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Costs and benefits to ratepayers of delaying the commissioning of the Site C Hydroelectric Project

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EXECUTIVE SUMMARY

During the first years after commissioning, not all of the energy produced by Site C will be needed in British Columbia. The surplus will be exported, producing revenues that will help to offset the annual cost of the project to ratepayers. However, because the unit cost of Site C power is so much greater than its value in the export market, these surplus sales represent a net loss.

If commissioning of Site C were deferred by one or two years, ratepayer costs in those years would be greatly reduced, even after taking into account lost export revenues and the purchase of replacement power.

BC Hydro estimates that, if construction were delayed by one year, it would result in increasing the Project's capital costs by $420 million. This would result in increasing the annual Site C cost to ratepayers by $29.7 million, from $619.7 million to $649.3 million. These additional costs, over the life of the project, tend to counteract the benefit caused by the delay in the first years.

I compared, on a cumulative and discounted basis, the costs and benefits flowing from a one- or two-year delay. My analysis demonstrates that:

- During the years prior to commissioning of the Site C Project, a one- or two-year delay would result in very significant ratepayer benefits;
- In the case of a one-year delay, during the first four decades after commissioning, ratepayer impacts of said delay would continue to be positive. From that point on, the cumulative effect would be negative, resulting in a present value ratepayer cost of $33.9 million by the end of the Project's financial life, based on the BC Hydro's most recent forecasts and assumptions. This amount represents approximately one-third of one percent of total project costs;
- In the case of a two-year delay, ratepayer of said delay would continue to be positive for the full 70-year financial life of the Project for a two-year delay, producing a present value ratepayer **benefit** of $26.3 million by the end of the Project's financial life, under the same assumptions. This amount also represents approximately one-third of one percent of total project costs; and

- These values are highly dependent on the input assumptions. Using BC Hydro's low market price scenario, both values become positive; using the high market price scenario, they both become negative.

I conclude from this analysis that, given the very substantial and unavoidable uncertainties in every element of these projections, the additional costs of delay identified in the Savidant affidavit, when combined with the very substantial positive ratepayer impacts that delay would produce prior to commissioning and in the first decades thereafter, are not significant.

This result reflects the fact that delaying commissioning will tend to reduce the losses that result from selling Site C surplus power in the export market at prices far below its production cost. This benefit tends to counterbalance the increased capital cost resulting from the delay. Whether the net result is slightly positive or slightly negative depends on the evolution into the distant future of parameters such as market prices, exchange rates and interest rates, the future values of which are highly uncertain and effectively unknowable.

DUTY OF AN EXPERT

I certify that I am aware of my duty as an expert witness under the Supreme Court Civil Rules to assist the court and not to be an advocate for any party. The attached report has been made in conformity with that duty. If I am called on to give testimony, I will do so in conformity with that duty.

STATEMENT OF QUALIFICATIONS

Cofounder of the Helios Centre, Philip Raphals has extensive experience in many aspects of sustainable energy policy, including least-cost energy planning, utility regulation (including transmission ratemaking) and green power certification.

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 fourteen (14) proceedings before the Régie de l'énergie du Québec. The Régie has recognized his expertise in a number of fields including transmission ratemaking, security of supply, energy efficiency and avoided costs.

In Nova Scotia, he has provided expert testimony in two proceedings concerning the Maritime Link, after being recognized by the Nova Scotia Utilities and Review Board as being expert in sustainable energy policy, least-cost energy planning and utility regulation (including transmission ratemaking).[1] His testimony included 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[2] and relied in part on his analyses.

In Newfoundland and Labrador, 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. The Newfoundland and Labrador Public Utilities Board has qualified Mr. Raphals as an expert in electric utility rate making and regulatory policy.[3]

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[1] Hearing Transcript, NSUARB-ML-2013-01/M05419, pages 2248 and 2252.

[2] NSUARB, Decision in the Matter of an Application for Approval of the Maritime Link Project, 2013 NSUARB 154, M05419, paragraph 195, p. 64.

[3] Hearing Transcript, September 29, 2015, page 5.

Mr. Raphals has also provided expert affidavits in proceedings before the U.S. Court of Appeals for the District of Columbia Circuit (1999) and for the Federal Court of Canada (2012).

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 (JRP) on the Site C Hydroelectric Project. The Panel cited him in its report and relied on his analyses for several of its findings.

From 1992 to 1994, Mr. Raphals was Assistant Scientific Coordinator for the Support Office of the Environmental Assessment of the Great Whale hydro project, where he coauthored a study on the role of integrated resource planning in assessing the project's justification.[4]

In 1997, he 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

[4] J. Litchfield, L. Hemmingway, and P. Raphals. 1994. *Integrated resources planning and the Great Whale Public Review*. Background paper no. 7, Great Whale Public Review Support Office, 115 pp. *(also published in French).*

(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.*"

1. INTRODUCTION

I have been asked to analyze the ratepayer implications for BC Hydro and its ratepayers of deferring commissioning of the Site C Project, taking into account both near-term effects in the 2020s and long-term effects over the life of the Project.

