shown in the slide).

This massive change in the required rate of return on the taxpayers' equity in the project does not really alter the costs and benefits of the project for all British Columbians, it merely shifts some of the burden of paying for the project from the electricity ratepayers to the provincial taxpayers, and it should be entirely ignored for purposes of investment decision making.

The final slide from that Government official's presentation summarizes the overall impact of the zero-return-on-equity policy on the relative costs being ascribed to Site C project vs. the alternative IPP projects:

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*
Rates Plan UEC at Point of Interconnection	**$58-61/MW.h**	**$96/MW.h**	**$85/MW.h**
Sunk Costs	Subtracts $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)	Subtracts $2	Subtracts $2	Subtracts $2
EA, permitting, FN and community benefit costs	Included	Adds $5	Included
Cost of Capacity Backup	Not applicable	Adds $5	Adds $5
Unit Energy Cost Delivered to Lower Mainland:	**$64-67/MW.h**	**$130/MW.h**	**$110/MW.h**

Slide 8

Whereas the Site C project and the alternative projects had each come to be regarded as costing about the same amount, around $85/MWh, with the zero-return-on-equity policy the Site C project cost is reduced to $67/MWh while the IPP alternative projects are inflated to $110/MWh by means of "adjustment adders."

Such a blatant taxpayer subsidy, while it may be acceptable for political reasons, should never be permitted as part of any fair-minded financial or economic evaluation intended to make rational investment decisions regarding the Site C project as compared to the competing alternatives.

The Auditor General of B.C. has recently qualified its opinion about the accounts of the Province of B.C. because of political direction pertaining to BC Hydro' deferral accounts[8]. While not identical to the political direction given with respect to BC Hydro's return on equity and dividend policy it is a clear indication that political direction can't be completely divorced from established practice.

[8] http://www.bcauditor.com/sites/default/files/publications/reports/SFS%20Audit%20Opinion%202017.pdf,"Inappropriate use of rate regulated accounting."

The 10 Year Rate Plan is a fluid political concept and can be easily changed as evidenced by the following extract from BC Hydro's 2016/17 Annual Service Plan Report[9]:

"*Under a Special Directive from the Province, the Company is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year…The Special Directive states that for fiscal 2018 and subsequent years, the payment to the Province will be reduced by $100 million per year based on the payment in the immediate preceding fiscal year until it reaches zero and will thereafter remain at zero until BC Hydro achieves a 60:40 debt to equity ratio.*

In July 2016, the Province issued Order in Council 589, which amends the Special Directive and states that BC Hydro must make a Payment to the Province of an amount no less than $259 million by June 30, 2017, as it relates to fiscal 2017. The Company paid the $259 million minimum payment to the Province in March 2017. The Payment to the Province was less than 85% of the Company's net income. The Payment to the Province calculation as at March 31, 2017 determined that no further payment was required due to the debt to equity ratio cap."

This zero-return-on-equity policy, stemming from the 10 Year Rate Plan, is not suitable for making financial evaluations, whether as part of the Model or in any Comparative Analyses, and in this respect should be disregarded.

This zero expected return on the Site C project equity was confirmed by a senior BC Hydro official when they were questioned by CEABC during the BCUC review of BC Hydro's 2015 Rate Design Application[10]:

> **CROSS-EXAMINATION BY MR. AUSTIN (Continued):**
>
> MR. AUSTIN: Q: This is in relation to the $65 a megawatt hour as calculated using 100 percent debt. Is it true to say that when that calculation is done that the Government is not expecting any return on the risk as owner of BC Hydro that it takes with respect to Site C for a period of 70 years?
>
> MR. REIMANN: A: So the effective result is that Site C would be 100 percent debt finance, so from that perspective that would suggest that that's probably true. I think in overall it's a question of how much the Government has as a return on its investment into BC Hydro.
>
> MR. AUSTIN: Q: But for the purpose of Site C it's expecting a zero return on Site C for 70 years.
>
> MR. REIMANN: A: That's right. It would be 100 percent debt finance.
>
> MR. AUSTIN: Thank you.

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[9] Note 17: Capital Management, pages 71 and 72.
[10] Transcript, v4, page 676

Even though the "zero return on equity" policy was apparently adopted for the Site C project, in a subsequent hearing, a BC Hydro response to a CEABC Information Request ("IR") unequivocally confirmed that an entirely different approach is being used in BC Hydro's financial evaluations of all other projects. The 70/30 weighted average cost of capital ("WACC") approach (including an 11.84% return on equity), was still the method being used:

Clean Energy Association of B.C. Information Request No. **1.12.4** Dated: **October 19, 2016** British Columbia Hydro & Power Authority Response issued **November 21, 2016**	Page 1 of 2
British Columbia Hydro & Power Authority **Fiscal 2017 – Fiscal 2019 Revenue Requirements Application**	**Exhibit: B-10**

12.0 Reference: Exhibit B-1-1, Application, Appendix G, 10 Year Capital Forecast Update (July 2016)

On page 13 of Appendix G, BC Hydro discusses a "Prioritization Framework - Value Dimension":

"The framework considers the financial value of projects which is assessed by Net Present Value divided by the upfront capital investment."

1.12.4 What cost of capital is used in the Net Present Value calculation and how is it derived, based on the respective costs and proportions of debt and equity?

RESPONSE:

For the purposes of net present value (NPV) evaluations of projects, BC Hydro uses a real discount rate which represents the weighted average cost of capital (WACC) including debt and equity components.

In situations where a project's cashflows include inflation, a nominal discount rate is used in the net present value calculation.

The nominal discount rate of the Weighted Average Cost of Capital is based on:

- **A deemed capital structure of 70 per cent debt and 30 per cent equity established by Special Direction HC2;**
- **The average of BC Hydro's forecasted cost of incremental debt over the next five years as provided by the Treasury Board;**
- **Allowed return on equity which is based on the pre-tax return on equity of FortisBC Energy Inc.; and**

The result is then rounded to the nearest 25 basis points and only changed if the movement is greater than 50 basis points from the previous discount rate. The calculation for fiscal 2017 is:

WACC = (Return on Equity x Target Equity Ratio) + (Forecast Average Cost of Debt x Target Debt Ratio)

For fiscal 2017, WACC = (11.84% x 30%) + (4.75% x 70%), or (3.55% + 3.33%) = 6.88%. This is then rounded to 7.00%. Since the fiscal2017 WACC is not more than 50 basis points different from the F2016 WACC of 7.00%, the WACC remains at 7.00% for F2017.

Clean Energy Association of B.C. Information Request No. **1.12.4** Dated: **October 19, 2016** British Columbia Hydro & Power Authority Response issued **November 21, 2016**	Page 2 of 2
British Columbia Hydro & Power Authority **Fiscal 2017 – Fiscal 2019 Revenue Requirements Application**	**Exhibit: B-10**

The real Weighted Average Cost of Capital is based on an average forecasted inflation of 2 per cent (per the Treasury Board) and is calculated as:

Real WACC = (1 +Nominal WACC)/(1 + average forecasted inflation), or (1.07/1.02) = 1.0490, or 4.90% and rounded to 5.00%.

For the purposes of doing financial analyses for the Site C project economics there is an assumption of zero return on equity, while for everything else BC Hydro uses the 70/30 WACC methodology (including the 11.84% return on equity), which was used for all the analyses presented during the JRP Review.

None of the actual calculations or models used to determine the Site C project's alleged UEC has ever been publicly released, so that all the assumptions and methodology could be reviewed and tested. The BCUC's review of the Site C project must make these assumptions and calculations clear and transparent.

4. SUBSIDY #1

A 2% DIFFERENTIAL BETWEEN THE COST OF CAPITAL USED FOR SITE C vs. THAT USED FOR ALL OTHER ALTERNATIVES

BC Hydro maintains that the cost of capital used for the Site C project should be lower than that for any non-BC Hydro alternative project because BC Hydro can borrow at the Government's low rate of interest.

Finance theory and practice totally rejects the use of such differential discount rates, which depend on the party sponsoring the project rather than on the inherent risks in the project being financed.

In the CD Howe Commentary entitled *"The Valuation of Public Projects: Risks, Cost of Financing and Cost of Capital"* (included as Appendix 2 to this submission), Marcel Boyer (Emeritus Professor of Economics, Universite de Montreal), et al. stated *"Four mistakes are commonly made when evaluating public and private investments."*

And of these four mistakes, the first two listed were:

1. *Calculating the net present value (NPV) of a given project by using different discount rates, depending on whether the project is carried out by the public sector (lower rate) or by the private sector (higher rate).*
2. *Using a cost of capital for the business as a whole (e.g. the weighted average cost of capital, or WACC, corresponding to the cost of financing) in the assessment (usually the*

NPV) of all its investments rather than using a specific cost of capital for each project, properly assessed against the risk of that particular project.

In its Site C project financial analyses, Model and Comparative Analyses, BC Hydro is committing both of these common errors. Finance theory is telling us that the cost of capital should recognize the specific risks of the project being financed, not the general risks of lending to the Government.

The fact that the Government can borrow at a very low rate of interest is not in dispute. However, this low rate has nothing to do with the risks inherent in the project that is being financed, but is simply because a loan to the Government presents very little risk to the lenders; the Government has access to many other means to repay the loan besides just this one project – including raising both electricity rates and taxes if the project does not perform as predicted.

What is needed is a cost of capital that is appropriate for the risks entailed in the Site C project, rather than for financing the diverse portfolio of the Government as a whole, or even the diverse portfolio of BC Hydro. The most appropriate rate would be the rate required to finance the Site C project as a standalone non-recourse entity. It should be a project financing rate, not a corporate or Government financing rate. The full cost of capital should also include an appropriate thickness of equity, and an appropriate return on that equity.

Boyer et al. go on to explain why a government's borrowing rate will be very much less than a specific project's financing rate (page 4):

> *"…a government has the power to levy additional fees and taxes to compensate and repay lenders if its projects incur cost overruns and/or lower than expected benefits…through its taxing power, it implicitly subscribes loan insurance wherein all taxpayers act as the insurer."*
>
> *"For the taxpaying 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. It corresponds to the value of the financial option (or insurance policy) granted by taxpayers to the government to obtain from them additional funds to cover a project's possible non-profitability. The lower cost of funding is mainly due to the unaccounted implicit cost of this option or insurance policy held by a government. If the 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 governmental agency."*

That is to say that the differential in financing costs that BC Hydro is observing simply represents the cost of the risks being assumed (unknowingly and without compensation) by BC Hydro's ratepayers and BC's taxpayers.

A fair comparative evaluation of the Site C project vs. the alternatives requires that the cost of these assumed risks must be included in the investment evaluation. The ratepayers and

taxpayers must be able to see the total costs, including the cost of the risks they are implicitly assuming, in order to make a rational comparative evaluation. In short, they need to see an evaluation done at a risk-adjusted cost of capital.

The obvious proxy for such a risk-adjusted cost of capital is to set the Site C project's cost of capital equal to that used for the alternative projects. That supposedly is the rate that private developers would require in order to cover the risks inherent in their projects on a project financing basis.

In actual fact, the rate for the Site C project should probably be significantly higher than the rate for smaller and shorter term projects, because the risks associated with the Site C project are much greater than all but a few of the smaller development projects. This is primarily because Site C is a much larger project, with many more risky aspects, and must be developed over a much longer time frame, in an unknown terrain, where many more things can go wrong to disrupt both the schedule and the cost. It's also intended to survive over a much longer term, when even many more things can go wrong, not the least of which may be unpredictable climate change.

5. THE USE OF A 70 YEAR TERM FOR SITE C IN THE MODEL AND COMPARATIVE EVALUATIONS

The term being used for the Site C Model and Comparative Analysis is from 2024 to 2094 or from 2017 to 2094 as the amounts are being expressed in 2017 dollars. The logic is that the Site C project will be depreciated over a 70 year period which is an accounting concept and the Site C debt will be repaid over the same period. Taxpayer equity is never forecast to be repaid.

This results in the need to make forecasts over the same period the results of which are imputed, where applicable, into the Site C Model and the Comparative Analysis. Some of these required 77-year forecasts are:

1. Government's cost of debt as it borrows on behalf of BC Hydro. This includes forecasting this government's credit rating.

2. The operating and maintenance costs for Site C including major maintenance.

3. BC Hydro's revenue which at a minimum is going to be dependent on forecasts for BC Hydro's electricity prices and load forecast. There are multiple other forecasts that are inherent in the load forecast including the expected provincial economic growth.

4. Inflation.

5. Wind and solar equipment prices which are currently declining and are projected to continue to decline.

6. Currency.

7. Export electricity prices.

8. The Government's return on its investment in BC Hydro.

9. The outcome of BC Hydro's application for a new water licence for the Site C project. A forty year forecast

Forecasts of this type and for 77 years are wild speculation and have no practical value. The terms of the fully executed Government of Canada arm's length guarantee of some of the debt for the Muskrat Falls hydro-electric project in Newfoundland include an amortization period of 35 years, a debt to equity ratio of 65/35, return on 100% equity funding prior to construction and 35% equity during construction and a debt service ratio of 1.4[11].

One of the factors that the BCUC must consider when reviewing the Site C project is technological change and the very high potential that the Site C project will become a stranded asset. This stranding will not be because the demand for renewable electricity will disappear but because there will be cheaper customer self-generation options than the Site C project. It is BC Hydro's customers that will disappear. The technological risk is not exclusive to this project and is applicable to wind and solar projects. However the corresponding term of contract available from BC Hydro which to date has not exceeded 40 years, with large wind installations about 25 years, ameliorates this risk. Lower priced generation can replace higher priced generation at the end of the term of contract. There is no such flexibility with respect to the Site C project until 2094.

The old adage that large hydro projects are a wise investment despite their high upfront costs because it is less expensive to build them today than tomorrow because of inflation is only true if there are no other similarly priced renewable generation alternatives or if there are, they are more expensive to replace at the end of their life. This is not today's paradigm. There are alternatives such as wind and solar and even with inflation they are decreasing in price and are expected to continue to decrease in price for some time to come. In the case of wind they are already lower priced than the Site C project, including capacity backup. Battery storage is also expected to decline in price.

The Term should be 40 years which is the maximum term of any Government bond issue. The bond market is placing an upper bound on the accuracy of some of the same forecasts that are inherent in the Term of the Model and the Comparative Analysis.

A Term of 40 years is also the maximum allowable term for the existing water licence for the Site C project, not including the development term, under the Water Sustainability Act[12] (B.C.). It is presumptuous to assume that a new licence will contain the same terms and conditions as the existing licence. There could be major modification or the decision could be made to

[11] Appendix 6
[12] Section 19(3)

require the decommissioning of the project because of adverse impacts especially those relating to First Nations Treaty rights or resulting from climate change. There is nothing sacrosanct about a crown corporation owned large run of river hydro project.

6. CanWEA and CEABC Report

Power Advisory LLC (Power Advisory) was engaged by the Canadian Wind Energy Association (CanWEA) and CEABC to provide an independent assessment of the cost of various renewable generation projects and the relative benefits of these projects compared to the Site C project.

The analysis focuses on four renewable and clean energy technologies that are likely to be the most cost-effective: onshore wind; solar PV; hydroelectric generation; and battery storage. Power Advisory developed a financial pro-forma model to estimate prices that would be required for renewable energy technologies to achieve a target rate of return based on assumptions regarding the cost of constructing and operating these technologies in BC.

a) Wind Pricing

Installed costs of wind projects have been declining and their capacity factors increasing as a result of technological improvements. Data from across Canada and the US shows a steady decline in unit energy cost of wind projects down to about CAD$65 to $73/MWh for 2016, depending on the region. Reflecting future changes in project costs yields a real levelized price of about CAD$68/MWh for BC. Onshore wind costs are forecast to continue to decline through 2050 and a recent study indicates that the median estimate of the reduction from 2014 to 2020 is 10%. Bloomberg New Energy Finance forecasts a 47% decline in the cost of electricity from onshore wind.

b) Solar Pricing

There have been dramatic decreases in the costs of solar energy. Costs for utility scale projects have declined by 68% from Q4 2009 to Q1 2016, with further reductions experienced in 2016. Continued cost reductions are anticipated going forward. GTM Research expects a 27 percent drop in average global project prices by 2022.

c) Hydroelectric Generation Pricing

Hydroelectric project capital and operating costs are project specific and reflect the project configuration required to most cost-effectively develop the underlying resource.

d) Battery Storage Technology

Batteries are particularly well-suited for grid integration of wind and solar technologies, primarily because of the ramping, load following and frequency control functions they provide. More importantly, battery storage technology can also serve as incremental load and therefore

assist with managing surpluses much more effectively than storage hydro. The cost of battery technology has fallen 50% since 2014 – a direct result of growing demand and competition. With predictions of an annual decline of 11.4% through 2020, battery storage will play an important role in providing variable generation like wind and solar with increased dependable capacity.

e) Alternative Technology Benefits

These benefits include: (1) smaller, targeted resource additions that avoid the risks and costs associated with large resource additions such as Site C; (2) lower development, construction, and operating risks; (3) tax payments to federal, provincial, and municipal governments; and (4) the opportunity to earn revenues from the sale of renewable energy credits.

f) Incremental Resource Additions

Site C would provide 1,100 MW of capacity and produce about 5.1 TWh per year of energy in an average water year. Adding such a large volume of energy to the system relative to forecast net load growth would result in a large surplus of energy which would likely be sold at Mid-Columbia (Mid-C) for about $26/MWh in 2024 and beyond. This price, when compared to the cost of Site C power represents a significant cost to BC ratepayers.

g) Comparative Risk Assessment

Independent Power Producers (IPP) are responsible for managing project development, construction, financing and operating risks for IPP projects, with little to no risk to ratepayers. Such projects have a very different risk profile than a utility project, which is built under the cost-of-service regulation model. Under cost-of-service regulation, the costs incurred by the utility generally flow through to ratepayers. Cost overruns must be borne by ratepayers and/or taxpayers, and the larger the project, the larger the risk. This is readily apparent from large hydroelectric projects such as Muskrat Falls in Labrador (72% cost overrun) and Keeyask in Manitoba (35% cost overrun), both with schedule delays.

h) IPP Tax Payments

IPPs make major contributions to the federal, provincial and municipal budgets. These financial contributions should be weighed when considering such investment and the value that these projects provide BC. The taxes include corporate and personal income taxes, property taxes, and other taxes such as water rentals or royalties paid to the provincial government. Based on analysis prepared for CEBC, Power Advisory estimates that the annual tax revenues produced by operating clean energy projects represent approximately $244 million per year, as compared to Site C that will not return one dollar on equity until 2094.

i) REC Eligibility and Pricing

Another potential source of value offered by clean energy projects developed by IPPs is the sale of renewable energy credits or certificates (RECs) associated with the production of this renewable energy. This is a source of incremental revenue that is available to the various renewable energy resources evaluated in this report, but which wouldn't be available to Site C.

California's Renewable Portfolio Standard is based on three distinct Portfolio Content Categories or bundles. Portfolio Content Category 1 is the highest value REC market in the West and one in which Powerex participates presumably by reselling renewable energy that is under contract to BC Hydro. Category 1 RECs were recently priced at US$14.

j) Integration Cost

Power Advisory studied wind integration costs across many jurisdictions and they are generally estimated to be below $6/MWh and can be as low as $0.50 to $2/MWh even at wind capacity penetration levels beyond 40%, with solar integration costs being lower. This review of variable output renewable energy integration costs indicates that BC Hydro's estimates are considerably higher than most estimates.

k) Capacity and Diversity of Renewables

Wind, solar and many hydroelectric projects are variable output renewable energy resources that generate electricity when the underlying renewable energy resource is available. The capacity value of these resources can be enhanced through the diversity of such resources. This diversity can include different wind projects in different wind regimes as well as the diversity offered by combining the output of wind, solar PV, and run-of-river hydroelectric projects. This diversity benefit has been demonstrated in numerous studies including the Pan-Canadian Wind Integration Study which found, among things, that distributed solar can complement wind and that the combination of wind and hydro provides a firm energy resource for use within Canada or as an opportunity to increase exports to U.S. This diversity enhances the capacity value of these resources as well as reduces the requirements for operating reserves to balance the variability of these resources. The net effect is to increase the value offered by these resources as well as to reduce the costs associated with integrating these resources.

7. FINANCIAL EVALUATIONS USED TO COMPARE SITE C TO THE ALTERNATIVES

For planning purposes, BC Hydro uses at least 3 different methods of financial/economic evaluation in attempting to evaluate how the widely varying characteristics of different generation and capacity resources will impact the overall BCH system. These three forms are distinctly different but they share similar components.

8. EVALUATION METHOD #1

Comparison of Plant Gate Prices

Individual Project Unit Energy and Unit Capacity Costs (UEC and UCC)

The first and most familiar form is the simple $/MWh value known as the UEC or the Unit Capacity Cost ("UCC"), which is a single $/MWh (or $/kW-yr in the case of capacity projects) which is generally attached to individual projects but may be calculated for groups of projects as well. This is a proxy number intended to allow widely differing projects to be to be ranked on the same scale of cost per MWh. It does create that ranking, generally speaking, but it is oversimplified. It can introduce a number of distortions into the comparison of projects, if all the underlying assumptions are not fully recognized when making project comparisons.

The following example is taken from BC Hydro's **2013 Resource Options Database** (Database page 203 of 520)**:**

RESOURCE OPTIONS DATABASE **2013 Resource Options Report Update Appendix 3**

Project: Wind_PC13

Resource Category: Onshore Wind Region: Peace River

Project Description

Potential onshore wind site identified in the 2009 BC Hydro Wind Data Studies.

Technical Information

Installed Capacity (MW)	135
Average Annual Energy (GWh/year)	541
Effective Load Carrying Capability (MW)	35.1
Annual Firm Energy (GWh/year)	541

Financial Information (in Fiscal $ 2013)

Direct Capital Cost ($1000s)*	$397,988
Fixed Operating & Maintenance Cost ($1000s/year)	$8,421.0
Variable Operating & Maintenance Cost ($/MWh)	$0.0
Fixed Taxes ($1000s)	$556
Variable Taxes ($1000s)	$0
Unit Energy Cost at Point of Interconnection ($/MWh)	$92
Project Life (Years)	20
Project Lead Time (Years)	5

* Direct Capital Cost excludes Interest During Construction (IDC) and Corporate Overhead (CO)

The general intent of the UCC is to calculate a "real" price per MWh. This can also be referred to as the "Plant Gate Price". It is a price that will remain constant in real terms, but will escalate at inflation in nominal terms, over the project life.

The shorthand way used by BC Hydro to calculate this value is referred to as the "annualized cost method". This method simply converts the initial capital cost to a level annuity payment at the real cost of capital. (In this example $397,988,000 converts to a 20-year annuity at 8%, of $40,535,000, which is $75/MWh.) Then annual operating and maintenance costs, taxes, etc. (in real dollar amounts) are divided by the Average Annual Energy (in MWh) and added to the capital annuity value to obtain an overall unit cost for the energy. (In this example, these amount to $17/MWh, which brings the total cost to $92/MWh)

Although this simplified UEC is very easy to use and implement when there are a large number of different projects to be evaluated, it contains some highly oversimplified assumptions that can lead to some greatly distorted comparisons.

For instance, the following is the similar summary for the Site C project, taken from the same 2013 Resource Options Database:

RESOURCE OPTIONS DATABASE **2013 Resource Options Report Update Appendix 3**

Project: Site C Clean Energy Project

Resource Category: Large Hydro Region: Peace River

Project Description

The Peace River Site C Clean Energy Project is a potential third dam and hydroelectric generating station on the Peace River in northeast BC.

Information based on Site C Environmental Impact Statement (EIS) submission filed in January 2013.

Technical Information

Monthly average is dependent on GMS operating decisions.

Installed Capacity (MW)	1100
Average Annual Energy (GWh/year)	5100
Dependable Capacity (MW)	1100
Annual Firm Energy (GWh/year)	4700

FINANCIAL INFORMATION (in Fiscal $ 2013)

Capital costs will change upon completion of the updated capital cost estimate based on the optimized project design. The capital costs shown here are based on Scenario G from the Stage 1 report (based on the historical design).

Direct Capital Cost ($1000s) *	$5,775,000
Fixed Operating And Maintenance Cost ($1000s/year)	$7,800
Sustaining Capital ($1000s/year)	$10,600
Variable Operating And Maintenance Cost ($1000s/year)	$0
Fixed Taxes and Grants-in-Lieu ($1000s)	$0
Variable Taxes ($1000s)	$0
Unit Energy Cost ($/MWh) **	$83
Project Life (Years)	70
Project Lead Time (Years)	10

* Direct Capital Cost excludes inflation, interest during construction (IDC), and Corporate Overhead (CO). The total Site C capital cost including these costs is $7.9 billion.
** The provided UEC is updated from $95/MWh used previously based on a change in discount rate from 6% to 5%.

This summary appears to calculate the UEC for the Site C project as $83/MWh. However, that value does not seem to compute, using the assumed 6% real cost of capital over 70 years, with either the $5,775,000,000 capital cost shown in the table, or the $7.9 billion stated in the

footnote. It is not clear what capital amount was used in the calculation, and BC Hydro appears to have also deducted some amount for a capacity credit. However, nothing is stated to explain the result.

Nothing is stated to explain why certain costs have been dropped completely from the Site C project description in the Resource Options Database. For instance, the following is the Site C project description from the previous version of the Resource Options Database:

2012 Integrated Resource Plan
Appendix 3A-4
2010 Resource Options Report - Appendix 3

RESOURCE OPTIONS DATABASE

Project: Site C Clean Energy Project

Resource Category: Large Hydro Region: Peace River

Project Description

The Peace River Site C Clean Energy Project is a potential third dam and hydroelectric generating station on the Peace River in northeast BC.

The information summarized below is based on the May 2011, Site C Clean Energy Project, Project Description Report.

Technical Information

Monthly average is dependent on GMS operating decisions.

Installed Capacity (MW)	1100
Average Annual Energy (GWh/year)	5100
Dependable Capacity (MW)	1100
Annual Firm Energy (GWh/year)	4700

FINANCIAL INFORMATION (in Fiscal 2011$)

Capital costs will change upon completion of the updated capital cost estimate based on the optimized project design. The capital costs shown here are based on Scenario G from the Stage 1 report (based on the historical design).

Direct Capital Cost ($1000s) *	$5,560,000
Fixed Operating And Maintenance Cost ($1000s/year)	$7,500
Sustaining Capital ($1000s/year)	$9,281
Variable Operating And Maintenance Cost ($1000s/year)	$40,215
Fixed Taxes and Grants-in-Lieu ($1000s)	$2,500
Variable Taxes ($1000s)	$0
Unit Energy Cost ($/MWh)	$95
Project Life (Years)	70
Project Lead Time (Years) **	10

* Direct Capital Cost excludes inflation, interest during construction (IDC), and Corporate Overhead (CO). The total Site C capital cost including these costs is $7.9 billion.

** The project in-service date is dependent on the regulatory process. As a result, the project lead time may change as this process is defined.

It should be noted that this edition of the Resource Options Database showed a very similar Direct Capital Cost (even though it is supposedly 2011$ vs. 2013$, which should make a 4% difference), and it contains the same $7.9 billion footnote, but it contains roughly $43,000,000 more in annual costs, that do not appear in the 2013 Update. Why have these costs vanished in the 2013 Update? How does the project now operate for free? What is the explanation?

The BCUC's review of the Site C project must make all of these assumptions and calculations clear and transparent. Without such transparency a proper financial evaluation of the project and the alternatives will be impossible.

At this point, it is also worth noting two of the most obvious abnormalities present in the above calculated Site C UEC value, when this project is being compared to another project that is quite

different in its assumptions, such as the wind project "PC-13", which was shown in the first extract from the database:

Abnormality #1 – The use of two different implicit costs of capital.

In this analysis, BC Hydro uses a 5% real cost of capital for the Site C project, but a 7% cost of capital for all the alternative projects. It insists this is because it can borrow at the Government's low rate of interest. However, as discussed under the heading: "A Fundamental Issue – Government Subsidies and BC Hydro's cost of Capital", this is a completely inappropriate assumption.

The cost of capital assumed for each project should depend on the risks inherent in the project, not on the fact that the Government has a lot of recourse to other funds if the project fails to perform financially.

The Government's low cost of borrowing reflects only that the lenders have a low risk when lending to the Government. The fact is that the ratepayers and taxpayers are assuming a lot of uncompensated risks by allowing this project to share such a low rate. The true cost of capital for the project could only be found if the financing for it was to be non-recourse to the taxpayers, and even to the ratepayers – that is to say, the project would have to finance itself, as a standalone, at a guaranteed price to the ratepayers (i.e. no recourse if the project goes over budget or fails to deliver the requisite amount of annual energy).

Abnormality #2 – The fact that these two projects have greatly differing project life-spans. The calculation of comparative UECs does not prohibit projects from having different life-spans. In fact, one of the virtues of using UECs for comparing projects is that it allows projects of differing life-spans to be compared on the same scale. However, in comparing a 20 year project to a 70 year project, there is an implicit assumption that the 20 year project can be extended to 70 years at the same real cost per MWh**.**

That is to say, at the end of the first 20 years, the 20-year project will be completely rebuilt at the exact same capital cost in real dollars, and with the identical annual costs in real dollars, and therefore the UEC will remain the same in real dollars for the next 20 years, and so on.

For the example being used, this introduces an enormous distortion. In fact, for such a wind project, probably close to 50% of the total initial capital will never need to be re-spent to keep the project going for another 20 years. All of the development costs, the roads and site preparation, and even the turbine towers, will probably last well beyond 20 years. It is really only the mechanical and electrical elements that will wear out and need replacement in 20 years – and if current trends persist, the costs of those items are declining rapidly, while turbine efficiencies are improving. Meanwhile the project is being forced to amortize its entire investment over the first 20 years, which forces up its apparent unit cost, making the comparison with the 70 year project completely invalid.

Still, these abnormalities go largely unmentioned in any media coverage and so, unfortunately, this $/MWh calculation remains by far the most prominent measure in the public's mind -- no doubt because of its simplicity, and because it is a metric that is easily compared to household rates, or to the supposed *"market prices."*

9. EVALUATION Sub-METHOD #1A

Extending UECs beyond the plant gate Adjustment Adders to the Unit Energy Cost – The basic project UECs (the Plant Gate prices), calculated in Method #1 above, are then augmented to become Adjusted UECs, by means of adjustment "adders" intended to be proxies for certain other costs or benefits which may be incurred by the BC Hydro system.

The following table taken from the 2013 Resource Options Update,[13] illustrates some of the adjustment adders being used by BC Hydro, which augment the apparent energy costs, particularly for 3rd party power projects.

2013 Resource Options Report Update Appendix 12

Resource Option	Project Name	Transmission Region[7]	Average Annual Energy (GWh)	UEC at POI ($/MWh)	Soft Cost Adder ($/MWh)	Firm Energy Adjusters[8] ($/MWh)	CIFT ($/MWh)	Line Losses ($/MWh)	GHG Cost ($/MWh)	Capacity Credit ($/MWh)	Wind Integration Cost ($/MWh)	Adjusted Firm UEC ($/MWh)
				1	2	3	4	5	6	7	8	∑1 to 8
Run-of-River Hydro	ROR_110-120_VI	VI	386	113	6	52	0	-1	0	0	0	169
Run-of-River Hydro	ROR_100-110_KN	KL	217	101	5	64	0	4	0	0	0	174
Run-of-River Hydro	ROR_110-120_NC	NC	135	115	6	54	1	8	0	0	0	183
Run-of-River Hydro	ROR_120-130_VI	VI	116	125	6	54	0	-1	0	0	0	185
Run-of-River Hydro	ROR_120-140_NC	NC	90	125	6	49	1	9	0	0	0	190
Run-of-River Hydro	ROR_120-130_LM	LM	649	125	6	64	0	0	0	0	0	195
Site C	Site C	PR	5,100	83	0	0	6	9	0	-11	0	88
Wind - Offshore	OBC24-1	VI	1892	166	8	-2	0	-1	0	0	10	182
Wind - Offshore	OBC25-1	VI	1347	167	8	-2	0	-1	0	0	10	183
Wind - Offshore	OBC28	VI	1442	181	9	-2	0	-1	0	0	10	196
Wind - Onshore	PC28	PR	591	90	5	-2	2	11	0	0	10	115
Wind - Onshore	PC21	PR	371	92	5	-2	2	11	0	0	10	117
Wind - Onshore	PC13	PR	541	92	5	-2	2	11	0	0	10	117

The first of the two highlighted entries in the table is Site C, where the "UEC at POI" is adjusted from $83 to $88 through a series of adders and credits. The 2nd highlighted entry is the previously cited wind project "PC13", where the UEC at POI is adjusted from $92 to $117.

