An Updated Portfolio Present Value Cost Analysis of the Site C Project

Philip Raphals

Richard Hendriks

October 2017

Publication Information:

Cite this report as:

Raphals, P. and Hendriks, R. (October 2017). An Updated Present Value Cost Analysis of the Site C Project

This submission was funded in part by academic research grants. Dr. Karen Bakker, who commissioned the report, acknowledges funding support from the Social Sciences and Humanities Research Council of Canada, and program support from the University of British Columbia. The authors are solely responsible for the report's contents. The report does not reflect the views of the University of British Columbia or of the funder.

EXECUTIVE SUMMARY

The purpose of this Report is to provide the BC Utilities Commission with information relevant to its Inquiry into the Site C Project.

Comparing the Options

Under its Terms of Reference, the Commission must advise the Government on the **implications** of three options: completing the Site C Project by F2024, suspending it, or terminating construction and remediating the site.

To evaluate the implications of these three options, it is necessary not only to determine the direct costs that flow from each one, but also to choose and apply a methodology to **compare** the consequences of each option — and in particular their costs — in accordance with the Commission's terms of reference.

The Deloitte reports address in detail the direct costs of each option, but say nothing about how they are to be compared. The Commission's Preliminary Report is also silent on this crucial methodological issue.

BC Hydro's Submission to the Commission makes reference to three types of comparative analysis. It identifies **Portfolio Present Value Analysis** as its primary tool for comparing resource options. It also refers to **Portfolio Unit Energy Cost (UEC) Analysis,** which it relies on for illustrative purposes. Finally, it presents a **70-year Rate Impact Methodology.**

While BC Hydro suggests that it has carried out a present value analysis comparing portfolios with and without the Site C Project, **nowhere in its Submissions does BC Hydro present results or the supporting detail of that present value analysis.** In Appendix Q of BC Hydro's Submissions, System Optimizer outputs are presented for 11 scenarios, but (unlike the similar outputs presented in the 2013 IRP) the key result of each one — the present value of its incremental costs — is not shown.[1] Figure 1compares the System Optimizer outputs presented in the Integrated Resource Plan (above) and the present inquiry (below). The actual present value costs are conspicuously absent from the outputs provided to the Commission.

[1] Outputs for an additional 26 portfolios are presented in BCUC IR 1.44.0, Attachment 2. The observations presented in this section apply equally to these new portfolio runs.

Figure 1. Sample portfolio output from 2013 IRP (above) and Site C Inquiry Submission (below)

Integrated Resource Plan Appendix 6A

Input Assumptions	Load	DSM	Market Scenario	Site C	Thermal Resources	Other
	Mid Load & No LNG	Mid DSM (Option2(constant)	Scenario 1	ISD fixed F2024	Included	7% IPP CoC, $10 wind adder, Capacity bridging before F2024

	Discounted to January 2013 (F2013 $) - Jan DSM TRC
PV of G& T Resource cost - $ millions	5,607
PV of Trade Revenue - $ millions	(1,977)
PV of DSM Option cost - $ millions	2,986
PV of Total Portfolio Cost - $ millions	6,615

Supply Totals through 2020

	Wind	Small Hydro	Other	Site C	Total
Dep. Capacity (MW)	0	0	0	0	0
Firm Energy (GWh)	0	0	0	0	0

Supply Totals through 2030

	Wind	Small Hydro	Other	Site C	Total
Dep. Capacity (MW)	0	0	0	1,100	1,100
Firm Energy (GWh)	0	0	0	5,103	5,103

Supply Totals through 2040

	Wind	Small Hydro	Other	Site C	Total
Dep. Capacity (MW)	341	19	2,092	1,100	3,543
Firm Energy (GWh)	4,885	175	2,205	5,103	12,349

DSM Level in:

2020	7,886 GWh	1,421 MW
2030	11,190 GWh	2,036 MW

UECs and **UCCs** are shown for energy and capacity resource respectively. The UEC/UCC shown includes wind integration costs, soft costs and network upgrade costs where applicable. The UECs for gas-fired generation resources (CCGTs) are not shown as the UEC varies from year to year depending on the forecasted natural gas price.

Resources Selected

Year	Zone	Resource	Capacity - MW Installed	Capacity - MW Dependable	Energy - GWh Firm	Energy - GWh Total	UEC / UCC $/MWh or $/kW-year
2023	BCH_PR	Site C	1100	1,100	5,100	5,100	79
2029	BCH_PR	GMS Units 1-5 Cap Increase	220	220			35
2030	BCH_REV	Revelstoke Unit 6	500	488	26	26	50
2031	BCH_LM	MSW2_LM	25	24	208	208	92
2032	BCH_KN	100 MW SCGT KN	309	294	450	450	88
2033	BCH_KN	100 MW SCGT KN	206	196	300	300	88
2034	BCH_KN	100 MW SCGT KN	309	294	450	450	88
2035	BCH_PR	Wind_PC28	153	40	591	591	111
2035	BCH_KN	100 MW SCGT KN	206	196	300	300	88
2035	BCH_LM	Run of River LM 80_100	62	10	174	223	108
2036	BCH_PR	Wind_PC14	144	37	527	527	117
2036	BCH_PR	Wind_PC19	117	30	441	441	113
2036	BCH_PR	Wind_PC21	99	26	371	371	112
2036	BCH_KN	100 MW SCGT KN	103	98	150	150	88
2036	BCH_VI	MSW1_VI	12	12	100	100	127
2037	BCH_PR	Wind_PC13	135	35	541	541	113
2037	BCH_PR	Wind_PC16	99	26	377	377	116
2037	BCH_LM	Pumped_Storage_LM	1000	1,000			126
2038	BCH_PR	Wind_PC10	297	77	1,023	1,023	118
2039	BCH_PR	Wind_PC20	159	41	610	610	119
2040	BCH_PR	Wind_PC15	108	28	382	382	119
2040	BCH_VI	Biomass_VI	30	30	239	239	142

Appendix Q

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

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

Resources Selected

Year	Zone	Resource	Capacity - MW Installed	Capacity - MW Dependable	Energy - GWh Firm	Energy - GWh Total	UEC / UCC $/MWh or $/kW-year
2024	BCH_LM	Pumped_Storage_LM	1000	1,000			124
2027	BCH_REV	Revelstoke Unit 6	500	488	26	26	46
2029	BCH_PR	Wind_PC19	138	36	524	524	92
2029	BCH_LM	2017 Load Curtailment	85	85			77
2031	BCH_PR	Site C	1145	1,145	5,286	5,286	34+Suspension Costs
2036	BCH_LM	Pumped_Storage_LM	1000	1,000			124
2037	BCH_PR	Wind_PC14	144	37	570	570	92
2038	BCH_PR	Wind_PC20	156	41	594	594	92
2039	BCH_PR	Wind_PC28	153	40	641	641	94
2039	BCH_PR	Wind_PC48	150	39	538	538	95
2040	BCH_PR	Wind_PC13	135	35	577	577	98
2041	BCH_NC	Wind_NC09	333	87	1,074	1,074	101

Thus, while BC Hydro affirms that it has carried out a System Optimizer portfolio analysis, **it has deleted from the scenario outputs the specific results that permit an economic comparison amongst the options.** These omissions undermine the credibility of the Submission, as the missing data are essential to understanding the implications of the options, as required by the Terms of Reference.

As for BC Hydro's Rate Impact Analysis, careful review demonstrates that it is flawed:

- It is not based on an actual load forecast. Specifically, it displays no load growth at all for the last 47 years;
- No derivation or justification is provided for the "Increase in the Cost of Energy" figures, which represent the additional energy costs that flow from terminating the Site C Project. These values, which in fact represent the key drivers for the dramatic results of the analysis (Figures 16 and 18, and Tables 12, 14, 15, 16, and 19 of BC Hydro's Submission) are entered into the Excel spreadsheet as numbers, not formulae, with no information provided concerning their source or derivation. Furthermore, while presented

in nominal dollars, in constant dollars terms, these figures remain constant for the last 40 years of the analysis (at $648.1 million/year, in constant 2018 dollars), suggesting that they do not flow from a year-by-year modelling exercise;

- Incremental DSM savings fall precipitously after F2030, and are zero from F2054 through F2094.

Based on the evidence produced before the Commission, one must conclude that, because the rate impact analysis presented in BC Hydro's August Submission is built on a foundation of unsupported and unsupportable assumptions, it has **no probative value.**

This leaves the Commission in the unfortunate situation where BC Hydro has not provided a rigorous analysis of the comparative costs to ratepayers of the Complete, Terminate and Suspend options.

Portfolio present value analysis

This submission updates the modelling effort presented in our August Submission. It takes into account new data that has been presented by BC Hydro, as well as determinations made by the Commission in its Preliminary Report.

Data sources

Many of the data uncertainties in our August Submission have been resolved by relying on the Commission's Preliminary Report, the Deloitte reports, and BC Hydro's submissions and IRs, including load forecasts, DSM options and costs, resources costs, including pumped storage and biomass, and capacity market reliance.

We have developed a declining cost structure for wind power, based on the future cost reductions identified in the Commission's Preliminary Report (page xx).

For solar PV, we have modelled a cost decline based on BC Hydro's response to two BCUC information requests, which suggests that utility-scale PV will be less expensive than wind energy starting in F2027. Using these costs, we have conservatively relied on PV to provide half of the additional required energy in a year, up to a limit of 500 GWh additional per year, starting in F2027.

In our August Submission, following BC Hydro's policy in the IRP, we used natural gas (SCGTs) to respond to capacity shortfalls. Now, given the requirement of OIC 244, we exclude all new natural gas generation, and instead, like BC Hydro, rely on energy storage technologies (including but not limited to pumped storage) to meet capacity shortfalls.

Regarding energy storage, we have modified our assumptions from the August Submission to take into account BC Hydro's claimed need for 10 hours' storage capability. Furthermore, we annex as Appendix A an indicative cost estimate provided by Hydrostor Inc. for an Advanced Compressed Air Storage (A-CAES) system of this same size (100 MW / 1000 MWh), with a capital cost of just US$175 million, plus fixed operating costs of US$2 million/year. The round-

trip efficiency is estimated at 60-65%. While we have not modified our energy storage cost estimates based on this information, we regard it as further evidence that BC Hydro's submissions do not adequately reflect the current state of the utility-scale energy storage market.

Methodological issues

In its Appendix M, BC Hydro argued that the present value approach used in our earlier study *Reassessing the Need* was inadequate because its 20-year horizon only encompasses part of the Site C Project's 70-year lifespan. We note, however, that BC Hydro's 2013 IRP was based on this same methodology. Furthermore, as noted above, the alternate methodology proposed by BC Hydro (its 70-year rate impact analysis) is flawed and inadequate for decision-making purposes.

That said, we have concluded that the portfolio present value analysis method is not adequate to compare scenarios in which a large capital project like Site C is delayed for many years. Delaying commissioning of the Site C Project by eight years would cut in half the number of years in which its costs and benefits occur during the analysis period. Furthermore, as these are the last years of the analysis period, they are the most heavily affected by discounting. The inevitable result is that the Suspension scenarios tend to show substantially lower present value costs for Site C than do the Completion scenarios, even though they have higher capital costs.

There is no methodological "fix" for this mismatch. For the purposes of the present Inquiry, we have come to conclude that, **while present value analysis is the appropriate methodology for comparing the costs and benefits of commissioning Site C in F2024 or of terminating it, that same methodology cannot be used to compare termination against suspension**. Consequently, we use present value analysis for comparison between the Complete and Terminate options, only.

Instead, we urge the Commission to conceive the "Suspend" option as a variant of the "Terminate" option (akin to an insurance policy in which an additional cost is incurred in order to maintain a "restart" option).

Site C capital costs

BC Hydro has elected not to use its weighted average cost of capital for project financing, but rather its forecast weighted average cost of debt (3.43%). No justification is provided for this figure, nor for the assumption that no equity component is required for project financing. The role of equity was stated by Mr. Swain:

> In corporate finance, equity is the buffer between unexpected realities and bankruptcy. BC Hydro is merely outsourcing this risk to the general BC taxpayer. They are not making it go away.[2]

In our initial Submission, we estimated the construction costs of the Site C Project at $10.6 billion, based on BC Hydro's actual and forecast capital expenditures and a WACC of 7%. A similar calculation using a debt cost of 3.43% yields a capital cost of $9.285 billion.

We have been unable to reconcile BC Hydro's reported year-by-year capital expenditures with the Final Investment Decision capital cost of $8.335 billion, either including or excluding the deferral account balance. Neither BC Hydro's Submission nor the Deloitte report included a demonstration of this cost figure based on year-by-year capital expenditures and financing costs, an unfortunate oversight. The omission of this vital piece of information means that the Commission does not have the full information necessary to conduct the required analysis.

Obviously, Site C is not a risk-free project. Thus, the question of the allocation of the costs of those risks is central to the Commission's analysis. BC Hydro's financing assumptions are based on the premise that these risks need not be included in its costs, because they will be assumed by the taxpayer.

While we are not in a position to assess BC Hydro's interpretation of OIC 244, it is not possible to compare the economic merits of the three options regarding the Site C Project without taking taxpayer contributions into account. The logic is similar to that underlying the approach taken by BC Hydro — and by the Commission — with respect to the economics of DSM. To compare DSM to other resource options, their costs are evaluated based on total resource cost, not just utility cost. While utility cost represent the amounts that would eventually be recovered in rates, the total resource cost includes all the costs borne by the consumer — those that are paid in rates and those that are paid for otherwise. Just because part of the cost is paid by the ratepayer at the hardware store doesn't make it go away. By the same logic, the part of the Site C cost that is paid by the ratepayer in his income taxes doesn't go away, either. Thus, costs absorbed by the government (shareholder) in direct relation to the matter at hand must be included in the analysis, not excluded.

This logic applies to the issue of the equity risk premium, absorbed implicitly by the government to the benefit of BC Hydro. If BC Hydro can finance a project of this magnitude on a risk-free debt basis, it can only be because another entity is supporting the risk. Thus, the most appropriate way for the Commission to analyze the relative costs and benefits of the three options would be to evaluate the construction costs of Site C on the basis of BC Hydro's WACC, not its cost of debt. We therefore recommend that the Commission:

- affirm that BC Hydro's projects are not risk-free,
- include an equity component in its analysis of financing costs, and

---

[2] F-36-1, p. 18.

- adopt estimates of the cost of completing the Site C project that explicitly take equity costs into account.

Treatment of sunk costs

In our August Submission, we treated the amounts spent to date as sunk, excluding them from all three options, even though, based on standard regulatory accounting, the recovery of this amount would occur differently under each of the three strategies.

Relying on a rate impact analysis rather than an economic (present value) analysis, BC Hydro has taken the opposite course, modelling the recovery of sunk costs over 1, 5 or 10 years.