Once in service, the Site C Hydroelectric Project will produce 1,100 MW of capacity and, on average, 5,100 GWh per year of energy. Its construction costs are estimated at $8.335 billion.[5] Those costs, together with operating costs, will be recovered from ratepayers over a 70-year period. The cost to ratepayers will be approximately $500 million per year, [6] starting with the year of commissioning.[7]

For several years after commissioning, not all of the energy produced by Site C will be needed in British Columbia. The surplus will be exported, producing revenue that will help to offset the annual cost of the project to ratepayers.

In August 2015, Michael Savidant produced an affidavit stating that, if construction of Site C were delayed by one year, its capital costs increase by an estimated $335 million.[8]

In his affidavit dated January 28, 2016, he estimates that, if construction were now delayed by one year, it would result in an estimated further increase of $85 million, resulting in a total impact of $420 million on the Project's capital costs.[9] However, the effect on capital cost is just

5 Government of British Columbia, Backgrounder, Site C Capital Cost Estimate, December 16, 2014.

6 Government of British Columbia, Backgrounder, Comparing the Options, December 16, 2014.

7 According to the Site C website, project construction is now expected to be completed in 2024 (https://www.sitecproject.com/about-site-c/project-overview, consulted February 5, 2016). However, the analysis presented in this report uses a commissioning date of 2023, as indicated in BC Hydro's Final Integrated Resource Plan (November 2013).

8 Savidant Affidavit, Exhibit B, paragraph 82, page 22.

9 Savidant affidavit, paragraph 4.

one of the factors that need to be considered to evaluate the net cost (or benefit) of a delay for BC Hydro's ratepayers, either in the short or the long term.

Based on well known principles, in use over many decades in British Columbia as in the rest of Canada and the United States, electricity rates are based on a utility's annual revenue requirements — the amount of revenues required to meet its costs and to allow a reasonable rate of return on its investments. While many other factors may come into play, the estimation of a utility's costs on a year-to-year basis remains an essential element of ratemaking. Delaying the commissioning of Site C would affect several factors, including BC Hydro's purchases and surplus sales, that would also affect its revenue requirements year after year. In this report, I will review the various factors that contribute to determining overall ratepayer impact, and will estimate that impact for a one- and two-year delay.

Delaying the commissioning of the Site C Project by one or two years would affect the supply-demand balance for several years. For each of these years, there would be changes in the utility's costs (relating to purchased power) and revenues (relating to the export of surplus power). Calculation of the net cost to BC Hydro ratepayers must take these factors into account, along with the increase in annual costs resulting from the increased capital cost.

In Section 2 of this report, I describe the sources of fact and the assumptions relied upon in my analysis.

In Section 3, I describe the tools used by BC Hydro to characterize its supply-demand balance and will present its most recent forecasts for future supply-demand balances for energy and capacity.

In Section 4, I present my analysis. In Section 4.1, I use the supply/demand balances described in Section 3 to determine the effects on these balances of delaying the commissioning the Site C Project by one year and by two years. We see that, for capacity, the effect of a two-year delay is limited to the years 2023 and 2024, whereas, for energy, the effect is felt in 2023, 2024 and 2025.

In Section 4.2, I analyze the ratepayer consequences of such a delay in the construction and commissioning of Site C on ratepayers in the 2020s, with respect to both energy and capacity.

A delay of one or two years would also create effects at the end of the Project's useful life.[10] Just as, in the event of a one-year delay in commissioning, ratepayers in 2023 would not pay the project's costs nor would they benefit from its electricity production, ratepayers in 2093 would face an additional year of project costs — but would also benefit from an additional year of electricity production. In Section 4.3, I address the end effects that result from deferring decommissioning of Site C by one or two years.

Finally, in Section 5, I present my conclusions, and, in Section 6, a list of sources to which I have referred.

Several important documents I have referred to are included as attachments.

[10] At different times, the useful life of the Site C project has been referred to as 50, 70 or even 100 years. For the purposes of this analysis, it is assumed to be 70 years.

2. FACTS AND ASSUMPTIONS

The facts used in this report are all derived from documents produced by BC Hydro — primarily the Final Integrated Resource Plan (November 2013). Reference is also made to certain documents produced by BC Hydro in the context of the Environmental Assessment of the Site C Clean Energy Project, as well as in the context of consultations with First Nations related to this project. All documents that are not readily available online, as well as certain other documents referred to, are produced in this report's appendices.

The assumptions used in this report are also derived from these same BC Hydro documents, as set out expressly in the analysis section of this report. When additional assumptions are made, for example in the comparison of multiple scenarios, they are clearly set out therein.

The increased capital costs described in the affidavit of Michael Savidant are assumed to be correct, but they have not been verified.