[13] Appendix 12 of the 2013 Resource Options Update, page 9 of 15

It should be noted that the adjustment adders shown in this table do not necessarily represent real and certain out-of-pocket costs or revenues to BC Hydro ratepayers. Rather, they are hypothetical provisions for costs or savings which could be incurred, but might actually be avoided, depending on how the system is operated.

For instance, the $11/MWh "Capacity Credit" being awarded to Site C project implies that, somewhere in the BC Hydro system, a revenue or a savings will be earned that amounts to $56 million per year for 70 years. Where will such a revenue come from? That amount of capacity can't be sold to the neighboring jurisdictions because there isn't enough capacity in the transmission system to deliver it. Besides that, the time of year when such a capacity would be valuable to sell, is the wintertime, when we need to retain it to cover BC Hydro system loads.

The $11 Capacity Credit is not predicated on the potential to sell that capacity. Rather, it is based on the assumption that BC Hydro will earn a savings by postponing another capacity project, such as Revelstoke 6. If so, that postponement may earn a saving of $56 million (the annualized carrying cost for the Revelstoke investment) for 2 to 5 years, but not for 70 years. So the $11 apparent cost reduction for Site C is more of an illusion than a real saving to the ratepayers.

Similarly, the $10 *"Wind Integration"* charge imposed on the PC13 project, is another hypothetical proxy charge intended to compensate in case BC Hydro might actually lose the opportunity to sell this amount of capacity in the day-ahead market. However, the charge is much higher than other jurisdictions have estimated, and there has been no evidence presented that such a sales opportunity would actually be jeopardized, or for how much of the year it might be lost given the transmission constraints in the inter-jurisdictional system.

For a further discussion of each of these adjustment adders and credits see Appendix 4 in this Submission, entitled "*Deep into the Details*."

For now, it is sufficient to understand that the right hand column of figures, entitled *"Adjusted Firm UEC"* contains the values that will be input to the next method of evaluation, namely, the Block Analysis.

10. EVALUATION METHOD #2

Evaluating portfolios of projects together Block Analysis -- the 2nd form of evaluation methodology assembles portfolios of projects, and attempts to calculate the total combined UEC, for comparison to other portfolios that are selected to exactly match the same energy and capacity production.

The example below is taken from the Site C Evidentiary Update, Sept 13, 2013.[14] ("Evidentiary Update") It illustrates one of the selected portfolios of projects that can produce the same annual energy and the same capacity as the Site C project.

BC hydro
FOR GENERATIONS

Evidentiary Update
September 13, 2013

Table 15 Details and UEC Calculations for Clean + Thermal Generation Block #1 (Revelstoke Unit 6 and 6 SCGTs)

Clean + Thermal Generation (No GMS, 6 SCGTs)				
Project Name	Dependable Capacity (MW)	Annual Firm/Effective Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	Total Cost ($1000)
Energy Costs				
MSW2_LM	25	211	90	19
Wind_PC28		591	121	71
Wind_PC21		371	123	46
Wind_PC13		541	123	67
MSW1_VI	12	101	123	13
Wind_PC19		441	124	55
Wind_PC16		377	126	48
Wind_PC14		527	127	67
Wind_PC15		382	130	50
Wind_PC20		609	131	80
REV6 Variable Costs (see note 1)	n/a	26	12	0
SCGT Variable Costs (see note 2)	n/a	924	66	61
Weighted Average excluding capacity resources	n/a	n/a	**124**	n/a
Weighted Average including capacity resources	n/a	n/a	**113**	n/a
Sub-total	36	5101	n/a	575
Capacity Costs	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Unit Capacity Cost ($F2013/kW-year)	Total Cost ($F2013M)
REV6 Fixed Costs	488	n/a	50	24
SCGT Fixed Costs	588	n/a	88	52
Sub-total	1076	n/a	71	76
	Dependable Capacity (MW)	Annual Firm Energy (GWh)	Adjusted Unit Energy Cost ($F2013/MWh)	Total Cost ($F2013M)
Total	1112	5101	**128**	651

Note:
1. REV6 variable cost include variable OMA and water rentals.
2. SCGT variable costs include variable OMA, fuel cost and GHG cost.
3. UECs include a soft cost adder of 5%, wind integration cost where applicable, adjustment for time of delivery a regional transmission cost adder of $6/MWh, and the cost of delivery to the lower mainland.

Block Analysis starts with the individual project UECs and UCCs, multiplies them by each project's annual energy or capacity to get a total annual cost, sums those costs and divides the

[14] http://www.acee-ceaa.gc.ca/050/documents/p63919/94428E.pdf

total by the total annual energy. The result is a total portfolio adjusted UEC ("Adjusted UEC") that includes the annualized cost of the needed capacity resources.

Unfortunately, this process is still not transparent, because it appears that other cost factors have been inserted in between the steps. For instance, the project "Wind PC13", that we have seen in the earlier tables, now shows up with an Adjusted UEC of $123. However, in the previous table it was only $117. What appears to have happened is that a further charge has been levied against it, of $6 for regional Network Transmission Upgrades. If so, this again is a hypothetical provision, that may or may not represent any real cost to the Hydro system, or to ratepayers. But nonetheless, it appears as if it were part of the project's total cost.

Block Analysis is intended to give an indicative total portfolio UEC for comparison to other portfolios (or, in this case, to the Site C project). However, it is inherently flawed in that it fails to give any consideration to the need or the timing of the various energy and capacity projects, and any necessary transmission upgrades. It still relies on the "adder" adjustments that have been affixed to the individual projects. i.e. It still incorporates the inaccuracies imbedded in the underlying project Adjusted UECs.

It is a simplified proxy, used because it is easy to calculate, but it lacks the sophistication and thoroughness of the 3rd form of evaluation.

11. EVALUATION METHOD #3

An Optimization Approach
Portfolio Analysis using a Linear Optimization Model

The third method of cost evaluation is considered by BC Hydro to be the most sophisticated, and is relied on as the best indication of long term ratepayer savings. To quote BC Hydro, from the Site C Evidentiary Update:

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Evidentiary Update
September 13, 2013

3.3.2 Portfolio Modelling using System Optimizer

This analysis evaluates the cost competitiveness of the Project by comparing the present value cost of portfolios with and without the Project using the System Optimizer. As described in Section 5.5.3.2 of the EIS as amended, System Optimizer is a model that selects a resource expansion sequence (i.e. the order in which new projects are built) that minimizes the present value (PV) of net system costs.

The analysis using System Optimizer is a more sophisticated approach than the Block Analysis and provides additional information not captured by the block analysis, including:

- Timing of resource additions including transmission additions or upgrades and associated capital and operating expenditures;
- Effects of resource additions to the overall system and the system load resource balance over the planning horizon;
- Economic dispatch reflecting the manner in which dispatchable resources will be operated;
- Electricity market trade benefits that vary with the flexibility of the overall portfolio.

Two key advantages of portfolio modelling, including modelling the expected operation, are: (1) it captures most of the economical dispatch value (for dispatchable resources such as the Project, natural gas-fired generation) which provides value to BC Hydro's customers and is a point of differentiation of the Project from intermittent clean or renewable resources such as wind and run-of-river; and (2) the 'lumpiness' of resources by modeling timing of resources and the net cost of energy imbalances by comparing acquisition costs to value in the electricity markets. As a result of this additional detail the resources selected by System Optimizer and the resulting annual energy surplus or deficit will differ depending on the portfolio – i.e. projects that do not include the Project will not produce the same annual surplus / deficit as portfolios with the Project.

It is clear that BC Hydro feels that this is the best of the three methods for evaluating future project investment choices, at least with respect to their economic outcomes. At least this optimization methodology avoids some of the dangerous oversimplifications of the other two methods. For instance, it selects transmission upgrades and capacity additions as needed by the system, rather than attempting to assign them to specific generation projects. However, even this most costly and sophisticated method still relies on a lot of the same root information taken from the individual project estimates in the Resource Options Database. It will, therefore, carry forward any of the same fundamental flaws that are imbedded in that data.

In this method, a complex (and proprietary) optimization *"black box"* is given the inventory of all project options, with all of their underlying energy, capacity, capital and operating cost estimates. It is also given the constraints of the energy and capacity demand forecasts. Then, in order to meet the forecast energy and capacity needs, the model systematically chooses which projects will be added in which years, with the objective of minimizing the 30-year present value of the total portfolio costs. Also, rather than attempting to add transmission upgrade costs and capacity addition costs onto individual projects, the model simply schedules capacity and transmission projects as they are needed. It can also use the forecast spot market

to fill any minor gaps or dispose of any surplus energy. In short, it creates an optimal balanced plan going forward, with generation, capacity, and transmission projects bound together with market sales and purchases so as to minimize the overall present value of all the costs, both capital and operating.

Different constraints or limitations can be placed on the portfolio selection (such as with the Site C project or without, with or without gas-fired, etc.). And the input data assumptions can also be adjusted to produce sensitivity analyses. For instance, the Load Forecast can be adjusted to produce a wider gap or a smaller gap in the forecast load vs. resource balance ("LRB"). The implicit cost of capital for the alternative projects can be adjusted. The capital cost of the Site C project can be varied, as can the $10/MWh *"integration"* charge being added to every wind project.

The results of the Base Case optimization, plus a few of the sensitivities, are shown in the following table.[15] The values in this table show the differences between the total present values of a portfolio which includes the Site C project vs. one that uses alternative projects to replace that energy and capacity. Capacity additions and transmission upgrades are selected by the optimization model as required to balance the total system over time, rather than being assigned to specific projects as if they were part of the cost of those projects.

Table 24 – Benefit of the Project: Sensitivity Analysis Summary

Difference in PV Cost (Portfolio without Site C minus with Site C) ($F2013 million)	Clean Generation Portfolios		Clean + Thermal Generation Portfolios	
	F2024	F2026	F2024	F2026
Base Case (Mid Gap, Mid-Market Price [Scenario 1], WACC Differential = 2%, Wind Integration Cost = $10/MWh	630	880	150	390
Large Gap	Note 1	Note 1	2,260	Note 1
Small Gap	(1,040)	(705)	(1,280)	(907)
WACC Differential = 1%	420	672	20	233
High Market Price (Scenario 3)	830	1,028	470	656
Low Market Price (Scenario 2)	450	755	(90)	217
Project Capital Cost +10%	360	650	(120)	170
Wind Integration Cost ($15/MWh)	720	Note 1	222	Note 1
Wind Integration Cost ($5/MWh)	530	Note 1	92	Note 1

A positive value in the table indicates that the Site C portfolio had a lower cost than the alternative portfolio. For instance, in the Base Case scenario, the Site C portfolio, with the expected in-service date of 2024, has a lower cost than the alternative "Clean + Thermal Generation Portfolio" by $150 million.

[15] Evidentiary Update, page 48

This is a complex table, and it is probably very confusing to the reader. However, if carefully examined the initial fog will clear.

1. Of the two alternative portfolios, the "Clean + Thermal" portfolio is clearly the superior alternative in every scenario. i.e. It shows the lowest present value deficits to the Site C portfolio. So the reader should ignore the first two columns. The "Clean + Thermal" columns tell you all you need to know.

2. Of the two in-service dates for Site C (2024 or 2026), the later date is superior for Site C in every scenario. i.e. Delaying Site C's in-service date has a $200 to $250 million advantage in every case. This is only logical, because the earlier the in-service date, the larger is the surplus of energy that must be sold off at cheap market prices. That was the situation when these numbers were calculated in 2013, but the situation has gotten much worse since then. The load forecast is now significantly lower, and the Site C project surplus situation will be much greater. Therefore, a delay should be even more advantageous. (Clearly, the modeling results need to be updated with a more current Load Forecast, one which shows the now much reduced Load-Resource gap.)

3. While the Base Case savings of $150 million sounds like a substantial benefit to ratepayers, when viewed in context this amount of savings is miniscule. It is less than 2% of the total present value of either of the two portfolios being differenced. i.e. The model is calculating the difference between two very large numbers. These portfolios each have present values of around $7 to $8 billion, and the difference between the two of them is only $150 million. The inaccuracy within the cost estimates themselves is far greater than this difference, being no less than +/- 20%.

4. While a ratepayer saving of $150 million is not to be dismissed lightly, it should also be noted that this amount of savings only results because the first $300 million of project expenditures was considered a "sunk cost" at the time of this analysis, and therefore not included in the present value calculations. i.e. The Site C project could only achieve its estimated $150 million net benefit precisely because BC Hydro had already spent the first $300 million, so that amount didn't count in the analysis.

   The Site C project is now at the point where $2 billion may have already been spent, so now, presumably, that entire amount will not be counted. This amounts to justifying the project with the circular argument, *"We're entitled to do the project because we've already started doing it."*

5. In the line in the table entitled *"Project Capital Cost + 10%"* it shows what would happen if the Site C project costs escalated above the $7.9 billion used in the modeling. The result is that the $150 million advantage turns into a $120 million deficit. i.e. the Clean + Thermal alternative portfolio is superior by $120 million (for the F2024 in-service date) – a total swing in present value of $270 million. The project has already had its cost estimates increased from $7.9 billion to $8.8 billion, an increase of over 11%.

6. The two lines "Large Gap" and "Small Gap" depict what happens to the financial analysis if the future demand vs. supply gap (the LRB gap, or Load-Resource Balance) is larger or smaller than the original forecast. Today, BC Hydro has become even more pessimistic about its future load forecast, so the "Small Gap" scenario is now the more likely outcome. The original $150 million advantage to the Site C project alternative would become a $1,280 million deficit. i.e. It becomes a $1,280 million advantage for the "Clean + Thermal" alternative portfolio – a present value swing of $1,430 million.

7. Along with lower future demand, and a smaller LRB gap, it would also be logical to have lower future market prices for the surplus electricity. Table 24 tells us that, if "Low Market Price" occurs, then the $150 million advantage for Site C project would become a $90 million deficit. i.e. Another swing in present value of $240 million, to the advantage of the alternative portfolio.

8. The line "WACC Differential = 1%" shows that if the 2% penalty imposed on the implicit cost of capital used for the alternative projects were reduced to only a 1% penalty, then the advantage to the Site C project would be reduced from $150 million to only $20 million. This is a swing of $130 million for a 1% change. In fact, the two costs of capital should be made equal, not biased by 2% in favour of the Site C project. This equality of WACCs would presumably cause a swing in present value of $260 million in favour of the "Clean + Thermal" alternative portfolio.

9. Note that these are BC Hydro's own original calculations, but that every one of the sensitivity scenarios depicted in this Table 24, has now occurred, each one with an adverse effect on the originally supposed economic advantage of the Site C project.

   For example, the project cost has already been increased by more than 10%. The forecast future load has reduced, so that a "Small Gap" is now the likely scenario. Low market prices go along with a smaller demand-supply gap. The Wind Integration Cost should be reduced to $5/MWh instead of $10. And, finally, notwithstanding the Government's low borrowing cost, the implicit cost of capital (the WACC) used for the alternative projects should properly be no worse than equal to that used for the Site C project, not biased by being 2% higher.

   But what will be the total expected impact of all these updated values on the economics? To summarize, Table 24 is telling us the following:

	PV Difference of Two Portfolios ($ millions)
Initial PV advantage to Site C	150
PV Swing due to:	
Project Capital Cost up 11%	(270)
Small Load-Resource Gap	(1,430)
Low Market Price	(240)
Wind Integration Cost $5	(60)
WACC Differential to 0%	(260)
Total PV Swing	**(2,260)**
PV Advantage to Clean + Thermal Alternative	**2,110**

This sensitivity analysis shows us that, if all of these changes to the Base Case assumptions do truly come to pass, then the economic advantage will have shifted away from the Site C Portfolio to the Clean + Thermal Portfolio by over $2.2 billion.

This means that BC Hydro's own sensitivity analysis is telling us that, **even if the amount of the Sunk Costs has now risen from $300 million (used in the original modeling) to $2 billion (as is now alleged, an addition of $1.7 billion), the swing in the PV advantage in favour of the alternative portfolio is still likely to be greater than that by $500 million.**

Clearly, the numbers need to be re-evaluated in light of the changed circumstances and the BCUC Review must do this.

A suspension of the Site C project in order to do a thorough job of re-evaluation would carry a minimal risk of financial harm.

12. CONCLUSIONS

The BCUC should approach the tasks that have been set for it under the Terms of Reference as a sophisticated potential purchaser would approach purchasing a partially completed development. It is not disrespectful to the seller if the purchaser asks the questions that need to be asked when it conducts its due diligence. It is also not disrespectful if the purchaser independently confirms the accuracy of the information being provided by the seller. It is the norm, not the exception.

As the reclamation costs of the Site C Project are now a matter for consideration by the BCUC they should also be the subject of due diligence and confirmation.

Continuing this analogy the central question that the Government has asked the BCUC to provide it with advice on is: "Given the semi-developed state of the Site C project, can it continue to be developed so that it makes money or at the very least doesn't lose money as compared to the competitive alternatives?" It is a simple commercial question that will require a good deal of effort and analysis to provide the requested advice. There is also the option of letting it sit until there is more certainty.

The CEABC's Submission consists of two parts:

1. Part 1 which is essentially a list of due diligence questions pertaining to the Site C Model including all the data and assumptions and all the calculations.

2. Part 2 contains some of the suggested steps for completing the due diligence of the Comparative Analyses. In some cases the line between the due diligence for the Model and the Comparative Analyses is blurred because some of the matters to be considered are common to both. In other cases, the CEABC doesn't know whether a matter has been addressed in the Model or the Comparative Analyses because it doesn't have access to the necessary material. In some cases there is access to publicly available information that provides assistance in performing due diligence and the CEABC has provided it and made comments about it.

Some of the key points in this Submission are:

1. An examination of how the optimization model indicates that the financial difference between the Site C project and a portfolio of alternative projects was almost negligible at the beginning of the JRP Review, and that changing circumstances such as the increase in the cost of the Site C project and the reduction in BC Hydro's load forecast since then have moved the financial advantages significantly in the direction of the alternative projects. The advantage in favour of the alternative projects is now so large that even if $2 billion on the Site C project has now been spent the alternative portfolio will be cheaper.

2. The identification of the fundamental issue of Government subsidies imbedded within BC Hydro's cost of capital, which will significantly interfere with any attempt to perform a "level playing field" comparative evaluation of the financial consequences of the Site C project as compared to the competing alternatives. The effect of these subsidies must be removed by this BCUC review in order to produce a fair and impartial comparative evaluation.
3. A supporting commentary by the CD Howe Institute explaining the finance theory and practice that rejects the use of such subsidies in making investment decisions.
4. A detailed examination of the three financial evaluation methodologies used by BC Hydro in its attempts to characterize the costs and values of the Site C project vs. the alternative projects. Many of the inadequacies and inherent biases within the methodologies and underlying assumptions are highlighted.
5. The CEABC is in agreement with BC Hydro that only the third methodology, the use of an optimization model, shows real promise in getting close to an accurate comparative analysis. Even this method is constrained by inaccuracies and oversimplifications within the basic level of resource data and assumptions.
6. A detailed commentary has also been provided on the inappropriateness and even impossibility of trying to evaluate any project over a 77 year time frame; and also on the high likelihood that the value being attributed to the energy and capacity of the Site C project is too high.

The CEABC and the Canadian Wind Energy Association have made a joint submission prepared by Power Advisory LLC that provides additional information in particular about the price of alternative renewable generation and the cost of integrating renewable generation with the BC Hydro system.

All of which is respectfully submitted.

Appendix 1

INDEPENDENT ASSESSMENT OF RENEWABLE GENERATION COSTS AND THE RELATIVE BENEFITS OF THESE PROJECTS COMPARED TO SITE C

Prepared for the Clean Energy Association of BC and the Canadian Wind Energy Association

August 30, 2017

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Executive Summary

Power Advisory LLC (Power Advisory) was engaged by the Canadian Wind Energy Association (CanWEA) and Clean Energy Association of British Columbia (CEBC) to provide an independent assessment of the cost of various renewable generation projects and the relative benefits of these projects compared to Site C.

The analysis focuses on four renewable and clean energy technologies that are likely to be the most cost-effective: onshore wind; solar PV; hydroelectric generation; and battery storage. Power Advisory developed a financial pro-forma model to estimate prices that would be required for renewable energy technologies to achieve a target rate of return based on assumptions regarding the cost of constructing and operating these technologies in BC.

Wind Pricing

Installed costs of wind projects have been declining and their capacity factors increasing as a result of technological improvements. Data from across Canada and the US shows a steady decline in unit energy cost of wind projects down to about CAD$65 to $73/MWh for 2016, depending on the region. Reflecting future changes in project costs yields a real levelized price of about CAD$68/MWh for BC. Onshore wind costs are forecast to continue to decline through 2050 and a recent study indicates that the median estimate of the reduction from 2014 to 2020 is 10%. Bloomberg New Energy Finance forecasts a 47% decline in the cost of electricity from onshore wind.

Solar Pricing

There have been dramatic decreases in the costs of solar energy. Costs for utility scale projects have declined by 68% from Q4 2009 to Q1 2016, with further reductions experienced in 2016. Continued cost reductions are anticipated going forward. GTM Research expects a 27 percent drop in average global project prices by 2022.

Hydroelectric Generation Pricing

Hydroelectric project capital and operating costs are project specific and reflect the project configuration required to most cost-effectively develop the underlying resource.

Battery Storage Technology

Batteries are particularly well-suited for grid integration of wind and solar technologies, primarily because of the ramping, load following and frequency control functions they provide. More importantly, battery storage technology can also serve as incremental load and therefore assist with managing surpluses much more effectively than storage hydro. The cost of battery technology has fallen 50% since 2014 – a direct result of growing demand and competition. With predictions of an annual decline of 11.4% through 2020, battery storage will play an important role in providing variable generation like wind and solar with increased dependable capacity.

Alternative Technology Benefits

These benefits include: (1) smaller, targeted resource additions that avoid the risks and costs associated with large resource additions such as Site C; (2) lower development, construction, and operating risks; (3) tax payments to federal, provincial, and municipal governments; and (4) the opportunity to earn revenues from the sale of renewable energy credits.

Incremental Resource Additions

Site C would provide 1,100 MW of capacity and produce about 5.1 TWh per year of energy in an average water year. Adding such a large volume of energy to the system relative to forecast net load growth would result in a large surplus of energy which would likely be sold at Mid-Columbia (Mid-C) for about $26/MWh

in 2024 and beyond. This price, when compared to the cost of Site C power represents a significant cost to BC ratepayers.

Comparative Risk Assessment

Independent Power Producers (IPP) are responsible for managing project development, construction, financing and operating risks for IPP projects, with little to no risk to ratepayers. Such projects have a very different risk profile than a utility project, which is built under the cost-of-service regulation model. Under cost-of-service regulation, the costs incurred by the utility generally flow through to ratepayers. Cost overruns must be borne by ratepayers and/or taxpayers, and the larger the project, the larger the risk. This is readily apparent from large hydroelectric projects such as Muskrat Falls in Labrador (72% cost overrun) and Keeyask in Manitoba (35% cost overrun), both with schedule delays.

IPP Tax Payments

IPPs make major contributions to the federal, provincial and municipal budgets. These financial contributions should be weighed when considering such investment and the value that these projects provide BC. The taxes include corporate and personal income taxes, property taxes, and other taxes such as water rentals or royalties paid to the provincial government. Based on analysis prepared for CEBC, Power Advisory estimates that the annual tax revenues produced by operating clean energy projects represent approximately $244 million per year, as compared to Site C that will not return one dollar on equity until 2094.

REC Eligibility and Pricing

Another potential source of value offered by clean energy projects developed by IPPs is the sale of renewable energy credits or certificates (RECs) associated with the production of this renewable energy. This is a source of incremental revenue that is available to the various renewable energy resources evaluated in this report, but which wouldn't be available to Site C.

California's Renewable Portfolio Standard is based on three distinct Portfolio Content Categories or bundles. Portfolio Content Category 1 is the highest value REC market in the West and one in which Powerex participates presumably by reselling renewable energy that is under contract to BC Hydro. Category 1 RECs were recently priced at US$14.

Integration Cost

Power Advisory studied wind integration costs across many jurisdictions and they are generally estimated to be below $6/MWh and can be as low as $0.50 to $2/MWh even at wind capacity penetration levels beyond 40%, with solar integration costs being lower. This review of variable output renewable energy integration costs indicates that BC Hydro's estimates are considerably higher than most estimates.

Capacity and Diversity of Renewables

Wind, solar and many hydroelectric projects are variable output renewable energy resources that generate electricity when the underlying renewable energy resource is available. The capacity value of these resources can be enhanced through the diversity of such resources. This diversity can include different wind projects in different wind regimes as well as the diversity offered by combining the output of wind, solar PV, and run-of-river hydroelectric projects. This diversity benefit has been demonstrated in numerous studies including the Pan-Canadian Wind Integration Study which found, among things, that distributed solar can complement wind and that the combination of wind and hydro provides a firm energy resource for use within Canada or as an opportunity to increase exports to U.S. This diversity enhances the capacity value of these resources as well as reduces the requirements for operating reserves to balance the variability of these resources. The net effect is to increase the value offered by these resources as well as to reduce the costs associated with integrating these resources.

1. Introduction

On August 2, 2017 the BC government instructed the British Columbia Utilities Commission (BCUC) to conduct a review of Site C based on the requirements set out in the government's Terms of Reference.[1] The Terms of Reference directed the BCUC to answer a series of questions including "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?"

Power Advisory LLC (Power Advisory) was engaged by the Canadian Wind Energy Association (CanWEA) and Clean Energy Association of British Columbia (CEBC) to provide an independent assessment of the cost of these commercially feasible generating projects and the relative benefits of these projects compared to Site C.

1.1 Review of Power Advisory's Relevant Experience

In late 2016, Power Advisory was engaged by BC Hydro, in conjunction with CEBC, to provide an independent assessment of the appropriate price for BC Hydro's Standing Offer Program (SOP), which is open to renewable and qualifying clean energy projects that are 15 MW and smaller. For this project, Power Advisory conducted a comprehensive review of the costs of developing qualifying SOP projects in BC. This analysis recognized the additional costs and foregone economies of scale that smaller generation projects experience.

Power Advisory is regularly engaged to develop independent or critically assess renewable generation project cost estimates. We advised the Ontario Power Authority with respect to the initial prices for its feed-in tariff program, which procured the full range of renewable energy technologies. From 2009 to 2013, we advised the Vermont Public Service Board with respect to the appropriate prices for its standard offer program for various renewable energy technologies and testified as an independent expert of behalf of the Vermont Public Service Board with respect to appropriate standard offer prices for the full range of qualifying renewable energy technologies. In addition, we advised the Alberta Department of Energy with respect to appropriate assumptions and cost estimates for a wide range of alternative energy technologies, including all of the generation technologies that we assess in this report.

With respect to how variable output renewable energy technologies fit within the existing electricity infrastructure, Power Advisory was recently engaged by Natural Resources Canada to draft a white paper regarding variable output renewable energy resources, changes to the electricity supply mix and the implications for the need for the essential reliability services identified by the North America Electric Reliability Corporation (NERC).[2] In 2013, Power Advisory drafted a report for Natural Resources Canada on the role of storage hydroelectric resources in facilitating the integration of variable output renewable energy resources.

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[1] Province of British Columbia, Order of the Lieutenant Governor in Council, Order in Council No. 244, August 2, 2017.

[2] NERC has identified as essential reliability services as the operational attributes of conventional generation to provide reactive power to maintain system voltages, physical inertia to maintain system frequency, and load following to balance demand and supply in real time.

2. Levelized Unit Energy Costs

Power Advisory employed a financial pro forma model to estimate prices that would be required for the renewable energy technologies evaluated to achieve a target rate of return based on assumptions regarding the cost of constructing and operating these technologies in BC. This is the same financial pro forma model that we used for BC Hydro to estimate an appropriate range of prices for SOP projects. For the SOP pricing analysis, prices were escalated at 50% of CPI over the assumed contract term, consistent with the current provisions in the SOP contract. To approximate the Levelized Unit Energy Costs (LUECs) calculated by BC Hydro, for this analysis we assumed that the price would escalate at an assumed inflation rate of 2% such that the price derived is a real levelized price (i.e., the price is constant in real terms). In addition, project cost and performance assumptions were updated to reflect current technology cost data and modified to reflect the fact that the renewable energy projects could be larger than the 15 MW project size limit that applied to SOP projects and as a result are able to achieve lower capital and operating costs.

To ensure that our analysis is transparent and assist the BCUC in reviewing our assumptions and hopefully provide a basis for the use of this information in their assessment, we devote considerable effort to reviewing the assumptions that we have employed and the basis for any adjustments to the underlying referenced data sources.[3] Furthermore, we have sought to use reliable and credible sources to ensure that the assumptions employed are reasonable and the prices derived are an accurate reflection of the prices required to develop, construct, and operate these renewable generating technologies.

The capital, operating and maintenance costs, operating performance and financial assumptions for these technologies are reviewed below. Projects are assumed to have a long-term power purchase agreement (PPA) with BC Hydro. This PPA presumably would be able to support project financing as under the financial assumptions reviewed below. The target rate of return was determined to be an 10% after-tax return on equity (ROE). We used an 11% after-tax ROE to estimate appropriate prices for BC Hydro's SOP. The SOP has a number of distinct differences that warrant a higher after-tax ROE for SOP projects. First of all, the projects are relatively small and as such require a higher return to attract capital. In addition, with any PPAs for larger wind projects to be awarded through a competitive process we expect that the competitive discipline will induce IPPs to accept a lower ROE in an effort to be successful. In Power Advisory's professional judgment it represents a reasonable return assumption for such projects.

A 26% corporate tax rate was assumed and reflected in the pro forma analysis.[4] A 5.5% cost of debt, 20-year debt term and a debt/equity ratio that provides an average 1.5 debt service coverage ratio over the term were also assumed.[5] We used an 18-year debt term for the SOP pricing analysis. Various developers indicated that with a 25-year PPA, they have been able to secure longer debt terms and that a 20-year debt term was a reasonable assumption if a 25-year PPA was available.[6,7] Given the useful life of the technologies, a 25-year

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[3] Attached as Appendix A is a copy of our financial pro forma model specified for a wind project in BC using the assumptions outlined in this report.

[4] Power Advisory has not reviewed the methodology that BC Hydro used to develop its LUEC for Site C. We understand that the models used to calculate these LUECs have not been made available. We note that to the degree that the Site C LUEC doesn't consider tax payments or payments in lieu of taxes, then the LUECs that we developed overstate the relative cost of the IPP clean energy generation projects relative to Site C.

[5] The 1.5 debt-service coverage ratio was a target. We'd expect that debt repayments would be sculpted to reflect project cash flows, whereas we calculated a constant debt and interest payment over the term of the loan.

[6] For wind projects this will also likely require that wind turbine manufacturers secure type certificates with at least an equivalent design life.

[7] The reasonableness of a 20-year debt term and 5.5% cost of debt for such projects was confirmed by Travelers Capital Corporation and Corpfinance International Limited. SaskPower and Hydro-Quebec commonly offer PPAs with 25-year terms for wind projects.

amortization period was assumed for wind and solar projects. Technology specific assumptions are reviewed in the following sections.

Our analysis focuses on four renewable and clean energy technologies that are likely to be the most cost-effective: (1) onshore wind; (2) solar PV; (3) hydroelectric generation; and (4) battery storage. Recognizing that BC Hydro has relied on requests for proposals (RFPs) that create competitive tension between proponents and promote the selection of the lowest cost generating resources, the project assumptions that we employ reflect "efficient projects" that are able to offer the lowest prices. This will result in the development of the most attractive sites, which offer the most favorable renewable resources or minimize the cost of developing these resources.

2.1 Wind Pricing

To provide context regarding the cost of wind generation, we first review announced prices for various PPAs that have been awarded. The two most recent competitive solicitations for wind generation for which pricing data is publicly available were in Ontario and Quebec. Ontario's Large Renewable Procurement 1 had a proposal submission date of September 1, 2015. Contracts were offered to four proponents offering five projects, with contract pricing ranging from $64.5 to $105.50/MWh. The broad range of pricing reflects the impact of: (1) transmission constraints that limited development of more cost-effective locations; and (2) non-price evaluation considerations that were weighed when awarding contracts and allowed proposals with higher prices to be evaluated more favorably to the degree that they performed better than other proposals with respect to these non-price considerations.[8] In December 2014, Hydro-Quebec awarded three contracts for 446 MW. Hydro-Quebec reported the average price was $76/MWh, including $13/MWh for transmission costs.[9] Competitive bidding processes are underway in both Alberta for 400 MW and Saskatchewan for 200 MW, but proposals have not been submitted.