We believe that this approach improperly favours the option that defers recovery of these sunk costs as long as possible. Thus, it creates a strong bias toward project completion, regardless of the underlying economics. For this reason, we will continue our practice of excluding sunk costs from all three options.

Portfolio present value analysis: Results

As in our First Submission, we have used an Excel-based model, modified as described above, to evaluate the incremental costs of resource portfolios to meet energy and capacity needs under the mid, high and low load forecasts (Scenarios 1, 2 and 3) for each of the following resource strategies:

- Option A: Complete the Site C project by F2024
- Option B: Cancel the Site C project

Scenarios were also prepared, when appropriate, in which reliance on the Canadian Entitlement is allowed.

The central finding of the modelling exercise is that, under all load scenarios but one, terminating the Site C Project will result in lower costs to ratepayers than completing it by F2024. However, the amounts of these differences are relatively small. This can be taken as an indication that the Site C Project is nearing the point of no return, since, as the sunk costs increase and the cost to complete declines, the Complete option looks increasingly favourable, compared to the Terminate option.

The present value costs for each strategy under each load scenario are summarized in Table 1, along with the differentials between the Complete and Terminate scenarios. It shows that Termination results in resource cost savings of between $178 million and $369 million, in the mid and low scenarios, but an increase of $289 million in the high scenario.

Table 1: Present value costs ($ millions)

load forecast	Complete	Terminate	Cost Reduction
mid	903	725	178
high	6,396	6,685	-289
low	-2,447	-2,816	369

However, in the high and medium load scenarios, allowing reliance on 50% of the energy and capacity of the Canadian Entitlement reduces present value costs by a substantial margin. Table 2 shows that, if reliance on the Canadian Entitlement were to be allowed, terminating the Site C Project would save ratepayers $345 million under the mid load scenario, or $249 million under the high load scenario, compared to completing the project by F2024. (In the low scenario, there is no change.)

Table 2: Differential present value costs ($ millions), with Canadian Entitlement

load forecast	Complete	Terminate	Reduction
mid	915	570	345
high	6,150	5,901	249
low	-2,447	-2,816	369

Sensitivity: Cost overruns

Deloitte identified three plausible ranges for the final Site C capital cost. Based on BC Hydro's determination that it will not meet its milestone of river diversion by F2019, with a resulting cost impact estimated at $600 million, it is now unlikely that the Project cost will remain within the "low" range.

Using the midpoint of the Deloitte high range, rather than the midpoint of the medium range, results in an increase of the Site C capital costs included in the model by $489 million. In other words, the present value of each Complete scenario increases by $489 million when the upper Deloitte value is used. Using this higher cost value thus inevitably increases the relative benefit of the Terminate option, as follows:

Table 3: Differential present value costs ($ millions), with cost overruns

load forecast	Complete	Terminate	Reduction
mid	1,391	725	666
high	6,792	6,685	107
low	-1,822	-2,816	994

Thus, in the eventuality that the Site C capital cost falls in the Deloitte high range, the benefit of Terminate over Complete increases to $107 million in the high scenario, $666 million in the medium scenario, and $994 million in the low scenario.

As we have seen, these conclusions are dependent upon a large number of inputs and assumptions. We have endeavoured to make assumptions that are reasonable and conservative. In most cases, we have followed BC Hydro's assumptions; when we have not, we have explained our reasoning.

We reiterate our offer, made in our August Submission, to make our model available to the Commission and its staff, in order to carry out similar comparisons based on its own findings and assumptions.

ABOUT THE AUTHORS

Philip Raphals is cofounder and executive director of the Helios Centre, a non-profit energy research and consulting group based in Montreal. Over the last 25 years, he has written extensively on issues related to hydropower and competitive energy markets, and has appeared many times as an expert witness before energy and environmental regulators in several provinces.

Mr. Raphals has been formally recognized as an expert witness by energy regulators in the provinces of Quebec, Nova Scotia and Newfoundland and Labrador:

- In Quebec, he has provided expert testimony in 14 proceedings before the Régie de l'énergie du Québec. The Régie has recognized his expertise in fields including transmission ratemaking, security of supply, energy efficiency and avoided costs;

- The Nova Scotia Utilities and Review Board has qualified Mr. Raphals as expert in sustainable energy policy, least-cost energy planning and utility regulation (including transmission ratemaking). He provided expert testimony in two proceedings there concerning the Maritime Link, including critical analysis of long-term demand forecasts, resource options and financial analyses submitted by NSP Maritime Link Inc., a subsidiary of Emera, in support of its proposal to build an undersea transmission link between Newfoundland and Nova Scotia, and the accompanying long-term electricity supply contracts. In its decision, the Board quoted Mr. Raphals' report and relied in part on his analyses;

- The Newfoundland and Labrador Public Utilities Board has qualified Mr. Raphals as an expert in electric utility rate making and regulatory policy. He has provided expert testimony in in 2011 Muskrat Falls Review and in its hearings on the 2013 General Rate Application of Newfoundland and Labrador Hydro.

Mr. Raphals is currently acting as an expert witness in rate proceedings before the Manitoba and Newfoundland and Labrador Public Utilities Boards.

Mr. Raphals appeared as an expert witness on behalf of Grand Riverkeeper Labrador Inc. in the hearings of the Joint Review Panel (JRP) on the Lower Churchill Generation Project, which relied on his analysis of project justification. The Panel cited him in its report and relied on his analyses for several of its findings.

In British Columbia, Mr. Raphals appeared as an expert witness on behalf of the Treaty 8 Tribal Association in the hearings of the Joint Review Panel on the Site C Hydroelectric Project. The Panel cited him in its report and relied on his analyses for several of its findings. He also presented expert affidavits in two related proceedings before the B.C. Supreme Court, one of which was not received by the Court.

From 1992 to 1994, Mr. Raphals was Assistant Scientific Coordinator for the Support Office of the Environmental Assessment of the Great Whale Hydroelectric Project, where he coauthored with James Litchfield and Roy Hemmingway a study on the role of integrated resource planning in assessing the project's justification.

In 1995, Mr. Raphals was commissioned by the Quebec Department of Natural Resources to prepare a report on electricity regulation in British Columbia, focussing on the structure and practices of the British Columbia Utilities Commission. The report formed part of the documentation supporting Quebec's Public Debate on Energy, which eventually led to the creation of the Régie de l'énergie.

In 1997, Mr. Raphals advised the Standing Committee on the Economy and Labour of the Quebec National Assembly in its oversight hearings concerning Hydro-Quebec. In 2001, he authored a major study on the implications of electricity market restructuring for hydropower developments, entitled *Restructured Rivers: Hydropower in the Era of Competitive Energy Markets*. In 2005, he advised the Federal Review Commission studying the Eastmain 1A/Rupert Diversion hydro project with respect to project justification. Later, he drafted a submission to this same panel on behalf of the affected Cree communities of Nemaska, Waskaganish and Chisasibi.

Mr. Raphals chairs the Renewable Markets Advisory Panel for the Low Impact Hydropower Institute (LIHI) in the United States. He has been an invited speaker before the Senate Standing Committee on Energy, the Environment and Natural Resources and at numerous energy industry conferences, including the Canadian Association of Members of Public Utility Tribunals (CAMPUT). He has also been an invited speaker at Yale University, Concordia University and McGill University.

In 2013, Mr. Raphals was an invited participant in an expert roundtable on electricity surpluses and economic development, convoked by the Quebec Commission on Energy Issues. The Commission's report relied on several of his analyses.

In 2015, he was a finalist for the R.J. Tremplin Prize, awarded by the Canadian Wind Energy Association for "scientific, technical, engineering or policy research and development work that has produced results that have served to significantly advance the wind energy industry in Canada."

Richard Hendriks is the director of Camerado Energy Consulting, an Ontario-based firm providing environmental assessment, energy planning, policy analysis, and research services to clients across Canada. For the past two decades, he has been engaged in the planning and assessment of several proposed large-scale hydroelectric developments, and provided testimony before regulatory bodies concerning their environmental effects, economic viability, socio-economic impacts and implications for Indigenous rights. Mr. Hendriks has played a key role in environmental assessment and negotiation processes regarding large hydroelectric and mining projects for several First Nations across Canada, including for the Innu Nation in

Labrador with respect to the Lower Churchill Project, and for the Treaty 8 Tribal Association, with respect to the Site C Hydroelectric Project.

From 1999 to 2002, Mr. Hendriks was the environmental and engineering analyst for Innu Nation in relation to hydroelectric development proposals in Labrador. There, he participated in environmental assessment, negotiation of an environmental protection chapter of an impacts and benefits agreement in relation to the proposed Lower Churchill Project, and technical and research support for negotiation of a compensation agreement for the existing Churchill Falls Project.

In 2003, Mr. Hendriks joined Chignecto Consulting Group as an Associate where he provided resource negotiation and environmental assessment support services to Indigenous groups across Canada. His work included negotiation of impacts and benefits agreements, regulatory interventions, and assessment of environmental, economic and social impacts and benefits related to hydroelectric, transmission and mining developments.

Since 2009, as director of Camerado Energy Consulting, Mr. Hendriks has conducted and managed environmental, technical and economic review of several large-scale proposed resource projects, including the Lower Churchill Hydroelectric Generation Project, the Labrador-Island Transmission Link, the Site C Clean Energy Project, the Côte Gold Project, and the proposed Slave River Hydro Project. He has also assessed the potential for compensation to Indigenous communities for historic and ongoing effects of hydroelectric and transmission development in Ontario, Labrador, Manitoba and the Northwest Territories.

In 2010, Mr. Hendriks testified before the Alberta Utilities Commission during its Inquiry on Hydroelectric Power Generation that was reviewing the policy, planning and regulatory context for additional hydroelectric development in that Province. The following year, Mr. Hendriks presented testimony on several economic and environmental matters before the Joint Review Panel for the Lower Churchill Project, who accepted many of his recommendations. More recently, Mr. Hendriks testified on several occasions before the Joint Review Panel for the Site C Project, who adopted several of his recommendations. In May 2014, the Manitoba Public Utilities Board qualified Mr. Hendriks as an expert in the policy and planning aspects of large-scale hydroelectric developments, including the socioeconomic implications and environmental consequences for Indigenous communities of these developments.

Together with Prof. Karen Bakker of the University of British Columbia, MM. Raphals and Hendriks were the authors of “Reassessing the Need for Site C”, a study published by the UBC Programme on Water Governance in April 2017.

TABLE OF CONTENTS

TABLES

FIGURES

1 Introduction

1.1 Terms of reference

Under the Terms of Reference provided in OIC 244:

> 3(a) the commission must advise on the implications of
>
> > (i) completing the Site C project by 2024, as currently planned,
> >
> > (ii) suspending the Site C project, while maintaining the option to resume construction until 2024, and
> >
> > (iii) terminating construction and remediating the site; (emphasis added)

The OIC goes on to specify that the intent is to evaluate the costs to ratepayers of the various possible courses of action:

> 3(b) more specifically, the commission must provide responses to the following questions:
>
> (i) After the commission has made an assessment of the authority's expenditures on the Site C project to date, is the commission of the view that the authority is, respecting the project, currently on time and within the proposed budget of $8.335 billion (which excludes the $440 million project reserve established and held by the province)?
>
> **(ii)** What are the costs to ratepayers of suspending the Site C project, while maintaining the option to resume construction until 2024, and what are the potential mechanisms to recover those costs?
>
> (iii) What are the costs to ratepayers of terminating the Site C project, and what are the potential mechanisms to recover those costs? (emphasis added)

The word “implications” in section 3(a) of the OIC is very broad. It clearly includes the direct costs associated with each option, but certainly is not limited to those costs. In our view, to evaluate the “implications” of the three options, one must choose and apply a methodology to **compare** the consequences of each option — and in particular their costs — in accordance with the Panel’s terms of reference.

The Deloitte Report #1[3] establishes estimates of the costs of suspending ($1.418 billion) and terminating ($1.203 billion) the Project, but does not attempt to **compare** those costs against the costs of completing the Project, and there is no indication that the Commission asked it to do so.

[3] A-8, Deloitte. 2017. British Columbia Utilities Commission Site C Construction Review.

Similarly, the Commission's Preliminary Report makes no attempt to **compare** the costs of suspension or termination with the costs of completion, nor does it discuss the methodology to be used in such a comparison.

To the best of our knowledge, only two of the submissions to the Commission perform quantitative comparisons between these three options: BC Hydro's (F-1-1) and ours (F-106-2). The remainder of this section will explore the similarities and differences between these two approaches.

1.2 Three methodologies

BC Hydro's Submission refers to three distinct methodologies: portfolio present value analysis, unit energy cost analysis, and rate impact analysis.

Portfolio present value analysis compares the present value of the streams of incremental costs (net of revenues) of different resource portfolios that meet the same energy and capacity needs.

Unit energy cost (UEC) analysis derives an average levelized unit cost (per kWh) of energy for each portfolio or scenario.[4]

Ratepayer impact analysis attempts to estimate energy sales and revenue requirements for each future year, and compares the resulting average price of energy.

BC Hydro and the BCUC have both clearly indicated that portfolio present value analysis is the most important tool for comparing resource strategies. For example, BC Hydro writes:

> BC Hydro's main tool to compare resources is a portfolio present value cost analysis, and not Block UECs. This was described in our August 30 Filing in section 5.5: "Portfolio present value cost analysis (Portfolio PV Analysis) is BC Hydro's main tool to compare resource options, and is standard utility practice for resource planning."
>
> The use of simplified Block UEC analysis provides assistance in explaining the results of the Portfolio PV Analysis. A simplified Block UEC has the advantage of being easy to relate to in relation to the cost of a single resource, but is not able to account for a number of factors…[5]

---

[4] For clarity, in this report we will use the term **"options"** to refer to the three possible courses of action envisaged in the Terms of Reference. We will use the term **"scenarios"** to refer to the future conditions in which these strategies are implemented — primarily the low, medium and high load scenarios. And we will use the term **"portfolios"** to refer to specific combinations and schedules of resource additions (both supply- and demand-side) used to meet energy and capacity needs, within a particular scenario and following a particular strategy.

[5] F1-5, BC Hydro, response 2.45.0, , p. 18 (pdf).