3. SUPPLY-DEMAND BALANCE AND BC HYDRO'S PLANNING

Planning for future energy needs is a complex undertaking that involves synthesizing substantial quantities of different types of information. In this section, I describe these elements and the basic tools used by BC Hydro to summarize and communicate its planning framework.

It is important to understand that utility planning must simultaneously address two important aspects of electric service: energy and capacity. Many images are used to illustrate this fundamental distinction. Perhaps the simplest approach is to think of the electricity system as a large flashlight, the brightness of which at any moment is determined by the amount of power required by the utility's customers.

"Capacity needs," measured in watts (or kilowatts, or megawatts) refers to the brightest level that will be required at any time during the year. Even if needed only for one hour during the year, the system must be sufficient to provide that level of capacity when required.

"Energy needs," on the other hand, measured in kilowatt-hours (or megawatt-hours, or gigawatt-hours) refers to the total number of batteries that will be required during the year to power that flashlight. Obviously, during hours when the flashlight is operating at its brightest level (at peak capacity), it will consume energy more rapidly than during hours when it is dim. Annual energy needs thus reflect the cumulative amount of energy used by BC residents and businesses during each hour of the year.

In the context of its consultations with First Nations in 2014, BC Hydro presented updated information concerning its load forecasts, its forecasts for electricity required by the LNG (liquified natural gas) industry,[11] DSM (energy conservation) targets,[12] and other elements of its

[11] Because of the substantial uncertainty about the extent to which electricity will be required by the LNG industry in B.C., LNG load forecasts are described separately from the regular load forecast. In its IRP, BC Hydro referred to several possible levels of future LNG loads, referring to them as "no LNG", "low LNG", "expected LNG" and "high LNG".

[12] Demand-Side Management (DSM) refers to efforts by a utility to help its customers reduce their energy consumption. BC Hydro forecasts the savings that will result from its current and future DSM programs.

planning framework. In response to a request from the Treaty 8 Tribal Association, it presented its updated planning scenarios in the same format as it had used in Appendix 9A of its Integrated Resource Plan. A copy of these tables, together with the emails describing them, is presented in Attachment 6.

These scenarios were provided in late November 2014. To the best of my knowledge, they are the most recent data made public by BC Hydro with regard to its planning. As these data were transmitted just weeks before the decision was announced to proceed with Site C, they likely also represent the most recent information available to government when that decision was made.

In these communications, BC Hydro provided up-to-date supply-demand balances that show supply and demand for capacity and for energy on a year-by-year basis. These balances were provided for each of four key scenarios: with and without Site C, and with and without recourse to thermal options. The four portfolios presented were:

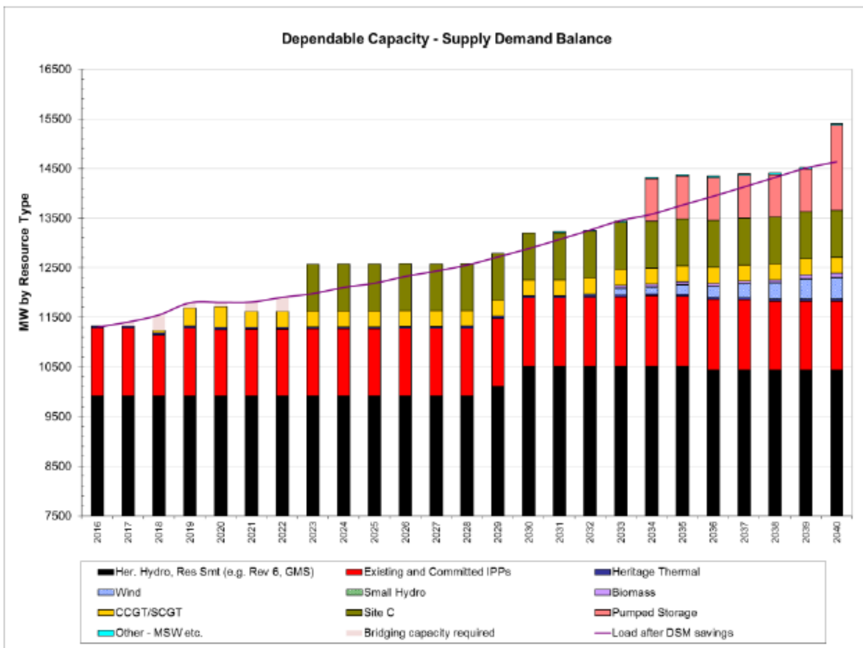
- Site C + Clean
- Site C + Clean + Thermal
- Clean
- Clean + Thermal

In BC Hydro's jargon, a Clean portfolio includes only renewable energy resources. "Clean + Thermal" refers to a scenario that, in addition to renewables, also includes additional thermal (natural gas powered) resources, within the greenhouse gas emission limits created by the *Clean Energy Act.*

All four of these portfolios used the same values for the regular load forecast (the medium scenario from the 2014 load forecast); for the load forecast for the LNG industry (the "Expected LNG" scenario, consisting of 360 MW and 3,000 GWh/year, ramping up from 2017 to 2020); and for forecast power and energy savings due to DSM.