Another point of reference is wind power purchase agreement (PPA) pricing reported in the US Department of Energy's (DOE's) *2016 Wind Technologies Market Report*. Figure 1 summarizes these PPA prices and breaks them out by region. Rising PPA prices from 2003 to 2009 follow a trend of increasing costs for wind turbines, with decreasing costs thereafter reflecting declining turbine prices and installed costs and increased project capacity factors. When evaluating US PPA pricing one needs to consider that these projects benefit from a federal production tax credit (PTC), which is currently 2.4 cents/kWh (or $24/MWh), for the first ten years of commercial operation.[10] The US DOE estimates that this has an effective value of at least 1.5 cents/kWh (or $15/MWh).[11] Therefore, the price for the Western Region of about $40/MWh in 2016, would be about $55/MWh without the PTC. Converting this to CAD$ using the average exchange rate for 2016, yields a PPA price of about CAD$73/MWh for 2016.[12,13]

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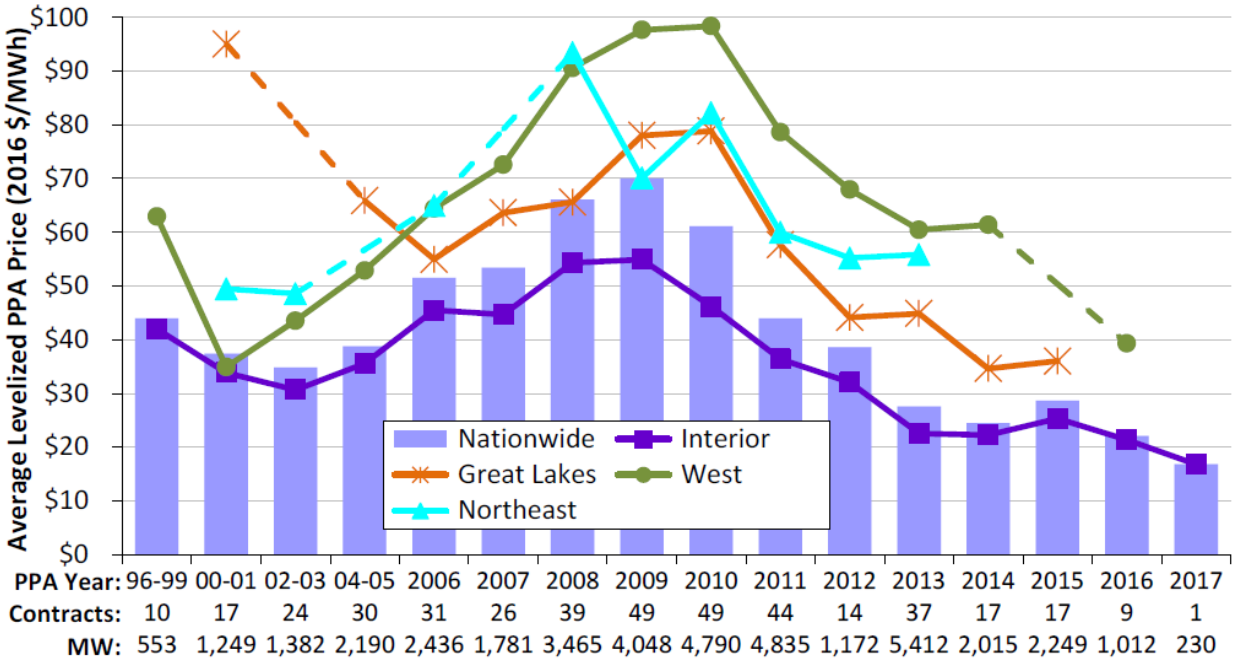
[8] These non-price considerations included evidence of community support and aboriginal participation.
[9] Power Advisory notes that bidders have reported that transmission costs were liberally interpreted and in some instances included the costs of collection facilities.
[10] The PTC increased from 2.3 cents/kWh ($23/MWh) to 2.4 cents/kWh ($24/MWh) in 2017.
[11] The PTC's estimated impact on PPA pricing is less than its value because the credit is realized over a ten-year period, whereas many PPAs are for 20 years. In addition, project developers are typically unable to utilize the PTC and require parties that have a "tax credit appetite" to participate in the project financing, with developers realizing an effective value for the PTC that is somewhat less than its "face value."
[12] Based on an annual average exchange rate of US$.7551 to CAD$1.00.
[13] Care needs to be taken when comparing these PPA costs with the real levelized price that we calculate. Wind project PPA prices generally don't escalate or escalate at a specified percent of inflation, such that these reported PPA prices would be higher than would be required for a PPA price that escalates with inflation.

Figure 1: Levelized PPA Prices by Execution Date and Region



Source: Berkley Lab, Energy Information Administration

2.1.1 Recent Pricing Trends and Projections

Historical US wind project installed costs (2016$/kW) are presented in Figure 2.[14] The installed costs for onshore wind in the US declined by 33% from 2010 to 2016.[15] From a Canadian perspective to a large degree these cost declines have been offset by the depreciation of the Canadian dollar relative to the U.S. dollar, which over the same six-year period has increased from an annual average of around $1.05 to $1.32 CAD to $1.00 US. Nonetheless, declines in the LUECs in CAD$ have been realized by increases in project capacity factors from higher hub heights and larger rotor diameters per capacity rating.[16]

These declines in LUECs are supported by the increases in capacity factors that have been realized recently and these declines are meaningful.[17] The US DOE notes that in 2016 the average capacity factor among projects built in 2014 and 2015 was 42.6% compared to 32.1% among all projects built from 2004 to 2011.[18] Recognizing that the most favourable wind regimes are typically developed first this increase in project capacity factors for 2014 and 2015 vintage projects is significant and clear evidence of the improvements in wind turbine technology and the resulting reductions in LUECs for wind.

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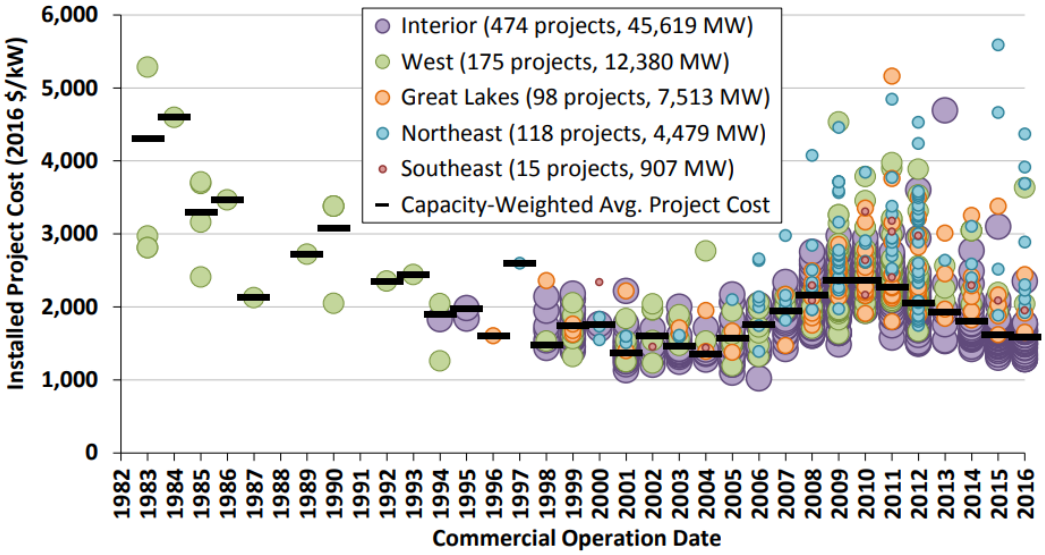
[14] Reported project costs reflect turbine purchase and installation, balance of plant, and any substation and/or interconnection expenses.
[15] *2016 Wind Technologies Market Report*, p. 49.
[16] The energy output of a turbine is roughly proportional to the swept area of the rotors. Similarly, all other things being equal, the energy yield is roughly proportional to the square root of the hub height due to higher wind speeds at greater heights.
[17] To the degree that wind project fixed costs are stable, increases in capacity factors will result in lower LUECs.
[18] *2016 Wind Technologies Market Report*, p. 39.

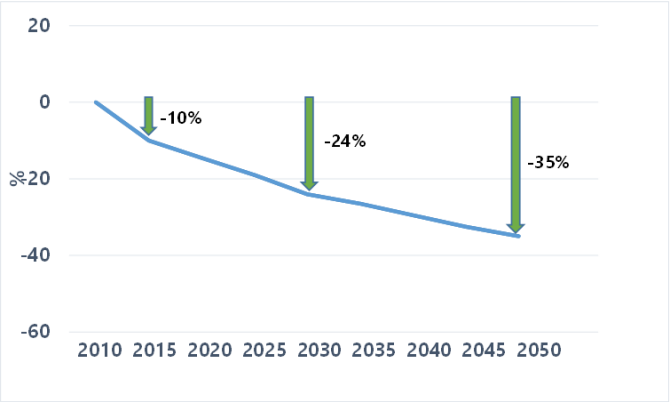
Figure 1: Wind Project Installed Costs Over Time (US$)



Source: US DOE, 2016 Wind Technologies Market Report

Onshore wind LUECs are forecast to continue to decline through 2050. Figure 3 is from a recent study that summarized LUEC projections based on expert opinion. It indicates that the median estimate of the LUEC reduction from 2014 to 2020 is 10%, and 35% by 2050. These estimates also consider cost reductions from higher capacity factors (e.g., higher tower heights, larger rotor diameters) as wind turbine technology improves. Similar cost reductions are forecast by Bloomberg New Energy Finance who forecasts a 47% decline in the levelized cost of electricity from onshore wind and the International Renewable Energy Agency (IRENA) who indicates that onshore wind farm costs could be 12% lower by 2020 than they are in 2011 and 23% lower by 2040.[19,20] The cost reductions estimated by IRENA are just for installed costs and don't reflect additional cost reductions attributable to enhanced project performance from higher capacity factors and lower operating and maintenance costs.

Figure 2 : Reduction in LUECs for Onshore Wind



Source: Nature, Energy Expert Elicitation Survey on Future Wind Energy Costs, September 2016.

[19] New Energy Outlook 2017, p. 2.
[20] Renewable Energy Technologies: Cost Analysis Series, Volume 1: Power Sector Issue 5/5, Wind Power, June 2012.

2.1.2 Projected Wind Costs

The starting point for our wind pricing estimate was the analysis of SOP pricing in which we estimated a range of required prices for a 15 MW wind project participating in BC Hydro's SOP. For this analysis, we relied upon a BC Hydro commissioned study performed by Hatch in early 2015 to estimate wind project costs for the Resource Options Update conducted as part of the Integrated Resource Plan. Hatch developed estimates for a range of sites across BC for project sizes ranging from 48 MW to 195 MW. We used the capital cost estimate for a 117 MW project in the Southern Interior as the starting point for our analysis.[21] At a cost of CAD$2,248/kW, these capital costs tied to the capital cost derived from the US Department of Energy's (DOE's) *2015 Wind Technologies Market Report*.[22] The alignment between these two installed cost estimates supports our use of the *Wind Technologies Market Report* to present more recent information regarding the installed costs of wind projects in BC.

We updated the cost estimate to reflect changes in wind project costs reported by the US DOE and changes in foreign exchange rates that are likely to affect wind project costs in BC given that wind turbine costs are more likely to be dominated in US$ or Euros. The *2016 Wind Technologies Market Report* indicated a weighted average installed cost of $1,590/kW (US$), reflecting a 5.9% decline relative to the installed costs reported in the 2015 report.[23] US DOE indicates that "early indications from a limited sample of twenty projects (3.0 GW) currently under construction and anticipating completion in 2017 suggest that capacity-weighted installed costs in 2017 will be similar to those in 2016."[24] Compounding the decline in installed costs with the escalation in CAD$ relative to the 2015 average exchange rate (and recognizing that the exchange rate is only likely to result in lower turbine and associated equipment costs) results in a 6.9% decline in the capital cost of wind projects, resulting in capital costs in CAD$ of about $2,328/kW for 2016-2017. Based on the US DOE indications that installed costs in 2016 appear to be similar to 2017, we assume that the CAD$2,328/kW installed cost is appropriate for 2017.

There is the potential for additional cost reductions from larger projects given economies of scale. Based on information presented by Hatch on wind project installed costs in BC,[25] we estimate that a 200 MW project offers an installed cost about 10% lower than a 100 MW wind project. There is a trend of larger wind project sizes to realize such economies of scale. For example, among the proposals recently selected by Emera Inc. as part of a recent request for proposals for renewable energy delivered to New Brunswick were proposals for a 402 MW and four 150 MW wind projects.

We scale this capital cost up by 2.5% to reflect interest during construction. To put these wind costs on a consistent basis with Site C, assumptions are required with respect to costs for the 2024 period. We note that the expert elicitation survey referenced above indicated a 10% reduction in LUEC's from 2014 to 2020, with continued reductions anticipated beyond that. To reflect that this capital cost was a 2017$ estimate, this cost

[21] These capital costs were increased to reflect foregone economies of scale.
[22] The reported weighted average installed cost for 2015 in US$ was $1,690/kW. The cost for installed cost for wind projects in the West Region was about $2,000/kW. Recognizing that this is an installed cost and doesn't reflect owners' costs of about 8% and that a portion of this cost (i.e., the 60% associated with wind turbines and associated equipment) must be converted to CAD$, the adjusted cost was estimated to be $2,520/kW. The average US$ to CAD$ exchange rate for 2015 was $.783 to $1.00. The CAD$ has subsequently strengthened and on August 22, 2017 was at US$.796 to CAD$1.00. Foreign exchange futures markets reflect a future strengthening of the CAD$ relative to the US$.
[23] Interestingly, the 2015 report indicated that "Early indications from a preliminary sample of projects currently under construction and anticipating completion in 2016 suggest no material change in installed costs in 2016." (p. ix)
[24] *2016 Wind Technologies Market Report*, p. 49.
[25] Hatch, Figure 1: CapEx Trend with Project Size

was then escalated by 2% per annum to reflect costs in 2024, with a 5% real cost reduction to reflect the cost reductions (approximately 50% of the 10% forecast) anticipated by industry experts.[26]

Another critical cost component are project fixed operations and maintenance (O&M) costs. For a 102 MW wind project, Hatch estimated these to range from $68 to $79/kW-year. These costs are considerably higher than those identified by the US Energy Information Administration (EIA) in its *Assumptions to the Annual Energy Outlook*, which were US$46.71/kW-year or about CAD$58.39/kW-year at the current exchange rate. [27] Alternatively, the US DOE's Wind Technologies Market Report indicates fixed O&M costs for recently installed projects of about US$30/kW-year. See Figure 4. For a project in Ontario that would be able to take advantage of a better developed wind industry service sector, we estimated fixed O&M costs of CAD$43.20/kW-year.[28,29] This fixed O&M cost estimate was based on current technology, which has more reliable component design, manufacturing and predictive maintenance software to allow for lower fixed O&M costs than earlier wind turbine models.

Power Advisory understands that O&M costs in BC are likely to be higher given the more remote locations of projects and the reduced ability to capitalize on economies of scale associated with the provision of these services given the smaller size of BC's wind sector.[30] However, we believe that the magnitude of the difference between the Hatch estimate and the figures reported for the US when converted to CAD$ calls into question the Hatch estimate. We used Hatch's fixed O&M estimate for the SOP pricing analysis because it was viewed as reasonable for a smaller 15 MW SOP project. However, we believe that it is high for a 200 MW wind project. Considering the EIA and US DOE data, but recognizing that fixed O&M costs in BC are likely to be higher given the remoteness of sites, we apply a 15% discount to the Hatch fixed O&M cost estimates and then adjust these to account for the reductions in fixed O&M for a 200 MW project.[31]

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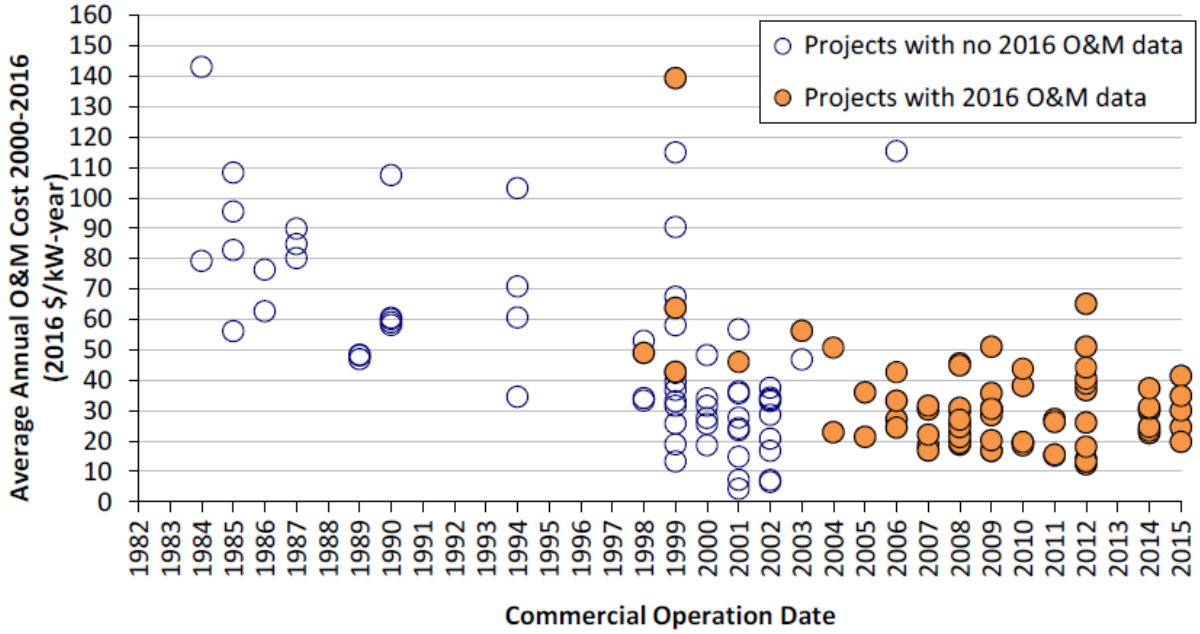
[26] In an effort to be conservative we only consider 50% of the anticipated cost decline.
[27] An exchange rate of US$.80 to CAD$1.00.
[28] Ontario currently has 4,781 MW of installed wind capacity almost ten times that of BC, which has 489 MW.
[29] This fixed O&M cost was anticipated to increase by about 13% in real terms in year 12 or 13 and then to remain constant in real terms of the remainder of the project's life.
[30] Power Advisory believes that the fixed O&M cost premium that Hatch appears to have reflected for BC is likely to be reduced as the wind industry in BC develops and additional wind projects are developed in Alberta and Saskatchewan, which will provide better access to various specialized O&M services for BC projects.
[31] This economies of scale adjustment was also derived from the Hatch analysis. Hatch presented fixed O&M estimates for a 102 MW and a 195 MW project on the North Coast. Power Advisory used the ratio of these two fixed O&M estimates to reflect the economies of scale offered by a 200 MW project. Economies of scale for the provision of O&M services are likely to be more significant in BC where there is a less well-developed wind industry support infrastructure than Ontario.

Figure 4: Average Annual O&M Costs from 2000 to 2016 by COD



Source: US DOE

In addition, to the fixed O&M costs estimated by Hatch we included the cost of land leases or royalties at $1.4/MWh.[32] With respect to project output, we assumed a 40% capacity factor, which reflects increases in output realized from higher tower heights and greater rotor diameters relative to project capacity ratings. BC developers indicated that they were able to achieve a 40% capacity for SOP projects,[33] which suggests that higher capacity factors could be realized for larger projects that can support longer transmission lead lines to access more favourable wind regimes. Assuming a 25-year amortization period and contract term, these assumptions yield a real levelized price of $68/MWh.[34] Recent estimates of the levelized cost of energy from IPP projects for direct comparison to Site C were $85/MWh. This reduction in costs likely reflects lower project installed costs and increased project capacity factors. The major assumptions and projected real levelized price are presented in Table 1. The capital (before consideration of interest during construction) and fixed O&M costs are costs in 2017CAD$ before escalation to 2024.

Table 1: Wind Project Levelized Costs 2024

Capital Cost $/kW	Fixed O&M $/kW- Year	Capacity Factor %	Amortization Years	Real Levelized Price $/MWh
$ 2,095	$ 56.31	40%	25	$68

Source: Power Advisory analysis

To put a wind project costs on a consistent basis as Site C, cost estimates are required for a replacement wind project given the longer useful life of a comparable hydroelectric project. Estimating wind project costs in

[32] We assumed a royalty payment of $1.00/MWh for the SOP pricing review.
[33] Furthermore, a number of BC wind project developers indicated that a 40% capacity factor was reasonable for BC with the application of new wind turbines and higher tower heights.
[34] Project developers typically reflect 25-year amortization periods in their project pricing and some wind turbine manufacturers are able to secure type certificates with a 30-year design lifetime. This assists developers in securing financing for projects that are based on such amortization periods.

2049 (25-year useful life) or 2054 (assuming a 30-year useful life) is difficult. As above various industry experts are predicting a 35% reduction in costs by 2050 (See Figure 3). Alternatively, Bloomberg New Energy Finance forecasts a 47% reduction by 2040. To be conservative (i.e., understate potential cost reductions) we use the lower cost reduction estimate of 35%.

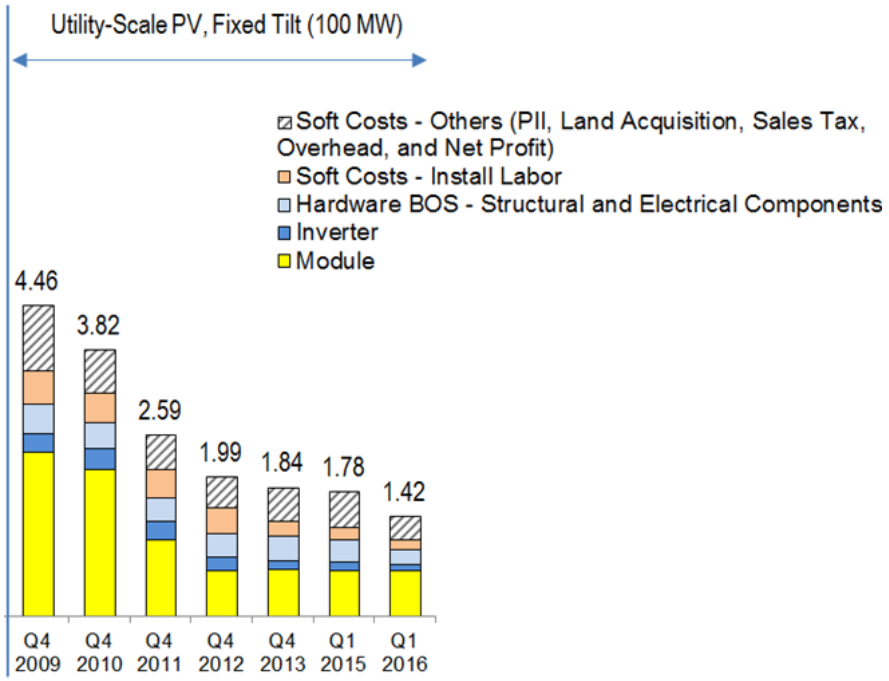
In addition, to these cost reductions such a project would be able to realize economies associated with the existing site including transmission substation, interconnection, some cabling, access roads, and various support facilities. This is likely to represent savings of 10 to 15% to project installed costs. Combining these cost reductions and savings, but recognizing that we have already assumed a 5% cost reduction in our 2024 estimate results in cost reductions of from 40 to 45%. Inflation at 2% per annum for 25 years results in an 64% increase in costs. This suggests that cost of wind in 2049 would be about 2 to 10% less than the 2024 cost.[35]

2.2 Solar Pricing

2.2.1 Recent Pricing Trends and Projections

There have been dramatic decreases in the costs of solar energy. The decline for utility scale (100 MW) PV system costs in US$ for the last six years are illustrated in Figure 5. Costs for utility scale projects have declined by 68% over that period, with further reductions experienced in 2016. A 100 MW solar project is likely to be large for BC given the relatively limited experience in the Province with utility scale projects. In addition, dual axis trackers are more appropriate for BC. The cost reductions shown are indicative of those that are being realized by large solar PV projects.

Figure 5: PV System Cost Summary (2016 USD/Watt DC) [36]



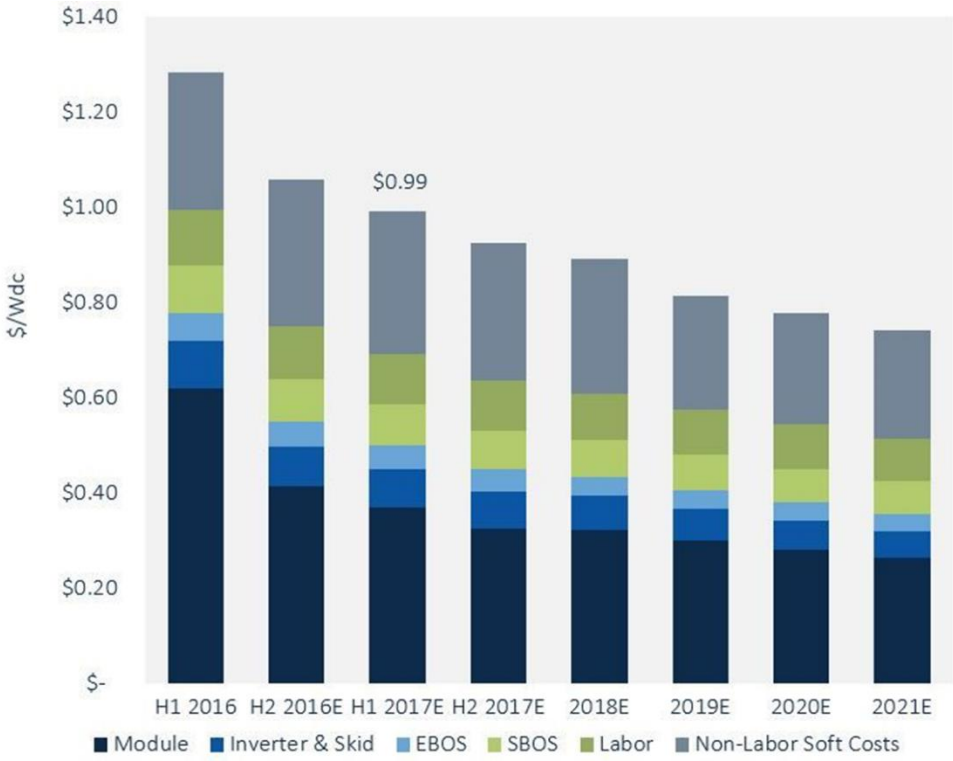
Source: NREL, U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016

[35] 1.64 x (1-40%) = 98% or 1.64 x (1-45%) = 90% .

[36] The various colours represent cost components for a PV system, with the all-in cost for the system displayed at the top of the bar chart.

Recent solar prices are considerably below the projections presented in Figure 5, with continued cost reductions anticipated going forward. For example, GTM Research expects a 27 percent drop in average global project prices by 2022, or about 4.4 percent each year.[37] Figure 6 below reflects a 5% compound annual reduction in solar PV costs from 2017 to 2022.

Figure 6: US Utility Solar PV Fixed Tilt EPC Pricing - 2016 H1 to 2021E ($/Watt DC)



Source: GTM 2016

2.2.2 Projected Costs

A range of sources were used to consider likely solar PV costs in BC for a utility scale project. BC Hydro commissioned a report from Compass Renewable Energy Consulting Inc. (Compass) to provide price and performance estimates for solar PV technology in BC. This June 2015 study was reviewed and is used as the basis of our project output estimates. In our review of SOP pricing we indicated that "the report's cost estimates to be overly optimistic (low) and to heavily rely on Ontario cost estimates that couldn't be independently verified." However, continued reductions in PV costs have caused these cost estimates to become more reasonable.

We also reviewed the previously identified National Renewable Energy Laboratory (NREL) study that benchmarked solar PV costs. This study disaggregated project costs into discrete items that readily allowed these costs to be estimated for BC. Costs were presented for a 10 MW project and for a 50 MW project, which allowed costs to be estimated for a 25 MW utility scale project. In light of the continued declines in solar PV costs in the final three quarters of 2016, additional cost reductions from the NREL estimates are

[37] Green Tech Media 2016 https://www.greentechmedia.com/articles/read/solar-costs-are-hitting-jaw-dropping-lows-in-every-region-of-the-world

appropriate. We reflected recent pricing information on module costs (i.e., assume module cost of US$.3/watt dc rather than the US$.64/watt dc reflected in the NREL cost estimate) and used that along with the NREL cost estimates for other cost elements adjusted to CAD$.[38]

Recognizing the pace of decline in solar PV costs that are being experienced, low and base capital cost estimates were derived. The base estimate reflects a 3% annual decline in solar costs through 2024, just below the GTM estimates indicated above. The low estimate reflects an additional 10% decline in installed costs and a 5% annual decline in solar costs through 2024.[39,40] Table 2 presents capital and fixed O&M costs estimates and assumed capacity factor and the resulting real levelized price for a low and base case. The capital cost estimates reflect 2024 costs and the fixed O&M estimates reflect 2017 costs.

Table 2: Solar Pricing 2024

	Capital Cost $/kW	Fixed O&M $/kW- Year	Capacity Factor %	Amortization Years	Real Levelized Price $/MWh
Low Case	$1,276	$22.88	16.5%	25	$100
Base Case	$1,606	$27.45	16.0%	25	$129

Source: Power Advisory

These solar costs and capacity factors are for projects with a one-axis tracker. Dual axis trackers are more likely to be employed in BC given its latitude, with the incremental capital cost more than offset by the higher project output. Compass estimated that a dual-axis tracker project would have an annual energy output that was 14.6% higher than fixed tilt. However, Power Advisory was unable to find detailed project cost estimates for utility scale dual-axis tracker projects in the time allotted to complete this report. We believe that our pricing estimate for solar could be high because we haven't reflected the economies offered by such technology.

2.2 Hydroelectric Generation

Hydroelectric project capital and operating costs are project specific and reflect the project configuration required to most cost-effectively develop the underlying hydraulic resource. This makes "generic" estimates of the costs of hydroelectric generation less meaningful. For its 2015 Resource Options Update, BC Hydro commissioned a study that developed project specific cost estimates presented as LUECs.[41] Aggregate project information was presented for projects that had similar LUECs, making it impossible to independently derive estimates of the costs and required prices for these projects. The LUECs presented in the referenced study are presented below in Table 3.

The study indicated that the unit energy costs were derived using a 5% real discount rate. While the amortization period for this study wasn't indicated, the previous report relied on a 40-year amortization period.[42]

[38] We assumed a 35% premium for labour costs in BC.
[39] UBS, US Solar & Alternative Energy, It's Not Just Solar Panel Costs Dropping, September 27, 2016.
[40] Power Advisory has employed a $1.00 US to $1.25 CAD$ exchange rate forecast for 2020. An earlier reference to a $.75 US to $1.33 CAD$ exchange rate is more reflective of current conditions.
[41] Kerr Wood Leidal, Run-of-River Hydroelectric Potential for British Columbia, Summary of 2015 Updates
[42] BC Hydro, IRP, Appendix 3A-27, 2013 Resource Options Report Update, Run-of-River 2013 Update Memorandum and 2010 Report

Table 3: Hydroelectric LUECs

Price Bundle ($/MWh)	Number of Projects	Average Annual Energy (GWh/yr)	Annual Firm Energy (GWh/yr)	Installed Capacity (MW)	Dependable Capacity (MW)
80 - 84	2	220	187	65	1
85 - 89	1	69	64	16	2
90 - 94	3	484	422	126	9

Source: Kerr Wood Leidal

2.4 Battery Storage Technology

Storage technologies have an important role to play in supporting increased levels of renewable energy investment and allowing variable output renewable energy technologies such as wind, solar PV and run-of-river hydro to provide the large volume of energy that would otherwise be provided by Site C.[43] Specifically, energy storage technologies are well-suited to provide the ramping, load following and frequency control functions that higher penetrations of renewable energy technologies require. Battery storage is particularly well-suited for wind and solar integration given that it can also serve as an incremental load and therefore assist with managing surpluses more effectively than storage hydro. In addition, as a modular technology they can be located to address specific transmission and distribution constraints and potentially avoid costly upgrades to resolve these constraints. Furthermore, with the significant decline in cost of battery storage, these technologies are able to more cost effectively provide longer duration energy storage services. California relied on battery technology to provide 70 MW of required peaking capacity to replace a portion of the natural gas-fired generation that was unavailable when the Aliso Canyon gas storage facility was shut down last year.