BC Hydro's 2013 Integrated Resource Plan ("IRP") was based on portfolio present value analysis. It justified this choice by referring to the BCUC's decision in the 2006 IEP/LTAP proceeding, where it "found that the economic evaluation criteria is the primary test, and that the ratepayer impact analysis is a less material, secondary test".[6] In that decision, the Commission wrote:

> The Commission Panel accepts BC Hydro's argument that two tests may be considered for use in project evaluation. The first, and the more important, is an economic analysis of a project, which should only use the incremental cash flows disbursed by BC Hydro as its key input. The second, and less material test is a ratepayer impact analysis which examines how BC Hydro will recover a project's costs from its ratepayers and which may include items typically not found in a conventional economic analysis such as sunk costs, interest during construction and costs allocated from other departments of BC Hydro.[7] (bold in original)

The Commission continued as follows:

> BC Hydro's evidence is not particularly clear with respect to the differences in the underlying cash flows used in its economic analysis and ratepayer impact analysis. … <u>The Commission Panel considers the economic analysis [the portfolio present value analysis] the more important analysis</u> and should be reasonably correlated with the incremental rate impacts attributable to projects.[8] (underlining added)

Despite insisting that portfolio present value analysis is its primary analytical tool, this analysis is described in only a cursory fashion in the current BC Hydro Submission; moreover, the results are not presented in detail. Sections 6 and 7 of BC Hydro's Submission argue that Completion is far preferable to Termination or Suspension, but do so by way of an analysis of *ratepayer impacts*.[9]

As for the sensitivity analyses, they are described in present value terms (Table 20 on page 97), but there is no indication that these are the present value of *incremental supply costs,* rather than simply these same *ratepayer impacts*.

---

[6] BC Hydro. 2013 IRP, page 6-149.

[7] IEP/LTAP Decision, pp. 200-201.

[8] Ibid., p. 201.

[9] For Termination: Table 12 on p. 66, Table 14 and Figure 16 on page 76; for Suspension, Tables 15 and 16 on page 81, Figure 18 on p. 92, and Table 19 on page 93.

BC Hydro's ratepayer impact methodology is described in Appendix R of its Submission.[10] This analysis is severely compromised by its unprecedented use of a 70-year analysis period, which requires making many critical and unsupported assumptions. For the reasons set out in Section 2.3, below, we conclude that this 70-year ratepayer impact analysis has **no probative value.**

While BC Hydro suggests that it has carried out a portfolio present value analysis, which it describes as its primary tool, neither results nor supporting detail are provided. While a number of assumptions for such an analysis are set out in the first pages of Appendix K and of Appendix Q, and partial outputs are provided in Appendix Q for 11 sample portfolios, the key result of each one — the present value of its incremental costs — is not shown.[11]. The actual present value costs are absent from the outputs provided to the Commission. As this is BC Hydro's primary methodology, this omission is notable and material.

Further, BC Hydro's approach in this current submission to the Commission stands in contrast to that of its 2013 IRP, where detailed results (including present value costs, excluded from Appendix Q) were provided for 91 distinct portfolios[12], and where that analysis formed the basis of the proposed resource plan — which included the development of the Site C Project.

1.3 Our approach

In this submission, we present an updated version of the portfolio present value cost analysis presented in our first submission, F106-2. That approach closely follows the methods used in BC Hydro's IRP, comparing the present value of incremental cash flows.[13] As described in the following pages, we have made some modifications to the analysis, in response to comments made in submissions and in the Commission's Preliminary Report. We have also used updated input data provided in these reports.

---

[10] The spreadsheets underlying Appendix R were provided in BC Hydro's response to the Panel question 1.3.0, in doc. A-12.

[11] Outputs for an additional 26 portfolios are presented in BCUC IR 1.44.0, Attachment 2. The observations presented in this section apply equally to these new portfolio runs.

[12] BC Hydro, 2013 Integrated Resource Plan, Appendix 6A, Portfolio Results.

[13] The IRP refers to this passage from the 2006 IEP/LTAP Decision (pp. 89-90): "The Commission Panel agrees with BC Hydro that a portfolio analysis is consistent with the Commission's Guidelines, which state: "For each of the gross demand forecasts, several plausible resource portfolios should be developed, each consisting of a combination of supply and demand resources needed to meet the gross demand forecast." The Commission Panel also agrees with BC Hydro that a portfolio analysis is a best practice for IEP or IRP analysis. Finally, the Commission Panel agrees a portfolio analysis is useful to BC Hydro management, stakeholders and the Commission in reviewing acquisition plans.".

BC Hydro criticized this approach in its Appendix M, dedicated to the report we published before this Inquiry began (F106-1). It is interesting to note that only one of the criticisms made by BC Hydro concerns our method (as opposed to our data inputs), and it focuses solely on the time period of the analysis (20 vs 70 years), and not on the methodology itself.

> The authors limit their analysis to the first thirteen years of a project with a 70 year life span. Selectively limiting the analysis to a very short time frame that shows the least need for alternative resources in the no Site C portfolios provides biased results. BC Hydro's core submission provides a more fulsome analysis that looks at the 70-year economic planning life of the Site C project.[14]

We conclude that BC Hydro has no objection to our methodology.

We also note that in its 2013 IRP, BC Hydro also relied on a 20-year study period, and showed no compunctions about drawing significant conclusions therefrom.[15] As for the "more fulsome" 70-year analysis, its flaws are explored in section 2.3.

In Section 2, we will address these methodological issues in greater detail.

In Section 3, we will address other issues raised by the Commission in its Preliminary Report.

In Section 4, we will present our updated present value analysis.

In Section 5, we will present the results of our present value analysis.

In Section 6, we draw conclusions.

Finally, in the appendices, we will comment on certain submissions made to the Commission to date, in particular those of BC Hydro, as well as the two Deloitte studies, and provide additional details concerning issues raised in the Commission's Preliminary Report.

2 BC Hydro's comparative analyses

In Section 2.1, we will review in detail the information provided by BC Hydro with respect to its portfolio present value cost analysis.

In Section 2.2, we will review BC Hydro's unit energy cost analysis.

---

[14] BC Hydro, F1-1, App. M, page 3 of 14 (p. 516 of pdf).

[15] The analysis period in the 2013 IRP was from F2014 through F2033 (as seen in the tables in Appendix 9A). The portfolio analysis (Appendix 6A) shows results through F2040, but no load forecast data were made available beyond the 20-year study period.

Finally, in Section 2.3, we will examine BC Hydro's 70-year rate impact analysis.

2.1 BC Hydro's Portfolio Present Value Analysis

BC Hydro claims that it has applied its standard portfolio approach to identify alternative resource portfolios that could be pursued in the event of termination of Site C, and that no alternative portfolio provides similar benefits to customers at a similar or lower cost than a portfolio including Site C.[16]

This "standard portfolio approach" is described in Appendix K, and some partial results are presented in Appendix Q. Nowhere, however, does BC Hydro describe in detail the portfolios it examined or their present value costs. Thus, while BC Hydro claims to have compared Site C to other portfolios, **nowhere in its Submissions does BC Hydro present results or the supporting detail of that present value analysis.**

Appendix K mentions two portfolio modelling tools: HYSIM and System Optimizer. HYSIM appears to be limited to short-term operational issues, and is not mentioned again. It is the output of System Optimizer that is presented in Appendix Q. The outputs of the System Optimizer runs cover the period 2018-2040.

In Appendix K, BC Hydro makes the following statement:

> Portfolio analysis results for fiscal 2041 and fiscal 2042 were used to extrapolate the portfolio results out to fiscal 2094.[17]

This is apparently a reference to the 70-year Rate Impact analysis, as the System Optimizer analysis does not extend to F2094. No justification is provided for extrapolating the results of one scenario planning exercise forward for another 54 years.

Electricity and gas market prices are forecast only to F2034.[18] No source is given for the forecast, nor are the assumptions used to project these forward to F2040 (for System Optimizer) and to F2094 (for the Regulatory Rate Impact Model, or RRIM) made explicit.

BC Hydro further indicates that it, for its discount rate, it "chose to use the Generic Cost of Capital as set out in Order G-129-16". This order, regarding FortisBC Energy Inc., adopts an equity rate of 8.75% and a common equity component of 38.5%.[19]

Nevertheless, BC Hydro then indicates that it does not use its Cost of Capital for project financing, but rather its cost of debt.[20] Consulting the spreadsheets provided shows this value to fall from 3.93% in F2018 to 3.43% in F2020, and to remain at this low level until F2094. No

---

[16] Submission, page 41.

[17] Appendix K, page 3 of 8.

[18] Ibid.

[19] Ibid. BC Hydro instead uses an equity component of 40%.

[20] Appendix K, page 4 of 8, and Appendix R, page 2 of 12.

justification is provided for the assumption that it will be able to borrow at this low rate for the next 70 years.

Finally, it is indicated that project financing for IPP projects is assumed to be at a WACC of 6.4% real (8.5% nominal) — almost 2 ½ times higher than the project financing rate for BC Hydro projects!

Appendix K then provides energy and capacity Load Resources Balances with and without the Site C Project. These balances identify resource shortfalls, but make no attempt to remedy them with other resources.

Additional information is presented in Appendix Q, which presents System Optimizer results for eleven scenarios.[21] Unfortunately, significant information is withheld that would be necessary to fully understand these scenarios.

The information provided about each of these eleven scenarios is presented in Table 4.

Table 4: List of portfolios presented in Appendix Q

scenario	indicator	load forecast	SITE C STRATEGY	DSM STRATEGY
1	MVM17_37KCF_400	mid	completed	current; then IRP
2	MOM17_37DCF_400	mid	suspended	IRP
3	MOM17_37NCF_400	mid	terminated	IRP
4	LTL17_37KCF_400	low	completed	current; then IRP
5	LTL17_37DCF_400	low	suspended	IRP
6	LTL17_37NCF_400	low	terminated	IRP
7	HTL17_37KCF_400	high	completed	current
8	HTL17_37DCF_400	high	suspended	current
9	HTL17_37NCF_400	high	terminated	current
10	MTM17_37KCF_400	mid + electrification	completed	no indication
11	MTM17_37NCF_400	mid + electrification	terminated	no indication

As in the 91 portfolio System Optimizer outputs presented in the IRP, each one has a unique indicator, describing its parameters. Unfortunately, no key was provided to decode these indicators. However, the meaning of several of them can be deduced from the indications provided. Apparently, the first letter (M, L our H) indicates the load forecast (mid, low or high). The first letter after the common indication “37” apparently indicates the Site C strategy (K=complete; D = cancel; N = suspend). However, the information provided is insufficient to allow decoding of the other parameters identified in these indicators.

The presentation of portfolio results in Appendix Q is similar to that of the 2013 IRP, but with several very important details omitted. Figure 2 presents a sample output from the portfolio analysis in the IRP. Across the top, it defines the scenario and portfolio under study. On the right, it lists the resources that System Optimizer selected. And in the upper left, it shows the

[21] Outputs for an additional 26 portfolios are presented in BCUC IR 1.44.0, Attachment 2. The observations presented in this section apply equally to these new portfolio runs.

present value of costs (revenues) for the three main portfolio components (Generation and transmission, Trade revenue, and DSM), as well as the total present value for the portfolio.

Figure 2. Sample portfolio output from 2013 IRP

Integrated Resource Plan Appendix 6A

Input Assumptions	Lead	DSM	Market Scenario	Site C	Thermal Resources	Other
	Mid Load & No LNG	Mid DSM Option2(constant)	Scenario 1	ISD fixed F2024	Included	7% IPP CoC, $10 wind adder, Capacity bridging before F2024

	Discounted to January 2013 (F2013 $) - Jan DSM TRC
PV of G& T Resource cost - $ millions	5,607
PV of Trade Revenue - $ millions	(1,977)
PV of DSM Option cost - $ millions	2,986
PV of Total Portfolio Cost - $ millions	6,615

UECs and **UCCs** are shown for energy and capacity resource respectively. The UEC/UCC shown includes wind integration costs, soft costs and network upgrade costs where applicable. The UECs for gas-fired generation resources (CCGTs) are not shown as the UEC varies from year to year depending on the forecasted natural gas price.

Supply Totals through 2020

	Wind	Small Hydro	Other	Site C	Total
Dep. Capacity (MW)	0	0	0	0	0
Firm Energy (GWh)	0	0	0	0	0

Supply Totals through 2030

	Wind	Small Hydro	Other	Site C	Total
Dep. Capacity (MW)	0	0	0	1,100	1,100
Firm Energy (GWh)	0	0	0	5,103	5,103

Supply Totals through 2040

	Wind	Small Hydro	Other	Site C	Total
Dep. Capacity (MW)	341	10	2,092	1,100	3,543
Firm Energy (GWh)	4,865	175	2,205	5,103	12,349

DSM Level in:

2020	7,608 GWh	1,421 MW
2030	11,190 GWh	2,036 MW
2040	11,154 GWh	2,110 MW

Clean Objective (%) - performance during the period 2016-2040

	Based on Generation	Based on Firm Capability
Average %	97%	94%
Lowest %	96%	93%

Transmission Expansion

Year	Project Description	Between	Capacity - MW
2023	Shunt compensation at WSN KLY	PR to KN	660
2029	Series compensation 5L1_2_3_7 from GMS to WSN	PR to KN	360
2029	Series compensation 5L11_12_13 from WSN to KLY	PR to KN	390
2029	Shunt compensation at NIC and MDN	KN to LM	570
2030	Series compensation of SL91 and SL98	SE to KN	147
2033	500 kV circuit 5L46 between KLY and Cheekye	KN to LM	1384
2040	500kV circuit 5L14 between WSN and KLY	CI to KN	2120

Resources Selected

			Capacity - MW		Energy - GWh		UEC / UCC
Year	Zone	Resource	Installed	Dependable	Firm	Total	$/MWh or $/kW-year
2023	BCH_PR	Site C	1100	1,100	5,100	5,100	79
2029	BCH_PR	GMS Units 1-5 Cap Increase	220	220			35
2030	BCH_REV	Revelstoke Unit 6	500	488	26	26	50
2031	BCH_LM	MSW2_LM	25	24	208	208	92
2032	BCH_KN	100 MW SCGT KN	309	294	450	450	88
2033	BCH_KN	100 MW SCGT KN	206	196	300	300	88
2034	BCH_KN	100 MW SCGT KN	309	294	450	450	88
2035	BCH_PR	Wind_PC28	153	40	591	591	111
2035	BCH_KN	100 MW SCGT KN	206	196	300	300	88
2035	BCH_LM	Run of River LM 80_100	82	10	174	223	108
2036	BCH_PR	Wind_PC14	144	37	527	527	117
2036	BCH_PR	Wind_PC19	117	30	441	441	113
2036	BCH_PR	Wind_PC21	99	26	371	371	112
2036	BCH_KN	100 MW SCGT KN	103	98	150	150	88
2036	BCH_VI	MSW1_VI	12	12	100	100	127
2037	BCH_PR	Wind_PC13	135	35	541	541	113
2037	BCH_PR	Wind_PC16	99	26	377	377	116
2037	BCH_LM	Pumped_Storage_LM	1000	1,000			126
2038	BCH_PR	Wind_PC10	297	77	1,023	1,023	118
2039	BCH_PR	Wind_PC20	159	41	610	610	119
2040	BCH_PR	Wind_PC15	108	28	382	382	119
2040	BCH_VI	Biomass_VI	30	30	239	239	142

MFM_1LT_NN0_05Q

Page 6A-19 of 6A-240 **November 2013**

In the IRP, this last value – the total present value of the portfolio – was the measure used for the economic comparison between portfolios. For example, Table 5, taken from Appendix 6A of the IRP, shows how the scenarios and their present values were used to compare the costs of pairs of portfolios, with and without the Site C Project. [22]

[22] BC Hydro, 2013 IRP, Appendix 6A, page 6A-36.