For the purposes of this report, we will look only at the two scenarios that include Site C. The supply and demand balances for these two scenarios, the "Site C + Clean" and the "Site C + Clean + Thermal" scenarios, are shown in Figure 1 and Figure 2, respectively. For each one, the supply and demand balance is shown separately for capacity and for energy. In each case, the chart shows the relationship between supply and demand for each year of the planning period. Site C is represented by the olive-green block that first appears in 2023.

Figure 1. BC Hydro updated planning scenarios (Site C + Clean Portfolio)



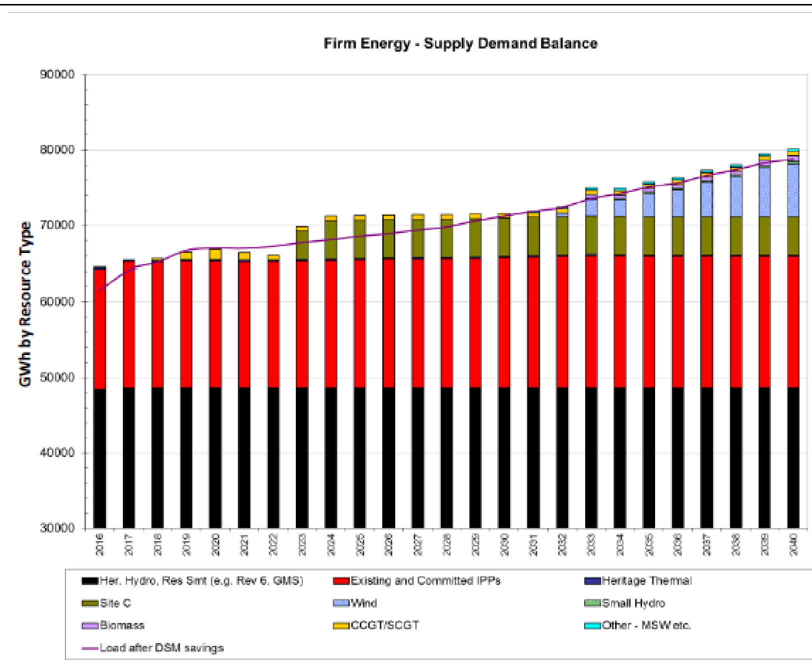
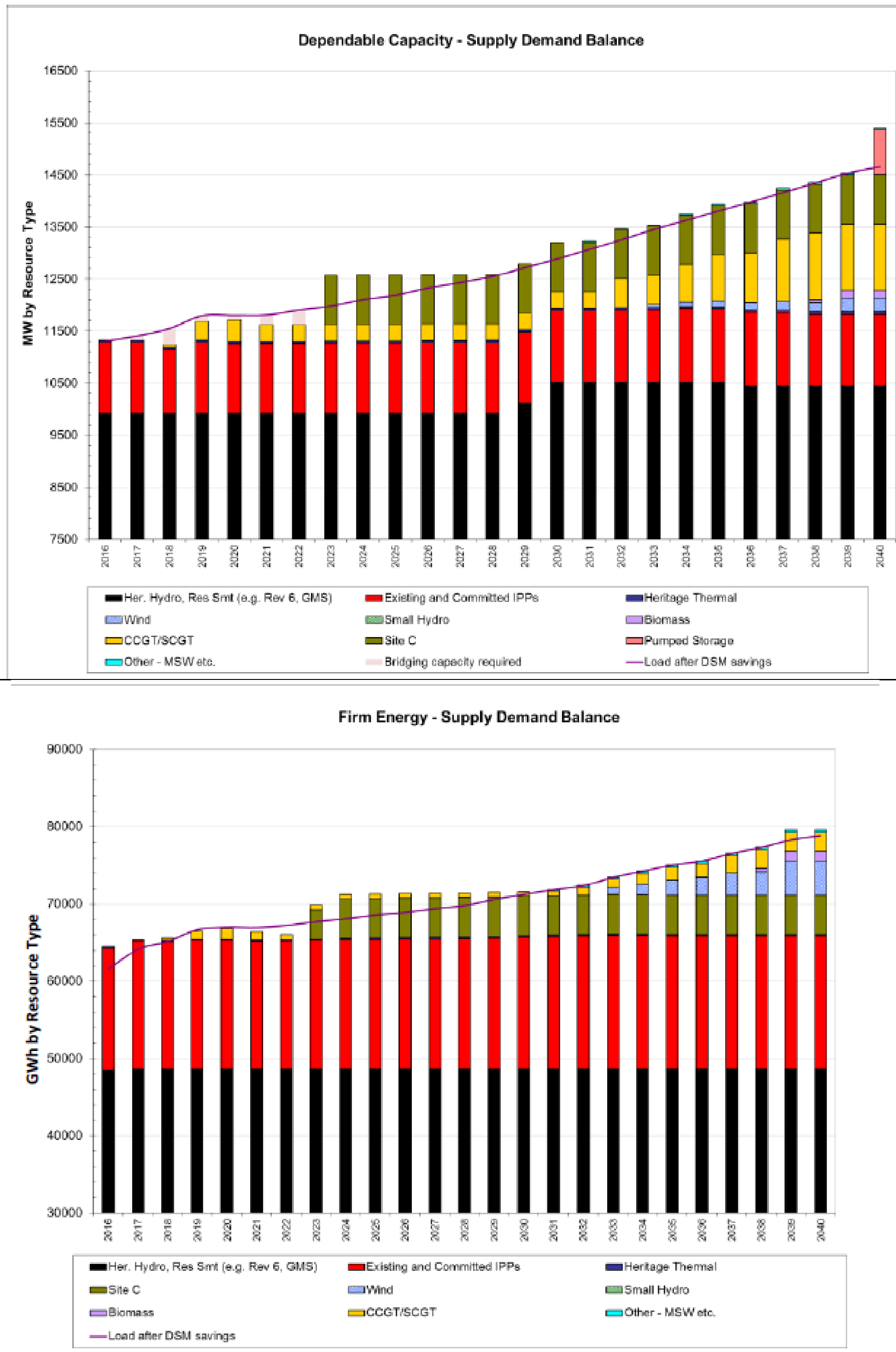