One of the primary contributors to the increased attention being paid to battery storage technologies is the dramatic cost reductions being experienced. Storage prices are falling faster than solar PV or wind technologies. Bloomberg New Energy Finance reports that as of year-end 2016 lithium-ion battery prices had fallen by almost 50% since 2014. Further cost declines are being realized and forecast. A recent study by a research team from the University of California and Technical University of Munich in Germany forecast the cost per MWh of a lithium-ion battery to decline at an average annual rate of 11.4% through 2020.[44] This research indicated that the primary contributors to these cost declines are increases in production output capacity and patent activity and that the learning rates for lithium-ion batteries are greater than for solar PV and wind technologies. This fall in prices is allowing combinations of solar, wind, and energy storage projects to offer costs that are more competitive than coal and natural gas plants.[45]

Clearly, a critical contributor to future cost declines will be increases in the deployment of the technology as a result of the "learning" that occurs with the increases in production capacity. With learning rates often measured in terms of percentage increases in capacity or production capacity, the cost declines realized overtime typically decline. However, in the case of lithium ion batteries these cost declines will support the

[43] Such battery storage facilities would be able to supplement the ability of BC Hydro's existing storage hydroelectric facilities to provide these services. (See discussion in Section 3.2.)
[44] Noah Kittner, Felix Lill and Daniel M. Kammen, Nature Energy, Volume 2, Energy storage deployment and innovation for the clean energy transition, July 31, 2017.
[45] Noah Kittner, Felix Lill and Daniel M. Kammen.

increased adoption of electric vehicles as well as other applications, which in turn will support greater learning. This suggests that significant cost declines are likely continue to be realized.

3. Other Costs and Benefits of These Resources

This section reviews other costs and benefits associated with these clean energy resources. Costs include variable generation integration costs, which BC Hydro typically considers when comparing wind resources to hydroelectric generation, and capacity value. To reflect the lower capacity value of wind and other variable output renewable resources, BC Hydro typically adds a cost to such resources.

Benefits offered include: (1) smaller, targeted resource additions that avoid the risks and costs associated with large resource additions such as Site C; (2) lower development, construction, and operating risks; (3) tax payments to federal, provincial, and municipal governments; and (4) the opportunity to earn revenues from the sale of renewable energy credits. These costs and benefits are discussed further below.

3.1 Variable Generation Integration Cost

As part of its 2013 Integrated Resource Plan (IRP), BC Hydro conducted a study of wind integration costs in BC.[46] The study evaluated the impacts and costs of 15, 25, and 35 percent wind penetration levels,[47] representing about 1,500, 2,500, and 3,500 MW of installed wind capacity. The study considered two scenarios for how these wind resources could be developed within BC. The first assumed that the lowest cost wind resources were developed first and the second assumed that there was diversity to the portfolio of wind resources developed. Two types of wind integration costs were identified: (1) operating reserve costs, which reflect capital and variable operating expenses associated with reserving generating resources so that sufficient generation is available to respond to system contingencies. These include the requirements for regulation, load-following and imbalance reserves and assume sufficient reserves are carried to cover a 97.7% (three standard deviation) confidence level; and (2) day-ahead opportunity costs, which reflect the opportunities lost from having to reduce BC Hydro's participation in the day-ahead market given the need to reserve hydroelectric resources to respond to the variability of wind generation. The results of this study are presented in Table 4.

Table 4: BC Hydro Wind Integration Cost Estimates

Scenario	Wind Penetration Level	Operating Reserve Costs ($/MWh)	Day Ahead Opportunity Costs ($/MWh)	Total Costs ($/MWh)
Lowest Initial Cost	15% (1,500 MW)	$7.83	$8.02	$15.85
	25% (2,500 MW)	$9.33	$14.85	$24.17
	35% (3,500 MW)	$8.67	$11.90	$20.57
High Diversity	15% (1,500 MW)	$4.03	$3.46	$7.49
	25% (2,500 MW)	$4.36	$4.66	$9.03
	35% (3,500 MW)	$5.36	$5.23	$10.59

Source: BC Hydro

[46] BC Hydro, 2013 IRP, Appendix 3E, Wind Integration Study Phase II. This was a Phase II study because BC Hydro undertook a wind integration study previously as part of its 2008 Long-Term Acquisition Plan. The Wind Integration Phase II Study was completed in November 2010.

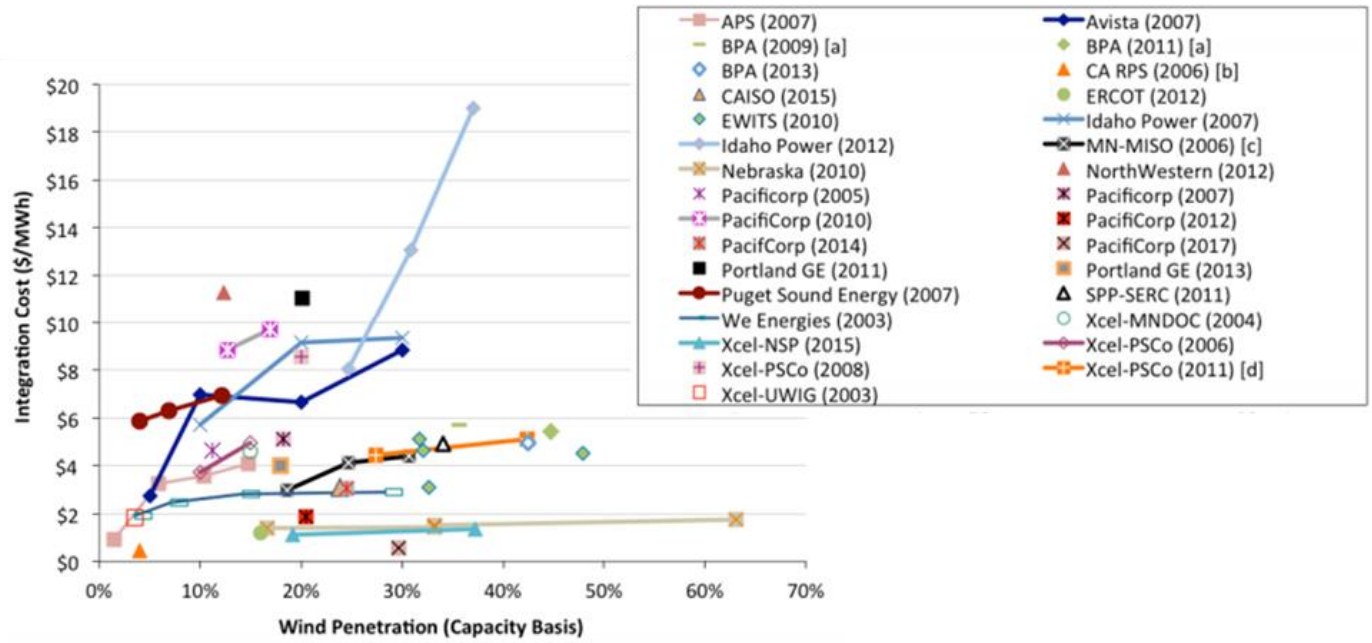
[47] Wind penetration was measured in terms of the proportion of BC Hydro's capacity.

3.1.1 Comparison to Other Variable Generation Integration Cost Estimates

While BC Hydro's analysis focused on the costs of integrating wind generation, the analysis is generally applicable to all variable output resources. Similar analyses are commonly performed by other electric utilities for a broader range of variable output renewable energy technologies.

Power Advisory offers the following comments on BC Hydro's wind integration cost estimates. They are generally high relative to those for other jurisdictions. Figure 7 reviews wind integration costs of various other electricity systems. These estimates are from US DOE's 2016 *Wind Technologies Market Report*. Each series on the graph represents a different cost study for different utilities or markets between 2003 and 2016. The US DOE report indicates that wind integration costs are generally estimated to be below $6/MWh and can be as low as $0.50 to $2/MWh even at wind capacity penetration levels beyond 40%.[48] The study indicates that variances in cost estimates are attributable, in part, to differences in methodologies, definitions of integration costs, differences in power system and market characteristics, fuel prices, wind output forecasting details and assumptions, and the degree to which thermal plant cycling costs are considered.

Figure 7: Integration Costs at Various Levels of Wind Penetration



Notes: [a] Costs in $/MWh assume 31% capacity factor; [b] Costs represent 3-year average; [c] Highest over 3-year evaluation period; [d] Cost includes the coal cycling costs found in Xcel Energy (2011). Listed below the figure are the organizations for which each study was conducted, and the year in which the analysis was conducted or published.

Source: U.S. DOE, "2016 Wind Technologies Market Report" August 2017, p.70 (Modified Figure 53).

Given the factors influencing wind integration costs discussed above, a case can be made that integration costs are more likely to align within a region or market. Therefore, Power Advisory surveyed recent renewables integration costs for both wind and solar resources in Western Electricity Coordinating Council (WECC) jurisdictions beyond BC. In the case of Portland General Electric, wind and solar are captured by the integration cost category of 'variable energy resources'. Partially due to a decline in natural gas prices, the

[48] The Western Wind and Solar Integration Study Phase 2 found that "from the perspective of the average fossil-fueled plant, 33% wind and solar penetration causes cycling costs to increase by $0.47–$1.28/MWh, compared to total fuel and variable operations and maintenance (VOM) costs of $27–$28/MWh." (p. vii)

integration cost estimates used in recent resource planning are significantly lower than in previous integrated resource plans. This trend is documented in the notes column of the table. Power Advisory notes that the wind integration costs average about US$3/MWh or about CAD$4/MWh, with one less than $1/MWh. Solar integration costs are generally lower than those for wind resources.

Table 5: Survey of Recent WECC Renewables Integration Costs

Jurisdiction	Integration Cost ($/MWh)	Year $*	Penetration Level (Capacity Basis)	Notes
Wind				
Arizona Public Service (APS)	3.25 / 4.08	2010	6% (468 MW) / 15% (1,185 MW)	As of the 2017 IRP, APS continues to base integration costs on its 2007 Wind Integration Cost Impact Study. Cost said to be updated "to increased penetration levels of wind in the APS systems and current fuel prices", but the specific value is not provided in the IRP.
PacifiCorp	0.57	2016	30% (3,007 MW)	2017 Flexible Reserve Study (FRS) conducted as part of the 2017 PacifiCorp IRP. Down from $3.06/MWh in the 2014 Wind Integration Study.
Pacific Gas and Electric (PG&E)	4.00	2014	Benchmark Average	Interim variable integration cost for wind approved by the California Public Utilities Commission in the 2014 RPS and IRP off-year proceeding.
Public Service Company of Colorado (PSCo) [Xcel Energy]	2.93	2016	28% (2,000 MW)	2016 ERP. Value based on 2011 Wind Integration Study methodology and updated natural gas prices. PSCo did not allow for gas prices below $3.24/MMBtu, while recognizing current and forecasted gas prices below this value. Average wind integration costs from 2011 were $3.68/MWh for 2 GW of wind.
Solar				
Arizona Public Service (APS)	2.00	2020	13% (1,038 MW)	Similar to wind, APS solar integration costs are currently benchmarked to a 2012 Black & Veatch Corporation study based on penetration levels and fuel prices. The costs reported in the 2012 study range from $1.53/MWh to $3.04 MWh. The planning value of $2.00/MWh in 2020 has been cited in the last two IRPs.
PacifiCorp	0.6	2016	20% (2,050 MW)	2017 Flexible Resource Study (FRS) conducted as part of the 2017 PacifiCorp IRP.
Pacific Gas and Electric (PG&E)	3.00	2014	Benchmark Average	Interim variable integration cost for solar approved by the California Public Utilities Commission in the 2014 RPS and IRP off-year proceeding.
Public Service Company of Colorado (PSCo) [Xcel Energy]	0.01 / 0.41	2016	14% (1,000 MW) / 25% (1,800 MW)	May 2016 "An Integration Cost Study for Solar Generation Resources on the Public Service Company of Colorado System" cited in 2016 ERP. Assumes annual natural gas costs of $4.37/MMBtu. The average solar integration costs in the 2011 ERP ranged from $1.25/MWh to $6.06 /MWh based on solar capacity and gas prices.
VER				
Portland General Electric (PGE)	0.92	2021	23% (1,160 MW)	2016 IRP Variable Energy Integration Study. Assumes 1,160 MW of VER capacity (3,210 GWh). Study is Phase 5 to previous wind integration studies. The reported cost of renewables integration was $4/MWh in the 2013 PGE IRP.

*All costs presented are in USD, with variance in the currency year indicated in this column.

This review of variable output renewable energy integration costs indicates that BC Hydro's estimates are considerably higher than most estimates. This is surprising given that BC Hydro has a predominately hydro system and such systems have greater operating flexibility than predominately fossil systems given the greater ramping and storage capability of many hydroelectric resources. A Power Advisory report for Natural

Resources Canada found that hydroelectric systems such as BC Hydro's are well suited to the integration of variable output wind resources and that they can allow large amounts of wind generation to be integrated at relatively low costs.[49]

A similar finding was made in the Pan-Canadian Wind Integration Study, which found that: (1) "Hydro generation, particularly hydro with pondage, provides a valuable complement to wind generation."; and (2) "The combination of wind and hydro provides a firm energy resource for use within Canada or as an opportunity to increase exports to U.S. neighbours."[50] The Pan-Canadian Wind Integration Study also found that: (1) "Regulation reserve requirements to mitigate wind variability appear to be a small fraction of the additional installed wind capacity;" and (2) Overall the additional regulation reserve requirements across all of Canada were less than 1.7% of the installed wind." The regulation reserve requirements (i.e., increased regulation requirement relative to wind capacity) for BC under the 35% penetration scenario were just .9%, representing about 50 MW. While curtailment of wind was required in high wind resource scenarios there was little need for such curtailment in BC.

3.1.2 Evaluation of BC Hydro's Wind Integration Estimate

CanWEA engaged Brendan Kirby, a noted utility industry expert who participated in the referenced Western Wind and Solar Integration Study Phase 2 among other similar studies, to assess BC Hydro's wind integration cost estimates.[51] The Kirby study found that there have been a number of changes since the 2010 BC Hydro study was conducted and that when the study assumptions are modified to reflect this new information, estimated wind integration costs are dramatically lower. In particular, Kirby noted that the 2010 study calculated costs based on MW installed, but expressed results as $/MWh. Therefore, the higher capacity factors realized by wind projects in BC than assumed in BC Hydro's wind integration study is likely to result in lower per MWh integration costs.

In addition, Kirby noted that BC Hydro relied upon ancillary service prices from the California ISO (CAISO) and that these prices have declined significantly (from 50 to 80%) since the data relied upon in the study. Furthermore, Power Advisory notes that the CAISO market has a dramatically higher proportion of thermal generation than BC and as such is likely to have significantly higher costs for ancillary services than would be appropriate for BC. The BC Hydro wind integration noted that "To ensure that the CAISO ancillary service pricing used in this study are reasonable, a comparison between the CAISO ancillary services market prices and existing contracts for ancillary services in the Pacific Northwest held by Powerex was undertaken. The findings confirm good agreement between these Pacific Northwest contract prices and the CAISO ancillary service market pricing." The fact that Powerex's contracts for ancillary services in the Pacific Northwest (PacNW) reflect "good agreement" with CAISO ancillary service market pricing doesn't mean that CAISO prices are appropriate for this analysis. This "good agreement" suggests that ancillary service pricing in the PacNW is aligned with that of CAISO. This isn't surprising given the close integration between these markets. The question regarding the wind integration study should be what is the cost to BC Hydro of providing these services? The difference is between costs and market value. When making resource investment decisions for the benefit of BC consumers and the required services are being provided by BC Hydro, Power Advisory believes that the cost of providing the service should be considered, not its theoretical value in a somewhat distant market.

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[49] *Case Study Analysis of Hydro-Variable Renewable Electricity Integration Strategies*, July, 2013.
[50] Pan-Canadian Wind Integration Study, Overview Presentation, p. 41.
[51] He retired from the Oak Ridge National Laboratory's Power Systems Research Program. He has 39 years of electric utility experience and has published over 180 papers, articles, book chapters, and reports on ancillary services, wind integration, restructuring, the use of responsive load as a bulk system reliability resource, and power system reliability.

Kirby also noted that sub-hourly scheduling reduces reserve requirements and the requirements for operating reserves for wind. In 2010, when the study was performed BC Hydro only had a 1-hour schedule. However, when he performed his assessment in 2014 15-minute scheduling was in place in BC. Kirby estimated that 15-minute scheduling would reduce incremental operating reserve requirements for wind by 51%. As discussed below, further reductions in these reserve requirement costs could likely be achieved through participation in Western Energy Imbalance Market, which is a 5-minute market.

As indicated in Table 4, day-ahead opportunity costs represent about half of the total wind integration costs. BC Hydro notes that "given the liquidity limitations of the real time market, BC Hydro does not anticipate relying on real time power trading markets to manage wind integration impacts to any significant degree. Therefore, the DA power trading market is the focus of this wind integration study."[52] Power Advisory notes that the Western Energy Imbalance Market was instituted in 2014 and now includes CAISO, PacifiCorp, Puget Sound, NV Energy, and Arizona Public Service, with many other market participants including Powerex scheduled to join. This energy imbalance market has clearly addressed the liquidity limitation of the real-time market. Furthermore, experience elsewhere suggests that with the presence of real-time and day-ahead markets allows market participants to arbitrage price differences between these markets such that there is unlikely to be significant sustained price differentials between these markets such as are assumed in BC Hydro's day-ahead opportunity cost estimate.

Kirby also notes that BC Hydro determines the maximum swing in wind generation within any hour based on a 99.7% day-ahead forecast confidence level. In the 2010 Wind Integration Study this required 100% backup of wind. However, BC Hydro's day-ahead forecast error for 487 MW of wind in February-April 2014 was just ±51.3 MW (i.e. ± 10.5% of installed capacity), indicating that a considerably lower forecast error estimate is appropriate. Considerable effort is being devoted to reducing the errors associated with forecasting wind output and this is producing more reliable forecasts, suggesting further reductions in integration costs. Kirby conservatively assumed a ±32% day-ahead reserve, three-times the forecast error from February-April 2014 period.[53] This along with the move to 15-minute scheduling and the resulting 51% reduction in reserve requirements, results in an 84% reduction in day-ahead opportunity costs.[54]

3.2 Capacity and Diversity Benefits of Variable Output Renewables

Wind, solar and many hydroelectric projects are variable output renewable energy resources that generate electricity when the underlying renewable energy resource is available. As a result, the inherent capacity value of these resources, or ability to generate electricity when needed to satisfy customer electricity demands, or respond to generator or transmission outages can be less than that of a conventional fossil or storage hydroelectric generation resource. The Pan-Canadian Wind Integration Study also found that at penetration rates of 20%, wind would have a capacity value of about 20 to almost 30% of its rated capacity.[55] However, the capacity value of these resources can be enhanced through the diversity of such resources. This diversity can include different wind projects relying on different wind regimes (e.g., differences in wind speeds on Vancouver Island, Kootenays, Okenagan, and lower Mainland) as well as the diversity offered by combining the output of wind, solar PV, and run-of-river hydroelectric projects. This diversity benefit has been demonstrated in numerous studies including the Pan-Canadian Wind Integration Study which found, among other things, that distributed solar can complement wind and that the combination of wind and hydro

[52] BC Hydro, 2013 IRP, Appendix 3E, Wind Integration Study Phase II, p. 3E-12. DA stands for day-ahead, i.e., a market that is organized around day-ahead financial or physical commitments for the delivery or purchase of power.
[53] This estimate takes no credit for improvements in wind forecasting that are being realized elsewhere and presumably can be realized in BC.
[54] The 84% is based on 51% x 32%, which is 16% of the original estimate, or an 84% reduction.
[55] Pan-Canadian Wind Integration Study, Final Report, p. 61

provides a firm energy resource for use within Canada or as an opportunity to increase exports to U.S. With respect to this last point, Massachusetts has recognized the value of such potential clean energy imports by enacting legislation to support the procurement of a large block of clean energy (i.e., 9.45 TWh per year) and specifically allowing a combination of variable output renewable energy resources along with hydroelectric resources that firm up this variable output energy.[56]

This diversity enhances the capacity value of these resources as well as reduces the requirements for operating reserves to balance the variability of these resources. The net effect is to increase the value offered by these resources as well as to reduce the costs associated with integrating them.

3.2 Benefit of Small, Targeted Resource Additions

Site C would provide 1,100 MW of capacity and produce about 5.1 TWh per year of energy in an average water year. This 5.1 TWh per year of energy represents about 9% of forecast load for 2024 or at current electricity demand growth rates about 6 years of demand growth after DSM impacts are considered. Absent major system retirements, this implies that it will take BC about six years to "grow into" the volume of energy provided by Site C. (See Table 6 where it takes six years for BC Hydro's load growth less increases in DSM to increase by the 5.1 TWh provided by Site C.) Adding such a large volume of energy to the system relative to forecast net load growth would result in a large surplus of energy. The energy surplus that would be produced by Site C, as reported by BC Hydro in its 2017-2019 Revenue Requirements Application (RRA), is shown in Table 6. BC Hydro's energy surplus as a percentage of net load increases from 105% in 2024 to 109% in 2025 after Site C is scheduled to enter commercial operation.

Given the limits on BC Hydro's energy storage capability this energy surplus will result in an increase in energy exports and the majority of these energy exports are likely to be during the off-peak when BC electricity demand is low. Off-peak electricity futures prices at Mid-Columbia (Mid-C) in 2024 are about $26/MWh, increasing to about $27/MWh in 2025, and $28/MWh in 2026.[57] With the cost of Site C well over twice this, the sale of such surplus energy represents a high cost to BC ratepayers and needs to be considered when comparing Site C to alternatives such as the smaller hydroelectric, wind, solar resources evaluated in this report that can be added in increments to better fit load growth and represent less risk to ratepayers. This cost can be quantified by calculating the difference between the cost of Site C and the export revenues earned on the resulting increase in exports attributable to Site C.

[56] In July 2016, the Massachusetts legislature directed the state's investor-owned electric distribution companies to solicit long-term contracts for 9.45 TWh per year of clean energy from renewable energy resources and/or large hydroelectric projects.
[57] Mid-C off-peak futures prices as reported for August 23, 2017.

Table 6: BC Hydro Energy Load Resource Balance

		F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028
Existing and Commited Resources													
Heritage Resources (Including Site C)	(a)	48,445	46,895	46,014	48,491	48,491	48,491	48,491	48,857	52,383	53,777	53,777	53,777
Existing and Committed IPP Resources	(b)	13,252	14,681	14,457	14,456	14,188	13,874	13,639	13,302	12,906	12,506	12,399	12,075
Future Supply-Side Resources													
IPP Renewals		61	234	569	647	779	936	1,114	1,349	1,628	1,951	2,032	2,223
Standing Offer Program		62	87	173	284	394	505	616	726	837	948	1,058	1,169
Revolstoke 6												26	26
Subtotal	(c)	123	321	742	931	1,173	1,441	1,730	2,075	2,465	2,899	3,116	3,418
Total Supply (Operational View)	(d) = a + b + c	**61,820**	**61,897**	**61,213**	**63,878**	**63,852**	**63,806**	**63,860**	**64,234**	**67,754**	**69,182**	**69,292**	**69,270**
Demand-Integrated System Total Gross Requirements													
2016 May Mid Load Forecast Before DSM		-58,334	-59,013	-60,413	-61,371	-62,309	-63,675	-64,836	-66,008	-67,109	-68,310	-69,267	-70,256
Expected LNG Load		-61	-148	-148	-252	-1,265	-2,299	-2,721	-2,848	-2,848	-2,848	-2,848	-2,848
Subtotal	(e)	-58,395	-59,161	-60,561	-61,623	-63,574	-65,974	-67,557	-68,856	-69,957	-71,158	-72,115	-73,104
Existing and Commited Demand Side Management & Other Measures													
SMI Theft Reduction		83	83	83	83	83	83	83	83	83	83	83	83
Voltage and VAR Optimization		67	152	171	188	219	240	254	259	263	268	285	290
2016 DSM Plan F16 Savings		982	970	939	940	935	926	923	917	912	885	863	855
Planned Demand Side Management Measures													
2016 DSM Plan F17 to F19 savings		389	988	1,679	1,896	1,931	1,969	1,956	1,935	1,917	1,908	1,896	1,853
2016 DSM Plan F20+ Savings		0	0	0	292	904	1,454	1,897	2,310	2,637	2,946	3,229	3,500
Subtotal	(f)	1,521	2,193	2,872	3,399	4,072	4,672	5,113	5,504	5,812	6,090	6,356	6,581
Surplus/(Deficit) (Operational View)	(g) = d + e + f	**4,946**	**4,929**	**3,524**	**5,654**	**4,350**	**2,504**	**1,416**	**882**	**3,609**	**4,114**	**3,533**	**2,747**
Surplus/ Deficit as % of Net Load (Planning View)		**113%**	**115%**	**115%**	**114%**	**111%**	**108%**	**106%**	**105%**	**109%**	**110%**	**109%**	**107%**
Small Gap Surplus/(Deficit) (Operational View)		7,266	7,487	6,536	9,044	8,219	6,890	6,181	5,920	8,949	9,749	9,380	8,839
Large Gap Surplus/(Deficit) (Operational View)		2,559	2,036	-70	1,250	-661	-3,248	-5,224	-6,122	-3,768	-3,650	-4,392	-5,505

Source: BC Hydro, 2017-19 RRA

As the BC Hydro energy load resource balance indicates, BC's need for the energy from Site C is based on forecast demand growth. This load growth is uncertain. A considerably lower risk supply alternative is to rely on smaller renewable resources that can be developed and built more quickly than Site C and as such would allow BC Hydro to expand its supply as needed to address increases in customer requirements. This includes the wind, solar and smaller hydroelectric projects considered as part of this assessment.

3.4 Comparative Risk Assessment

The LUECs that Power Advisory has derived for these alternative clean energy technologies are predicated on costs of capital and financing assumptions that are appropriate for IPP projects where the project proponent is responsible for managing project development, construction, financing and operating risks. IPPs are able to bear development, financing, construction and operating risks and to offer long-term fixed prices because the projects that they are developing typically have shorter development time frames;[58] a high proportion of capital costs are associated with modular components that provide a high measure of cost certainty and allow developers to take advantage of competitive tension from competing equipment manufacturers; have shorter construction timeframes which reduce construction risks; and finally, the performance of these generating technologies in different operating conditions can be accurately modeled to produce reliable estimates of output and operating costs.

IPP projects have a very different risk profile than a utility project, which is built under the cost-of-service regulation model. Under cost-of-service regulation, the costs incurred by the utility generally flow through to

[58] This advantage is less apparent for the smaller hydroelectric projects developed by IPPs given their long development time frames. However, because IPPs are generally awarded contracts after a considerable amount of development work has been performed, these risks are more manageable.

ratepayers, except when these costs are disallowed by the regulator. When large projects are being built by investor-owned utilities, the costs of building these projects are generally added to the utility's rate base and the utility is allowed to recover these costs and earn a return on the rate base. Where the investor-owned utility is found to have been imprudent with respect to the construction of such a project, the imprudently incurred costs are generally not allowed to be recovered from customers and these costs are effectively paid by shareholders. However, when the cost-of-service model is applied to Crown-owned utilities, where the Province is the shareholder, there is little opportunity for the risk-sharing that can occur with investor-owned utilities. As a result, cost overruns must be borne by ratepayers and/or taxpayers, and there's generally relatively limited differences between these two groups. This is significant given the risks posed by the development and construction of large hydroelectric projects.

Given their long development time frames, difficult construction environments, extended construction schedules, and relatively high proportion of construction costs that are site related, the risks profiles of large hydroelectric projects such as Site C are dramatically greater than for most IPP projects. This is readily apparent from the construction cost overruns that have recently been experienced by such projects. Total costs, including financing costs,[59] for the Muskrat Falls Hydroelectric project (824 MW producing 4.9 TWh per year) in Labrador have escalated from $7.4 billion at project sanctioning to $12.7 billion, a 72% increase and these increased costs are forecast to contribute to an almost doubling of domestic electricity rates in Newfoundland to 23.34 cents/kWh in 2022 from 11.7 cents/kWh currently.[60] Similarly, the costs of the 695 MW Keeyask Hydroelectric Project in Manitoba have increased from $6.5 billion to $8.7 billion, a 34% increase, with a 21-month delay in the project's scheduled commercial operation date.[61]

Recent experience with Muskrat Falls and Keeyask clearly indicate the cost and schedule risks associated with large hydroelectric projects. These are risks that BC Hydro ratepayers are exposed to with the continued development of Site C.

3.6 REC Eligibility and Pricing

Another potential source of value offered by clean energy projects developed by IPPs is the sale of renewable energy credits or certificates (RECs) associated with the production of this renewable energy. This is a source of incremental revenue that is available to the various renewable energy resources evaluated in this report, but which wouldn't be available to Site C.

While project developers would sell BC Hydro a bundled product that would include energy, capacity, and renewable and environmental attributes, BC Hydro, or its affiliate Powerex, could sell these RECs in the various markets in the Pacific Northwest and California where they have incremental value. As discussed, further below in most markets this would require the sale of the REC and the associated energy.

The Western Renewable Energy Generation Information System is the independent REC issuance, tracking, and retirement system for the WECC interconnection region, to which BC Hydro, Pacific Northwest utilities and the CAISO belong.[62] A REC represents 1 MWh of qualifying renewable energy. The qualifications for

[59] It is appropriate to consider financing costs because the costs associated with accrued interest during construction increase significantly from project delays.
[60] Nalcor Energy, Muskrat Falls Project Update, June 23, 2017.
[61] https://www.hydro.mb.ca/corporate/news_media/news/2017-03-07-control-budget-for-keeyask-generating-station-revised.shtml
[62] The one exception is that Nevada uses both the WREGIS and NVTREC systems.

producing such RECs vary by state and are typically specified in the rules and regulations that establish their Renewable Portfolio Standards (RPS).[63]

California's RPS is based on three distinct Portfolio Content Categories or bundles. Portfolio Content Category 1 requires a minimum procurement of eligible renewable energy resources that are at least 50%, 65%, and 75% of a utility's retail sales RPS obligations by the end of 2013, 2016, and 2020, respectively. This category is to be filled by electricity generation directly connected, scheduled into, or dynamically transferred to a California Balancing Authority (CBA) that is primarily located in California. This is the highest value REC market in the West and one in which Powerex participates presumably by reselling renewable energy that is under contract to BC Hydro. Portfolio Content Category 2 comprises firmed and shaped electricity products providing incremental electricity. Portfolio Content Category 3 comprises eligible electricity products, including unbundled RECs, that do not qualify under Categories 1 or 2. Maximum procurement for Category 3 is 10 % of retail sales RPS obligations for the 2017-2020 compliance period.

Imports of renewable energy resources, namely solar and wind, from BC are eligible as bundled or unbundled products in Categories 1, 2 or 3. However, the California Energy Commission (CEC) has found that BC run-of-river hydro projects do not qualify, as they do not meet the environmental protections as similar hydroelectric facilities in California. Four BC wind projects, representing 487.2 MW of nameplate capacity, are known to be certified facilities under California's RPS - Cape Scott Wind Farm, Bear Mountain Wind Park, Dokie Wind Energy Project and Quality Wind Project.[64] The 180 MW Meikle Wind Project near Tumbler Ridge was also pre-certified as of early 2017.

Each of the three Portfolio Content Categories are associated with distinct REC pricing. Category 1 RECs were recently priced at US$14; Category 2 RECs at US$6/MWh and Category 3 RECs at US$1.50/REC.[65]

Washington State's Renewable Energy Standard requires that the facility must be located in the Pacific Northwest or the electricity from the project is delivered to Washington on a real-time basis.[66] The location definition of Pacific Northwest excludes BC. RPS compliance REC prices for the years of 2011-2014 were US$2.13.[67] For the 2015-2018 compliance years the Washington RPS REC prices are indexed to be US$4.25/REC.

In Oregon the RPS, as increased by SB 1547 in 2016, is 50% by 2040 for the large investor-owned utilities (IOU) that serve a majority of the state and lower for other types of utilities.[68] Solar, wind, and hydropower are all eligible technologies, with additional restrictions on the amount of hydro based on type and vintage. Eligible resources must be located within WECC, which includes BC. Unbundled RECs can meet 20% of a large IOUs obligation and a majority percentage of smaller utilities' compliance obligations, with the generation facility also located in the WECC territory.