Table 5. Portfolio summary from the IRP

4.2 Portfolio PV Differences

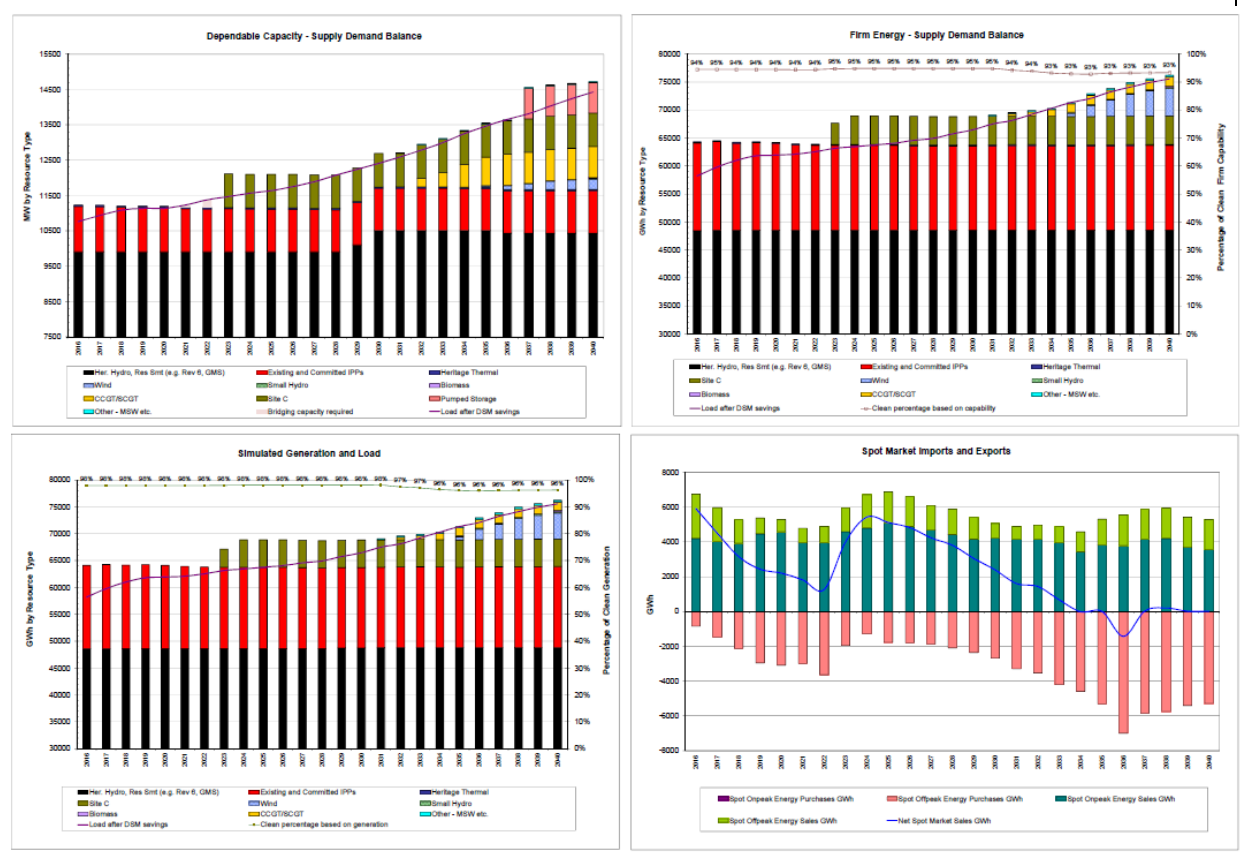
Table 3 provides details supporting the portfolio PV difference shown in section 6.4.3 of the IRP: Site C Base Case.

Table 3 Portfolio PV for Site C Base Case Analysis

Sections in the IRP	Portfolio type	Site C Timing	Portfolios without Site C Portfolio name Portfolio PV (M$)	Portfolios with Site C Portfolio name Portfolio PV (M$)	PV Difference (M$) (w/o Site C portfolio minus w Site C portfolio)
6.4.3 Benefit of Site C - base case	Clean Generation	F2024	M&M_1NC_NN0_05Q 6,766	M&M_1LC_NN0_05Q 6,138	630
		F2026	M&M_1NC_NN0_05R 6,741	M&M_1KC_NN0_05R 5,864	880
	Clean + Thermal Generation	F2024	M&M_1NT_NN0_05Q 6,030	M&M_1LT_NN0_05Q 5,883	150
		F2026	M&M_1NT_NN0_05R 6,001	M&M_1KT_NN0_05R 5,608	390

A second page was also provided for each portfolio, including four graphs, as shown in Figure 3. The top two graphs show the supply/demand balance in capacity and in energy. The third graph shows the simulated generation and load, and the last graph shows annual imports and exports.

Figure 3. Sample portfolio output from 2013 IRP (graphs)



While the year-to-year energy and capacity balances were not provided in tabular form, they clearly were calculated in order to generate these charts.

As seen in Figure 3, the portfolio outputs in the 2013 IRP went to F2040, although the load forecast and the Base and Contingency Resource Plans only went to F2033. Clearly, some sort of load forecast was used to generate these scenarios but, to the best of our knowledge, it was never made public.

Appendix Q provides output sheets similar to those presented in the IRP, and were clearly generated by the same System Optimizer program. However, there is one very important difference: **in Appendix Q, the present value costs of each portfolio are omitted, as seen in** Figure 4. The detailed portfolio and scenario definitions, found across the top of the page in the IRP portfolios (Figure 2), are omitted as well.

Figure 4. Sample portfolio output from BCUC Submission

Appendix Q

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

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

Resources Selected

Year	Zone	Resource	Capacity - MW Installed	Capacity - MW Dependable	Energy - GWh Firm	Energy - GWh Total	UEC / UCC $/MWh or $/kW-year
2024	BCH_LM	Pumped_Storage_LM	1000	1,000			124
2027	BCH_REV	Revelstoke Unit 6	500	488	26	26	46
2029	BCH_PR	Wind_PC18	138	36	524	524	92
2029	BCH_LM	2017 Load Curtailment	85	85			77
2031	BCH_PR	Site C	1145	1,146	5,286	5,286	34+Suspension Costs
2036	BCH_LM	Pumped_Storage_LM	1000	1,000			124
2037	BCH_PR	Wind_PC14	144	37	570	570	92
2038	BCH_PR	Wind_PC20	156	41	594	594	92
2039	BCH_PR	Wind_PC28	153	40	641	641	94
2039	BCH_PR	Wind_PC48	150	39	538	538	95
2040	BCH_PR	Wind_PC13	136	35	577	577	98
2041	BCH_NC	Wind_NC09	333	87	1,074	1,074	101

Transmission Expansion

Year	Project Description	Between	Capacity - MW
2027	Nicola-Vaseux Lake Compensation (N-VLC)	SEL to KN	147
2031	Increase series compensation of SL1, SL2, SL7 from GMS to WS	PR to CI	360
2031	Increase series compensation of SL11, SL12, SL13 from WSN to	CI to KN	390
2031	Static VAr compensation at WSN	PR to KN	650
2094	Shunt compensation at N/C and MDN	KN to LM	570

MOM17_37DCF_400

BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project

Page 6 of 28

Thus, while BC Hydro affirms that it has carried out a System Optimizer portfolio analysis, **it has deleted from the scenario outputs the specific results that permit an economic comparison amongst the options.** These omissions undermine the credibility of the Submission, as the missing data are essential to understanding the implications of the options, as required by the Terms of Reference.

Similarly, since the present value of each portfolio is not provided, no tables are presented to compare the present value of a portfolio with Site C to the corresponding portfolio without Site C.

As noted earlier, the summary tables in Sections 6, 7 and 8 of BC Hydro's Submission indicate that they are describing "ratepayer impacts". Since they describe impacts through 2094, it is clear that they represent the results of the rate impact analysis, described in Appendix S (and in response to BCUC IR 3.0). This leads to a question: **where are the results of the present value portfolio analysis?** Despite BC Hydro's insistence that present value analysis is its primary analytical tool,[23] **the results of such an analysis are nowhere to be found in its**

[23] BC Hydro, Submission, F1-1, page 60, lines 5 to 7.

submission. While summary statements are made about the results of this analysis, no supporting documentation (portfolio outputs, year-by-year costs, data in Excel format) has been made available to the Commission. These omissions undermine the credibility of these results.

On the other hand, while present value portfolio analysis is mentioned but not presented, BC Hydro has presented in detail its 70-year rate impact analysis, based on an estimation of future revenue requirements (Appendix R). We review this analysis in detail in the following section and conclude that, because it is built on a foundation of unsupported and unsupportable assumptions, it has no probative value.

This leaves the Commission in the unfortunate situation where BC Hydro has not provided a rigorous analysis of the comparative costs to ratepayers of the Complete, Terminate and Suspend options.

2.2 Portfolio UEC Analysis

In BCUC 2.45.0, BC Hydro described results of an analysis of portfolio unit energy costs (UECs). This analysis was provided in response to a request from the Commission (BCUC Preliminary Report, page 103), where the Commission noted the incompleteness of the data provided regarding BC Hydro's portfolio analysis. As BC Hydro had provided an "alternative portfolio UEC", the Commission sought clarification as to the precise portfolio on which it was based.

In our view, however, this question is of secondary importance, given that BC Hydro has acknowledged that the UEC analysis is a simplified tool designed to facilitate communication. As noted above:

> While Portfolio PV Analysis is BC Hydro's preferred approach to making resource acquisition decisions, looking at resources' Unit Energy Costs can help explain the results of Portfolio PV Analysis. Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced.[24]

Unfortunately, in its Preliminary Report the Commission requested clarification of the portfolio(s) used in BC Hydro's "alternate portfolio UEC calculation" (p. 103), but not the details of its full portfolio present value analysis.

2.3 BC Hydro's 70-year rate impact methodology

BC Hydro presents the results of its ratepayer impact analysis in sections 5, 6 and 7 of its Submission, with further details provided in Appendix R.

[24] BC Hydro, Submission, F1-1, page 60, lines 20 to 22.

As noted earlier, ratepayer impact analysis is a secondary tool for BC Hydro and for the Commission. Portfolio present value cost analysis, a form of economic analysis, is the primary tool for resource selection:

> **The Commission Panel accepts BC Hydro's argument that two tests may be considered for use in project evaluation. The first, and the more important, is an economic analysis of a project, which should only use the incremental cash flows disbursed by BC Hydro as its key input. The second, and less material test is a ratepayer impact analysis which examines how BC Hydro will recover a project's costs from its ratepayers and which may include items typically not found in a conventional economic analysis such as sunk costs, interest during construction and costs allocated from other departments of BC Hydro.**[25] (bold in original)

In its Submission, BC Hydro explains its Regulatory Rate Impact Model (RRIM) as follows:

> The RRIM assumes a Base Case, and estimates BC Hydro's total revenue requirement over the fiscal 2018 to fiscal 2094 period. The year fiscal 2094 represents the end of the 70-year economic planning life of Site C.[26]

Appendix R goes on to state:

> BC Hydro is using the Regulatory Rate Impact Model (RRIM), which has been submitted in previous BCUC applications, to estimate the ratepayer impacts under different scenarios. This is a model with which the BCUC is familiar, and which allows for BC Hydro to compare scenarios under different assumptions.[27]

However, the way this methodology is used here differs drastically from what has been presented in the past to the Commission.

Indeed, the model has been used in recent CPCN applications before the Commission, in particular for the Dawson Creek/Chetwynd Area Transmission ("DCCAT") Project, and for the John Hart Generating Station Replacement Project ("John Hart"), both of which relied on a 20-year analysis period.

It is noteworthy that, in both these cases, the RIM analysis presented to the BCUC covered **a 20-year period,** even though the accounting lifetimes of the two projects are significantly longer.

In Appendix K, BC Hydro states:

---

[25] BCUC, IEP/LTAP Decision, 2007, p. 200-201.

[26] Appendix R, page 1.

[27] Appendix R, page 1 (pdf p. 788).

> Portfolio analysis results for fiscal 2041 and fiscal 2042 were used to extrapolate the portfolio results out to fiscal 2094.[28]

This is apparently a reference to the 70-year Rate Impact analysis, as the System Optimizer analysis does not extend to F2094. No justification is provided for extrapolating the results of one scenario planning exercise forward for another 54 years.

As noted earlier, BC Hydro chose to use the Generic Cost of Capital as set out in Order G-129-16, which adopts an equity rate of 8.75%.[29] BC Hydro elects, however, not to use its Cost of Capital for Project Financing, but rather to use its forecast weighted average cost of debt (Appendix R, page 2 of 12). The spreadsheets provided in support of Appendix S show that this value falls from 3.93% in F2018 to 3.43% in F2020, and remains at this level until F2094. **No justification is provided for the assumption that it will be able to borrow at this low rate for the next 70 years.**

Other noteworthy details include:

- Both the DCCAT and John Hart Project analyses used an equity rate of 12.75%, and a debt-equity ratio of 70:30;
- The John Hart Project attributed a value of $129/MWh (in real 2011 $) to energy produced by the Project.

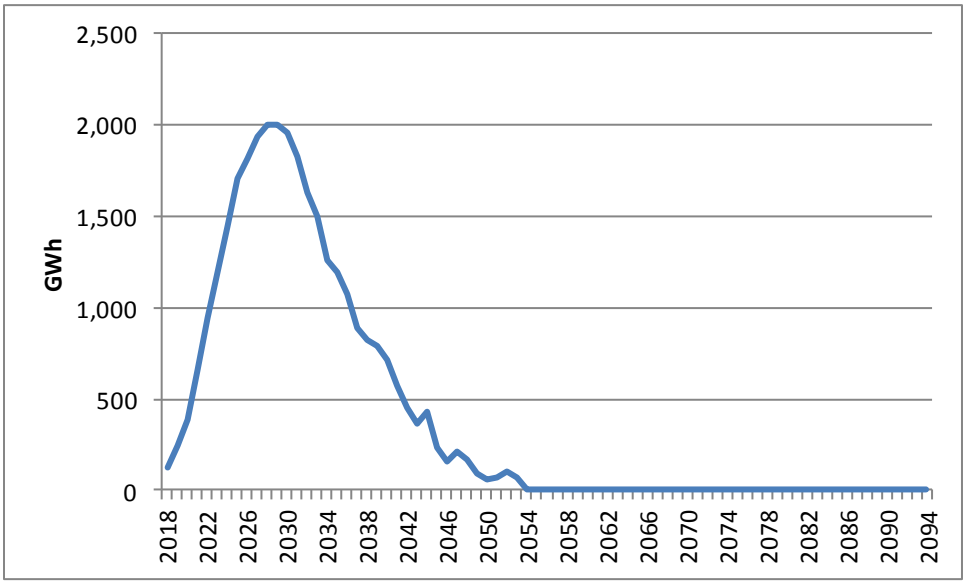
While it may be justifiable to use a 70-year depreciation period for the Site C Project, there is, to the best of our knowledge, no precedent for a 70-year economic analysis.