Figure 2. BC Hydro updated planning scenarios (Site C + Clean + Thermal Portfolio)



In Figure 1 and Figure 2, the upper graphs show the capacity balance, and the lower ones the energy balance. In each case, the rising line represents net demand, composed of forecast needs (the medium load scenario) plus forecast needs for LNG (the Expected LNG loads), minus the expected DSM savings for each year.

The bars represent the resources available in each year to meet those needs. The sequence of resource additions was selected by BC Hydro using System Optimizer software in order to minimize total costs.[13]

Whenever the demand line passes above the bars, e.g. as it does in both energy graphs for 2022, system resources are not sufficient to meet demand. This shortfall is to be met with market purchases. On the capacity side, these market purchases are indicated with a pale pink bar, labelled “Bridging capacity required”. On the energy side, the resource insufficiency is simply shown as a shortfall.[14]

Whenever the line cuts through the bars, e.g. as it does in all four graphs in 2023-2027, system resources exceed requirements. Surplus energy is presumed to be exported to the US market, producing market revenues. In its Integrated Resource Plan (“IRP”), BC Hydro presented long-

[13] “Resource portfolios for the IRP were developed using System Optimizer which is a product of Ventyx. System Optimizer is a deterministic mixed integer programming optimization model that determines an optimal sequence 1 of generation and transmission resource expansions, referred to as a portfolio, for a given set of input assumptions. It does so by minimizing the PV of net cost required to meet a given load under average water conditions. The net costs include the incremental fixed capital and operating costs for new resources, total system production costs, and electricity trade cost and revenues. System Optimizer does not value the ancillary benefits provided by future potential resources such as the ability to integrate intermittent resources and to increase the firm capability of other resources. This value could be significant for resources such as Site C, natural gas-fired generation or pumped storage.” BC Hydro, Final Integrated Resource Plan, Chapter 4, pages 4-60 to 4-61.

[14] “The BRPs and CRPs are constructed using the following general methodology:

…

- meet interim energy and capacity shortfalls prior to Site C with cost effective market purchases first and power from the Columbia River Treaty second …”

BC Hydro, Final Integrated Resource Plan, Appendix 9A – Load Resource Balances, Base Resource Plans and Contingency Plans, pages 9A-1 to 9A-2.

term market price forecasts,[15] and these can be used to estimate the value of these surplus energy sales.

Surplus capacity may or may not be marketable in the future. This issue is addressed below in section 4.2.3.1.