Miller Creek Generating Facility Units 1 & 2 (combined 32.8 MW) and Brown Lake Generating Station (7.2 MW) are the only BC facilities currently approved under Oregon's RPS.[69] Power Advisory sought to find market data on REC prices for Oregon, but was unable to find reliable data. A PacifiCorp RPS compliance

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[63] RPS are the broader programs that typically create RECs as a compliance mechanism and allow RECs to be traded to provide greater flexibility for prospective buyers (e.g., entities with an RPS compliance obligation) and sellers (e.g., renewable generators that produce RECs).
[64] CEC "California's Renewables Portfolio Standard (RPS) List of Facilities" Updated January 23, 2017.
[65] Platts, California Renewable Energy Certificate Markets, August 24.
[66] State of Washington Chapter 19.285 RCW "Energy Independence Act".
[67] SNL "Renewable Energy Credits (Data)" Accessed August 21, 2017. Indexes for "WA RPS REC."
[68] Oregon Department of Energy "Renewable Portfolio Standard" Accessed August 21, 2017. http://www.oregon.gov/energy/energy-oregon/Pages/Renewable-Portfolio-Standard.aspx
[69] Oregon Department of Energy "List of RPS Approved Facilities" July 31, 2017.

filing suggested that its costs for RECs was about $1.33/REC.[70] At best these costs reflect prior purchases and aren't necessarily reflective of current market prices.

3.5 IPP Tax Payments

IPPs make major contributions to the federal, provincial and municipal budgets. These financial contributions should be weighed when considering such investment and the value that these projects provide BC. The taxes include corporate and personal income taxes, property taxes, and other taxes such as water rentals or royalties paid to the provincial government. Based on analysis prepared for CEBC, Power Advisory estimates that the annual tax revenues produced by operating clean energy projects represent approximately $244 million per year.[71]

[70] PacifiCorp Renewable Portfolio Standard Oregon Compliance Report for 2015, June 1, 2016.
[71] Independent Power Producers Association of British Columbia, Economic Impact of Independent Power Projects in British Columbia, December 2009.

Appendix A: Pro Forma Model for Calculating Real Levelized Price for Wind

NPV		($0.00)	10.0%						
IRR		10.00%			Royalties				
Renewable Energy Payment	$/MWh	$68			$1.4	$/MWh			
Renewable Energy Payment Escalator		100%							
Project Start Year		2024							
Base Year for Costs		2017							
Inflation Rate		2.00%							
Rated Capacity	MW	200							
Capacity Factor		40.0%							
Output	MWh/year	700,800				Capital Cost			
					2016	$ 2,500			2017 to 2023 Escalation
All-in Capital Cost (incl IDC)	$/kW	$ 2,147			2017	$ 2,500			14.9%
Construction Period	years	1		Adj.		$ 2,328	6.9%		
Total Installed Cost	$	$471,858,027		Econ of Scale		$ 2,095	10.0%		5.0% LCOE Adj
									9.9% Effective Escalation
Fixed Operating Cost	2017$/kW/year	$ 56.31							
				Ave. Debt Serv. Cov.					
Debt:Equity Ratio	%	68%			1.5				
Debt Term	years	20							
Interest Rate	%	5.5%							
Debt Financing	$	$320,863,458							
Book Depreciation Rate	%	4%							
Income Tax Rate (various)	%	26.0%		QB		26.5%			
8% CCA Rate		8%		ON		26.5%			
50% CCA Rate		50%		NS		31.0%			
CCA 8% Rate Share	%	30%		NB		27.0%			
CCA 50% Rate Share	%	70%		PEI		31.0%			
				BC		26.0%			

Wind Pro Forma

					1	2	3	4	5
				2023	2024	2025	2026	2027	2028
Inflation	$461,645,879			1.13	1.15	1.17	1.20	1.22	1.24
Technology REP ($/MWh)	$79.8				68.31	69.68	71.07	72.49	73.94
FACILITY OPERATIONS									
Installed Capacity (MW)	1,650.37			0.00	200.00	200.00	200.00	200.00	200.00
Generation Output (MWh)	5,782,900			0	700,800	700,800	700,800	700,800	700,800
INCOME STATEMENT									
Revenue				$0	$47,873,981	$48,831,461	$49,808,090	$50,804,252	$51,820,337
Operating Costs				$0	($13,918,755)	($14,197,130)	($14,481,073)	($14,770,694)	($15,066,108)
Book Depreciation				$0	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)
Interest				$0	($17,647,490)	($17,141,372)	($16,607,417)	($16,044,095)	($15,449,790)
Property Tax (incl in FOM)				$0	$0	$0	$0	$0	$0
Income Tax				$0	$18,701,726	$30,482,759	$13,835,548	$5,246,267	$687,439
NET INCOME				**$0**	**$16,135,141**	**$29,101,397**	**$13,680,827**	**$6,361,408**	**$3,117,556**
BALANCE SHEET									
Assets									
Gross Plant			$0	$0	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027
Accumulated Depreciation			$0	$0	($18,874,321)	($37,748,642)	($56,622,963)	($75,497,284)	($94,371,605)
Net Plant			$0	$0	$452,983,706	$434,109,385	$415,235,064	$396,360,743	$377,486,422
Work In Progress			$0	$471,858,027	$0	$0	$0	$0	$0
Cash			$0	$0	$0	$0	$0	$0	$0
TOTAL			**$0**	**$471,858,027**	**$452,983,706**	**$434,109,385**	**$415,235,064**	**$396,360,743**	**$377,486,422**
Liabilities and Equity									
Short Term Liabilities			$0						
Long Term Liabilities			$0	$320,863,458	$311,661,309	$301,953,042	$291,710,820	$280,905,276	$269,505,427
Equity and Retainted Earnings			$0	$150,994,569	$141,322,397	$132,156,343	$123,524,244	$115,455,467	$107,980,995
TOTAL	5.06262E-14		**$0**	**$471,858,027**	**$452,983,706**	**$434,109,385**	**$415,235,064**	**$396,360,743**	**$377,486,422**
Check				0	0	0	0	0	0
CASH FLOW STATEMENT					-64688.17561				
Cash Flow from Operations									
REP Revenue				$0	$47,873,981	$48,831,461	$49,808,090	$50,804,252	$51,820,337
Variable Operting Cost				$0	$0	$0	$0	$0	$0
Revenue Sharing		$	1.40	$0	($981,120)	($1,000,742)	($1,020,757)	($1,041,172)	($1,061,996)
Fixed Operating Costs				$0	($12,937,635)	($13,196,388)	($13,460,316)	($13,729,522)	($14,004,112)
Interest paid				$0	($17,647,490)	($17,141,372)	($16,607,417)	($16,044,095)	($15,449,790)
Property Tax				$0	$0	$0	$0	$0	$0
Income Tax				$0	$18,701,726	$30,482,759	$13,835,548	$5,246,267	$687,439
TOTAL				**$0**	**$35,009,462**	**$47,975,718**	**$32,555,148**	**$25,235,729**	**$21,991,877**
Cash Flow from Investment									
Capital Investment				($471,858,027)	$0	$0	$0	$0	$0
Interest During Construction				$0	$0	$0	$0	$0	$0
TOTAL				**($471,858,027)**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash Flow From Financing									
Cash Flow to Owners				$150,994,569	($25,807,313)	($38,267,451)	($22,312,926)	($14,430,185)	($10,592,028)
Borrowing				$320,863,458	$0	$0	$0	$0	$0
Debt repayment				$0	($9,202,149)	($9,708,267)	($10,242,222)	($10,805,544)	($11,399,849)
TOTAL				**$471,858,027**	**($35,009,462)**	**($47,975,718)**	**($32,555,148)**	**($25,235,729)**	**($21,991,877)**
Change in Cash				**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEBT STATEMENT									
Opening Balance	Annual Financing Obligation			$0	$320,863,458	$311,661,309	$301,953,042	$291,710,820	$280,905,276
Borrowing	($26,849,639)	###########		$320,863,458	$0	$0	$0	$0	$0
Repayment				$0	$9,202,149	$9,708,267	$10,242,222	$10,805,544	$11,399,849
Interest				$0	$17,647,490	$17,141,372	$16,607,417	$16,044,095	$15,449,790
Closing Balance	0		$0	$320,863,458	$311,661,309	$301,953,042	$291,710,820	$280,905,276	$269,505,427
check					26,849,639	26,849,639	26,849,639	26,849,639	26,849,639
INCOME TAXES									
Revenue				$0	$47,873,981	$48,831,461	$49,808,090	$50,804,252	$51,820,337
Expenses				$0	($31,566,245)	($31,338,502)	($31,088,490)	($30,814,789)	($30,515,898)
8% CCA Rate				$0	($5,662,296)	($10,871,609)	($10,001,880)	($9,201,730)	($8,465,591)
50% CCA Rate				$0	($82,575,155)	($123,862,732)	($61,931,366)	($30,965,683)	($15,482,842)
Taxable Income				**$0**	**($71,929,715)**	**($117,241,383)**	**($53,213,647)**	**($20,177,951)**	**($2,643,995)**
Tax				$0	$18,701,726	$30,482,759	$13,835,548	$5,246,267	$687,439
UCC 8% Plant				$141,557,408	$135,895,112	$125,023,503	$115,021,623	$105,819,893	$97,354,301
UCC 50% Plant				$330,300,619	$247,725,464	$123,862,732	$61,931,366	$30,965,683	$15,482,842
Income Tax Rate					26.0%	26.0%	26.0%	26.0%	26.0%
Energy Margin					$47,873,981	$48,831,461	$49,808,090	$50,804,252	$51,820,337
Debt Service Coverage									
Debt Service					$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639
Cash Flow					$52,656,952	$65,117,090	$49,162,565	$41,279,825	$37,441,667
Coverage Ratio					1.96	2.43	1.83	1.54	1.39

Wind Pro Forma

	6	7	8	9	10	11	12	13
	2029	2030	2031	2032	2033	2034	2035	2036
Inflation	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46
Technology REP ($/MWh)	75.42	76.93	78.47	80.04	81.64	83.27	84.94	86.64
FACILITY OPERATIONS								
Installed Capacity (MW)	200.00	200.00	200.00	200.00	200.00	200.00	200.00	200.00
Generation Output (MWh)	700,800	700,800	700,800	700,800	700,800	700,800	700,800	700,800
INCOME STATEMENT								
Revenue	$52,856,743	$53,913,878	$54,992,156	$56,091,999	$57,213,839	$58,358,116	$59,525,278	$60,715,784
Operating Costs	($15,367,430)	($15,674,779)	($15,988,275)	($16,308,040)	($16,634,201)	($16,966,885)	($17,306,223)	($17,652,347)
Book Depreciation	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)
Interest	($14,822,798)	($14,161,322)	($13,463,465)	($12,727,225)	($11,950,492)	($11,131,039)	($10,266,516)	($9,354,445)
Property Tax (incl in FOM)	$0	$0	$0	$0	$0	$0	$0	$0
Income Tax	($1,855,555)	($3,390,865)	($4,423,382)	($5,206,335)	($5,867,106)	($6,470,131)	($7,048,360)	($7,618,991)
NET INCOME	**$1,936,639**	**$1,812,591**	**$2,242,714**	**$2,976,078**	**$3,887,719**	**$4,915,740**	**$6,029,858**	**$7,215,680**
BALANCE SHEET								
Assets								
Gross Plant	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027
Accumulated Depreciation	($113,245,927)	($132,120,248)	($150,994,569)	($169,868,890)	($188,743,211)	($207,617,532)	($226,491,853)	($245,366,174)
Net Plant	$358,612,101	$339,737,780	$320,863,458	$301,989,137	$283,114,816	$264,240,495	$245,366,174	$226,491,853
Work In Progress	$0	$0	$0	$0	$0	$0	$0	$0
Cash	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	**$358,612,101**	**$339,737,780**	**$320,863,458**	**$301,989,137**	**$283,114,816**	**$264,240,495**	**$245,366,174**	**$226,491,853**
Liabilities and Equity								
Short Term Liabilities								
Long Term Liabilities	$257,478,586	$244,790,269	$231,404,095	$217,281,681	$202,382,534	$186,663,934	$170,080,811	$152,585,617
Equity and Retainted Earnings	$101,133,514	$94,947,510	$89,459,363	$84,707,456	$80,732,282	$77,576,561	$75,285,363	$73,906,236
TOTAL	**$358,612,101**	**$339,737,780**	**$320,863,458**	**$301,989,137**	**$283,114,816**	**$264,240,495**	**$245,366,174**	**$226,491,853**
Check	0	0	0	0	0	0	0	0
CASH FLOW STATEMENT								
Cash Flow from Operations								
REP Revenue	$52,856,743	$53,913,878	$54,992,156	$56,091,999	$57,213,839	$58,358,116	$59,525,278	$60,715,784
Variable Operting Cost	$0	$0	$0	$0	$0	$0	$0	$0
Revenue Sharing	($1,083,236)	($1,104,900)	($1,126,998)	($1,149,538)	($1,172,529)	($1,195,980)	($1,219,899)	($1,244,297)
Fixed Operating Costs	($14,284,195)	($14,569,878)	($14,861,276)	($15,158,502)	($15,461,672)	($15,770,905)	($16,086,323)	($16,408,050)
Interest paid	($14,822,798)	($14,161,322)	($13,463,465)	($12,727,225)	($11,950,492)	($11,131,039)	($10,266,516)	($9,354,445)
Property Tax	$0	$0	$0	$0	$0	$0	$0	$0
Income Tax	($1,855,555)	($3,390,865)	($4,423,382)	($5,206,335)	($5,867,106)	($6,470,131)	($7,048,360)	($7,618,991)
TOTAL	**$20,810,960**	**$20,686,912**	**$21,117,035**	**$21,850,399**	**$22,762,040**	**$23,790,061**	**$24,904,179**	**$26,090,001**
Cash Flow from Investment								
Capital Investment	$0	$0	$0	$0	$0	$0	$0	$0
Interest During Construction	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash Flow From Financing								
Cash Flow to Owners	($8,784,119)	($7,998,595)	($7,730,860)	($7,727,985)	($7,862,893)	($8,071,461)	($8,321,056)	($8,594,807)
Borrowing	$0	$0	$0	$0	$0	$0	$0	$0
Debt repayment	($12,026,841)	($12,688,317)	($13,386,174)	($14,122,414)	($14,899,147)	($15,718,600)	($16,583,123)	($17,495,195)
TOTAL	**($20,810,960)**	**($20,686,912)**	**($21,117,035)**	**($21,850,399)**	**($22,762,040)**	**($23,790,061)**	**($24,904,179)**	**($26,090,001)**
Change in Cash	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEBT STATEMENT								
Opening Balance	$269,505,427	$257,478,586	$244,790,269	$231,404,095	$217,281,681	$202,382,534	$186,663,934	$170,080,811
Borrowing	$0	$0	$0	$0	$0	$0	$0	$0
Repayment	$12,026,841	$12,688,317	$13,386,174	$14,122,414	$14,899,147	$15,718,600	$16,583,123	$17,495,195
Interest	$14,822,798	$14,161,322	$13,463,465	$12,727,225	$11,950,492	$11,131,039	$10,266,516	$9,354,445
Closing Balance	$257,478,586	$244,790,269	$231,404,095	$217,281,681	$202,382,534	$186,663,934	$170,080,811	$152,585,617
check	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639
INCOME TAXES								
Revenue	$52,856,743	$53,913,878	$54,992,156	$56,091,999	$57,213,839	$58,358,116	$59,525,278	$60,715,784
Expenses	($30,190,229)	($29,836,101)	($29,451,739)	($29,035,265)	($28,584,693)	($28,097,924)	($27,572,739)	($27,006,792)
8% CCA Rate	($7,788,344)	($7,165,277)	($6,592,054)	($6,064,690)	($5,579,515)	($5,133,154)	($4,722,501)	($4,344,701)
50% CCA Rate	($7,741,421)	($3,870,710)	($1,935,355)	($967,678)	($483,839)	($241,919)	($120,960)	($60,480)
Taxable Income	**$7,136,750**	**$13,041,790**	**$17,013,007**	**$20,024,366**	**$22,565,792**	**$24,885,118**	**$27,109,078**	**$29,303,811**
Tax	($1,855,555)	($3,390,865)	($4,423,382)	($5,206,335)	($5,867,106)	($6,470,131)	($7,048,360)	($7,618,991)
UCC 8% Plant	$89,565,957	$82,400,681	$75,808,626	$69,743,936	$64,164,421	$59,031,268	$54,308,766	$49,964,065
UCC 50% Plant	$7,741,421	$3,870,710	$1,935,355	$967,678	$483,839	$241,919	$120,960	$60,480
Income Tax Rate	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
Energy Margin	$52,856,743	$53,913,878	$54,992,156	$56,091,999	$57,213,839	$58,358,116	$59,525,278	$60,715,784
Debt Service Coverage								
Debt Service	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639
Cash Flow	$35,633,758	$34,848,234	$34,580,500	$34,577,624	$34,712,532	$34,921,100	$35,170,695	$35,444,446
Coverage Ratio	1.33	1.30	1.29	1.29	1.29	1.30	1.31	1.32

Wind Pro Forma	14	15	16	17	18	19
	2037	2038	2039	2040	2041	2042
Inflation	1.49	1.52	1.55	1.58	1.61	1.64
Technology REP ($/MWh)	88.37	90.14	91.94	93.78	95.66	97.57
FACILITY OPERATIONS						
Installed Capacity (MW)	200.00	200.00	200.00	200.00	200.00	200.00
Generation Output (MWh)	700,800	700,800	700,800	700,800	700,800	700,800
INCOME STATEMENT						
Revenue	$61,930,099	$63,168,701	$64,432,075	$65,720,717	$67,035,131	$68,375,834
Operating Costs	($18,005,394)	($18,365,502)	($18,732,812)	($19,107,468)	($19,489,617)	($19,879,410)
Book Depreciation	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)
Interest	($8,392,209)	($7,377,050)	($6,306,058)	($5,176,161)	($3,984,120)	($2,726,516)
Property Tax (incl in FOM)	$0	$0	$0	$0	$0	$0
Income Tax	($8,191,334)	($8,770,755)	($9,360,645)	($9,963,407)	($10,580,958)	($11,214,978)
NET INCOME	**$8,466,841**	**$9,781,073**	**$11,158,240**	**$12,599,360**	**$14,106,115**	**$15,680,609**
BALANCE SHEET						
Assets						
Gross Plant	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027
Accumulated Depreciation	($264,240,495)	($283,114,816)	($301,989,137)	($320,863,458)	($339,737,780)	($358,612,101)
Net Plant	$207,617,532	$188,743,211	$169,868,890	$150,994,569	$132,120,248	$113,245,927
Work In Progress	$0	$0	$0	$0	$0	$0
Cash	$0	$0	$0	$0	$0	$0
TOTAL	**$207,617,532**	**$188,743,211**	**$169,868,890**	**$150,994,569**	**$132,120,248**	**$113,245,927**
Liabilities and Equity						
Short Term Liabilities	$134,128,187	$114,555,598	$94,112,016	$72,438,538	$49,573,018	$25,449,895
Long Term Liabilities	$73,489,345	$74,087,613	$75,756,874	$78,556,031	$82,547,229	$87,796,031
Equity and Retainted Earnin	$207,617,532	$188,743,211	$169,868,890	$150,994,569	$132,120,248	$113,245,927
TOTAL	0	0	0	0	0	0
Check						
CASH FLOW STATEMENT						
Cash Flow from Operatio						
REP Revenue	$61,930,099	$63,168,701	$64,432,075	$65,720,717	$67,035,131	$68,375,834
Variable Operting Cost	$0	$0	$0	$0	$0	$0
Revenue Sharing	($1,269,183)	($1,294,567)	($1,320,458)	($1,346,868)	($1,373,805)	($1,401,281)
Fixed Operating Costs	($16,736,211)	($17,070,935)	($17,412,353)	($17,760,601)	($18,115,813)	($18,478,129)
Interest paid	($8,392,209)	($7,377,050)	($6,306,058)	($5,176,161)	($3,984,120)	($2,726,516)
Property Tax	$0	$0	$0	$0	$0	$0
Income Tax	($8,191,334)	($8,770,755)	($9,360,645)	($9,963,407)	($10,580,958)	($11,214,978)
TOTAL	**$27,341,162**	**$28,655,394**	**$30,032,561**	**$31,473,681**	**$32,980,436**	**$34,554,930**
Cash Flow from Investme						
Capital Investment	$0	$0	$0	$0	$0	$0
Interest During Construction	$0	$0	$0	$0	$0	$0
TOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cash Flow From Financir						
Cash Flow to Owners	($8,883,732)	($9,182,805)	($9,488,980)	($9,800,203)	($10,114,917)	($10,431,807)
Borrowing	$0	$0	$0	$0	$0	$0
Debt repayment	($18,457,430)	($19,472,589)	($20,543,581)	($21,673,478)	($22,865,520)	($24,123,123)
TOTAL	**($27,341,162)**	**($28,655,394)**	**($30,032,561)**	**($31,473,681)**	**($32,980,436)**	**($34,554,930)**
Change in Cash	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEBT STATEMENT						
Opening Balance	$152,585,617	$134,128,187	$114,655,598	$94,112,016	$72,438,538	$49,573,018
Borrowing	$0	$0	$0	$0	$0	$0
Repayment	$18,457,430	$19,472,589	$20,543,581	$21,673,478	$22,865,520	$24,123,123
Interest	$8,392,209	$7,377,050	$6,306,058	$5,176,161	$3,984,120	$2,726,516
Closing Balance	$134,128,187	$114,555,598	$94,112,016	$72,438,538	$49,573,018	$25,449,895
check	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639	26,849,639
INCOME TAXES						
Revenue	$61,930,099	$63,168,701	$64,432,075	$65,720,717	$67,035,131	$68,375,834
Expenses	($26,397,603)	($25,742,552)	($25,038,870)	($24,283,629)	($23,473,737)	($22,605,926)
8% CCA Rate	($3,997,125)	($3,877,355)	($3,383,167)	($3,112,513)	($2,863,512)	($2,634,431)
50% CCA Rate	($30,240)	($15,120)	($7,560)	($3,780)	($1,890)	($945)
Taxable Income	**$31,505,131**	**$33,733,674**	**$36,002,479**	**$38,320,795**	**$40,695,992**	**$43,134,532**
Tax	($8,191,334)	($8,770,755)	($9,360,645)	($9,963,407)	($10,580,958)	($11,214,978)
UCC 8% Plant	$45,966,940	$42,289,584	$38,906,418	$35,793,904	$32,930,392	$30,295,961
UCC 50% Plant	$30,240	$15,120	$7,560	$3,780	$1,890	$945
Income Tax Rate	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
Energy Margin	$61,930,099	$63,168,701	$64,432,075	$65,720,717	$67,035,131	$68,375,834
Debt Service Coverage						
Debt Service	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639	$26,849,639
Cash Flow	$35,733,371	$36,032,444	$36,338,619	$36,649,842	$36,964,556	$37,281,446
Coverage Ratio	1.33	1.34	1.35	1.37	1.38	1.39

Wind Pro Forma

	20	21	22	23	24	25
	2043	2044	2045	2046	2047	2048
	1.67	1.71	1.74	1.78	1.81	1.85
Inflation	99.52	101.51	103.54	105.61	107.72	109.88
Technology REP ($/MWh)						
FACILITY OPERATIONS	200.00	200.00	200.00	200.00	200.00	200.00
Installed Capacity (MW)	700,800	700,800	700,800	700,800	700,800	700,800
Generation Output (MWh)						
INCOME STATEMENT	$69,743,361	$71,138,218	$72,560,982	$74,012,202	$75,492,446	$77,002,294
Revenue	($20,276,998)	($20,682,538)	($21,096,189)	($21,518,112)	($21,948,475)	($22,387,444)
Operating Costs	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)	($18,874,321)
Book Depreciation	($1,399,744)	$0	$0	$0	$0	$0
Interest	$0	$0	$0	$0	$0	$0
Property Tax (incl in FOM)	($11,867,039)	($12,538,672)	($12,847,451)	($13,157,753)	($13,469,985)	($13,784,533)
Income Tax	**$17,325,248**	**$19,042,687**	**$19,743,021**	**$20,462,015**	**$21,199,664**	**$21,955,996**
NET INCOME						
BALANCE SHEET						
Assets	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027	$471,858,027
Gross Plant	($377,486,422)	($396,360,743)	($415,235,064)	($434,109,385)	($452,983,706)	($471,858,027)
Accumulated Depreciation	$94,371,605	$75,497,284	$56,622,963	$37,748,642	$18,874,321	$0
Net Plant	$0	$0	$0	$0	$0	$0
Work In Progress	$0	$0	$0	$0	$0	$0
Cash	**$94,371,605**	**$75,497,284**	**$56,622,963**	**$37,748,642**	**$18,874,321**	**$0**
TOTAL						
Liabilities and Equity						
Short Term Liabilities	($0)	($0)	($0)	($0)	($0)	($0)
Long Term Liabilities	$94,371,605	$75,497,284	$56,622,963	$37,748,642	$18,874,321	$0
Equity and Retainted Earnir	**$94,371,605**	**$75,497,284**	**$56,622,963**	**$37,748,642**	**$18,874,321**	**$0**
TOTAL	0	0	0	0	0	0
Check						
CASH FLOW STATEMEN						
Cash Flow from Operatio	$69,743,361	$71,138,218	$72,560,982	$74,012,202	$75,492,446	$77,002,294
REP Revenue	$0	$0	$0	$0	$0	$0
Variable Operting Cost	($1,429,307)	($1,457,893)	($1,487,051)	($1,516,792)	($1,547,127)	($1,578,070)
Revenue Sharing	($18,847,691)	($19,224,645)	($19,609,138)	($20,001,321)	($20,401,347)	($20,809,374)
Fixed Operating Costs	($1,399,744)	$0	$0	$0	$0	$0
Interest paid	$0	$0	$0	$0	$0	$0
Property Tax	($11,867,039)	($12,538,672)	($12,847,451)	($13,157,753)	($13,469,985)	($13,784,533)
Income Tax	**$36,199,569**	**$37,917,008**	**$38,617,342**	**$39,336,336**	**$40,073,985**	**$40,830,317**
TOTAL						
Cash Flow from Investme	$0	$0	$0	$0	$0	$0
Capital Investment	$0	$0	$0	$0	$0	$0
Interest During Constructio	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
TOTAL						
Cash Flow From Financi	($10,749,674)	($37,917,008)	($38,617,342)	($39,336,336)	($40,073,985)	($40,830,317)
Cash Flow to Owners	$0	$0	$0	$0	$0	$0
Borrowing	($25,449,895)	$0	$0	$0	$0	$0
Debt repayment	**($36,199,569)**	**($37,917,008)**	**($38,617,342)**	**($39,336,336)**	**($40,073,985)**	**($40,830,317)**
TOTAL						
Change in Cash	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
DEBT STATEMENT						
Opening Balance	$25,449,895	($0)	($0)	($0)	($0)	($0)
Borrowing	$0	$0	$0	$0	$0	$0
Repayment	$25,449,895	$0	$0	$0	$0	$0
Interest	$1,399,744	($0)	($0)	($0)	($0)	($0)
Closing Balance	($0)	($0)	($0)	($0)	($0)	($0)
check	26,849,639	0	0	0	0	0
INCOME TAXES						
Revenue	$69,743,361	$71,138,218	$72,560,982	$74,012,202	$75,492,446	$77,002,294
Expenses	($21,676,742)	($20,682,538)	($21,096,189)	($21,518,112)	($21,948,475)	($22,387,444)
8% CCA Rate	($2,423,677)	($2,229,783)	($2,051,400)	($1,887,288)	($1,736,305)	($1,597,401)
50% CCA Rate	($472)	($236)	($118)	($59)	($30)	($15)
Taxable Income	**$45,642,459**	**$48,225,661**	**$49,413,275**	**$50,606,742**	**$51,807,636**	**$53,017,435**
Tax	($11,867,039)	($12,538,672)	($12,847,451)	($13,157,753)	($13,469,985)	($13,784,533)
UCC 8% Plant	$27,872,284	$25,642,501	$23,591,101	$21,703,813	$19,967,508	$18,370,107
UCC 50% Plant	$472	$236	$118	$59	$30	$15
Income Tax Rate	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
Energy Margin	$69,743,361	$71,138,218	$72,560,982	$74,012,202	$75,492,446	$77,002,294
Debt Service Coverage						
Debt Service	$26,849,639					
Cash Flow	$37,599,313					
Coverage Ratio	1.40					

Appendix 2

INSTITUT C.D. HOWE INSTITUTE

COMMENTARY

NO. 388

The Valuation of Public Projects: Risks, Cost of Financing and Cost of Capital

Current evaluations of public projects by governments suffer from serious flaws, exposing taxpayers to unaccounted risks and bad investment decisions.

Marcel Boyer, Éric Gravel and Sandy Mokbel

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The Study In Brief

It is often said 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 financing cost) is lower than what is available to the private sector, the cost of goods or services will necessarily be lower if it is funded by government. However, there is confusion between the cost of financing and the cost of capital (or discount rate) that stems from an analytical error in assessing 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.

This analytical illusion is due to the fact that a significant portion of the government's cost of capital is unaccounted for or not recognized. This portion is the implicit option granted by taxpayers to their government to require additional funds in order to meet the commitments made to the lenders when a project does not meet the expected level of profitability. Discounting at an essentially risk-free rate is often justified by "the virtually unlimited taxing power of the Crown" – the project appears risk-free to lenders, but is obviously not risk-free for taxpaying citizens.

The authors identify the implications for the evaluation of public investments and relevant public policies such as direct subsidies to businesses, government endorsements of corporate borrowings, the comparison of public sector versus private sector delivery of public projects and holding a portfolio of risky investments dedicated to the future repayment of the debt. It goes without saying that other evaluations of government policies and interventions could be similarly challenged.

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We often hear that it is more expensive for private companies than governments to finance a project, because government can borrow at lower interest rates. However, this statement is only half true, as it ignores the costs resulting from government authority to levy, when required, additional fees and taxes to repay lenders if one or several funded projects prove unprofitable.

This governmental power, which means a kind of insurance policy is held on the project, involves a cost to taxpayers that is essentially the difference between the financing rates for private and public parties for the same project. Our analysis of public and private investments and related public policies considers factors such as:

- direct subsidies to companies;
- governmental endorsement of corporate borrowing;
- a comparison of public-sector versus private-sector delivery of public projects (Infrastructure Ontario's "Value for Money Assessment" methodology); and
- holding a portfolio of risky investments dedicated to future repayment of public debt as an alternative to immediate repayment (Québec's Fonds des générations).

1. Framing the Issue

Four mistakes are commonly made when evaluating public and private investments. These mistakes are based on persistent analytical errors that are the cause of value destruction among public and private undertakings. They are:

1. Calculating the net present value (NPV) of a given project by using different discount rates, depending on whether the project is carried out by the public sector (lower rate) or by the private sector (higher rate).
2. Using a cost of capital for the business as a whole (e.g., the weighted average cost of capital, or WACC, corresponding to the cost of financing) in the assessment (usually the NPV) of all its investments rather than using a specific cost of capital for each project, properly assessed against the risk of that particular project.
3. Using a single cost of capital or discount rate for a project that is dependent upon several factors or sources of risk.
4. Using a discounting method such as NPV that fails to quantify the value of managerial flexibility in the development, implementation and/or continuation of a project in a changing and volatile environment.

This *Commentary* deals mainly with the first mistake, which is particularly relevant to the public sector. Nevertheless, in Section 4 we briefly discuss the other three mistakes because of their sometimes pernicious presence in public and

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private organizations and their potential for value destruction.

With the management of some public services increasingly delegated to private-sector organizations and the emergence of more complex risk-sharing arrangements with the private sector, among other developments, the determination of an appropriate public discount rate has taken on even greater importance, especially as it pertains to the risks involved in assessing public projects.[1]

We often hear 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 financing cost) is lower than what is available to the private sector, the cost of goods or services will necessarily be lower if it is funded by government. However, there is confusion between the cost of financing and the cost of capital (or discount rate) that stems from an analytical error in assessing 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.

It is important to mention that we are not dealing with all aspects of evaluating public investment projects.[2] This *Commentary* relates mainly to the distinction between the discount rate to be applied in the evaluation of public projects and the interest rate at which a government finances its activities.