This analysis relies on a number of surprising assumptions, several of which will be examined in detail below. First, it forecasts zero increase in energy sales from F2047 to F2094. Second, DSM additions fall to zero in F2054, as seen in Figure 5.

Figure 5. Forecast DSM energy savings in BC Hydro Rate Impact Analysis

[28] Appendix K, page 3 of 8.

[29] Ibid. BC Hydro instead uses an equity component of 40%.



Furthermore, it is assumed that there will be no real rate increase after F2024, despite existing regulatory account balances and the commissioning of Site C. However, the utility is careful to explain that this forecast is made for the purposes of this Inquiry only:

> Additionally, BC Hydro's assumed annual rate increases and revenue requirement over the fiscal 2025 to fiscal 2094 period does not represent BC Hydro's view as to future Revenue Requirement Applications (RRAs), and any rate increases requested in future RRAs will be based on BC Hydro's assessment of its expected revenues and costs at the time of filing. Similarly, the incremental rate impact assessment of various scenarios related to the Site C Project are not determinative of BC Hydro's view of its future annual rate increases and revenue requirement but gives an indication of the incremental impact to ratepayers under these various scenarios.[30]

It is also surprising that there is a separate complex spreadsheet for each graph, rather than a single spreadsheet incorporating the different scenarios.

BC explains its method as follows:

> BC Hydro's estimated annual revenue requirement over the fiscal 2018 to fiscal 2094 period is not based on a long term forecast of specific annual costs (i.e., it is not a 'bottom-up' forecast of individual costs). Rather, it represents an estimate from the revenue side, making the assumption that customer rates over time will be increasing only in order to recover its total costs (total revenue requirement). And therefore total revenue received from customers in a future year will equal the total costs to be recovered from ratepayer in that same year.[31]

---

[30] Appendix R, page 4.

[31] Appendix R, page 4.

It is hard to find any meaning in this paragraph, other than to say that rates will follow revenue requirements. At the same time, it is explained elsewhere that:

> Portfolio analysis results for fiscal 2041 and fiscal 2042 were used to extrapolate the portfolio results out to fiscal 2094.[32]

Nowhere in its Submission does BC Hydro actually identify the portfolios that it suggests would be developed if Site C were to be terminated or suspended.[33] Appendix K shows the Load Resource Balances with and without Site C, but in neither case does it add the resources that would be required to maintain energy and capacity balance.

Buried deep in each of these spreadsheets, on the page entitled "Input Data", under the heading "Increase (Decrease) in the Cost of Energy, is a line labelled "Cost of Energy – Item #1". This line is transferred directly to the Summary page (line 1, "Domestic Energy Costs").

Review of the structure of this Summary page reveals that this line is the primary driver behind line 8 ("Estimated Total Change in Revenue Requirement"), which is in turn the primary driver behind the "Estimated Incremental Impact of Future Rates" and the "Estimated Incremental Cumulative Rate Impact". It is this last line that is plotted in the dramatic Figures 16 and 18, reproduced below, which purport to demonstrate the catastrophic rate impact of termination or suspension of the Site C Project.

Figure 6. BC Hydro Rate Impact Forecasts

Figure 16 **Annual Ratepayer Impact of Site C Termination**

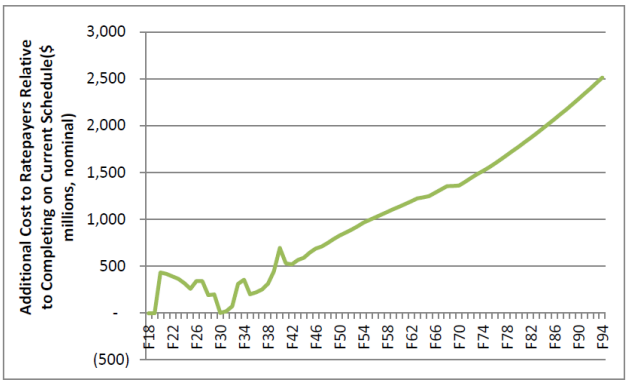
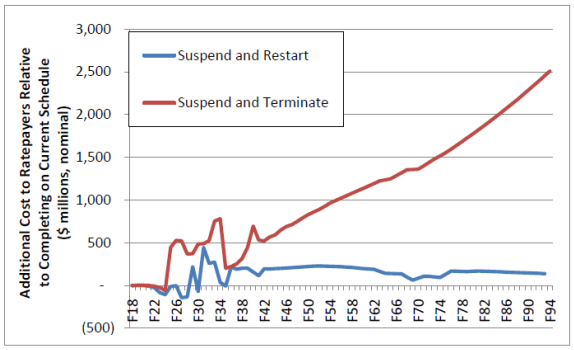


Figure 18 **Annual Ratepayer Impact of Site C Suspension**



How was this "Increase in the Cost of Energy" derived? In an Excel spreadsheet, the formulas for the cells that make up this line would normally indicate how they were derived. **However, in this spreadsheet, there are no formulas in the "Increase in the Cost of Energy" row.**

---

[32] Appendix K, page 3 of 8.

[33] A number of portfolios were provided in Appendix Q, but there is no indication as to their status.

Rather, the values are entered into the Excel spreadsheet as numbers, not formulae, with no information provided concerning their source or derivation.

Thus, the seven complex spreadsheets provided in response to BCUC IR 1.3.0 in fact all depend on a series of values, representing the additional energy costs that would flow from the termination of the Site C Project, that have been inputted manually rather than derived from identified sources and methods. This raises the question: how were these figures calculated? And why did BC Hydro omit an explanation of the underlying calculations?.

Similarly, a close examination of BC Hydro's spreadsheets reveals that BC Hydro did not actually forecast energy demand 70 years into the future. In BC Hydro's current load forecast, the annual growth in energy sales slows to about 1%/yr as of F2027, and remains at this level through F2036. In these rate impact spreadsheets, this approximate level is maintained through F2044 (though with some surprising bumps, to 1.28% in F2040, and to 1.25% in F2043). No explanation is provided for the source of this load forecast through F2044.

After F2044, however, load growth falls to approximately zero and, after F2047, to precisely zero. **According to these spreadsheets, energy sales in F2094 will be at precisely the same level as in F2047.**

Another surprising feature is the rate of growth of the "black box" figures provided for "Increase in the Cost of Energy". These values, presented in nominal dollars, grow following a curve that closely resembles the rate impact curves seen in Figures 16 and 18 of F1-1. Converted to real dollars, however, they tell a different story. **From F2054 through F2094, the Increase in the Cost of Energy remains constant, at precisely $648.1 million (in constant 2018 dollars).**

Where is the underlying analysis behind these figures? Apparently, BC Hydro has carried out an analysis of the resource portfolio that would be required to meet forecast energy and capacity requirements through F2094 (assuming, apparently, that there is no load growth after F2037), in the event of the termination of the Site C Project, and it has found that the annual additional costs of that portfolio would be precisely $648.1 million (2018$).

To the best of our knowledge, that portfolio has not been described in BC Hydro's submissions, nor has any demonstration been made that its additional costs would remain at this level for 40 years.

Based on the evidence produced before the Commission, one can only conclude that the rate impact analysis presented in BC Hydro's August Submission has **no probative value.**

3 Portfolio present value analysis: Data sources and methods

As noted in our First Submission, our model follows the approach set out in BC Hydro's 2013 IRP for comparing resource portfolios. The present value of the streams of incremental costs (net of revenues) of different resource portfolios that meet the same energy and capacity needs

are compared. These costs are broken down into capacity costs (including fixed costs of new capital resources), energy costs (including costs of new clean resources purchased under a PPA, market purchases, export revenues and additional DSM costs above the base case. The present value of this stream of annual costs and revenues is calculated, and the resource choices are optimized to meet requirements (within the selected resource strategy) at the lowest present value cost.

Thus, the model calculates the present value of the year-by-year costs for incremental resources, net of incremental revenues from export of surplus energy and capacity. Costs of elements that remain unchanged are not included in the analysis. As a result, the costs reported below in relation to the various scenarios are only meaningful in comparison to one another, not in absolute terms.

We have made a number of modifications from the method and the data inputs used in our First Submission. These modifications are detailed in the following sections.

3.1 Data sources

Many data uncertainties have been resolved, in some cases through data communicated by BC Hydro (e.g. its medium, high and low load forecasts for energy and capacity), and in other cases by determination of the Commission (e.g., the specific costs related to project completion and termination).

- The capacity and energy capabilities of the Site C Project have been updated to 1,132 MW and 5,286 GWh/year (BCUC IR 2.24.0)
- As discussed in section 3 of Hendriks and Raphals (October 2017a), we have included a cost for the GHG emissions from Site C, based on the emissions described in the EIS and BC's current carbon tax, which will increase to $50/tonne ($45 in 2016$) in 2021. We have further assumed that this carbon tax will remain stable in 2016$.
- Costs related to augmented DSM are derived from unit costs implicit in BCUC IR 2.64.0, Att. 1.
- Pumped storage: We have relied on BC Hydro's resource cost of $124/kW-yr for a 1,000 MW unit capable of providing 10 hours of storage (BCUC IR 2.71.0);
- Biomass: BC Hydro indicates a unit energy cost of $133/MWh. However, biomass plants are dispatchable, and so can provide capacity without necessarily operating as baseload plants. Based on a capital cost of $4,740/kW installed (as per the 2013 ROR)[34], we have derived a capacity cost of $413/kW-yr. Based on BC Hydro's UEC of $133/MWh, we

[34] BC Hydro. November 2013. Integrated Resource Plan Appendix 3A-1 2013 Resource Options Report Update, p.173. Available at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a01-nov-2013-irp-appx-3a-1.pdf.

have estimated an implied energy cost of $80/MWh. However, this resource is not economic in any scenario studied, and so has not been included in any of the portfolios.

- Capacity market reliance: BC Hydro has reduced its maximum capacity market reliance to 300 MW, from 400 MW in the IRP. While no reasons were given for this change, we have adopted it as well, to maintain comparability with BC Hydro's scenarios.
- Energy market reliance: While in Appendix K, BC Hydro indicates that explicit reliance on energy markets is not included, all but two of the portfolios presented in Appendix Q include substantial energy imports in some years, going as high as 4000 GWh. Nevertheless, we have conservatively limited energy market reliance to a maximum of 400 GWh in any one year.
- Mica units 1-4 maintenance outages: Appendix K indicates that Mica units 1-4 maintenance outages are scheduled to start in F2026 in all scenarios. However, as BC Hydro has flexibility in the timing of this maintenance, we have varied the timing in each scenario in order to minimize costs.

3.2 Alternate resources – energy

3.2.1 Wind power costs

In our August Submission, we used at an adjusted unit energy cost of $80/MWh beginning in the late 2020s, when wind resources would first be required, to the end of the planning period in F2036.

This cost followed from BC Hydro's determination in the RRA of $100/MWh, reflecting a 20% decline in wind costs since the 2013 IRP.[35] Bloomberg New Energy Finance, in its New Energy Outlook 2016, projected that the cost of onshore wind would drop 41% by 2040.[36] For its part, IRENA projected that the global weighted average levelized cost of energy from wind could fall 26% by 2025.[37] In a recent elicitation survey of 163 of the world's foremost wind experts, these

[35] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-46.

[36] Bloomberg New Energy Finance. June 2016. New Energy Outlook 2016 Executive Summary. Available at: https://www.bloomberg.com/company/new-energy-outlook/

[37] International Renewable Energy Agency. June 2016. The Power to Change: Solar and Wind Cost Reduction Potential to 2025, p.67. Available at: http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf.

experts anticipate a 24% reduction in the levelized cost of energy from onshore wind by 2030 and a 35% reduction by 2050.[38]

In its Preliminary Commission Report, the Panel requested that BC Hydro model a reduction in the capital cost of wind energy as follows:[39]

2020	2025	2030	2035	2040
10%	25%	30%	40%	45%

Based on this request to BC Hydro, we adjusted the cost of wind energy used in our portfolios accordingly.

3.2.2 Solar PV

We did not make use of utility scale solar in our August 30 submission. We established unit energy costs for solar PV based on the responses of BC Hydro to the following two requests of the Panel to BC Hydro:

- 47. BC Hydro is requested to model a capital cost of solar energy of $1.64/W in 2017, and a reduction of 60% in the capital cost by 2040.

- 68. Assuming the solar investment was financed by BC Hydro, and using a 6 percent discount rate, what is the estimated levelized cost in today's dollars of a 5MW utility solar PV investment made in in (a) F2025 and (b) F2035, assuming delivery at (i) the plant gate and (ii) delivered to the Lower Mainland. Please show supporting assumptions (including capital cost assumptions, real power losses etc.) and calculations.

[38] Wiser, R. et al. 2016. Expert elicitation survey on future wind energy costs. *Nature Energy*, Article 16135, p.4.

[39] A-13, p.104.

In response to the first request, BC Hydro reported that costs would decline to $0.66/W by 2040.

	UEC at gate ($/MWh)	UEC delivered to lower mainland ($/MWh)
5 MW Cranbrook solar in 2025	48.04	59.04
5 MW Cranbrook solar in 2035	44.31	54.72

BC Hydro noted that these UECs do not include the cost of additional capacity that would be required by ratepayers, and are thus not a direct comparator to the Site C UEC. BC Hydro did not provide an estimate of the cost of that additional capacity. We have estimated that capacity to be similar to that required to integrate wind resources, namely $5/MWh.[40] This would result in an adjusted UEC of $65/MWh. We believe that this cost may reflect an overly aggressive cost decline for solar PV, and have instead used an adjusted UEC of $80/MWh in F2025, declining less rapidly thereafter.

Using these costs, have conservatively relied on PV to provide half of the additional required energy in a year, up to a limit of 500 GWh additional per year, starting in F2027.

3.3 Alternate resources – capacity

3.3.1 Capacity-focused DSM

In Raphals and Hendriks (August 2017), relying on potentials identified in BC Hydro's 2013 Final IRP and in its 2012 Draft IRP, we assumed modest gains capacity-focused DSM of 30 MW/yr, leading to a total in some scenarios of 570 MW in F2036, at an estimated average cost of $50/kW-yr.