15 BC Hydro, Final Integrated Resource Plan (November 2013), Appendix 5A.

4. ANALYSIS

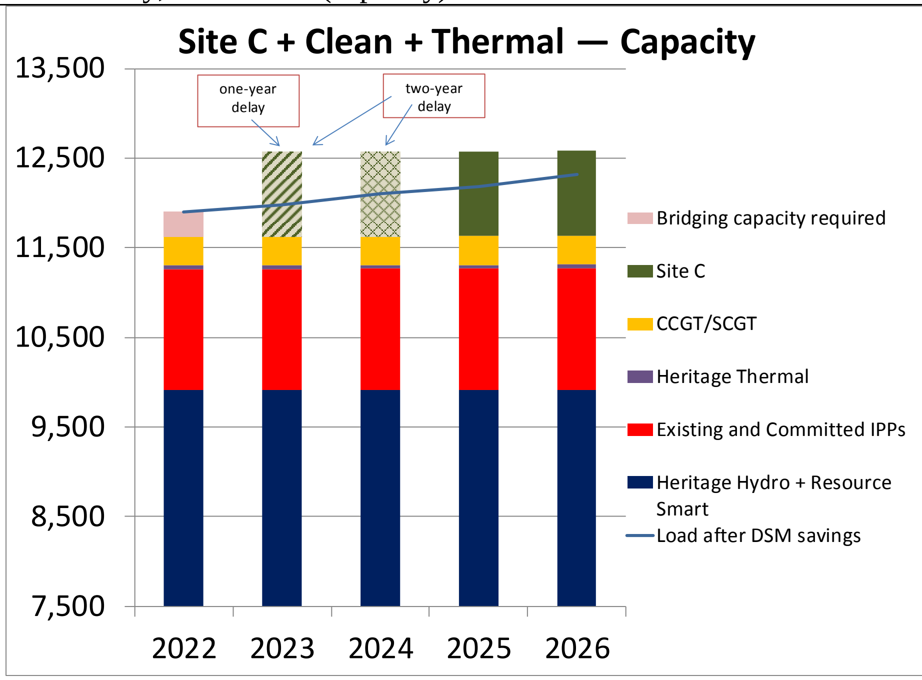
4.1. Effects of delay on the supply-demand balance

Using these charts, we can see very precisely the consequences of a one-year or a two-year delay in the commissioning of Site C. Figure 3, for example, presents a detail view of Figure 2, illustrating the effect of a delay of one or two years on the capacity balance in the “Site C + Clean + Thermal” scenario. In the original scenario, there is a capacity shortfall in 2022, for which “bridging capacity is required”. When Site C comes on line in 2023, it creates a surplus that then lasts for several years.

In the event of a one-year delay in commissioning of Site C, the hatched green block in 2023 would disappear, thus requiring bridging capacity in both 2022 and 2023. In the event of a two-year delay, the 2024 cross-hatched green block would disappear as well. Again, bridging capacity would be required, at a level slightly higher than in 2022 and 2023.

From 2025 on, however, a one-year or two-year delay in the commissioning of Site C would have no effect on the capacity balance. Thus, the only effects of a one-year or two-year delay on the capacity balance would occur during the years 2023 and 2024.

Figure 3. Effect of delay, 2022-2025 (capacity)

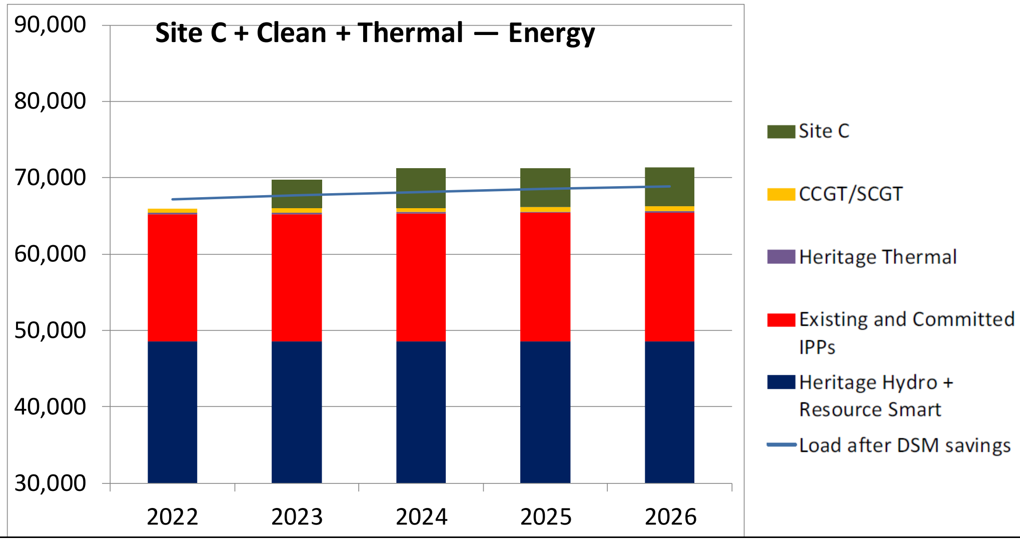


On the energy side, the picture is slightly more complicated, because Site C will not provide its full annual energy production in its first year.[16] Figure 4 shows the effect of a one-year and a two-year delay on the energy balance.

[16] To produce its full complement of energy in the first year, commissioning would have to take place on the first day of the year. On the capacity side, BC Hydro considers that full capacity will be available during the annual peak of the year of commissioning.