2. Origin of the Public Sector's Lower Financing Costs

It is undeniable that the public sector can generally borrow at lower interest rates than the private sector. But why is the cost of financing lower for a public-sector enterprise if it is involved in the same activities and in the same way as a private-sector company – same technology, same inputs, same

1 Recent books, articles and studies including, among many others, Gollier (2011), Burgess and Jenkins (2010), Harrison (2010), Sick (2009), Boardman, Moore and Vining (2010), Lopez (2008), Azar (2007), Montmarquette and Scott (2007), Caplin and Leahy (2004), Young (2002), Dasgupta, Mäler and Barrett (2000) and Pearce and Ulph (1995) reflect this unabated and steadily renewed interest in the relations between risks and social discount rates for public project evaluation. In most if not all of the above sources, the analysis suffers from neglecting the above four "mistakes," in particular the first one – Harrison (2010) is a notable exception here – which is the specific subject of this *Commentary*. The worldwide significant and increasing indebtedness of the public sector may in part be due to faulty public investment analysis.

2 For example, we do not deal directly with the specific role of discounting future cash flows to bring them to a common basis in today's dollars. Further, we are not dealing with the estimate per se of cash flow, cash benefits and costs, or the assessment of non-cash flow benefits or costs and their expression in monetary equivalents, risky or not. Neither do we refer to externalities, induced effects or eviction effects of public projects, although they may be relevant to their evaluation. We also do not deal with the role or the inclusion of taxes, as benefits of a project or as payments for goods and public services such as roads, business law and social security, used in a project. We do not deal with the inclusion of normative elements (equity, distribution of income or wealth) versus descriptive elements (efficiency and effectiveness, opportunity or alternative costs) in the value assessment of projects. Neither do we refer to various market imperfections that may be relevant such as distorting taxes, fixed prices and wages. Finally, it is important to note that we will not deal directly with the determinination of the risk-free discount rate reflecting the time-preference rate; in this context, we do not address the problems of endogenous preferences and time consistency – see Boyer (1975) and Caplin and Leahy (2004). On the other hand, our analysis does not exclude the possibility that the public sector considers the various effects of a project on public consumption and private investment, but in this case it is better to express the non-market benefits and costs (externalities, induced effects) in terms of their monetary equivalents that are clearly risky – see Bradford (1975), Boyer (1975, 1979), Dasgupta, Mäler and Barrett (2000), and the synthesis effort of Gollier (2011).

markets, same price – and, therefore, faces the same risk factors?

The answer is that a government has the power to levy additional fees and taxes to compensate and repay lenders if its projects incur cost overruns and/or lower than expected benefits. The interest rate paid by the public sector reflects the fact that, through its taxing power, it implicitly subscribes loan insurance wherein all taxpayers act as the insurer. This means that lenders to the public sector require only a small risk premium regardless of the project.[3]

As shown in Appendix A, the risk premium 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 systemic (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 in case of default. 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 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).

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. It corresponds to the value of the financial option (or insurance policy) granted by taxpayers to the government to obtain from them additional funds to cover a project's possible non-profitability. The lower cost of funding is mainly due to the unaccounted implicit cost of this option or insurance policy held by a government. 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 governmental agency.

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 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) is equivalent and 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.

In the investment community, there is much confusion between the risk ultimately borne by taxpayers and the cost of government funding which, reflecting the lender's point of view, does not take into account the cost of the implicit insurance provided by taxpayers to their government. This translates into a subtle, but undeniable error.

In the analysis of PPP partnerships, for example, one must be careful in comparing the commitments of the different partners, namely the first partner – client or principal – and the second

3 The liquidity of securities is undoubtedly a factor in explaining the difference in rates, but this liquidity is directly related to the option or implicit insurance that the government enjoys. In addition, rates of various securities guaranteed by government may differ from the government rate because of the expected transaction costs to validate such guarantees. Regardless of those differences, probably transactional in nature, it remains essential to distinguish the evaluation issue from the financing issue. The risk of a project must be taken into account in the assessment, regardless of the identity of the promoter and the financing method.

partner – supplier or contractor. The analysis of the commitments of the first partner should be based on the risks incurred by that partner whether public – in a public-private partnership- or private – in a private-private partnership. Similarly, the analysis of the commitments of the second partner should be based on the risks incurred by that partner. In a PPP, the risks incurred by the partners are very different and should be assessed accordingly. But the evaluation of the project by the first partner whether it is public or private should be the same. The value of a PPP formula actually lies in the sharing and more effective management of risk, along with the more rigorous management of costs and schedules made possible by a better alignment of incentives, but not because of the public or private nature of the partners.

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

3. The Public Sector Cannot and Should Not Ignore Systemic Risk

The confusion in assessing the public sector's cost of financing and cost of capital has led many economists to suggest using the cost of government financing, essentially a risk-free rate, to discount the cash flows of public projects. Two main reasons are provided to justify this practice.

For one, these economists say that the government is able to finance its projects by borrowing at a risk-free rate and that this justifies not incorporating a risk premium in the discount rate because the risk does not appear in the government's cost of financing. As discussed in the previous section, this view stems from the confusion between the cost of financing and the cost of capital. Since the risk in government-financed projects is borne by taxpayers rather than by lenders, such lenders will require no risk premium on their loans. On the other hand, taxpayers will or should require, implicitly if not explicitly, that the project compensates them for the risk incurred, and the government must take this into account when determining the project's cost of capital (for an example, see Box 3).

Secondly, it is argued that the government has a significant portfolio of projects and, therefore, the risk is completely discharged through the diversification effect. As shown in Appendix A, if the systemic risk associated with a portfolio of projects is not nil, this statement is false.

These two "reasons" result from analytical errors in the evaluation of public investment projects and, as such, promote value destruction rather than value creation. For a given project, an investor must be compensated for non-diversifiable risk characterized by the correlation between the return on the project and the return on the overall market portfolio. Therefore, the discount rate for any particular project – public or private – should reflect the project's level of systemic risk.

Assuming that government has no interest at heart other than that of the citizens it represents, the allocation of public funds should follow the same principles used in the allocation of private funds since in both cases the funds come from the same source, the taxpaying citizens. Thus, a dollar to be received at moment t should have more value for typically risk-averse taxpayers if the correlation with general economic conditions is low. As a result, using the risk-free rate as the discount rate will lead to an error proportional to the project's non-diversifiable systemic risk as shown in Appendix A.

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.

4. Three Other Analytical Mistakes When Assessing Projects

In this section, we briefly discuss the three other important mistakes identified in the introduction. These three mistakes are just as damaging as the one above, but we provide only an overview here given the limited space available.

When using the company's cost of capital as a whole (WACC) in the assessment of its investments, one will undervalue the risk of some projects whose level of risk is higher than the average risk of the company's project portfolio, thus over-investing in those projects. Similarly, one will overestimate the risk of other projects whose risk level is lower than the average risk of the company's project portfolio and, as a result, under-invest in such projects. Ultimately, this causes a potentially large destruction of value in the company. When assessing a particular project, we must use a discount rate or cost of capital specific to this project, pegging it to the project's specific systemic risk level.[4]

Concerning the mistake made by using a single cost of capital in assessing a project when it is dependent on several sources of risk, Boyer and Gravel (2006) show that the NPV methodology is at variance with or violates the principles of additivity[5] and of no arbitrage opportunities.[6] The use of a single discount rate for a project's net cash flows is the main problem, even when the rate is risk-adjusted. We cannot avoid considering separately the cash-flow components that are dependent on different sources of risk and assigning them a risk premium of their own. The optimized net present value or O-NPV developed by Boyer and Gravel (2006) overcomes the shortcomings of the standard NPV and, in the presence of multiple sources of risk, restores the correctness of investment choices with an objective of creating wealth.

Finally, when managers may intervene in the development, implementation, tracking and/or future of a project by reacting to a changing and volatile environment, the traditional NPV must be replaced with real option valuation (ROV). The latter 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.

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

4 Kruger, Landier and Thesmar (2011) verify investment biases empirically and measure the value destruction caused by this mistake in businesses.

5 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.

6 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.

developments as well as to changes in the intensity of competitive forces. There 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 evaluated using similar methodology. Neglecting them produces a bias, usually downwards, in project evaluation.[7]

5. Economic Policy Implications

Funding costs and discounted cash flows in the presence of risk must be considered separately when evaluating public projects. The public sector's advantage with respect to financing costs is primarily related to the implicit risk insurance provided and supported by taxpayers. Since the government has a responsibility to protect the collective, or taxpayers', wealth, these elements must not be ignored when doing a cost-benefit assessment.

In evaluating an investment project, risk assessment should not differ according to the entity (public versus private) undertaking the project.[8] Our analysis shows that there is essentially no significant difference in cost of capital (including all components) for a given project between the public and private sector.

We may, therefore, wonder about the merits of subsidies and loan guarantees granted by a government to private companies based on the argument that the cost of government funding is lower than that of the private sector. Many public projects are routinely assessed on the basis of this faulty logic (see Box 1).[9]

We may also question whether it is appropriate for a government to hold a portfolio of risky investments rather than repay its debt, under the pretext that there may be a long-term capital gain or profit equal to the difference between the cost of government funding and the performance of said portfolio (see Box 2).

These examples raise the critical question: what is the best way for a government to assess and make transparent the cost of subsidies and other forms of assistance to businesses? Those grants and subsidies may be unavoidable but they represent for the taxpayers risky commitments, the cost of which must be determined.

A procedure applicable to the vast majority of government-supported initiatives would be to submit the project to an auction: the government would offer a number of local and international financial consortia to take responsibility for the project, bearing the costs and collecting repayments at levels and conditions determined by the

7 Dixit and Pindyck (1994) authored a classic reference book on real options, and Chevalier-Roignant and Trigeorgis (2011) is the source on strategic real option valuation; see also Boyer, Christoffersen, Lasserre and Pavlov (2003), and Boyer and Gravel (2012a, 2012b).

8 Klein (1997) deals with the consideration of risk when assessing public projects from an approach similar to ours, at least in spirit. Klein considers a project with a single source of risk and concludes that the discount rate adjusted for the risk of a project should be the same, regardless of the public or private nature of the entity undertaking the project. Klein concludes his analysis by stating that a given investment should be made by the public or private sectors depending on the effectiveness and efficiency provided by either sector in completing the investment. However, the discount rate should be the same for all practical purposes.

9 Having said this, the justification for such subsidies and guarantees may refer to various market failures (including financial markets), so that these projects could not be completed without the government's financial involvement, regardless of their economic or social viability. In such cases, the social cost of public funds must still be properly determined so that the decision is actually wealth-generating.

Box 1: Assessing Value for Money (Infrastructure Ontario)

The approach used by Infrastructure Ontario (IO) to evaluate and compare the public-sector delivery cost of a project with the private-sector delivery cost of the same project is in part fundamentally and fatally incorrect. The IO approach is likely to generate important losses of potential value for the taxpayer.[a] We identify four problems in this IO approach.

According to the IO 2007 *Guide* (page 10): "Total financing costs under AFP [private-sector Alternative Financing and Procurement] are typically higher than public-sector financing costs because the private sector borrows at a higher rate than the Province. This is a common criticism of the AFP." As we have demonstrated, the public-sector-observed cost of borrowing hides a significant cost of raising public funds, namely the cost of the implicit insurance policy or financial option granted to the government by taxpayers allowing the government to request additional money if necessary, through taxes and other fees, to compensate and repay lenders. Therefore, the evaluation methodology followed by IO will often lead to wrong decisions.

The *Guide* also states regarding risky costs: "[T]he discount rate chosen should match the uncertainty inherent in these 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 uncertainty 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. An appropriate method to avoid this result is to quantify the embedded uncertainty in costs through a comprehensive risk assessment" (page 15). This quote reflects a second shortcoming of the IO approach. It stems from the view that a lower discounted value of costs when costs are more risky is counterintuitive. It may be counterintuitive, but it is nevertheless correct! The reason why this so-called counterintuitive result is correct is that risky costs, assuming that the systemic riskiness of costs is properly measured, 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 project more valuable and should not lead to manipulations (or "comprehensive risk assessment" in IO's vocabulary) to "avoid this result."

Third, IO calls for applying the same discount rate to any publicly delivered project, namely the same risk-free rate for all projects. As we have shown above, using a unique discount rate would be value destroying insofar as some projects may be subject to multiple sources of risk: some valuable (positive NPV) project delivery will end up being rejected and some non-valuable (negative NPV) project delivery will end up being accepted.

Finally, the IO approach invokes (page 15) that "As the public sector financing rate reflects the virtually unlimited taxing power of the crown to repay its debt, crown borrowings are viewed as risk free" to justify a risk-free discount rate. Indeed, those Crown borrowings are seen as risk free by the lenders, but certainly not by taxpayers who will be called to foot the bill if the public projects turn out to be less profitable than expected, if not disastrously so.

a The procedure at Infrastructure Québec raises similar problems, but since the process is explicit and transparent in Ontario, while it is rather opaque in Quebec, we will stick to IO.

Box 2: Investing v Repaying the Debt (Québec Fonds des générations)

The Québec Government created the *Fonds des générations* in 2006. The Fonds is dedicated to the future repayment of public debt and to inter-generational equity, sustainable social programs and prosperity.

The Fonds reached $4.4 billion by the end of March 2012 and is expected to more than double to $10.1 billion by 2016. Since its inception, the Fonds has posted a relatively low 2.2 percent average annual return, in part due to the financial crisis, compared to the government's average annual cost of financing of 4.4 percent over the same period (Joanis 2012).

At the time of the inception of the Fonds, the Department of Finance calculated that the cost of debt financing was 6.9 percent over the 1995 to 2005 period, compared to a rate of return of 9.4 percent at the Caisse de dépôt et placement du Québec: hence the expected profitability of the Fonds.

As shown here, this comparison is flawed, since the first rate does not consider the cost of the implicit insurance policy or financial option granted to the government by taxpayers allowing the government to raise taxes and other fees if necessary to compensate and repay lenders, while the Caisse's rate of return includes a significant risk premium.

On the other hand, the existence of the Fonds may be seen as a constant reminder that the government must contribute each year to the Fonds and therefore implicitly repay the provincial debt, this being something it could otherwise easily neglect.[a] At the time of the September 2012 provincial election, the Parti Québécois platform called for the immediate use of the Fonds to repay the provincial debt, but this element of the party program was scrapped after the election of the PQ minority government.

a Initially, the Fund was to be provisioned mainly through hydro royalties to be paid by Hydro-Québec and private producers of hydroelectric power and, depending on the evolution of the situation, by other sources of income identified by the government. The 2013/14 provincial budget includes the following contributions to the Fonds des générations: revenues that result from the indexation of the price of the "heritage electricity pool" from 2014 (i.e., $95 million in 2014/15; $190 million in 2015/16; $290 million in 2016/17 and $395 million in 2017/18); all mining royalties from 2015/2016 ($325 million yearly); future Hydro-Québec cost savings fixed at $215 million per year as of 2017/18, in part resulting from the decision to abandon the Gentilly 2 nuclear plant; and $100 million per year from 2014/15 from the increase in the alcohol tax.

government, in exchange for a premium paid by the government. Obviously, if a government sets up an aid and/or subsidy project for a company or companies, it means that the conditions attached to the project are more business-friendly than those available on the financial markets. This explains the premium that would be required by the consortia called upon to take charge of the project. For the government, the anticipated cost of the project is equal to this premium, the most favourable one generated by the auction. It could and should consider this premium as a budget expenditure (see Box 3 for a practical example of what would be entailed by this suggestion).

Box 3: Determining the Costs of Subsidies and Guarantees through Auctions

The federal and provincial governments often grant loans, subsidies or other financial support to private firms as a contribution to the development of new products or to ensure the very survival of firms in difficult financial positions.

Consider the hypothetical case of different levels of government coming together to provide comprehensive financial assistance to a private firm for the development of a risky project or product tied to some repayment terms.

A proper assessment of such business support measures offered by governments requires not only disclosure of the characteristics of the measures including repayment terms but also that the benefits and costs can be quantified, especially in highly volatile markets involving significant risks. Various support measures are often justified and criticized with opportunistic political arguments, which is an obstacle to the pursuit of efficiency and transparency.

To make possible an explicit and objective assessment of the costs of these publicly financed support measures or contracts, they should be transferred to the competitive sector at market value. How could this market value be determined? By auctioning off such measures or contracts (both the commitments in terms of loans and investments and the repayment provisions). If the best bid requires the government to compensate the winning consortium for accepting the responsibility of the support measure or contract, this amount would be entered as an expense in the government budget. This amount is indeed for taxpayers the best estimate of the expected cost or net benefit of the measure or contract.

This sanction by the market would also allow citizens to verify that their government is defending and protecting their interests.

Various models for the contract with the selected consortium could be considered, such as annual payments for a few years or variable payment options, as well as the possibility of the government taking over the project. Alternatively, the government could take out an insurance policy to ensure that the project will be carried out, with taxpayers fully compensated for the risks involved.

6. Conclusion

In this *Commentary*, we have shown how and why 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. Our analysis suggests that the underlying rationale for this approach stems from an 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.

This analytical illusion is due to the fact that a significant portion of the government's cost of capital is unaccounted for or not recognized. That is the implicit option granted by taxpayers to their government to require additional funds in order to meet the commitments made to the lenders when a project does not meet the expected level of profitability. Discounting at an essentially risk-free

rate is often justified by "the virtually unlimited taxing power of the Crown" (Infrastructure Ontario) – the project appears risk-free to lenders, but is obviously not risk-free for taxpaying citizens.

We have identified the implications suggested by our analysis with respect to the evaluation of public investments and relevant public policies such as direct subsidies to businesses, government endorsements of corporate borrowings, the comparison of public-sector versus private-sector delivery of public projects and holding a portfolio of risky investments dedicated to the future repayment of the debt. It goes without saying that other evaluations of government policies and interventions could be similarly challenged.

Unlike the current methodology that evaluates public investment projects essentially by discounting flows at the rate at which the government can finance its debt, we must instead define and measure the systemic risk of each specific project and discount the cash flows or cash equivalents of the project in question at a cost of capital properly pegged to this systemic risk. The result: different discount rates for different projects with different levels of systemic risk. Generally, for a project characterized by a given level of systemic risk, the discount rate to be used should not depend on the public or private nature of the company or organization that undertakes it.[10]

Given the significant value destruction potential entailed by the standard approach to the evaluation of public policies and projects, a thorough and urgent examination of this approach and its components should be undertaken.

10 However, the flows to be discounted may differ to the extent that different companies or organizations responsible for the project have different reporting environments. For example, the presence of externalities and induced effects may be relevant to the public sector but not to the private sector. If this is the case, the discount rate to be used may differ to the extent that the project's level of systemic risk depends on the relevant reporting environment to be considered. Such differences in reporting environments require that they be clearly and properly identified, justified, and measured.

APPENDIX

A.1 Determination of The Risk Premium for A Borrowing

To illustrate our argument, consider the simple case of an organization that must borrow $100 for one year to buy a quantity of natural gas valued at $100 today that will be sold in a year at prevailing market prices. Let us assume that the probability of default P_D equals the probability that the project will not be able to repay the entire loan ($100 plus interest at the end of a year), given the price of gas at $t = 1$.

To assess the value of the debt V_0, assuming that the lender bears the risk, we proceed as follows. Rather than weighing the various possible cash flows of a project or a loan by the probability $(1-P_D)$ of receiving such cash flows and discounting this expected cash flow at a risk-adjusted discount rate, we can, as is often done for the valuation of bond products, weigh the possible cash flow using the risk-neutral probability of default $\tilde{P}_D$ which takes into account the risk premium in order to obtain the certainty equivalent cash flows and discount these back using the risk-free rate.

Assuming r_f is the risk-free rate, $\tilde{r}$ is the rate required by the lender and L_D is the loss in case of default (expressed as a percentage of the amount owed),[a] we have today's value of the loan (asset) for the lender V_0: $V_0 = e^{-r_f}\left[e^{\tilde{r}}\left(1-\tilde{P}_D\right)100 + e^{\tilde{r}}\tilde{P}_D\left(1-L_D\right)100\right]$. At the time of the transaction, the rate $\tilde{r}$ required by the lender will be determined by the condition $V_0 = 100$, which gives us the following expression for the risk premium: $\tilde{r} - r_f = -\ln\left[\left(1-\tilde{P}_D\right) + \left(1-L_D\right)\tilde{P}_D\right]$. In cases where government carries out the project, we assume a situation of full insurance for the lender $L_D = 0$, since the taxpayers and not the lender will absorb the losses, if any. In this situation, the risk premium associated with the loan is equal to zero: $\tilde{r} = r_f$.

a For example, if at the time of default the loan balance (including accrued interest) is $105 and the sale of the assets securing the loan generates $80, the loss in case of default L_D expressed as a percentage of the loan will be equal to ($105 – $80)/$100 = 25%.

A.2 The Consideration of Risk in A Portfolio of Projects

The variance of returns associated with a portfolio N of projects can be expressed as $\sigma_{R_p}^2 = \sum_{i=1}^{N}\sum_{j=1}^{N} w_i w_j \sigma_{ij}$, where w_i is the weight (value between 0 and 1, representing the relative importance of the project) of project i within the portfolio, σ_{ii} is the variance of project's i's returns, and σ_{ij} is the covariance between the returns of projects i and j, where $i \neq j$. Let us assume, without loss of generality, that each project has the same weight $w_i = 1/N$ in the portfolio. In this case, the variance of portfolio returns becomes

$$\sigma_{R_p}^2 = (1/N^2)\sum_{i=1}^{N}\sigma_{ii} + (1/N^2)\sum_{i=1}^{N}\sum_{\substack{j=1 \\ i\neq j}}^{N}\sigma_{ij}.$$

Let us assume L is the largest variance of project returns. The first term in the above expression is thus always smaller than or equal to $(1/N^2)NL$. In a portfolio with a large number of projects, this term tends to zero. Now suppose that $\overline{\sigma_{ij}}$ is the average covariance of all pairs of projects. The second term of the above expression can then be written as $(1/N^{2)}N\left(N-1\right)\overline{\sigma_{ij}} = \overline{\sigma_{ij}}\left(1-(1/N)\right)$. With a very large number of projects, this term tends to $\overline{\sigma_{ij}}$.

For total elimination of risk through diversification, *all* projects in the portfolio must be independent (zero covariance). If the cash flows of a number of projects are correlated with general economic conditions, logically, these projects will be correlated, therefore, it will not be possible to reduce the variance of project-portfolio returns to zero. For all practical purposes, even with a very large number of "government projects," systemic risk persists.

A.3 Evaluation Error Caused by The Use of The Risk-free Rate

Using the risk-free rate for public sector project assessments leads to errors proportional to the level of the project's systematic (non-diversifiable) risk. For instance, the present value at the risk free rate r_f of an uncertain amount V_t receivable at period t is equal to $V(r_f) = E[V_t]e^{-r_f t}$.

Applying the capital asset pricing model with a single risk factor represented by the overall market portfolio, we get $V(r_v) = E[V_t]e^{-r_v t}$ by discounting at the rate $r_V = r_f + \beta_V \left(E[r_m] - r_f\right)$, with $\beta_V = (\rho_{Vm}\sigma_V)/\sigma_m$, where ρ_{Vm} is the correlation between the cash flows of the project and the market portfolio, and σ_V and σ_m are respectively the volatility of project cash flows and of the market portfolio. If the particular project has no systemic risk, it is correct to use the risk-free rate, because $\beta_i = 0$.

Using the ratio of the two discounted values $V(r_f)$ and $V(r_v)$, we have:

$$\ln\left[\frac{V(r_f)}{V(r_v)}\right] = \beta_V \left(E[r_m] - r_f\right)t. \tag{1}$$

The mistake made in using $V(r_f)$ instead of $V(r_v)$ increases in significance with the level of the project's systematic risk (β_V), the price of the risk $\left(E[r_m] - r_f\right)$ which is established on financial markets and the timing of the flow V_t. The situation is the same in the private sector. In expression (1), the level of risk β_V is calculated for the particular project.

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Appendix 3

BRITISH COLUMBIA
The Best Place on Earth

November 30, 2007 173031

Steve Davis, President
Independent Power Producers
Association of British Columbia
26 – 181 Ravine Drive
Port Moody BC V3H 4T7

Dear Mr. Davis:

Thank you for your October 19 letter addressed to the Honourable Carole Taylor, Minister of Finance, and the Honourable Richard Neufeld, Minister of Energy, Mines and Petroleum Resources, regarding BC Hydro's approach to evaluating its capital projects. Minister Taylor has asked me to respond. Please accept my apology for the delay in response.

As announced in the 2007 Budget, the government is currently reviewing BC Hydro's legislated debt cap and debt to equity targets in recognition of planned high levels of capital spending and resulting increases in borrowing requirements. Your comments will be incorporated into that review.

The participation of the Independent Power Producers Association of British Columbia in the pre-budget consultations and your submission to the Select Standing Committee on Finance and Government Services are appreciated. The feedback the Minister receives through this process helps to shape government's fiscal priorities to meet the future needs of British Columbians.

Sincerely,

Molly Harrington
Chief Executive Officer and Assistant Deputy Minister

pc: Honourable Richard Neufeld, Minister of Energy, Mines and Petroleum Resources
Bob Elton, President and Chief Executive Officer, BC Hydro

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BRITISH COLUMBIA

173031

NOV 06 2007

Steve Davis, President
Independent Power Producers Association of BC
#26 - 181 Ravine Drive
Port Moody, BC V3H 4T7

Dear Mr. Davis:

Thank you for your letter of October 19, 2007, regarding BC Hydro's 100% debt financing approach.

I have forwarded your letter to senior staff within the Ministry of Finance and asked that they review the issues you have raised. I have asked that staff respond to you directly, and provide my office with a copy for my files.

Thank you for bringing this issue to my attention.

Sincerely,

Carole Taylor.

Carole Taylor
Minister

pc: Hon. Richard Neufeld

Ministry of Finance

Office of the Minister

Mailing Address:
PO Box 9048 Stn Prov Govt
Victoria BC V8W 9E2

Telephone: 250 387-3751

Location:
Parliament Buildings, Victoria

IPPBC Independent Power Producers
association of British Columbia

October 19, 2007

Honorable Carol Taylor, Minister of Finance, and
Honourable Richard Neufeld, Minister of Energy, Mines,
& Petroleum Resources
Parliament Buildings
Victoria, BC

Re: BC Hydro 100% debt financing approach

Dear Ministers:

We continue to be concerned with BC Hydro's approach to evaluating its capital projects as if they were financed with 100% debt. This practice creates a totally false impression of the true cost of these projects.

We last wrote to both of you on this subject June 29, 2006. Minister Neufeld responded by e-mail dated August 4, 2006, in which he stated "I believe the BCUC review of BC Hydro's 2006 Integrated Electricity Plan and Long Term Acquisition Plan is the correct forum for debating the methodology for evaluating projects."

We agreed, and we intervened very actively in that hearing.

The IEP-LTAP proceeding has now been concluded and the Commission recently issued its Decision (May 11, 2007). Yet we feel the matter is still unresolved.

Ordinarily, we would simply accept the Commission's decision as the judgment of an impartial arbiter. However, in this case, we feel it is prudent to bring to your attention the fact that certain statements by the Commission in its Decision, and by BC Hydro in its evidence, suggest that both were lacking a requisite degree of clarity regarding the government's 'intent' with respect to its special directions HC1 and HC2.

We therefore feel it is appropriate for the government to issue further policy statements or directions to help clarify its 'intent' on this matter, for the benefit of all concerned.

The Commission's statements

The key statements by the Commission, to which we allude, are found on pages 202-203 of the IEP/LTAP Decision:

> ***"However, based on forecasts of capital expenditures and debt levels prepared by BC Hydro in this proceeding, the Commission Panel accepts that for the foreseeable future incremental capital projects will effectively be financed with 100 percent debt.***
>
> *While the Commission Panel accepts this as an outcome of the actual mechanical operation of HC1 and HC2, the Commission Panel is sympathetic to the arguments made by Terasen and IPPBC regarding the intention of HC1 and HC2. The Commission Panel agrees with Terasen that HC Equity will in fact be a source of funds for capital expenditures in coming years. However, the Commission Panel also agrees with BC Hydro that given the way HC1 and HC2 work in practice, there is no direct linkage between the level of capital spending and the level of equity in the company. As a result, the Commission Panel agrees with BC Hydro that, based on current capital spending projections and debt limits, capital expenditures by BC Hydro can only affect debt levels in the company and therefore the cost of debt represents the opportunity cost of these expenditures, either via increasing debt levels or reducing the rate at which debt would otherwise be retired.*

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The Commission Panel also agrees with IPPBC's characterization of the role of retention policies in commercial corporations to fund normal capital investment. ***However, since BC Hydro's owner has provided no policy statement regarding the intention of HC1 and HC2 and has not intervened in these proceedings to clarify its policy intention,*** [emphasis added] *the Commission Panel must accept the evidence of BC Hydro regarding the operation of HC1 and HC2 and their effect on the impact of incremental capital expenditures on ratepayers."*

The Commission accepted that equity (in the form of retained earnings) would certainly be a source of funds, as demonstrated in cross-examination by both Terasen and IPPBC, but the Commission was persuaded that the mechanical operation of HC1 and HC2 would result in the accumulation of equity regardless of the amount of BC Hydro's capital investments. Therefore, it concluded, the equity was not in any way connected with the investment decisions. Yes, it agreed, equity would accumulate, but that accumulation was completely disconnected from any investments made by Hydro and therefore should not be considered in the opportunity cost of that investment capital.

IPPBC argued (Final Argument of the IPPBC in the IEP/LTAP proceedings, Doc 14456, 02-23-07, pages 4-8) that the government's plan, with regard to the dividend policy prescribed in HC1 and HC2, was well designed to provide BC Hydro with sufficient equity capital to allow it to pursue the necessary programs of capital replacement and growth, through the foreseeable future, without compromising its balance sheet to an extent that would throw undue risk onto the taxpayer.

However, in the absence of any further clarification from BC Hydro's owner, the notion that the accumulation of equity was mechanically unrelated to the capital investments became the notion that prevailed in the minds of the Commission Panel.

BC Hydro's statements

The key statements by BC Hydro, to which we allude, are found in the Transcript of the IEP/LTAP proceedings, Volume 18, pages 2770-2772, the testimony of Mr. Standbrook, under cross-examination by Mr. Perttula of Terasen Gas Inc.:

Mr. STANDBROOK: A: *"...And I think you have to step back a little bit, I guess, and look at opportunity cost in BC Hydro versus opportunity cost in, say, an investor-owned unregulated utility. When cash is raised in an unregulated or an investor-owned utility, I think management has basically four choices that they can use with that cash. They can pay down debt, they can return it to their shareholders, either by way of a dividend or by buying back shares. They can keep it in the company, invested in assets. Or they can do some combination of the above.*

And in having that combination available to them, one of the combinations they could pick is to pay down debt and refund equity in the same ratio as their target debt/equity ratio. So, they have the opportunity, then, to return that to shareholders, and that would generate their weighted average cost of capital return. So they would look at their financing, then, as always being at their weighted average cost of capital, because they shouldn't decide to retain cash in the business if they couldn't at least make the return that they would make by paying off the debt and returning it to the shareholders.

At BC Hydro, that's not really quite the same, ***because we don't have the option to adjust our dividend policy****. That's set by Special Direction. It's 85 percent of our distributable surplus. And we certainly don't have the option to buy back shares that are out there in the marketplace, as there are none. So we really don't have that option.* ***The only two options we have are paying off debt or retaining it in business****.* [emphasis added]

So for BC Hydro, our opportunity cost is the cost of debt. ***And therefore, we look at it as every – every capital expenditure that we have is in fact financed by debt****. And that is a little bit counterintuitive compared to other corporations* ***because of the restrictions we have on our dividend policy, and on our ability to return equity to the shareholder****."* [emphasis added]

Mr. PERTTULA: Q: *"Do you agree with me that the portion of annual earnings that BC Hydro retains, i.e. the 15 percent retained according to the Special Direction, is a source of funds that's available to BC Hydro to deploy in its annual capital expenditures and for other uses?"*

Mr. STANDBROOK: A: *"Certainly. And again, I would reiterate that our opportunity cost of that cash is debt, because what we would otherwise do with that, if we didn't otherwise expend it, is to pay down debt."*

From the above testimony it is clear that BC Hydro considers the cost of debt to be their "opportunity cost" of capital for all investments, primarily because they do not have the option of varying their dividend policy and, say, paying a special dividend to their shareholder, in order to prevent their equity from growing too high. Mr. Standbrook is implying that if BC Hydro had the option of repaying its equity to its shareholder, that would completely alter the way it views its opportunity cost. It appears that simply having the option to pay additional dividends to the shareholder would be sufficient for BC Hydro to then consider its opportunity cost of capital to be a weighted average of debt and equity.