In its August Submission, BC Hydro identified 85 MW of industrial load curtailment. In Appendix M, BC Hydro criticized this choice, stating that 570 MW of capacity-focused DSM is unproven and requires further testing and piloting before it can be relied upon.

In its responses to the BCUC, BC Hydro has now identified an additional 450 MW of demand response by F2027, at a levelized cost of $55/kW-yr.[41] BC Hydro's current estimates of capacity-focused DSM (including demand response) are thus nearly identical to those modelled in Hendriks et al.

BC Hydro emphasizes that "these initial results have a high degree of uncertainty", and considers that "further work is required before they can be used for planning purposes."

---

[40] A-13, p.88

[41] BCUC IR 2.73.0, page 3 of 4.

However, just as a load forecast must endeavour to account for probable outcomes, a long-term planning exercise cannot disregard resources that are likely to be confirmed in the later years, simply because they are not proven today. In the modelling exercise underlying this report, we have maintained the same assumptions as before, namely annual gains in capacity-focused DSM of 30 MW/yr, at an average cost of $50/kW-yr.

3.3.2 Natural gas generation

In our First Submission, we followed BC Hydro's policy implemented in the IRP to use SCGTs to provide any capacity shortfalls.[42]

However, BC Hydro now indicates that, based on the wording of OIC 244 ("maintenance or reduction of 2017/17 greenhouse gas emissions levels"), "there is no room for the addition of any gas-fired generation".[43] It therefore appears that BC Hydro now plans to use pumped storage for any capacity shortfalls (other than those that can be met with Revelstoke 6 and load curtailment), with or without the Site C Project.[44] This can also be seen from the Resources Selected in each of the 11 portofolio results presented in Appendix K, where Revelstoke 6, "Pumped Storage_LM" and "2017 Load Curtailment" are the only capacity resources identified.

Consequently, in this submission, we exclude all new natural gas generation.

3.3.3 Energy storage

In our August Submission, we cited estimates from the Energy Storage Association showing the installed cost of a 100 MW 4-hour lithium-ion storage system falling from around US$1700/kW to around US$1000/kW by 2020. However, these systems generally provide numerous other system benefits as well, the value of which needs to be subtracted from the sticker price to determine the applicable cost for planning purposes. Taking into account these additional system benefits, the net cost was estimated to decline from about US$1400/kW to around US$600/kW (around CA$800/kW) by 2020. We conservatively used a value of CA$1000/kW in 2020, with a subsequent decline of 2%/year (real). Based on a 10-year equipment life (also conservative, because while the batteries need to be replaced after 10 years, the balance of plant does not), we obtained a unit cost of CA$109/kW-yr in 2020.

In BCUC 2.48.0, BC Hydro estimated the capital cost of a 100 MW 10-hour Li-ion storage system at US$743 million, or US$7430/kW, with a unit cost of $651/kW-yr (2018$). While

---

[42] This can be observed in the Base Resource Plan and the Contingency Resource Plan (Tables x and y, respectively), found in Appendix 9A of the IRP.

[43] BCUC IR 2.70.0.

[44] BCUC IR 2.71.0

mention is made of an analysis by Lazard and Enovation Partners (2016), no precise reference was provided, nor were the calculations explained.

Based on our confidential discussions with commercial providers of Li-ion storage systems, it appears that a 1000 MWh system could be acquired **today** in Canada for CA$500 to $600 million, together with an asset management (fixed OMA) contract of $5 million/year. In other words, systems are available **today** at prices lower than those estimated by BC Hydro for twenty years from now, in the late 2030s.

Furthermore, in a document addressed to Energy Storage Canada, Hydrostor Inc. has provided an indicative cost estimate for an Advanced Compressed Air Storage (A-CAES) system of this same size (100 MW / 1000 MWh), with a capital cost of just US$175 million, plus fixed operating costs of US$2 million/year. The round-trip efficiency is estimated at 60-65%. The document, which specifies that salt-cavern geology is not required, is attached to this submission as Appendix A.

While we have not modified our energy storage cost estimates based on this information, we regard it as further evidence that BC Hydro's submissions do not adequately reflect the current state of the utility-scale energy storage market.

For this submission, we have retained the installed cost price from our August submission. However, we have multiplied those costs by 2.5 to account for a 10-hour storage period, as called for in BCUC IR 2.71.0.

Following BC Hydro, we assume that pumped storage will be used with a capacity factor of 18%,[45] and we use the same figure for battery storage. We also use Hydro's figures for round-trip efficiency (70% for pumped storage, and 93% for battery storage). This last factor is quite significant. 100 MW of storage used with an 18% capacity factor results in 158 GWh/year being stored. The losses would thus be 47 GWh/year for pumped storage, but just 11 GWh/yr for battery storage, or 36 GWh/year less. At $50/MWh, that is a difference of $18 million per year, just in differential energy losses.

3.4 Methodological issues

3.4.1 Analysis horizon

We have carefully considered the criticisms of our earlier study made by BC Hydro in Appendix M of its Submission. Most of these comments concern specific assumptions, and are addressed in a separate submission. Only one of these comments, however, concerns the evaluation methodology. On page 3, Hydro writes:

> The authors limit their analysis to the first thirteen years of a project with a 70 year life span. Selectively limiting the analysis to a very short time frame that shows the

[45] BCUC IR 2.71.0, page 2 of 4.

> least need for alternative resources in the no Site C portfolios provides biased results. BC Hydro's core submission provides a more fulsome analysis that looks at the 70-year economic planning life of the Site C project.

As noted above, BC Hydro has indicated that portfolio present value cost analysis is the primary tool, and rate impact analysis only of secondary value. However, nowhere in its Submission has BC Hydro presented the results of a present value portfolio analysis on a 70-year timeframe. In fact, as noted above, it has failed to provide any details whatsoever regarding the results of its present value portfolio analysis. Instead, the only quantitative analysis presented is the 70-year rate impact analysis.

In the 2013 IRP, data load forecasts and resource plans were presented only through F2032. At the same time, System Optimizer outputs were shown through F2040 — though it was never explained how these were carried out, given that the utility's load forecasts ended eight years earlier.

Thus, the PV analysis quoted above, showing the Site C scenarios to be preferable to those without the project, were based on just 8 years of thoroughgoing analysis after commissioning (F2024 through F2032), or at most 16 years of simulated results (F2024 through F2040). The differential present value of these scenarios was the primary justification for the choice to proceed with the Site C Project. [46]

As discussed above, BC Hydro's 70-year analysis relies on unjustified assumptions concerning elements that are unknown and unknowable in that time frame, and thus cannot be relied upon.

However, the mismatch between the analysis period and the useful life of the Site C Project is clearly problematic. However, we remain convinced, as BC Hydro was when it produced the IRP in 2013, that, despite this mismatch, portfolio present value cost analysis nevertheless provides a reasonable basis for making an economic comparison between portfolios including and excluding the Site C Project.

While it is true that an analysis of this type excludes a substantial part of the energy value that the Site C Project will produce during its lifetime, it also excludes a significant part of its costs. The results reproduced below demonstrate that, for scenarios including the Site C Project, the costs attributed it amount to only $1.885 billion (in constant 2016$), which is a small fraction of the project's capital cost. Without real year-by-year projections of energy and capacity needs and of the costs of competing resources — which are conspicuously absent from the BC Hydro Submission — there is no rigorous way to know if these end effects (the costs and benefits that occur after the end of the analysis period) are favourable or disfavourable to the scenarios including the Site C Project.

---

[46] Government of British Columbia and BC Hydro. "Site C to provide more than 100 years of affordable, reliable clean power". Backgrounder: Comparing the Options. Available at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power.

Thus, we remain of the view that the present value portfolio analysis remains the best methodology for comparing the Completion and Termination strategies. The timing mismatch does, however, create a real challenge with respect to the "Suspension" strategy. Delaying commissioning of the Site C Project by eight years would cut in half the number of years in which its costs and benefits occur during the analysis period. Furthermore, as these are the last years of the analysis period, they are the most heavily affected by discounting. The inevitable result is that the Suspension scenarios tend to show substantially lower present value costs for Site C than do the Completion scenarios, even though they have **higher** capital costs.

There is no methodological "fix" for this mismatch. For the purposes of the present Inquiry, we have come to conclude that, **while present value analysis is the appropriate methodology for comparing the costs and benefits of commissioning Site C in F2024 or of terminating it, that same methodology cannot be used to compare termination versus suspension for eight years**. Consequently, we will use present value analysis for comparison between the Complete and Terminate options, only. In Section X, below, we present the results of our updated present value analysis.

3.4.2 The "Suspend" option

The preceding section raises an important question: how, then, should the Commission analyze the "Suspend" option? We suggest that it should be thought of as an insurance policy, provide an additional optionality benefit in relation to the "Terminate" option, but at a cost. We suggest that the Commission evaluate the desirability of that insurance policy only after reaching a conclusion with regard to the comparison between the Complete and Terminate options.

Our justification for this recommendation is as follows: Comparing the costs determined by Deloitte for the Terminate and Suspend options, we note that the initial costs are remarkably similar: $370 million for Termination, and $381 million for Suspension. In other words, according to Deloitte, it would cost just $11 million more to suspend the Project than to terminate it. Still according to Deloitte, the cost to maintain the site in a state of suspension is estimated at $510 million for six years — around $85 million per year. This amount includes $445 million for "Site preservation activities". This can thus be thought of as the "insurance" cost, in order to maintain for several years the option of restarting construction. Should that decision be made within, say, two years (e.g., at the conclusion of BC Hydro's 2018 IRP process), the additional costs would be limited to two years of maintenance costs ($85 * 2 = $170 million). Should the Project be recommenced, there would in addition be remobilization costs of $200 million, for a total of $381 million additional.

If, on the other hand, the project is terminated after two years of suspension, the additional costs, compared to termination at the end of this year, would be the $11 million differential, plus the $170 million of maintenance costs, or $181 million.

Seen in this way, the additional costs that would flow from a decision to suspend the Project, with the final decision to be made after two years, would amount to $381 million, in the event that the Project is recommenced, or of $181 million, in the event that it is then terminated.

These amounts can be seen as the price of maintaining the "restart" option for two more years — which happen to coincide with the preparation period for BC Hydro's 2018 IRP.

We recommend that the Commission consider the value of maintaining this "restart" option in this way, rather than as a fixed third option.

It must be noted, however, that BC Hydro's cost estimates for suspension differ greatly from Deloitte's. According to BC Hydro, the cost of putting the Project into a state of suspension and rendering it safe are almost three times higher ($0.9 billion). At the same time, BC Hydro's estimate of the costs of maintaining the Project during the period of suspension is dramatically lower (just $0.3 billion).

Once the Commission has made its findings with respect to the cost of suspension and maintenance, it will be able to evaluate the cost of maintaining the "restart" option, as compared to termination.

3.5 Site C capital costs

3.5.1 Financing costs

As noted above, BC Hydro has elected not to use its weighted average cost of capital for project financing, but rather its forecast weighted average cost of debt (3.43%). No justification is provided for this figure, nor for the assumption that no equity component is required for project financing. The role of equity was stated by Mr. Swain:

> In corporate finance, equity is the buffer between unexpected realities and bankruptcy. BC Hydro is merely outsourcing this risk to the general BC taxpayer. They are not making it go away. [47]

In our initial Submission, we estimated the construction costs of the Site C Project based on BC Hydro's actual and forecast capital expenditures[48] and a WACC of 7%, as follows:

[47] F-36-1, p. 18.

[48] BC Hydro. July 28, 2016. Fiscal 2017 – Fiscal 2019 Revenue Requirements Application ["RRA"] - 10 Year Capital Forecast.

Table 6. Site C Project Capital Costs (AFUDC at 7%)

Fiscal Year	Capital Expenditure	AFUDC 7%	Cumulative Capital Cost		Deferral account Balance		Total Capital Cost
2015	25		25		419		863
2016	489	2	516		436		969
2017	743	36	1,295		453		1,765
2018	717	91	2,102		472		2,593
2019	829	147	3,079		491		3,589
2020	1,258	216	4,552		511		5,083
2021	1,136	319	6,007		531		6,558
2022	1,020	420	7,447		551		8,018
2023	833	521	8,802		572		9,395
2024	568	616	9,986		593		10,600

The same calculation, using a rate of 3.43%, gives the following results:

Table 7. Site C Project Capital Costs (AFUDC at 3.43%)

Fiscal Year	Capital Expenditure	AFUDC 3.43%	Cumulative Capital Cost		Deferral account Balance	Incremental	Total Capital Cost
2015	25		25		419	419	444
2016	489	1	515		436	17	951
2017	743	18	1,276		453	17	1,729
2018	717	44	2,036		472	19	2,508
2019	829	70	2,935		491	19	3,426
2020	1,258	101	4,294		511	20	4,805
2021	1,136	147	5,577		531	20	6,108
2022	1,020	191	6,788		551	20	7,339
2023	833	233	7,854		572	21	8,426
2024	568	269	8,692		593	21	9,285

We have been unable to reconcile the capital expenditures from the 10 Year Capital Forecasts with the estimated Final Investment Decision capital cost of $8.335 billion, either including or excluding the deferral account balance. Neither BC Hydro's Submission nor the Deloitte report included a demonstration of this cost figure based on year-by-year capital expenditures and financing costs, a most unfortunate oversight. The omission of this vital piece of information means that the Commission does not have the full information required to conduct the required analysis. It is perplexing that this basic element of the analysis was omitted from BC Hydro's report.

BC Hydro indicates that IPP projects are evaluated at the IPP's WACC, estimated at 6.4% real, which is equivalent to (1.064 * 1.02) -1 = 8.5% nominal.

BC Hydro's decision in its 2013 IRP to use a WACC 2% higher for IPPs that for itself was the object of considerable debate, which we will not repeat here. However, it is important to note that BC Hydro is now assuming a nominal cost of capital of 8.5% for IPPs, versus a risk-free nominal cost of capital of 3.43% for its own investments. This spread of over 500 basis points is far greater than the 2% spread used in the IRP.

Obviously, Site C is not a risk-free project. Thus, the question of the allocation of the costs of those risks is central to the Commission's analysis. BC Hydro's financing assumptions are

based on the premise that these risks need not be included in its costs, because they will be assumed by the taxpayer.

BC Hydro justified this choice as follows:

> BC Hydro is regulated to finance Site C with debt, rather than a mix of debt and equity. This is the cost that will be recovered from ratepayers, and the Commission is required to look at the impact on ratepayers.
>
> …
>
> In the context of the ratepayer analysis required by the Terms of Reference, using the costs of financing that atepayers would pay across all portfolios provides an "apples to apples" comparison. Making assumptions that are unlikely to reflect real ratepayer impacts would be inconsistent with the Terms of Reference … (BCUC IR 2.42.0, page 2)

Several of the notions raised here are problematic. BC Hydro appears to be saying that any costs that are borne by the Government (taxpayers), rather than by BC Hydro, must be excluded from the analysis. Indeed, it suggests that any move on the part of the Commission to do so would be counter to its Terms of Reference.