Figure 4. Effect of delay, 2022-2026 (energy)

No delay



1 year delay

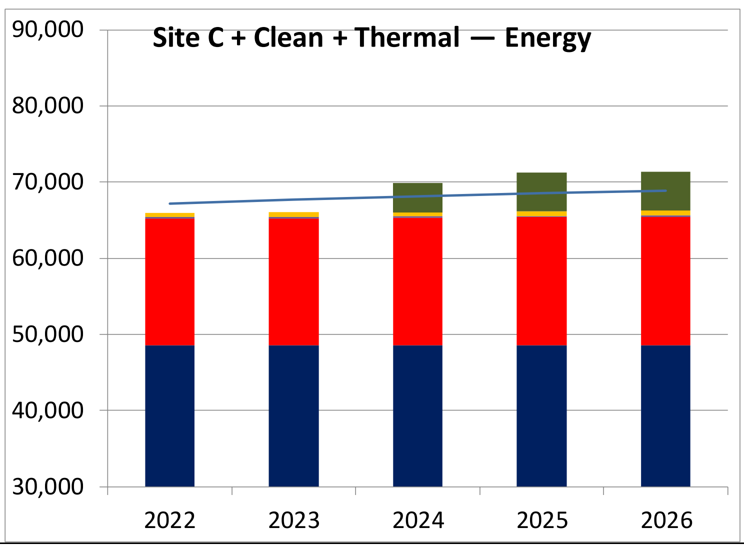
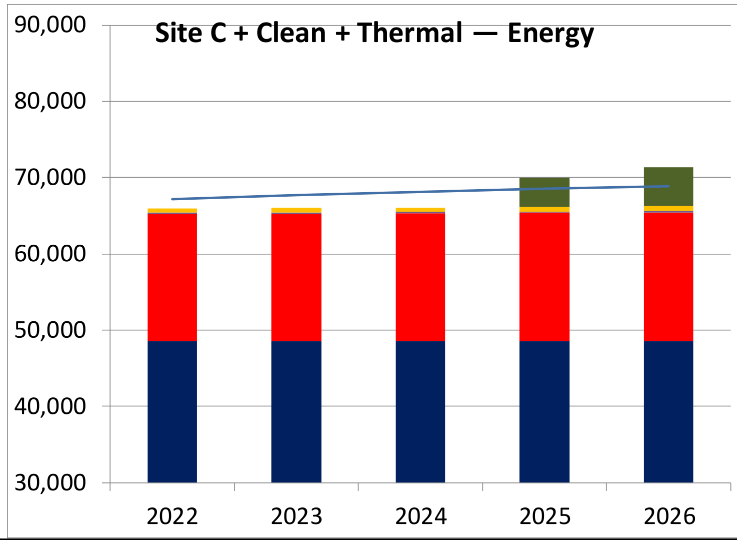


Figure 4. Effect of delay (energy)

2 year delay



Thus, the effects of a one-year delay on the energy balance are felt in 2023 and 2024, and those of a two-year delay are felt in 2023-2025. Neither a one-year delay nor a two-year delay have any effect after 2026, other than the end effects, addressed below in section 4.3. The only effects on energy balance of a one-year or two-year delay would thus occur during the years 2023, 2024 and 2025. In each case, for the years in question, a planned energy surplus would be replaced by an energy deficit as a result of delay in the construction and commissioning of Site C.

The capacity and energy balances for a given year can each be described with a single number, either positive (surplus) or negative (deficit). This number is the available supply minus the demand (net of DSM). These effects are quantified in the following section.

4.1.1. Effects of delay on the capacity balance

As we have seen, the effects of a one-year or two-year delay on the capacity balance are limited to two years: 2023 and 2024. Table 1 shows the capacity balance for the years 2022 to 2025 under the original schedule and with a one-year and two-year delay.[17] The impacts are the same for the Site C + Clean portfolio and for the Site C + Clean + Thermal portfolio.

Table 1. Capacity balances 2022-2025, with and without delay

Capacity balance (MW)	2022	2023	2024	2025
Original schedule	-277	597	474	391
1-yr delay	-277	-349	474	391
2-yr delay	-277	-349	-472	391

This shows that, in all scenarios, there is a capacity deficit of 277 MW in 2022, to be supplied by "bridging capacity". With a one-year delay, the 597 MW surplus originally planned for 2023 is replaced with a deficit, of 349 MW. With a two-year delay, there is a further effect in 2024, when the 474 MW surplus originally planned would also be replaced with a deficit of 472 MW.

4.1.2. Effects of delay on the energy balance

The effect of delay on the energy balance is similar, but it extends for an additional year. The equivalent information is shown in Table 2. As before, the impacts are the same for the Site C + Clean portfolio and for the Site C + Clean + Thermal portfolio.