The IPPBC, in its cross-examination by Mr. Austin (IEP/LTAP Transcript Volume 17, pages 2606-2651), demonstrated that BC Hydro has, in fact, paid a special dividend to its shareholder in the past, and has also paid profit sharing refunds to its ratepayers in the past, and so it already does have the ability to control its debt/equity ratio, <u>if it chooses to</u>. Our argument, however, was apparently not fully persuasive to the Commission Panel. Apparently, BC Hydro needs an <u>instruction</u> from the government to do this.

What is needed?

Both the Commission and BC Hydro have pointed to the government's directives HC1 and HC2 as being so restrictive of BC Hydro's latitude for managing its debt to equity ratio, as to eliminate all connection between the equity on the balance sheet and the investment program. The IPPBC does not believe that was the government's intent. The need for the equity on BC Hydro's balance sheet most certainly is (and properly should be), related to BC Hydro's investment program. The equity is there to balance the risk between the ratepayers and the taxpayers (see the discussion in the following section below).

What is needed at this time may be as simple as a statement from the government to clarify its intent. Did it intend HC1 and HC2 to operate in a strict mechanical sense, and thereby preclude BC Hydro from actually managing its debt to equity ratio? Did it intend that the equity accumulating on BC Hydro's balance sheet should bear no relationship to its investment program? Or did it simply wish to give BC Hydro some latitude to manage its balance sheet within certain constraints? The IPPBC believes the government's intent was the latter, and that **the situation can be remedied by giving some clarifying instructions to BC Hydro**. To do so, the government can use either or both of the following approaches:

1) Amend the dividend mechanism that appears to be causing the problem -- causing BC Hydro to perceive that its balance sheet equity is completely disconnected from its capital investment decisions, and that it has neither the ability nor the obligation to manage its balance sheet debt to equity ratio. The amendment needs to direct that BC Hydro, in consultation with its shareholder, shall set targets for its debt/equity structure that are appropriate for its projected level of investments, and that BC Hydro shall manage this structure towards those targets, within the limitations of HC1, but not precluding the making of additional payments to the government, as needed to manage the structure.

2) Direct that, for the purposes of forecasting and evaluating the economic and ratepayer impacts of any investments of the authority's capital, BC Hydro shall include a presumption that each investment will earn a rate sufficient to cover all the items in Section 2 of HC2, specifically including a pro-rata share of the authority's debt and equity.

What is the proper level of debt and equity for BC Hydro?

It is possible that the government intends that BC Hydro should not require any equity to support its investment program (or only a minimal amount of equity). If that is true, then the ratepayers would be eternally grateful if BC Hydro would simply pay out all of its surplus equity to the government and cease charging the ratepayers that 13-14% every year in their electricity rates.

The IPPBC does not believe, however, that this is the government's intent. We believe that the government realizes all too well, just as all IPPBC members do, that equity is required in every project investment, in order to cushion the lenders from some of the risks (notably the capital cost overrun risk, but also a number of other risks associated with every capital investment). Either that equity has to be provided explicitly, on BC Hydro's balance sheet, or it will be provided implicitly, by the guarantee of the shareholder (the taxpayers of B.C).

The lower BC Hydro's balance sheet equity becomes, the greater is the risk to the taxpayers, and the greater is the implicit equity being provided by their guarantee. However, the lower BC Hydro's balance sheet equity becomes, the lower are the returns paid to the taxpayers, in the form of dividends. Consequently, if BC Hydro does not have sufficient equity to support its own investment program, then the taxpayers will be implicitly bearing additional risk – and that additional risk will be under-compensated by dividend payments.

While too little equity exposes the taxpayers to undue, uncompensated risk. **too much equity exposes the ratepayers to unduly high electricity rates** (because equity is charged at more than twice the rate of debt). There must be a 'proper' balance struck between these two extremes. And BC Hydro must be required to manage that balance towards some long-term target, which should be established in consultation with its shareholder, and with recognition to the size of its intended investment program.

If BC Hydro were to attempt to finance its projects on a standalone basis, with no recourse to the taxpayers of British Columbia, it would soon find out from the lending institutions, what is the 'proper' level of equity they would deem necessary to cushion the risks of any particular investment, or portfolio of investments. We suspect it would be similar to commercial corporations in the same line of business, in the range of 60-70% debt and 30-40% equity (measured by GAAP rules).

A ratio of 67/33 (GAAP basis, equivalent to about 60/40 using the HC definition of equity) was supported by evidence that BC Hydro itself provided (response to IPPBC IR 2.1.2 Attachment 1, which was taken from an internal presentation to the BC Hydro Board of Directors, August 2, 2003). A similar ratio is also shown to be an achievable target over the next 20 years, even with an annual capital program of $1-$1.2 billion (BC Hydro's response to BCUC IR 3.32.1 and 3.32.2, which is discussed in Mr. Perttula's cross-examination of BC Hydro's Panel 6 on pages 2772-2787 of the IEP /LTAP Transcript, Volume 18).

IPPBC's concern

Our concern is not necessarily with respect to a head to head competition between specific BC Hydro projects and IPP projects, because government policy has separated these so that they rarely compete head to head. Rather, our concern is that the entire government policy with respect to private sector power development could be called into question if BC Hydro continues to understate the true cost of public sector projects.

Our concern is over the public perception of the cost of BC Hydro projects (relative to IPP projects), which, if understated, will only fuel the arguments of those who oppose the government's energy policy on the grounds that public sector projects are much less expensive for the ratepayers. We know this argument to be faulty, but it is only given more credence if BC Hydro understates the true costs of its projects by ignoring the equity component of its cost of capital.

This public perception is one of the key reasons why IPPs continue to argue for a "level playing field". Yet our concept of a level playing field has been often misunderstood. IPPs have even been unfairly accused of trying to "tilt" the playing field in their favour. In fact, IPPs have no difficulty recognizing when BC Hydro projects have a legitimate claim to lower costs.

IPPs have no difficulty understanding why Resource Smart projects are likely to be lower cost alternatives for the ratepayers than are greenfield IPP projects. Projects which merely expand on existing facilities or infrastructure should be cheaper, less risky, and easier to develop than greenfield projects.

It doesn't worry us if BC Hydro projects have some legitimately lower costs. We still believe that IPP projects will continue to be very competitive for the ratepayers because they can be managed more efficiently, with lower overhead expenses, and because they offer the ratepayers a much greater protection from risk.

Even if public sector projects may look less expensive in the forecasts, those forecasts are quite different from the long-term firm prices contracted with IPPs. With public sector projects, the ratepayers (and ultimately the taxpayers as well) continue to be exposed to the open-ended residual risks – when the actual costs turn out to be much higher than they were forecast, the ratepayers must bear the additional burden. Whereas with IPP projects, the contracted price is the price the ratepayers will pay – the IPP, not the ratepayer, bears the risk of managing the project costs.

Although we can accept any legitimate reasons for BC Hydro projects having lower costs, we have great difficulty accepting the pretense that the capital charge for a BC Hydro project should be less than half that for a comparable IPP project, **simply because BC Hydro management hasn't been granted the ability to manage its own balance sheet**. BC Hydro is saying that, because the government directives have taken over the control of the equity content on BC Hydro's balance sheet, therefore that equity is no longer considered a cost of capital, and need not be considered when evaluating the economic and ratepayer impacts of capital investments.

We do not consider that argument to be legitimate. It is an artificial pretense, and it fosters the illusion of a cost which isn't true -- an illusion which will only undermine the government's policy in the public's mind.

Nevertheless, the remedy would appear to be in the government's hands. BC Hydro needs to have the obligation, and the ability, to control its equity level by paying additional dividends to the government.

It would thereby be able to manage its balance sheet ratios toward some long-term target that is appropriate for its desired level of capital investment. Only then, it appears, would BC Hydro's management consider the cost of equity to be part of its opportunity cost of capital, and evaluate capital projects accordingly, using a weighted average cost, rather than 100% debt.

Conclusion:

We therefore urge your government, as the shareholder of BC Hydro, to clarify to BC Hydro management that it should consider the cost of equity to be part of its opportunity cost of capital, and evaluate capital projects accordingly, using a weighted average cost, rather than 100% debt.

If you would like to discuss this matter, or to set a meeting, my direct line is (604) 926-8352.

Yours sincerely,

Steve Davis
President

Cc: Bob Elton, BC Hydro

P.S. In response the Ministry of Finance's invitation for Pre-budget Consultation on the theme "What choices would you make for a greener future?" the IPPBC made a Submission to the Select Standing Committee on Finance and Government Services on October 19, 2007. That Submission included reference to and recommendation on BC Hydro's 100% debt financing approach. A copy of this letter is appended to that Submission.

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Appendix 4 – Deep Into the Details

In the body of this submission, there is a description of three methods of financial/economic evaluation being used by BC Hydro for its comparisons of the Site C project to the alternative clean energy projects.

Although these three evaluation methods have slightly different applications, they all commence at the same starting point. All rely, for their starting points, on the UECs and UCCs taken directly from the Resource Options Report,[15] (the basic inventory of possible energy and capacity projects), and/or the underlying energy, capacity, and cost estimates assembled therein.

In this Appendix, some of the calculations and adjustments that have gone into the basic (Plant Gate) UECs and UCCs, and the Adjusted UECs and Adjusted UCCs, will be explored in more detail to highlight some of the more uncertain or inherent bias.

The Basic UEC and UCC at the Point of Interconnection

Each UEC and UCC starts with a **basic value** that represents the constant real $ cost of a project's energy (in $/MWh) or capacity (in $/kW-yr), **up to the point of interconnection ("POI")**. These basic values can be referred to as the **plant gate prices.**

The basic POI values for the UECs and UCCs are determined for each resource inventoried in the Resource Options Report, using a simplified annualization calculation. In either case the process consists of four steps:

1. The real $ capital cost is inflated with interest during construction ("IDC"), based on some assumed rate of spending over the number of lead-up years prior to commercial operation.
2. The capital cost plus IDC is then converted to an annualized annuity over the project life, at a real discount rate of 5% for BC Hydro projects and 7% for independent power projects ("IPPs").
3. The real $ annual operating cost is added to the real $ annualized capital cost to get the total annual cost (still in real present dollars).
4. If it is an energy project, the total annual cost is divided by the average annual energy to give the UEC ($/MWh).

   Or, if it is a capacity project, the total annual cost is divided by the "dependable" capacity to give the UCC ($/kW-yr)

Although the process is simple, there are a number of **points of contention**:

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[15] https://www.bchydro.com/energy-in-bc/planning-for-our-future/irp/current-plan/document-centre/reports/2013-ror-update.html

- Is the **capital cost** and pre-startup spending pattern correctly estimated?
- Is the **capital escalation** properly estimated? Many capital components may not simply escalate with inflation, which is the assumption when "real" dollar costs are used?
- Is the **IDC** properly estimated to reflect the estimated debt-financed construction spending schedule?
- Is the **discount rate** appropriate? The 5% used for the Site C project vs. 7% used for all the alternatives, greatly favours the Site C project over any alternative projects (see the discussion under the heading "Government Subsidies and BC Hydro's Cost of Capital")?
- Is the **project life** appropriate? A shortened estimated life-span will increase the apparent cost; a longer assumed life will reduce the apparent cost? This is definitely an inherent bias when comparing wind generation projects forced to amortize in 20 years, while the Site C project is given the luxury of 70 years.
- Are the **operating costs** properly annualized, including periodic capital replacement costs? Where, for instance, is the missing $43 million per year erased from Site C project's costs in the 2013 Resource Options Update?
- Is the **annual energy** or **"dependable" capacity** correctly estimated?

Firm Energy and Dependable Capacity

Both Firm Energy and Dependable Capacity are important definitions affecting the determined cost of IPP projects, and should therefore be **important topics to explore further.**

Firm Energy refers to the amount of annual energy that BC Hydro can count on to meet its load during critical low water years. For wind projects, 100% of their average annual generation is considered firm. For run-of-river projects, only 78%.

The reduced Firm Energy value for run-of-river projects assumes that 22% of the average annual energy either will not be available during critical low water, or it will not arrive at a time when BC Hydro can use it to serve its load. (e.g. Excess energy arriving during the freshet may have to be sold to the US or Alberta because BC Hydro doesn't have the loads available to utilize that energy. It should be noted that the Site C project will suffer from this same problem during the freshet season, due to the inflows from the West Moberly and Halfway Rivers. This, however, is a condition due to a lot of other variables outside the purview of the project, and many of which could change dramatically over the life of a project.)

Dependable Capacity refers to the amount of its capacity that a project can deliver during the critical high-load winter months. It is generally more dependent on the reliability of the fuel source than the technology, and it can be impacted by operating requirements such as minimum flow or ramping rate restrictions. It can be attributed to individual projects, and it is the essential attribute for calculating a capacity project's UCC.

It can also allow an energy project to receive a capacity credit in its overall Adjusted UEC. One interesting quirk of the capacity credit calculation is that a project with a lower capacity factor will earn a greater $/MWh credit than an equal sized project with a higher capacity factor. Thus, the Site C project, with a 50% capacity factor, receives a capacity credit of $11/MWh, whereas a geothermal project, with a 95% capacity factor, receives only $6/MWh. (This occurs because the capacity credit allows for a fixed annual amount of $50,000 per MW of dependable capacity, but that number has to be divided by the total MWh, and the number of annual MWh per MW of capacity is greater for the geothermal project.)

The whole issue of the value of capacity is highly questionable in the first place, since new capacity added to a system that is already in surplus (which BC Hydro's system is), is worth nothing unless it can be sold, and that is constrained by the market and by the transmission connections. Other than that, new capacity may postpone a later capacity addition for a few years, but only for a few years. Site C has been granted a capacity credit worth $56,000,000 per year for 70 years.

Another measure of capacity contribution is the ELCC (Effective Load Carrying Capability). Although it is not assigned to individual projects, it is used in portfolio analysis to determine when additional capacity resources are required. ELCCs for intermittent resources are determined through statistical analysis. Wind resources are assigned 26% of their installed capacity, and run-of-river resources ("ROR") are attributed 60% of their average megawatts during December and January.

The UEC and UCC Adjusters

In the body of this submission, the section entitled "EVALUATION Sub-METHOD #1A – Adjustment Adders to the Unit Energy Cost", dealt briefly with some of the adjustment adders. A sample table (taken from the 2013 Resource Options Update) was given which listed a number of cost and/or savings adders that are used by BC Hydro to "adjust" the Unit Energy Cost ascribed to any particular project. i.e. to produce the Adjusted Firm UEC that is then used in the subsequent evaluation methodology.

For convenience, that table is again included below.

Note how, by means of these adjustment adders, Site C is given a capacity credit to offset its line losses, and moves from an $83 UEC at POI, to an $88 Adjusted Firm UEC. While a wind project moves from $92 at the plant gate to $117 (and, as noted earlier, ultimately to $123 once a further unknown adjustment is applied in the next stage). A bundle of ROR projects near the top of the table, starts with a $101 cost at the plant gate, but escalates to $174 once adjusted.

Resource Option	Project Name	Transmission Region[7]	Average Annual Energy (GWh)	UEC at POI ($/MWh)	Soft Cost Adder ($/MWh)	Firm Energy Adjusters[8] ($/MWh)	CIFT ($/MWh)	Line Losses ($/MWh)	GHG Cost ($/MWh)	Capacity Credit ($/MWh)	Wind Integration Cost ($/MWh)	Adjusted Firm UEC ($/MWh)
				1	2	3	4	5	6	7	8	∑1 to 8
Run-of-River Hydro	ROR_110-120_VI	VI	386	113	6	52	0	-1	0	0	0	169
Run-of-River Hydro	ROR_100-110_KN	KL	217	101	5	64	0	4	0	0	0	174
Run-of-River Hydro	ROR_110-120_NC	NC	135	115	6	54	1	8	0	0	0	183
Run-of-River Hydro	ROR_120-130_VI	VI	116	125	6	54	0	-1	0	0	0	185
Run-of-River Hydro	ROR_120-140_NC	NC	90	125	6	49	1	9	0	0	0	190
Run-of-River Hydro	ROR_120-130_LM	LM	649	125	6	64	0	0	0	0	0	195
Site C	Site C	PR	5,100	83	0	0	6	9	0	-11	0	88
Wind - Offshore	OBC24-1	VI	1892	166	8	-2	0	-1	0	0	10	182
Wind - Offshore	OBC25-1	VI	1347	167	8	-2	0	-1	0	0	10	183
Wind - Offshore	OBC28	VI	1442	181	9	-2	0	-1	0	0	10	196
Wind - Onshore	PC28	PR	591	90	5	-2	2	11	0	0	10	115
Wind - Onshore	PC21	PR	371	92	5	-2	2	11	0	0	10	117
Wind - Onshore	PC13	PR	541	92	5	-2	2	11	0	0	10	117

As shown in this table, there are a series of "Adjusters" added to the basic UEC or UCC of each individual project. These are intended to compensate for the different locations and different characteristics of various projects. However, some of these adders seem to be quite arbitrary and they can be hugely significant -- in some cases more than doubling the "apparent cost" of a project.

The fundamental concept of these adders is simple -- to estimate the economic impact of different project attributes on BC Hydro's overall system. However, the resulting calculations can create an apparent price, as shown to the public, which is double the amount actually received by the project.

Although the underlying purpose for these adders is well-intentioned, every item in the list is fraught with uncertainties and judgments that are well beyond the project's ability to control.

Most of these do not represent actual cash outlays from ratepayers' pockets, but rather hypothetical contingency allowances for future events that might possibly occur (or may not occur at all).

The Soft Costs Adder

This is a new 5% cost adder for the 2013 Resource Options Report, not previously included in 2010. It's intended to capture extra costs that may have been missed in the capital cost estimates, such as assessment, mitigation, or accommodation for environmental, First Nations, or other community matters.

Inherent Bias: Again, it is a hypothetical allowance, and whether it is needed or not is entirely dependent on the accuracy of the underlying capital cost estimates are. Certainly, making it a percentage of the overall UEC seems less appropriate than making it a percentage of the capital cost portion. Also, it may be unnecessary for technologies like wind or solar, where cost estimation guidelines are not keeping up with the significant drop in equipment costs relative to productivity gains.

The Firm Energy Adjuster

This adjuster can affect the apparent price of run-of-river hydro projects in a significant way. It's mainly a penalty for delivering freshet energy. The ROR bundle mentioned earlier receives a $64/MWh charge for this item, which simply means that a large portion of its energy production is being down-graded to non-firm, and receives only the forecast spot market price of $42/MWh. That drives up the price required for the remaining "firm" energy to $174/MWh in order to achieve the overall average of $101 needed to finance the project. (i.e. The project is still receiving an average of $101/MWh for its production, but it is listed in this table as costing $174/MWh.)

Inherent Bias: The ironic consequence of this adjuster is that it drives up the "published" price of this IPP power to $174/MWh without changing the actual average price received by the project, $101/MWh. What makes it worse is that the public then erroneously believes that Hydro is paying IPPs an exorbitant $174 for power that it has to sell for $42. This is somehow a matter of perceptions gone sadly wrong.

This "freshet charge" is an allowance based on looking backward instead of forward. The freshet "problem" is caused by the coincidence of Hydro's lack of load at a time of high spring run-off. The main impetus for the penalty charge is BC Hydro's desire to import as much cheap freshet energy as possible but it lacks the load to be able to do so.

Again, this "freshet charge" is not a cash cost to ratepayers. It is a 40-year long allowance for an event that may be reduced or even eliminated within a decade. The freshet could be rendered a non-problem if either the load in that time period increases, or the spring run-off moves to an earlier time. Incidentally, Hydro has instituted a "Pilot Freshet Rate" as a result of its 2015 Rate Design Application, to incent industrial customers to increase their load during the freshet period, and thus allow Hydro to keep buying cheap imported power to stock its reservoirs.

Global warming could eliminate much of the problem with reductions in snow-pack or increases in spring and summer air conditioning. So could the acquisition of any significant amount of year round industrial load such as LNG, or Google data centres, or new mines, or the electrification of the Northeast B.C. gas fields. So, in fact, could the construction of any significant amount of pumped storage. (Yet, interestingly, the high cost of pumped storage in the ROR does not include any offsetting benefit from the ability to buy up cheap freshet energy,

store it and sell it back during the high season for a significant gain. Instead, it prices pumped storage as a pure capacity resource. Furthermore, when it costs the addition of pumped storage to its Mica reservoir, it doesn't use the zero-cost-of-equity cost of capital, which could reduce the cost by more than half.)

Line Losses

The line loss adjuster for northern projects is roughly 10% added to the UEC because it represents transmitting all the energy from each project to the Lower Mainland -- even though the new load in the northern region is likely to be growing just as fast as any new generation in the region.

Inherent Bias: This allowance appears to be based on looking backward, at past energy flows, instead of forward, at future flows. Because it is assuming flows that won't necessarily happen, it is again a hypothetical allowance that may never become an actual cash outlay for ratepayers. These hypothetical costs won't become real costs if the system isn't operated that way.

The line losses are also based on a study done by the BC Transmission Corporation that primarily dealt with peak load losses, so they probably overestimate the losses under average load conditions. Again, this is a contingency allowance – it may be this bad, but on the other hand it may be a lot less.

In the future, the real exercise in planning will be in the coordination of distributed generation with the growth of distributed loads -- and BC is ideally endowed with a great potential for both. Utilities will have to beware of stranded assets as energy enters the age of empowerment.

Network Upgrades

This adjuster doesn't explicitly appear in the table, but seems to have been imposed off-page in arriving at the values that flow into the next stage of evaluation, and so it will be briefly dealt with here.

This adder represents an allocation of the projected cost of regional transmission enhancements between the POI and the bulk transmission system.

Inherent Bias: Unfortunately, any causality seems to be missing, or at least very difficult to establish. There is not necessarily any direct link between these upgrades and any specific generation projects. Hence these costs are not true incremental costs that would occur directly as a result of the building and operation of any specific project. These costs are an accounting allocation but they are being assigned to projects as if they were a direct consequence. Another potentially imaginary cost is being added, but the calculation method of that assignment is not revealed for scrutiny.

One of the advantages to using the System Optimization Model (described in the body of this submission under the heading "Evaluation Method #3"), is that this kind of cost is dealt with as it is needed by the total system, based on the loads and the generation sources selected by the optimizer. No attempt is made to assign those costs to specific projects. The costs simply appear within the total (minimized) present value.

Cost of Incremental Firm Transmission (CIFT)

This adder represents an assignment of the cost of future upgrades to the bulk transmission system (the 500kv grid) needed to bring power from remote parts of the province to the Lower Mainland. As with line losses, the implicit assumption is that any new energy will not be used in the region where it's generated.

Inherent Bias: The need for bulk transmission upgrades can only be determined from a complete analysis of where the new loads are going to be located and where will be the dependable generation to serve those loads during peak periods. Perhaps this analysis can be dealt with by the linear optimization model used for the Portfolio Analysis, but it is very difficult to attach causality to specific small intermittent projects. The need for bulk transmission upgrades is largely determined by the location of the large hydro dams that are designated to serve the big load centres during the peak load periods.

Wind Integration Charge (also sometimes referred to as Foregone Exports)

This is currently a charge of $10/MWh levied on individual wind projects' UECs.

Inherent Bias: Once again, this is not a definite cash outlay from ratepayers' pockets. Rather it is an allowance to compensate for a possible lost opportunity to sell capacity in the day forward market across the border -- an opportunity which may or may not be real, depending on many other variables, including available transmission capacity.

The amount was set in 2008, reaffirmed in 2010, and continued in use for the 2013 IRP. However, BC Hydro indicated in 2015 that a reevaluation of this charge was being undertaken, with results targeted for July 2016. Those results have never been revealed, but the report by Power Advisory, attached to this submission as Appendix 1, gives some comparative costs from other jurisdictions.

Capacity Credit / Adder (also referred to as the Cost of Capacity Backup)

The calculation of the Capacity Credit was largely dealt with in the earlier discussion of Dependable Capacity.

Another related charge, that arises in the Block Analysis (see the discussion of Evaluation Method #2 in the body of this submission), is the **Cost of Capacity Backup**. This is something that has never appeared before, in any Resource Options Report, and appears to be a 3rd way of imposing a charge for the same thing, i.e. for providing capacity. In the Block Analysis, a block

of energy projects needs to be "topped up" with some capacity projects in order to match a specific comparator, like Site C.

Inherent Bias: What this means is that 3 differential charges are being imposed for providing capacity:

1. Site C is given an $11/MWh credit for having capacity;
2. Each wind project is charged $10/MWh for not having capacity;
3. And, finally, the entire block of projects is charged an additional amount for acquiring the capacity projects to provide its own backup, such as simple cycle gas turbines that will rarely run except on the coldest days of the year, because all dependable hydro will be dispatched first, to avoid the carbon tax, which could equate to $13/MWh or more.

This really amounts to triple-charging for the same thing.

There is no good reason why this capacity charge should be imposed on a project by project basis or even for a block of projects. Hydro acquires energy projects when it needs energy and capacity projects when it needs capacity. It does not have to acquire a capacity project to back up every energy project. Its need for new capacity is not determined by the acquisition of the energy project. Its need is determined by the growth of its peak customer load (i.e. the total system load on the 4 coldest days of the year), and there are many other possible, and much cheaper, ways to deal with that peak load requirement. The cheapest obvious remedy would be to pay large industrial users for load curtailment. The curtailment is only ever needed on a few days out of the year, and most years it will never be needed at all

APPENDIX 5 – SITE C CAPACITY AND ENERGY

On paper the Site C project will provide 1,100 megawatts of capacity but the availability of this capacity and hence its values are unknown. The starting point for answering these questions lies in BC Hydro's Site C model. This is by no means the end point because suitable due diligence has to be undertaken on the figures in this model including a critical examination of the assumptions and the methodologies. "Have there been any abnormal adjustments?" The process is not unique to the value being placed on the capacity of the Site C project. It applies to all project data.

The Site C project is the third in a series of hydro-electric projects on the Peace River. Because of it enormous storage reservoir, the controlling project is the WAC Bennett Dam, which contains the Lake Williston reservoir, and the GMS powerhouse ("GMS"). Neither of the two downstream projects – Peace Canyon and Site C have large storage reservoirs. When the generators at the GMS are in use, the water being discharged downstream cannot be readily stored in Dinosaur Lake or the Site C reservoir. In most cases the equivalent amount of water must be used to concurrently generate electricity at Peace Canyon and Site C or concurrently spilled.

According to BC Hydro:

"*The Site C reservoir will be one of the most stable in the BC Hydro system with relatively little fluctuation in water levels during typical operations. The proposed maximum normal operating range for the Site C reservoir will be 1.8 metres – between 460.0 and 461.8 metres. However during typical operations the reservoir is expected to fluctuate within a smaller range*."

By contrast the level of the Williston reservoir which is created by the Bennett Dam must be maintained between 672.08 and 640.08 metres for a drawdown range of 32 metres.

The Site C reservoir cannot be deeply drawdown for example in advance of upstream discharges from Bennett or spring freshet flows from the West Moberly and Halfway rivers which flow directly into the Site C reservoir. Like Peace Canyon which has a nameplate capacity of 700 megawatts and a dependable capacity of 600 megawatts or a difference of about 17%, Site C is a very large run of river project.

In addition to operating constraints because of the drawdown limitations minimum flow releases from the Site C project will be required at various times of the year. Restricted flows will also be required during the ice formation period to help prevent flooding at the town of Peace River.

There should be little or no value in the Site C model for the firming, shaping and storage provided by the Site C project/reservoir and because of the above restrictions on operation, the dependable capacity should be less than the nameplate capacity.

During the spring freshet the flows from West Moberly and Halfway rivers cannot be stored. They must be used to generate electricity or spilled. Site C becomes a must run facility providing energy and capacity that BC Hydro may or may not need.

Value of Capacity and Energy

Depending on how much dependable capacity Site C can provide, the Site C model should contain a forecast value for this capacity until 2094. Under the heading "The use of a 70 Year Term for Site C in the Model and Comparative Evaluations" the CEABC explains why forecasts of this length are pure speculation and a 40 year term for evaluating Site C and the alternatives is the standard that should be used. It coincides with the maximum term of any Government bond issue. The CEABC does not know what forecast capacity value is in the Site C model but it is a matter that should be of interest to the BCUC . As noted under the heading "Evaluation Sub-Method #1A BC Hydro has assigned the Site C project a capacity value of $11/MWh and this assignment requires some due diligence.

In the chart entitled "*Comparing Unit Energy Costs of Site C and IPPs*" on page 7 of this Submission in the line entitled: "*Cost of Capacity Backup*" there is an ascribed a value of $5/MW. This is not a very high value.

The revenues obtained by the Government from the sale of the energy and capacity that is available under the Columbia Treaty are a very broad proxy for the trend in the value of energy and capacity. Annually there are about 1,300 megawatts of capacity and 4,500 GWh of energy available but it can be terminated on 10 years' notice. The annual revenue over the past 10 years has been in a slow decline[16] and the Budget Estimate for fiscal 2016/2017 is $126 million. Powerex's annual net income has experienced a similar fate[17]. Both indicate that open market sales of energy and capacity don't have a high value.

With the worldwide effort that is going into reducing the cost of battery storage, the overall trend to lower capacity costs is expected to continue. See page Appendix 1 under the heading: "*Battery Storage Technology*".

[16] Government of B.C. Budget documents, "Revenue by Source".

[17] Various BC Hydro Annual Reports. See also BC Hydro Fiscal 2017-Fiscal 2019 Revenue Requirements Application, Exhibit B-10, BC Hydro Response to CEABC Information Request 1.14.1.

Appendix 6

Agreement Providing Key Terms and Conditions For the

FEDERAL LOAN GUARANTEE BY HER MAJESTY THE QUEEN IN RIGHT OF CANADA

FOR THE DEBT FINANCING OF THE LOWER CHURCHILL RIVER PROJECTS

PREAMBLE

Nalcor Energy ("Nalcor"), Emera Inc. ("Emera"), the Province of Newfoundland and Labrador ("NL"), and the Province of Nova Scotia ("NS") have informed Her Majesty the Queen in Right of Canada ("Canada") (all collectively called the "Parties") that Nalcor and Emera or their affiliates intend to develop, construct and operate, with the support of NL and NS, the Muskrat Falls Generation Facility, Labrador Transmission Assets, Labrador Island Link, and Maritime Link Projects (the "Projects"). Canada, NL, and NS subsequently signed a Memorandum of Agreement to support the Projects on August 19, 2011 (the "MOA").

It is essential to Canada that the Projects have national and regional significance, economic and financial merit, and significantly reduce greenhouse gas emissions. Canada's Guarantee of the Guaranteed Debt of each Project will significantly enhance the credit quality of the Financing of each Project. Canada hereby agrees to guarantee the Guaranteed Debt of each Project and will provide the Guarantees for the Projects as more fully described, and subject to the terms and conditions described herein.

The agreements of Canada hereunder are made solely for the benefit of Nalcor, Emera, and their affiliates including the Borrowers, and for the benefit of the Lenders ultimately selected by them to make the Financing available for the Projects and may be relied upon by all such persons but may only be enforced by Nalcor and Emera and affiliates including the Borrowers.

Once it has been accepted by all the Parties, this agreement may be disclosed publicly by or on behalf of any of Canada, Nalcor, Emera, their affiliates, NL and NS.

As regards the MF, LTA and LIL Projects, MFCo, LTACo, LILCo, LIL Opco,Nalcor, NL and Canada, this agreement shall be governed by, and construed in accordance with, the laws of the Province of Newfoundland and Labrador and the federal laws of Canada applicable therein and all actions, suits and proceedings arising will be brought in the courts of competent jurisdiction of NL. subject to any right of appeal to the Federal Court of Appeal or to the Supreme Court of Canada. As regards the ML, MLCo, Emera, NS and Canada, this agreement shall be governed by and construed in accordance with the laws of the Province of Nova Scotia and the federal laws of Canada applicable therein and all actions, suits and proceedings arising will be brought in the courts of competent jurisdiction of NS, subject to any right of appeal to the Federal Court of Appeal or the Supreme Court of Canada. This agreement sets forth the entire agreement among the Parties with respect to the matters addressed herein as regards the Projects and supersedes all prior communications, written or oral, with respect thereto including MOA. This agreement may be executed in any number of counterparts, each of which, when so executed, shall be deemed to be an original and all of which, taken together, shall constitute one and the same agreement. Delivery of an executed counterpart of this agreement by telecopier or electronically shall be as effective as delivery of a manually executed counterpart of this agreement.