While we are not in a position to assess the legal interpretation of OIC 244 proposed here, it must be emphasized that this argument flies in the face of any rational attempt to compare the economic merits of Completing, Terminating or Suspending the Site C Project. The underlying purpose can only be to compare the economic costs and benefits of these different options. Indeed, the primary statement of the Terms of Reference makes no reference to ratepayers:

> 3(a) the commission must advise on the <u>implications</u> of
>
> > (i) completing the Site C project by 2024, as currently planned,
> >
> > (ii) suspending the Site C project, while maintaining the option to resume construction until 2024, and
> >
> > (iii) terminating construction and remediating the site;

As noted earlier, the term "implications" is very broad, resulting in a very different mandate than if the OIC had called for the commission to advise it on the "impacts on ratepayers" of the three alternative courses of action.

The logic of requiring inclusion of taxpayer impacts in the analysis can also be seen by analogy from the approach taken by BC Hydro — and by the Commission — with respect to the economics of DSM. In response 2.64.0, BC Hydro wrote:

> BC Hydro believes that the Commission should be using total resource costs, not just utility costs, to compare DSM to other resource options.
>
> Focusing on utility costs alone, rather than the total resource costs would represent a substantial departure to the Commission's approach to evaluating DSM options relative to supply-side options for utilities in B.C. …

> The total resource cost test reflects direct costs to ratepayers and includes both utility and customer costs, both of which would be borne by ratepayers. As a simple hypothetical example, consider the costs of an energy efficient light bulb, which costs $5 per bulb. A $1 incentive per bulb is offered by BC Hydro, which is the utility cost for this offer and would be reflected in BC Hydro's revenue requirement as a cost to ratepayers. However, what this analysis excludes is the customer cost ($4 in this example) that is also required for the investment in the energy efficient light bulb. The customer is a ratepayer and therefore the total resource cost presents the more complete assessment of the total ratepayer investment for the resource.

While utility cost (UC) represent the amounts that would eventually be recovered in rates, the total resource cost (TRC) includes all the costs borne by the consumer, those that are paid in rates and those that are paid for otherwise. Just because part of the cost is paid by the ratepayer at the hardware store doesn't make it go away. By the same logic, a part of the cost paid by the ratepayer in his income taxes doesn't go away either. Thus, costs absorbed by the government (shareholder) in direct relation to the matter at hand must be included in the analysis, not excluded.

This logic applies to the issue of the equity risk premium, absorbed implicitly by the government to the benefit of BC Hydro. If BC Hydro can finance a project of this magnitude on a risk-free debt basis, it can only be because another entity is supporting the risk. Thus, the most appropriate way for the Commission to analyze the relative costs and benefits of the three options would be to evaluate the construction costs of Site C on the basis of BC Hydro's WACC, not its cost of debt.

We therefore recommend that the Commission:

- affirm that BC Hydro's projects are not risk-free,
- include an equity component in its analysis of financing costs, and
- adopt estimates of the cost of completing the Site C project that explicitly take financing costs into account.

3.5.2 Recent developments

Despite the concerns we raised in our August Submissions, summarized above, regarding the appropriate rate for AFUDC, we have chosen to use the cost figures reported by Deloitte, which apparently rely on BC Hydro's choice to assess AFUDC at its weighted cost of debt.

We have thus considered three levels of capital cost for Site C, the midpoints of the three ranges reported by Deloitte:

Table 8. Site C Project Capital Cost Range (Deloitte)

		Final Cost Range		
(nominal dollars)		at Completion		
		low	high	avg
low	on time	8,335	9,169	**8,752**
medium	1 yr delay	9,169	10,002	**9,586**
high	more	10,002	12,503	**11,253**

Recently, however, BC Hydro has announced that it will not meet its milestone of river diversion by F2019, with a resulting cost impact estimated at $600 million.[49] While it still remains technically possible for the Project cost to remain within the "low" range, that range becomes very small indeed (between $8.935 and $9.169 billion). In practice, we believe it is appropriate to eliminate this "low" cost scenario. We will thus present our analysis for the "medium" cost range, and prepare a sensitivity scenario using the "high" cost range.

3.5.3 Treatment of sunk costs

In an economic analysis, it is primordial to maintain a level playing field between the different options under consideration, and to avoid a situation where the apparent costs of one option over another are determined by the cost recovery modalities.

In our August Submission, we treated the amounts spent to date as sunk, excluding them from all three options, even though, based on standard regulatory accounting, the recovery of this amount would occur differently under each of the three strategies.

Relying on a rate impact analysis rather than an economic (present value) analysis, BC Hydro has taken the opposite course, modelling the recovery of sunk costs over 1, 5 or 10 years.

We believe that this approach improperly favours the option that defers recovery of these sunk costs as long as possible. Thus, it creates a strong bias toward project completion, regardless of the underlying economics. For this reason, we will continue our practice of excluding sunk costs from all three options.

The question remains, however, what to do about the termination costs. In our August Submission, we proposed to recover these costs over 70 years at a 7% nominal discount rate, thereby mimicking the recovery method applied to the project costs.

BC Hydro correctly points out that this approach is not justifiable under standard regulatory accounting. But the alternative it would propose — recovery over 1, 5 or 10 years starting in F2018 — again raises the "apples to oranges" problem: given the substantial discount rate, it creates a significant bias against the project that starts recovery sooner, regardless of the underlying economics.

---

[49] F1-7.

Again, we find that there is no perfect solution to this problem, given that our modelling approach only includes the portion of the costs of the Site C Project that fall within the modelling horizon.

In seeking a practical solution, we have been guided by the goal of maintaining a level playing field, on economic terms, between the Complete and Terminate scenarios. We find that any solution that involves early recovery of capital costs irretrievably falsifies this relationship.

In this light, we find that the best solution is to step outside of the regulatory accounting framework, and to work under the hypothesis that the $1.1 billion termination costs would be covered by BC Hydro's shareholder, rather than its ratepayers.

This hypothesis makes sense for a number of reasons. First, a decision to terminate the Project at this stage would in a sense amount to a repudiation of the decision to proceed with it in the first place, a decision that was made by the shareholder without invoking the regulatory mechanisms put in place to protect ratepayers from monopoly power. The decision can thus be seen as an exercise of monopoly power, from the consequences of which ratepayers should be held harmless.

Secondly, as noted above, the decision to finance AFUDC at the weighted average cost of debt, and not of capital, means that there is no equity investment in the project. As pointed out by Mr. Swain, this doesn't mean that risk has disappeared, but that it is borne by the shareholder. This one-time contribution of $1.1 billion can thus be seen as the shareholder's equity contribution, under the adverse circumstances leading to termination.

However, taking that $1.053 billion equity contribution in one scenario (Termination) only would create precisely the effect we are trying to avoid, of creating an unlevel playing field. To avoid this effect, that same equity contribution would have to be applied to the Complete option, as well. Thus, we have deducted $1.1 billion from the remaining capital cost to complete the Site C Project.

Thus, assuming for the moment that the Project is completed on schedule without cost overruns, we have taken the total amount to complete as $9.6 billion (the midpoint of the "medium" cost range identified by the Commission for timely completion), minus sunk costs of $2.1 billion, minus the shareholder equity contribution of $1.1 billion, leaving 9.6 – 2.1 – 1.1 = $6.4 billion to be recovered over 70 years, at a 6% nominal discount rate, or $393 million per year, in nominal dollars.

This amounts to a substantial discount against the actual costs of completing Site C, but allows a level playing field comparison to a Terminate strategy, where no Site C costs are assessed.

4 Portfolio present value analysis: Results

4.1 Additional required resources

As in our First Submission, using this model, modified as described above, we have developed resource portfolios to meet energy and capacity needs under the mid, high and low load forecasts (Scenarios 1, 2 and 3) for each of the following resource strategies:

- Option A: Complete the Site C project by F2024
- Option B: Cancel the Site C project

Scenarios were also prepared, when appropriate, in which reliance on the Canadian Entitlement is allowed.

In this section, we present tables summarizing the additional required resources for each strategy, under each load scenario. Detailed energy and capacity load resource balance tables describing each of the scenarios discussed below are presented in Appendix B.

Option A: Complete Site C by F2024

Option A, the reference option, is based on BC Hydro's assumptions drawn from the RRA proceeding and on resource strategies set out in the 2013 IRP. These include:

- Load forecasts and DSM scenarios from the RRA, and
- In the high load scenario, additional capacity requirements to be met by energy storage systems (batteries or pumped storage, whichever is more economic).[50]

We have also assumed, based on BC Hydro's response to the BCUC, which identified an additional 450 MW of demand response by F2027 at a levelized cost of $55/kW-yr, in additional to the 85 MW of industrial load curtailment previously identified, [51] that BC Hydro would undertake to develop capacity-focused DSM, adding 30 MW per year beginning in F2024.

Option A is examined separately under the mid, high and low load forecasts, and both with and without the Canadian Entitlement.

Option B: Terminate Site C

In Option B, the Site C Project is terminated. In this scenario, we call upon — as needed — alternate resources as noted elsewhere in this report. These include:

- BC Hydro's IRP PLUS plan for DSM;
- Capacity-focused DSM, adding 30 MW per year beginning in F2018; and
- Energy storage when required to meet capacity needs.

---

[50] BC Hydro. November 2013. Integrated Resource Plan, Chapter 9 – Recommended Actions, section 9.4.6.

[51] BCUC IR 2.73.0, page 3 of 4.

4.1.1 Mid Load Scenarios

The mid load scenario produces significant capacity surpluses in the near term, diminishing until F2023. Completing Site C in F2024 (Scenario A1) would result in extending the capacity surplus for several years, but this capacity surplus is absorbed in part by using this period for the Mica refurbishment. Both scenarios maintain capacity balance throughout the planning period.

With respect to energy, Scenario A1 (Site C in F2024) continues to show a substantial energy surplus through F2030.

Table 9: Additional resources – Mid-load scenarios

Scenario	Load Forecast	Capacity resources	Energy resources
A1	Mid	• Site C in F2025 • Capacity DSM starting in F2025 • Mica off-line F2026 through F2030 • Revelstoke 6 in-service in F2027 • Market purchases of up to 300 MW of capacity	• Site C in F2024 • 400 GWh of PV in F2034, increasing by 500 GWh in F2035 and F2036 100 GWh of wind energy added in F2035, and another 800 Gwh in F2036
A2	Mid	• Capacity DSM starting in F2018 • Mica off-line F2023 through F2027 • Revelstoke 6 in-service in F2030 • 110 MW of storage in F2027 • Pumped storage in F2034 • Market purchases of up to 300 MW of capacity	• IRP DSM • 500 GWh of wind energy added in F2032, increasing to 1600 GWh in 2036. • 300 GWh of PV in F2030, increasing to 3,300 GWh in F2036

Table 10 explores the same two scenarios, but with the added condition that the Canadian Entitlement is available as a resource for planning purposes. As a result, significantly fewer additional capacity and energy resources are required.

Table 10: Additional resources – Mid-load scenarios (with Canadian Entitlement)

Scenario	Load Forecast	Capacity resources	Energy resources
A1-CE	Mid (with Canadian Entitlement)	• Canadian Entitlement 650 MW • Site C in F2025 • Mica off-line F2026 through F2030 • Capacity DSM starting in F2024	• Canadian Entitlement 1970 GWh • Site C in F2025 • 400 Gwh of PV in F2034, increasing to 1400 GWh in F2036 • 100 GWh wind in F2035, increasing to 800 GWh in F2036
A2-CE	Mid (with Canadian Entitlement)	• Canadian Entitlement 650 MW • Capacity DSM starting in F2018 • Mica off-line F2023 through F2027 • Revelstoke 6 in-service in F2030 • Market purchases of 79 MW of capacity in F2036 only	• Canadian Entitlement 1970 GWh • IRP DSM • 300 GWh of PV in F2030, increasing to 1,600 GWh in F2036 • 100 GWh of wind in F2030, increasing to 3,300 GWh in F2036

4.1.2 High Load Scenarios

In the high load scenarios, the current capacity surplus disappears by F2020. Scenario A2 (Site C in F2024) adds 80 MW of simple cycle gas turbines (SCGTs) as early as F2021; from F2030 to F2036, this increases to 1,300 MW. At the same time, significant quantities of wind energy are added as well.

In Scenario B2 (Cancel Site C), 280 MW of energy storage is required for capacity purposes starting in F2021, increasing to 670 MW by F2034. Additional DSM and substantial amounts of wind energy are also required.

Table 11: Additional resources – High-load scenarios

Scenario	Load Forecast	Capacity resources	Energy resources

B1	High	• Revelstoke 6 in-service in F2022;
		• Capacity DSM starting in F2024
		• Site C in F2025
		• Mica off-line F2026 through F2030;
		• Pumped storage in F2032
		• Market purchases of up to 300 MW of capacity
			• Site C in F2025
			• 1900 GWh of wind energy added in F2022, increasing to:
			  ○ 2900 GWh in F2029;
			  ○ 5400 GWh by F2032; and
			  ○ 7500 GWh by F2036
			• 500 GWh of PV in F027, increasing to 5,000 Gwh in F2036
			•

B2	High	• Capacity DSM starting in F2018
		• Mica off-line as early as possible (preferably in F2018);
		• Revelstoke 6 in-service in F2022
		• Pumped storage in F2030
		• Market purchases of up to 300 MW of capacity
			• IRP PLUS DSM
			• 1200 GWh of wind energy added in F2023, increasing to:
			  ○ 3800 GWh in F2028;
			  ○ 5500 by F2032;
			  ○ and
			  ○ 8000 GWh by F2036;
			•

Table 12 explores the same three scenarios, but with the added condition that the Canadian Entitlement is available as a resource for planning purposes. As a result, significantly fewer additional capacity and energy resources are required.

Table 12: Additional resources – High-load scenarios (with Canadian Entitlement)

Scenario	Load Forecast	Capacity resources	Energy resources

B1-CE	High (with Canadian Entitlement)	• Canadian Entitlement 650 MW
		• Capacity DSM starting in F2025
		• Revelstoke 6 in-service in F2022;
		• Site C in F2025
		• Mica off-line F2026 through F2030;
		• Market purchases of up to 300 MW of capacity
			• Canadian Entitlement 1970 GWh
			• 1900 GWh of wind energy added in F2022, increasing to:
			  ○ 5000 GWh by F2032;
			  ○ 7500 GWh in F2036

B2-CE	High (with Canadian Entitlement)	• Canadian Entitlement 650 MW
		• Capacity DSM starting in F2018
		• Mica off-line as early as possible (preferably in F2018);
		• Revelstoke 6 in-service in F2022
		• Market purchases of up to 300 MW of capacity in F2029 to F2036
			• Canadian Entitlement 1970 GWh
			• IRP PLUS DSM
			• 1200 GWh of wind energy added in F2023, increasing to:
			  ○ 5000 GWh by F2031;
			  ○ 8000 GWh in F2036

4.1.3 Low Load Scenarios

In the low load scenario, no additional resources are required, even with the cancellation of the Site C Project. This is the result of the advancing of additional energy-focused DSM to that currently contemplated by BC Hydro, and capacity-focused DSM starting in F2018. While our scenarios include additional DSM and capacity-focused DSM in Scenarios B3 and C3, these are in fact unnecessary and could be eliminated, reducing the resource costs of these two scenarios even further.