Canada understands that Nalcor and Emera, or their affiliates, will be soliciting offers for the Financings from a range of Lenders. Given the importance of a Federal Loan Guarantee to the Financing for each Project, Canada hereby acknowledges and agrees that upon request by Nalcor or Emera within a reasonable period of time prior to any proposed meeting, it shall make available senior representatives of Canada, and its legal advisors and financial consultants as appropriate, responsible for the provision and oversight of the Federal Loan Guarantee, for participation in meetings with credit rating agencies and potential Lenders to respond to queries concerning the Federal Loan Guarantee.

TERMS AND CONDITIONS

1. THE PROJECTS AND THE TRANSACTION PARTIES	
1.1 Projects:	The Muskrat Falls Generation Facility ("MF"), the Labrador Transmission Assets ("LTA"), the Labrador-Island Link ("LIL") and the Maritime Link ("ML"), each as more fully described as follows: MF: an 824-MW hydro-electric generation facility in the vicinity of Muskrat Falls, Labrador, which Nalcor will develop. LTA: a 345-kV HVac transmission interconnection between Muskrat Falls and Churchill Falls, which Nalcor will develop. LIL: a HVDC transmission line connecting the Island of Newfoundland to generation facilities in Labrador which Nalcor will develop but in which Emera Inc., via a Newfoundland and Labrador corporate entity, will have an opportunity to invest. ML: a transmission line connecting the Island of Newfoundland to the Province of Nova Scotia, which will be developed by Emera. Each of (i) MF and LTA together; (ii) LIL; and (iii) ML is referred to herein as a "Project" and together as the "Projects".
1.2 Guarantor:	Her Majesty the Queen in Right of Canada ("Canada" or "Guarantor").
1.3 Proponents:	Nalcor Energy ("Nalcor"), acting on its own behalf and not as agent of the Province of Newfoundland and Labrador ("NL Crown"), and Emera Inc. ("Emera.
1.4 Borrowers:	MFCo: a special purpose wholly-owned subsidiary of Nalcor.

	LTACo: a special purpose wholly-owned subsidiary of Nalcor. LILCo: a special purpose limited partnership controlled by Nalcor and held by it alone or together with Emera ("LILCo"). The obligations of LILCo will be guaranteed by LIL OpCo, a special purpose wholly-owned subsidiary of Nalcor ("LIL OpCo"). MLCo: a special purpose wholly-owned subsidiary of Emera. Each a "Borrower" and collectively, the "Borrowers".
1.5 Lenders:	Subject to the form of Financing Structure selected by the Borrower, with respect to each Borrower, a financial institution or a group of financial institutions or financiers that will purchase debt securities to be issued by such Borrower or make credit facilities available to such Borrower, which will be guaranteed by Canada pursuant to the Federal Loan Guarantee, defined herein (the "Lender" or "Lenders"). Lenders shall include a Guarantee Agent and Collateral Trustee for the benefit of the Lender, where applicable.
2. TRANSACTIONS	
2.1 Federal Loan Guarantee:	The Federal Loan Guarantee ("FLG") shall, in respect of each Project, be an absolute, continuing, unconditional and irrevocable guarantee of payment (not collection) when due of the Guaranteed Debt of the relevant Borrower to the Lenders. The Lenders shall not be bound to pursue or exhaust their recourses against the relevant Borrower or any security held by them before demanding payment from the Guarantor. Subrogation - Canada shall be subrogated in the rights of the Lenders for any Project in respect of and at the time of each and every particular payment made by the Guarantor. Acceleration - It shall be a term of any Financing Document for any Project that in the event of default by a Borrower thereunder, the Lenders shall not accelerate the loan. With respect to MF, LTA and LIL, "FLG Agreement" means the agreement among the Guarantor, MFCo, LTACo, LILCo and Nalcor containing their respective rights and obligations as contained in this Term Sheet. With respect to ML, "FLG Agreement" means the agreement among the Guarantor, ML and Emera containing their respective rights and obligations as contained in this Term Sheet.
2.2 Transaction Structure:	Canada, the Borrowers and the Proponents will work to agree on a Transaction Structure that in conjunction with the FLG Agreement will result in the Project debt achieving Canada's AAA credit rating. The parties agree that the credit rating agencies will be asked to confirm that the FLG Agreement and Transaction Structure would achieve this objective. The Parties agree that they will work together to finalize the Transaction Structure and form of

	Guarantee, including obtaining confirmation from the credit rating agencies, by January 31, 2013 in order to facilitate the start of the financing process.
2.3 Financing Structure:	Following the execution and delivery of all Financing Documents (defined in Section 3.5), ("Financial Close"), the Borrowers intend to pay for Project costs which would include construction costs, interest, fees and other related costs, using a combination of equity to be provided by the Proponents and debt to be made available by the relevant Lenders. The Parties agree that Financial Close for ML must occur by the later of 90 days after the Nalcor Projects, or December 31, 2013. The Financing Structure will be flexible enough to allow each Borrower to raise debt , by way of: (i) bank credit facilities; (ii) a commercial paper program; (iii) a single bond or a series of bonds with staggered short-term maturity dates or a single maturity date issued and maturing within the Construction Period (the period between Financial Close and Commercial Operations Date (defined herein)); (iv) a single long-term bond or a series of long-term bonds issued during the Construction Period; or (v) a combination of one or more of the foregoing options, together with any related hedging instruments. The Guaranteed Debt incurred during the Construction Period for each Project may be refinanced by way of loans, bonds or a combination thereof, provided that: (a) the principal amount of such refinancing does not exceed the then outstanding principal amount of the Guaranteed Debt; and (b) the term thereof does not extend beyond the end of the FLG Term, it being expressly agreed that any loan or bond that matures on or after the earlier of: (i) 2 years after COD; or (ii) 7 years after Financial Close, may not be further refinanced. All of the foregoing is hereinafter collectively referred to as the "Financing". As may be required by the nature of the Financing, a hedging program shall be put in place for each Borrower at Financial Close. In order to ensure certainty in the cost of the Financing for each of the Projects, any interest expense risk will be hedged. The Project hedging principles will be agreed to with the Guarantor prior to Financial Close. Canada, the Borrowers and the Proponents will work to agree on a Financing Structure for the Projects, it being acknowledged that a range of financing structures may be considered. "Commercial Operations Date" ("COD"), in respect of each Project, shall be the date upon which construction is certified by the Borrowers' Engineer to be complete and confirmed by the Independent Engineer, which is currently expected to be July, 2017.

3. FLG TERMS

3.1 Guaranteed Debt:	A. The total maximum amount of borrowing and hedging obligations (including principal, interest, fees, and costs) under the Financing to be guaranteed by Canada ("Guaranteed Debt") shall be the lesser of the following for each of the Projects: i. A fixed dollar-based cap of $6.3 billion, allocated among the Projects as follows: a. MF/LTA: up to $2.6 billion, b. LIL: up to $2.4 billion; and c. ML: up to $1.3 billion; herein called "Individual Project Debt Caps". ii. The amount of debt implied by the maximum Debt to Equity Ratios ("DER") for each Project as follows: a. MF/LTA: 65:35 b. LIL: 75:25 c. ML: lower of Nova Scotia Utility and Review Board (UARB) approval or 70: higher of UARB approval or 30; or iii. The amount of debt that provides a minimum Debt Service Coverage Ratio ("DSCR") of 1.40x for each Project throughout the Term of the FLG. B. The terms and conditions of the Guaranteed Debt shall be those commonly used in similar commercial transactions, shall be subject to Canada's approval, acting reasonably, and shall include the following: (i) Rate of Interest that is no greater than that which would be offered by Lenders to an entity with a "AAA" credit rating; (ii) The proceeds from the Guaranteed Debt and the Additional Debt shall be used for the sole purpose of the Project; and (iii) Any long-term bond issued in connection with the Guaranteed Debt may carry a call feature.
3.2 Term of the FLG:	The FLG Term shall begin on Financial Close and shall terminate on the earlier of: (a) payment in full of the Guaranteed Debt; or (b) the Maximum Term for each Project, as follows: (i) MF/LTA: 35 years after Financial Close; (ii) LIL: 40 years after Financial Close; and (iii) ML: 40 years after Financial Close.
3.3 FLG Amortization Profile:	The Guaranteed Debt shall be repaid in accordance with the following amortization profile: MF/ LTA : simple mortgage-style amortization, ending no later than 35 years after Financial Close; LIL : level amortization, ending no later than 55 Years after Financial Close; and

	ML : level amortization, ending no later than 40 years after Financial Close. The Amortization period is to begin on the earlier of: (i) Commercial Operations Date, and (ii) seven (7) years after Financial Close. The Amortization Profile shall be such that there is no principal outstanding at the end of each amortization period for each Project. In each case, save if bullet maturity bonds are used, there shall be at least one payment a year. Bullet maturity bonds may be used instead of amortizing bonds. Bullet maturities will be matched as closely as possible to the relevant FLG Amortization Profile.
3.4 FLG Maximum Exposure:	The maximum exposure to the Guarantor under the FLG at any given time shall be the actual amount outstanding on the Guaranteed Debt at such time based on the FLG Amortization Profile.
3.5 FLG Conditions Precedent:	A. The following conditions precedent (the "FLG Conditions Precedent") must be satisfied in form and substance acceptable to the Guarantor prior to the execution and delivery of the FLG for all Projects: (i) Confirmation by Credit Rating Agencies of indicative credit ratings for each of MF, LTA, and LIL (prepared on a non-guaranteed basis) equal to or higher than investment grade; (ii) Provision by Credit Rating Agencies of indicative credit ratings for the ML (prepared on a non-guaranteed basis and based on information provided in the application to the UARB) equal to or higher than investment grade; (iii) Enactment of legislation, and execution of formal agreements between the NL Crown and Nalcor (or related entities), which put into legally binding effect the commitments made by the NL Crown as outlined in Schedule "A", both the legislation and the agreements being to the Guarantor's satisfaction.; (iv) The formalization of a regulatory framework by the Province of Nova Scotia ("NS") in legislation and/or regulations; (v) Execution of an inter-governmental agreement (the "IGA") between Canada and the NL Crown in which NL Crown: (a) makes the commitments outlined in Schedule "A" to Canada; (b) indemnifies Canada for any costs that it may incur under the FLG as a result of a regulatory decision or regulatory change (including through legislation or policy) that prevents a Borrower from recovering Project costs and fully servicing the Guaranteed Debt; and (c) guarantees completion of the MF, LTA and LIL Projects to COD such that, where non-completion is due to NL Crown's failure to comply with the commitments outlined in Schedule "A", NL Crown shall indemnify Canada for any costs Canada may incur as a result of those Projects not achieving COD. (vi) Execution of an agreement between Canada and NS in which NS

	indemnifies Canada for any costs it may incur under the FLG as a result of a regulatory decision or regulatory change (including through legislation or policy) that prevents a Borrower from recovering Project costs and fully servicing Guaranteed Debt; (vii) Sanction of all Projects, including ML; (viii) Execution of an agreement (the "Emera Guarantee Agreement") between Canada and Emera, wherein Emera shall guarantee: (a) the payment of $60 million to the Guarantor in the event that Financial Close is not achieved by the date set out herein or funds are not drawn from Guaranteed Debt within a reasonable time after Financial Close; and (b) following the first draw of Guaranteed Debt, Emera will guarantee to complete the ML or to provide required funds to complete the ML; (ix) That all necessary environmental legal and policy authorities have been complied with to the satisfaction of the Guarantor; and (x) That all necessary aboriginal consultation obligations have been complied with to the satisfaction of the Guarantor. B. The following conditions precedent (the "FLG Conditions Precedent") must be satisfied by the applicable Borrower in form and substance acceptable to the Guarantor prior to the execution and delivery of the FLG for each Project of such Borrower: (i) Execution of the FLG Agreements and all other relevant documents necessary to effect Financial Close ("Financing Documents"); (ii) Provision by Credit Rating Agencies of indicative credit ratings for the ML (prepared on a non-guaranteed basis) equal to or higher than investment grade in the event that the UARB decision differs from the application submitted by MLCo; (iii) Satisfaction, in the sole discretion of the Guarantor, of any and all Project-related due diligence deemed necessary by the Guarantor, including satisfactory review of all required revenue-producing agreements and other agreements including the MF PPA, TFA, LIL Assets Agreement; (iv) Approval by the Guarantor, acting reasonably, of the Financing, Financing Structure, Financing Documents, and the Transaction Structure; (v) A report provided by an independent expert that the Projects have sufficient insurance coverage in place that is customary in projects of this nature and size; (vi) As required by the nature of the Financing, an interest rate hedging program be in place to hedge expected interest expense with respect to the Guaranteed Debt; (vii) All necessary permits, approvals, land-use agreements and other authorizations required at Financial Close have been obtained;

	(viii) Execution and delivery of the indemnity referred to in Section 4.9; (ix) Review of technical aspects of the Projects, including engineering, water resource and any other required due diligence by the Independent Engineer (as defined herein), and preparation and finalization (as confirmed by the Guarantor and Lenders, acting reasonably) of a technical due diligence report (the "IE DD Report") confirming that the Project execution plans are commercially reasonable, and consistent with Good Utility Practice; and (x) Other Conditions Precedent customarily included in commercial project financing transactions.
Date: _____ 3.6 Costs Incurred by Guarantor:	All reasonable third-party costs incurred by the Guarantor in relation to an FLG shall be at the expense of the Borrower for the benefit of which such FLG has been issued.
3.7 Guarantee Fee:	No fees shall be payable to the Guarantor in respect of the provision of any FLG.
3.8. Commitment Fees:	Any fees paid to the Lenders under the Project Financing, such as commitment fees or up-front fees, shall be commercially reasonable.
4. PROJECT DEBT	
4.1 Debt Service Coverage Ratio Definition and Test:	Definition: The Debt Service Coverage Ratio ("DSCR") in respect of any Borrower, and in respect of any 12-month period shall be calculated as follows: DSCR = Base Cash Flow / Debt Service, where: Base Cash Flow = Liquidity Reserves plus Contracted Revenues less Cash Operating Costs Debt Service = Amortization plus Interest Expense Amortization = The amortization amount corresponding to the FLG Amortization profile in respect of each Borrower Interest Expense = The interest expense for the period Contracted Revenues: (i) MF: (a) For purposes of Initial Debt Sizing, DSCR shall include only the Base Block Revenue plus Liquidity Reserve; and (b) For all other purposes, DSCR shall include the Base Block Revenue plus Liquidity Reserve, plus revenue from power purchase agreements with investment grade parties, based on total annual energy sales not to exceed (P50) energy production for MF. (ii) LTA: For all purposes, DSCR shall include LTA Tariff Revenue plus Liquidity Reserve. (iii) LIL: For all purposes, DSCR shall include revenue from NL Hydro under

	the LIL Assets Agreement plus any Liquidity Reserve. (iv) ML: For all purposes, DSCR shall include revenues collected from ratepayers under the cost-recovery framework imposed by the Nova Scotia Utility and Review Board plus any Liquidity Reserve. Cash Operating Costs includes all cash costs of the Borrower, excluding interest and principal on any Guaranteed Debt. <u>Test:</u> The DSCR Test shall apply both prospectively and retrospectively except as follows: (a) The DSCR Test shall apply prospectively in the context of the maximum Guaranteed Debt as defined in 3.1; and (b) The DSCR Test shall apply prospectively in the context of the Additional Debt. For purposes of the ML, the prospective calculation of the DSCR shall be based on the UARB-approved return on equity. DSCR will be calculated monthly on a rolling 12-month basis. "Base Block Revenue" means amounts paid by NL Hydro to MF in respect of the Base Block Energy purchase commitments as set out in the MF power purchase agreement and as described in the Memorandum of Principles.
4.2 Debt Service Coverage Ratio:	The DSCR for each Project shall be a minimum of 1.40x.
	If the DSCR falls below 1.40x, then a 30-day consultation process between the Guarantor and the relevant Borrower is triggered during which time information shall be provided to Canada to advise it of the reasons for such a decline and how the Borrower proposes to increase the DSCR. If it falls below 1.20x, then there shall be no distribution to equity holders. If it falls below 1.10x, it shall constitute an Event of Default.
4.3 Cross-Default Provisions:	MF, LTA, and LIL will have cross-default provisions such that an event of default of any one Borrower will represent an event of default of each of the other two Borrowers. There shall be no cross-default provisions in respect of Maritime Link.
4.4 FLG Events of Default:	The following is a non-exhaustive list of Events of Default in respect of each Project for purposes of the FLG: (i) Failure to satisfy any covenants in the Financing Documents or FLG Agreement, and to cure same within 30 days of notice of default; (ii) Misrepresentation, fraud, or breach of material representation; (iii) Bankruptcy, restructuring, and insolvency of a Proponent or a Borrower; (iv) Termination (other than a scheduled termination), invalidity, unenforceability or default (by any party to such agreement) of any key project agreement (eg. the MF PPA, TFA, LIL Assets Agreement, ML revenue collection agreement) that is not cured within any applicable grace period in that agreement (or within 30 days of the date of occurrence of such event if there is no applicable grace period), or replaced by an equivalent agreement within 30 days. This will be an Event of Default for the defaulting Party only; (v) Sale or Change of Control of Nalcor or the Borrowers, other than

	among the Parties, or non-permitted assignment of any key contracts; (vi) Insufficient funding of Cost Overruns or Cost Escalations that continues for 90 days after being identified by the Independent Engineer; (vii) Abandonment of a Project by the owner of the Project; (viii) Breach or termination of any contract of the Borrowers, including the commercial agreements between Nalcor and Emera, that is not cured within any applicable grace period in that agreement, (or within 30 days of the date of occurrence of such event if there is no applicable grace period) or replaced by an equivalent agreement within 30 days. This will be an Event of Default for the defaulting Party only; (ix) Unauthorized sale of any material Project assets; (x) Failure to provide certificate of the Independent Engineer confirming that budgeting and maintenance of the Project is being conducted in conformity with Good Utility Practice and such failure is not cured within 30 days; (xi) The DSCR falls below 1.10x; (xii) Failure to fund or maintain the Debt Service Reserves or the Liquidity Reserves as required in Section 4.16 and to cure same within 5 business days of payment therefrom; (xiii) Failure to pay principal or interest within 5 business days of due date; and (xiv) Other Events of Default customarily included in commercial financing documents.
4.5 Lenders' Events of Default:	The only Lenders' Event of Default in respect of the Guaranteed Debt shall be the failure by a Borrower and the Guarantor to pay a scheduled principal and interest payment. Upon the occurrence of a Lender's Event of Default, Lenders shall have all available remedies.
4.6 Security:	The security for the Guaranteed Debt shall include the following: (i) the assets of the Borrowers (including Liquidity and Debt Service Reserves); (ii) all contracts of the Borrowers, including key project agreements, as identified by the Guarantor; and (iii) the shares of the Borrowers provided that the shares of MFCo, LTACo and LILCo, may only be pledged to Canada or an agent of Canada. For greater certainty, the priorities of Security taken by the Guarantor shall be determined by the Financing Structure agreed upon, and in any event shall be subject in priority only to Security taken by a Lender, if any. The Borrowers shall take all actions necessary, in the opinion of the Guarantor, to maintain the validity, enforceability, and priority of the Guarantor's security.
4.7 Permitted Liens:	The Borrowers shall not be permitted to create or suffer to exist any lien on their assets except liens that are customary in project financing transactions including, without limitation: (i) liens for assessments or governmental charges or levies which are not delinquent (taking into account any relevant grace periods) or, if overdue, the

	validity or amount of which is being contested diligently and in good faith by appropriate proceedings and in respect of which adequate reserves in accordance with the accounting standard that has been adopted by the Borrower, that is, International Financial Reporting Standards, US GAAP or another recognized reporting standard, have been recorded on the balance sheet of such Borrower; (ii) construction, mechanics', carriers', warehousemen's, storage, repairers' and materialmen's liens but only if the obligations secured by such liens are not due and delinquent and no lien has been registered against title to any assets of such Borrower, or if a lien has been registered, same does not affect the Guarantor's priority in the Security and is being defended diligently and in good faith by appropriate proceedings and in respect of which adequate reserves in the amount of the lien plus 20% have been recorded on the balance sheet of such Borrower; (iii) easements, encroachments, rights of way, licences, reservations, covenants, restrictive covenants or other similar rights in land granted to or reserved by other persons provided that they are reasonable and have been complied with and can be assigned to the Guarantor; (iv) any lien securing purchase money obligations permitted to be outstanding, provided that each such lien affects only the property with respect to which the purchase money obligation it secures was incurred; and (v) any lien securing Additional Debt (defined in Section 4.8) permitted to be outstanding.
4.8 Permitted Debt:	The Borrowers shall not incur debt during the Construction Period and the FLG Term except for: (i) Guaranteed Debt (also known as "Project Debt"); (ii) Additional Debt (as described in 4.8(a)); (iii) Debt secured by a lien which is a Permitted Lien (other than a lien securing purchase money obligations); (iv) Trade payables or similar debt incurred in the ordinary course of business and for the purpose of carrying on same, representing the deferred purchase price of property or services; (v) Debt under purchase money obligations provided, however, that the aggregate principal amount of purchase money obligations outstanding at any time shall not exceed at any time: (i) for MF/LTA $15 million; (ii) for LIL $15 million; and (iii) for ML $15 million.
4.8(a) Additional Debt:	No additional debt may be incurred by the Borrowers during the term of the FLG, other than: (i) for an operating line of credit to a maximum of $10 million for MF/LTA, for LIL, and for ML; and (ii) additional debt to finance cost increases from the DG3 capital cost estimates provided to the Guarantor and the final estimates at Financial Close ("Cost Escalations"), to finance cost increases after Financial Close ("Cost Overruns"), and to finance costs associated with major repairs and refurbishments after COD, (collectively called "Additional Debt").

	Additional Debt shall be subject to the following conditions: (a) It shall not be covered by the FLG; (b) It may be secured provided that it is subordinate to the Guaranteed Debt; and (c) It must satisfy the Debt Equity Ratios and DSCR-based tests on a prospective, aggregate basis (taking into account the Guaranteed Debt and the Additional Debt) throughout the term of the Additional Debt. Additional Debt with bullet maturities will be subject to a deemed periodic amortization profile in order to preserve the validity of the DSCR-based test.
4.9 Independent Engineer:	An engineer (the "Independent Engineer" or "IE") shall have been appointed to permit each Lender and the Guarantor to complete their due diligence and to ensure compliance with the terms of the FLG Agreements and all Financing Documents required to effect Financial Close. The Independent Engineer will represent the Guarantor and the Lenders. The Borrowers shall provide written confirmation, that has been confirmed in writing by the IE, that they have no contractual or other relationship with the IE other than the obligation to pay the fees of the IE. The IE shall review the Project documents and any information provided in support of any drawdown requested by a Borrower and shall make a recommendation to the Lender by way of an IE certificate. The Independent Engineer shall be assigned a scope of responsibility designed to ensure the Projects are developed, maintained, and operated in a manner which is consistent with Good Utility Practice (as defined herein). The Independent Engineer shall have full access to all information related to the Projects and access to management and employees of the Proponents or Borrowers as required. The cost of the Independent Engineer shall be borne by the Borrowers. The Borrowers shall indemnify and save the Guarantor harmless from and against any liability that the Guarantor incurs solely by virtue of being found, in respect of the Projects, liable as a partner or joint venturer.
4.10 Expected Costs to Complete:	Cost Overruns for a Project must be funded with Equity and/or Additional Debt (subject to the provisions of section 4.8(a)) as follows: (i) Equal annual amounts calculated by dividing such Cost Overrun amount by the number of years remaining until COD. Each annual payment shall be funded no later than the date of the first advance of Guaranteed Debt in each year prior to COD, and the first annual amount shall be funded prior to the first advance under Guaranteed Debt after such calculation is made; (ii) The Independent Engineer will confirm the Borrower's revised estimates of Expected Costs to Complete and any related changes to the construction schedule, all by way of an IE certificate; and (iii) Adjustments may be made to such funding requirements from time to time as estimates of Expected Costs to Complete (and related date at which COD is expected to be achieved) are updated or

	revised, all as confirmed by the Independent Engineer. The foregoing shall not in any way limit the enforceability of the provisions of Sections 3.1 or 4.8. The expected costs to complete ("Expected Costs to Complete") in respect of any Borrower at any given time shall be determined by the Borrowers and reviewed and confirmed by the IE by way of an IE certificate to be provided in connection with any drawdown requests prior to COD. The DG3 Capital Cost Estimates shall form the basis for the Independent Engineer's review of and confirmation of any proposed changes to such estimates on an ongoing basis as construction proceeds. Expected Costs to Complete shall include contingencies and escalation. Expected Costs to Complete shall also include any interest during construction and costs associated with the Financing prior to COD, calculated on a pro forma basis.
4.11 Change of Control:	There shall be,no sale or change of control of any Borrower or subsidiaries, except as among the Parties, and no sale of any material Project assets. There shall be no sale or change of control of Nalcor.
4.12 Independent Engineer Certificate post COD::	On each anniversary following COD, and until the end of the FLG Term, the Borrower or the IE shall provide an Independent Engineer's certificate, in form and substance acceptable to the Guarantor, acting reasonably, confirming that budgeting and maintenance of the Project are being conducted in conformity with Good Utility Practice. Failure of the Borrower to budget and maintain in accordance with Good Utility Practice that results in the IE being unable to provide such certification shall constitute an Event of Default subject to a 30-day cure period.
4.13 Good Utility Practice:	"Good Utility Practice" means those project management design, procurement, construction, operation, maintenance, repair, removal and disposal practices, methods and acts that are engaged in by a significant portion of the electric utility industry in Canada during the relevant time period, or any other practices, methods or acts that, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could have been expected to accomplish a desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be the optimum practice, method or act to the exclusion of others, but rather to be a spectrum of acceptable practices, methods or acts generally accepted in such electric utility industry for the project management, design, procurement, construction, operation, maintenance, repair, removal and disposal of electric utility facilities in Canada. Notwithstanding the foregoing references to the electric utility industry in Canada, in respect solely of Good Utility Practice regarding subsea HVdc transmission cables, the standards referenced shall be the internationally recognized standards for such practices, methods and acts generally accepted with respect to subsea HVdc transmission cables. Good Utility Practice shall not be determined after the fact in light of the results achieved by the practices, methods or acts undertaken but rather shall be determined based upon the consistency of the practices, methods or acts when undertaken with the standard set forth in the first two sentences of this definition at such time.

4.14 Debt-Equity Contributions:	Construction costs shall be funded only with equity prior to Financial Close. Subject to the conditions provided herein (including, without limitation, the Individual Project Debt Caps in respect of any Guaranteed Debt, and the funding of Cost Overruns), following Financial Close, debt and equity funds shall be invested as follows: (i) 100% debt until such time as the target Debt Equity Ratio is achieved; and (ii) thereafter, debt and equity shall be invested on a *pro rata* basis in accordance with the targeted Debt Equity Ratio for each Project.
4.15 Distributions:	There shall be no distribution to shareholders by the Borrowers: (i) Where the DSCR is below 1.20x; (ii) During the Construction Period; and (iii) Where an Event of Default has occurred which has not been cured during the cure period if same has been provided.
4.16 Debt Service Reserves and Liquidity Reserves:	Each Borrower shall at all times maintain Debt Service Reserves in a dedicated reserve account. The Debt Service Reserves will, at all times, be funded in an amount at least equal to the debt service (principal and interest) obligations of such Borrower for the forward-looking 6-month period. The Debt Service Reserve is for the benefit of the Guarantor and in the event that the Guarantor is required to make payment to the Lenders under the FLG, then it shall be entitled to immediate reimbursement of such amount from the Debt Service Reserve. MFCo and LTACo shall, for the MF/LTA Project, also fund with equity and maintain a Liquidity Reserve in a dedicated reserve account that permits MFCo and LTACo to maintain a DSCR of no less than 1.40x for a period of ten (10) years after COD. LIL and ML may each establish a Liquidity Reserve in connection with the DSCR.
4.17 Prepaid Rent Reserve for LIL:	During the Construction Period all prepaid rent received by LILCo from LIL Opco under the LIL Assets Agreement shall be kept in a reserve account and upon completion and receipt of the first rental payment from LIL Opco the amounts in the prepaid rent reserve shall be released and applied in accordance with the waterfall established under the LIL Project Financing Documents. During the Construction Period, distributions equal to the investment returns on the capital invested in the prepaid rent reserve account may be made to the Nalcor LIL limited partner provided no default or Event of Default exists.

4.18 Reports:	The Guarantor shall be entitled to regular financial and operational reports for the Projects at the expense of the Borrowers. This will include all customary reports and all rights to access and audit as are provided to the Lenders.
4.19 Covenants:	Customary affirmative and negative covenants to be provided by the Borrowers.
4.20 Representations and Warranties:	Customary Representations and Warranties are to be provided by the Borrowers.

SCHEDULE "A"

NL Crown commits to do the following:

1. Approve the creation of those subsidiaries or entities controlled by Nalcor which are required in order to facilitate the development and operation of MF, the LIL and the LTA, and to ensure Nalcor and existing and new subsidiaries or entities have the authorized borrowing powers required to implement the Projects and meet any related contractual or reliability obligations.

2. Provide the base level and contingent equity support that will be required by Nalcor to support successful achievement of in-service for MF, the LTA and the LIL, in cases with and without the participation of Emera.

3. Ensure that, upon MF achieving in-service, the regulated rates for Newfoundland and Labrador Hydro ("NLH") will allow it to collect sufficient revenue in each year to enable NLH to recover those amounts incurred for the purchase and delivery of energy from MF, including those costs incurred by NLH pursuant to any applicable power purchase agreement ("PPA") between NLH and the relevant Nalcor subsidiary or entity controlled by Nalcor that will provide for a recovery of costs over the term of the PPA and relate to:

   a) initial and sustaining capital costs and related financing costs (on both debt and equity), including all debt service costs and a defined internal rate of return on equity over the term of the PPA;

   b) operating and maintenance costs, including those costs associated with transmission service for delivery of MF power over the LTA (as described further in 5 below);

   c) applicable taxes and fees;

   d) payments pursuant to any applicable Impact & Benefit agreements;

   e) payments pursuant to the water lease and water management agreements; and

   f) extraordinary or emergency repairs.

4. Ensure that, upon the LIL achieving in-service, the regulated rates for NLH will allow it to collect sufficient revenue in each year to enable NLH to recover those amounts incurred for transmission services, including those costs incurred by NLH pursuant to any applicable agreements between NLH, the LIL operating entity and/or the entity holding ownership in the LIL assets, that will provide for a recovery of costs over the service life of the LIL and relate to:

   a) initial and sustaining capital costs of the LIL and related financing and debt service costs, including a specific capital structure and regulated rate of return on equity equal to, at least, a minimum value required to achieve the debt service coverage ratio agreed to in lending agreements by the LIL borrowing entity;

b) operating and maintenance costs;

c) applicable taxes and fees; and

d) extraordinary or emergency repairs;

5. Ensure that, upon LTA achieving in-service, the regulated rates for the provision of transmission service over the LTA will provide for a recovery of costs over the service life of the LTA including initial and sustaining capital costs, operating and maintenance costs, extraordinary or emergency repairs, applicable taxes and fees and financing costs (on both debt and equity), including all debt service costs and a defined internal rate of return on equity over the term of any applicable agreement.

This agreement shall ensure to the benefit of Nalcor and Emera and their affiliates including the Borrowers and their respective permitted successors and assigns and shall be binding on the Parties. The Parties represent and warrant that once this agreement is accepted by the Parties as herein provided, it shall constitute the irrevocable, legal, valid and binding obligation of the Parties, enforceable in accordance with its terms.

IN WITNESS WHEREOF each of the Parties has executed this agreement as of the date set forth below.

HER MAJESTY THE QUEEN IN RIGHT OF CANADA, as represented by The Right Honourable Prime Minister of Canada,

Per: _____

The Honourable Stephen Harper

Date: _____

HER MAJESTY IN RIGHT OF NEWFOUNDLAND AND LABRADOR, as represented by the Premier

Per: _____

The Honourable Kathy Dunderdale

Date: _____

HER MAJESTY IN RIGHT OF NOVA SCOTIA, as represented by The Premier

Per: _____

The Honourable Darrell Dexter

Date: _____

NALCOR ENERGY

Per: _____

Name:

Title:

Date:

I / we have authority to bind the Corporation

EMERA INC.

Per: _____

Name:

Title:

Date:

I/we have authority to bind the Corporation

NOV 30 2012