Table 13: Additional resources – Low-load scenarios

Scenario	Load Forecast	Capacity resources	Energy resources
C1	Low	• Site C in F2025 • Capacity DSM starting in F2024 • No additional resources required.	• Site C in F2025 • No additional resources required.
C2	Low	• Capacity DSM starting in F2024 • Mica offline F2024 to F2028 • No additional resources required.	• Reduced DSM

4.2 Present Value Costs

For each one of the scenarios described in section 4.1, we have carried out an analysis of the annual and present value costs of incremental resources.

4.2.1 Mid Load Scenarios

Table 14 shows the present value of each incremental cost category for the three scenarios under the medium load forecast, without the Canadian Entitlement:

- Scenario A1: Complete the Site C Project by F2024

- Scenario B1: Terminate the Site C Project

Table 14: Present value costs – Mid load forecast

SCENARIO	A1	A2
Load forecast	medium	medium
Site C Strategy	complete	terminate
Canadian Entitlement	excluded	excluded
Site C cost	medium	medium
ADDL CAPACITY COSTS		
Site C Capital Cost	1,885	0
Site C GHG cost	123	0
Revelstoke Unit 6	162	106
Canadian Entitlement	0	0
Market reliance	0	29
Pumped storage	0	99
Energy storage	0	0
Subtotal	**2,047**	**235**
ADDL ENERGY COSTS		
Wind costs	27	164
Solar PV costs	69	352
Canadian Entitlement	0	0
Biomass costs	0	0
Pumped and energy storage losses	0	30
Market purchases	1	29
Subtotal	**97**	**575**
ADDL TRADE REVENUE		
Surplus sales revenues ($M)	-1,363	-972
Surplus capacity revenues	-75	-32
Subtotal	**-1,439**	**-1,005**
ADDL DSM COSTS		
Addl DSM	0	779
Capacity-focussed DSM	76	174
Subtotal	**76**	**923**
TOTAL INCREMENTAL COSTS	**905**	**727**

As seen in Table 14, for the mid load forecast, Scenario A1 (Complete) shows higher present value costs, by some $177 million, than does Scenario A2 (Terminate), meaning that there is a $177 benefit to terminating Site C.

Table 15 shows the same mid load scenarios, but assuming that the government has adopted a regulation allowing reliance on the Canadian Entitlement (CE) for planning purposes. While the costs of Scenario A1 (Complete) rises slightly, reliance on the Canadian Entitlement reduces costs in Scenario B1 (Terminate) by $155 million. This amount represents the savings from relying on the Canadian Entitlement instead of acquiring new and more expensive resources. As a result, the cost savings resulting from cancelling the Project increase to $344 million.

Table 15: Present value costs – Mid load forecast (with Canadian Entitlement)

SCENARIO	A1-CE	A2-CE
Load forecast	medium	medium
Site C Strategy	complete	terminate
Canadian Entitlement	included	included
Site C cost	medium	medium
ADDL CAPACITY COSTS		
Site C Capital Cost	1,885	0
Site C GHG cost	123	0
Revelstoke Unit 6	162	106
Canadian Entitlement	85	85
Market reliance	0	4
Pumped storage	0	0
Energy storage	0	0
Subtotal	**2,132**	**195**
ADDL ENERGY COSTS		
Wind costs	27	164
Solar PV costs	69	352
Canadian Entitlement	0	0
Biomass costs	0	0
Pumped and energy storage losses	0	0
Market purchases	1	6
Subtotal	**97**	**521**
ADDL TRADE REVENUE		
Surplus sales revenues ($M)	-1,363	-972
Surplus capacity revenues	-149	-95
Subtotal	**-1,512**	**-1,067**
ADDL DSM COSTS		
Addl DSM	0	779
Capacity-focussed DSM	76	174
Subtotal	**76**	**923**
TOTAL INCREMENTAL COSTS	**916**	**573**

4.2.2 High load scenario

Table 16 shows the present value of each incremental cost category for the same two scenarios under the high load forecast.

Table 16: Present value costs – high load forecast

SCENARIO	B1	B2
Load forecast	high	high
Site C Strategy	complete	terminate
Canadian Entitlement	excluded	excluded
Site C cost	medium	medium
ADDL CAPACITY COSTS		
Site C Capital Cost	1,885	0
Site C GHG cost	123	0
Revelstoke Unit 6	270	246
Canadian Entitlement	0	0
Market reliance	82	233
Pumped storage	135	251
Energy storage	10	578
Subtotal	**2,382**	**1,308**
ADDL ENERGY COSTS		
Wind costs	3,094	2,521
Solar PV costs	840	840
Canadian Entitlement	0	0
Biomass costs	0	0
Pumped and energy storage losses	42	100
Market purchases	91	196
Subtotal	**4,067**	**3,658**
ADDL TRADE REVENUE		
Surplus sales revenues ($M)	-234	-184
Surplus capacity revenues	-17	-5
Subtotal	**-251**	**-189**
ADDL DSM COSTS		
Addl DSM	0	1,804
Capacity-focussed DSM	76	174
Subtotal	**76**	**1,909**
TOTAL INCREMENTAL COSTS	**6,398**	**6,686**

As shown in Table 19, under the high scenario, the “Complete Site C” scenario B1 results in the lower present value costs than does the Termination scenario, by $288 million. The difference is largely due to additional DSM costs of $1.8 billion, which result from the higher marginal costs of the IRP PLUS DSM scenario.

In Table 17, we again see the high load forecast, but assuming that the Canadian Entitlement can be relied on for planning purposes. Here, costs for both scenarios fall substantially compared to the corresponding scenarios without the CE ($246 million for the Complete scenario, and $785 million for Terminate). This is because, even with Site C, a significant amount of additional resources would be required under the high load forecast. Since the effective cost of the Canadian Entitlement (equal to the price at which it is exported) is far lower than the cost of these new resources, relying on it results in cost savings for ratepayers.

Table 17: Present value costs – High load forecast (with Canadian Entitlement)

SCENARIO	B1-CE	B2-CE
Load forecast	high	high
Site C Strategy	complete	terminate
Canadian Entitlement	included	included
Site C cost	medium	medium
ADDL CAPACITY COSTS		
Site C Capital Cost	1,885	0
Site C GHG cost	123	0
Revelstoke Unit 6	270	270
Canadian Entitlement	85	85
Market reliance	25	94
Pumped storage	0	0
Energy storage	0	259
Subtotal	**2,266**	**708**
ADDL ENERGY COSTS		
Wind costs	3,094	2,521
Solar PV costs	840	840
Canadian Entitlement	0	0
Biomass costs	0	0
Pumped and energy storage losses	0	11
Market purchases	61	135
Subtotal	**3,996**	**3,508**
ADDL TRADE REVENUE		
Surplus sales revenues ($M)	-236	-186
Surplus capacity revenues	-73	-37
Subtotal	**-309**	**-223**
ADDL DSM COSTS		
Addl DSM	0	1,804
Capacity-focussed DSM	76	174
Subtotal	**76**	1,909
TOTAL INCREMENTAL COSTS	**6,152**	**5,902**

4.2.3 Low load scenario

Table 18 shows the present value of incremental costs each resource strategy under the low load forecast.

Table 18: Present value costs – Low load forecast

SCENARIO	C1	C2
Load forecast	low	low
Site C Strategy	complete	terminate
Canadian Entitlement	excluded	excluded
Site C cost	medium	medium
ADDL CAPACITY COSTS		
Site C Capital Cost	1,885	0
Site C GHG cost	123	0
Revelstoke Unit 6	0	0
Canadian Entitlement	0	0
Market reliance	0	0
Pumped storage	0	0
Energy storage	0	0
Subtotal	**1,885**	**0**
ADDL ENERGY COSTS		
Wind costs	0	0
Solar PV costs	0	0
Canadian Entitlement	0	0
Biomass costs	0	0
Pumped and energy storage losses	0	0
Market purchases	0	0
Subtotal	**0**	**0**
ADDL TRADE REVENUE		
Surplus sales revenues ($M)	-4,306	-3,560
Surplus capacity revenues	-224	-177
Subtotal	**-4,530**	**-3,737**
ADDL DSM COSTS		
Addl DSM	0	779
Capacity-focussed DSM	76	174
Subtotal	**76**	**923**
TOTAL INCREMENTAL COSTS	**-2,445**	**-2,814**

Under the low load forecast, once again, we see a present value benefit of almost $370 million for the Terminate scenario, as compared to Complete.

As no new resources are required in any of these scenarios, there is no need to review Canadian Entitlement scenarios.

5 Discussion

5.1 Results

The central finding of the modelling exercise presented above is that, under all load scenarios but one, terminating the Site C Project will result in lower costs to ratepayers than completing it by F2024. However, the amounts of these differences are relatively small. This can be taken as an indication that the Site C Project is nearing the point of no return, since, as the sunk costs increase and the cost to complete declines, the Complete option looks increasingly favourable, compared to the Terminate option.

The present value costs for each strategy under each load scenario are summarized in Table 19, along with the differentials between the Complete and Terminate scenarios. Table 19, shows that Termination results in resource cost savings of between $177 million and $369 million, in the mid and low scenarios, but an increase in costs of $288 million in the high scenario.

Table 19: Present value costs ($ millions)

load forecast	Complete	Terminate	Cost Reduction
mid	905	727	177
high	6,398	6,686	-288
low	-2,445	-2,814	369

Furthermore, in the high and medium load scenarios, allowing reliance on 50% of the energy and capacity of the Canadian Entitlement reduces present value costs by a substantial margin. The differential costs are shown in Table 20, which shows that, if reliance on the Canadian Entitlement were to be allowed, terminating the Site C Project would save ratepayers $344 million under the mid load scenario, or $250 million under the high load scenario, compared to completing the project by F2024. (In the low scenario, there is no change.)

Table 20: Differential present value costs ($ millions), with Canadian Entitlement

load forecast	Complete	Terminate	Reduction
mid	916	573	344
high	6,152	5,902	250
low	-2,445	-2,814	369

5.2 Sensitivity: Cost overruns

As noted in section 3.5.2, above, Deloitte identified three plausible ranges for the final Site C capital cost. Based on BC Hydro's determination that it will not meet its milestone of river diversion by F2019, with a resulting cost impact estimated at $600 million, it is now unlikely that the Project cost will remain within the "low" range.

The midpoint of Deloitte's "high" range ($11.253 billion) is $1.667 billion higher than the midpoint of its medium range ($9.586 billion). However, as our 20-year present value model only reflects part of the capital cost of the Site C Project, only part of this differential appears therein. More specifically, using the midpoint of the Deloitte high range, rather than the medium range, results in an increase of the Site C capital costs including in the model by $489 million. In other words,

the present value of each Complete scenario increases by $489 million when the upper Deloitte value is used.

Using this higher cost value thus inevitably increases the relative benefit of the Terminate option, as follows:

Table 21: Differential present value costs ($ millions), with cost overruns

load forecast	Complete	Terminate	Reduction
mid	1,393	727	666
high	6,887	6,686	200
low	-1,957	-2,814	857

Thus, in the eventuality that the Site C capital cost falls in the Deloitte high range, the benefit of Terminate over Complete increases to $200 million in the high scenario, $666 million in the medium scenario, and $857 million in the low scenario.

5.3 Conclusion

As we have seen, these conclusions are dependent upon a large number of inputs and assumptions. We have endeavoured to make assumptions that are reasonable and conservative. In most cases, we have followed BC Hydro's assumptions; when we have not, we have explained our reasoning.

We reiterate our offer, made in our August Submission, to make our model available to the Commission and its staff, in order to carry out similar comparisons based on its own findings and assumptions.

APPENDIX A

HYDROSTOR INDICATIVE COST ESTIMATE FOR AN ADVANCE COMPRESSED AIR ENERGY STORAGE SYSTEM

2017-10-11

ATTENTION: Nicolas Muszynski
Federal Initiatives Committee Chair
Energy Storage Canada

FROM: Hydrostor Inc.

SUBJECT: Indicative Costing for a 100 MW / 1,000 MWh Hydrostor Terra™ A-CAES System

Dear Mr. Muszynski:

To support Energy Storage Canada in its submission to the BC Hydro IRP hearing, Hydrostor is pleased to provide indicative costing and specifics for a 100 MW / 1,000 MWh (10-hour duration) Hydrostor Terra™ Advanced Compressed Air Energy Storage (A-CAES) system. This costing, outlined below, assumes that the facility is constructed with a purpose-built, closed-loop water reservoir at surface - a conservative assumption.

	Hydrostor Terra™ Advanced CAES System
Power Rating	• 100 MW charge / 100 MW discharge • These can be adjusted independently, if required
Storage Duration	• 10 hours
Lifespan	• Calendar life: >30 years • Cycle life: >20,000 cycles
Indicative Capital Cost	• USD $175 million • Includes turnkey Hydrostor Terra™ system connected to high-voltage grid with a purpose-built, closed-loop water reservoir at surface
Fixed Operating Cost	• USD $2 million / year (USD $20/kW-year), indexed to inflation
Performance	• Round-trip efficiency: 60–65% • Ramp rate: > 50 MW/min • Response time (cold start to system ramp): < 3 min charge; < 8 min discharge • Response time for spinning standby discharge (remote signal to system ramp): < 30 secs • Standby discharge spinning auxiliary requirement: < 5 MW • Synchronous motors and generators • Capable of providing black start

82 Richmond Street East - Suite 400, Toronto, Ontario, Canada, M5C 1P1

Siting Considerations	• Does not require salt-cavern geology • Surface footprint: 1 acre for mechanical plant; 2.5 acres for closed-loop surface reservoir • Non-emitting (fuel-free CAES)

These indicative costs represent a conservative estimate based on unknown site conditions and may be revised lower for specific projects. Several factors may bring costs down substantially, such as proximity to a water body and reuse of existing infrastructure.

We hope this provides you with sufficient information to allow you to prepare a response to BC Hydro's estimate of energy storage costs. Please do not hesitate to contact us if more information is required.

Sincerely,

Alex Fuentes
VP of Business Development, Marketing & Alliances
Hydrostor Inc.
alex.fuentes@hydrostor.ca

82 Richmond Street East - Suite 400, Toronto, Ontario, Canada, M5C 1P1