Table 2. Energy balances 2022-2026, with and without delay

Energy balance (GWh)	2022	2023	2024	2025	2026
Original schedule	-1,218	2,097	3,121	2,710	2,458
1-yr delay	-1,218	-1,669	1,784	2,710	2,458
2-yr delay	-1,218	-1,669	-1,982	1,373	2,458

Once again, we see that in 2022 a deficit is forecast, of 1,218 GWh. According to the original commissioning schedule, this would be followed in 2023 by a surplus of 2,097 GWh. However, with either a one-year or two-year delay, there would instead be a deficit of 1,669 GWh in 2023.

[17] These values were computed from tables supplied by BC Hydro in the context of its consultations with First Nations, that were used to generate the figures presented in Figure 1. A copy of these tables is attached as Appendix B.

In 2024, a surplus of 3,121 GWh is forecast. However, with a one-year delay, this would be reduced to a surplus of 1,784 GWh, and with a two-year delay, to a deficit of 1,982 GWh.

In 2025, the forecast surplus of 2,710 GWh would also occur with a one-year delay. With a two-year delay, however, that surplus would be reduced to 1,373 GWh.

Finally, from 2026 on, the energy balance would be the same, regardless of a one-year or two-year delay.

As we have seen above, BC Hydro's energy balance shows a deficit in 2021 and 2022. As noted above on page 15, BC Hydro intends to use imports to cover this deficit until Site C is in service.

Presumably, this same strategy can be applied to the slightly larger forecast for 2023 and 2024, in the event of a two-year delay. It should be noted that, in its Integrated Resource Plan, BC Hydro relied on market purchases for over 4,000 GWh in certain scenarios.[18]

4.2. Evaluating the implications of delay for ratepayers

As we have seen, delaying the commissioning of Site C by one or two years would affect BC Hydro's capacity balance in the years 2023 and 2024, and its energy balance in the years 2023 through 2025. In order to estimate the ratepayer consequences of these changes, it is necessary first to forecast the price of electricity in the export market for those years.

Energy price forecasts are prepared regularly by a number of institutions. These forecasts are addressed in section 4.2.2.

Capacity price forecasts are considerably more uncertain. These are addressed in section 4.2.3.

First, however, we will consider the annual costs of the Site C project.

[18] BC Hydro, Integrated Resource Plan, Appendix 9A, Table 9, page 9A-18.

4.2.1. Annual cost of Site C

Any additional costs incurred by BC Hydro in the event of a one- or two-year delay in the commissioning of Site C would be counterbalanced by a corresponding delay in recovery of the costs of the Site C Project itself.

A backgrounder released by the B.C. Government indicates the evolution of the annual cost of Site C. A chart from the backgrounder is reproduced here as Figure 5.[19] It shows that, for 70 years after commissioning, the annual cost will vary within a narrow band around $500 million per year.[20] The annual cost can be thought of as the amount which, when discounted over the financial life of the project, is equal to the capital cost.[21]

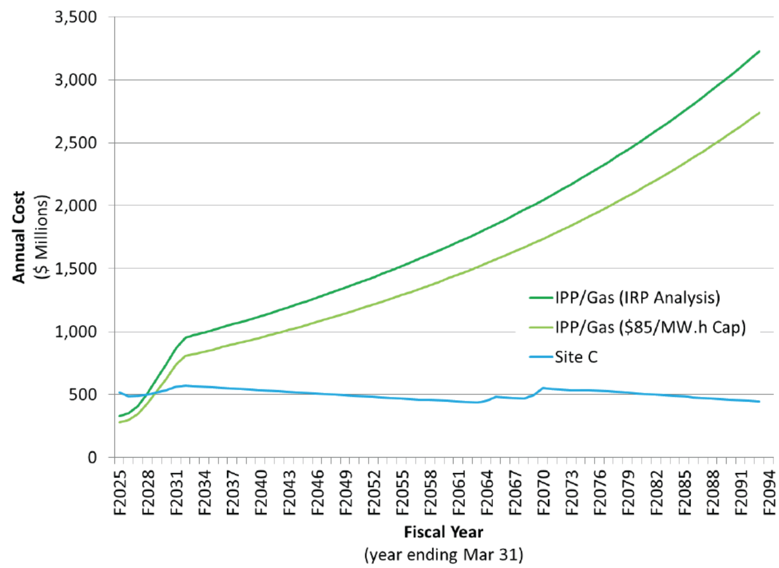
This amount is in many ways like a mortgage, paid at a constant yearly amount (in nominal dollars) over a long period of time. Like a mortgage, this amount includes debt service (consisting of interest and capital repayment), in proportions that change over time.

[19] Government of British Columbia, Backgrounder, Comparing the Options (December 16, 2014). These annual costs include both capital and operating costs, but, in the first decades after commissioning, capital costs represent by far the larger share. While it does not so specify, the chart apparently refers to nominal dollars.

[20] The other two lines shown in the graph, describing the costs of an IPP/Gas scenario, are not relevant for this analysis, though they do demonstrate clearly that the graph is portraying nominal (not constant) dollars.

[21] Disregarding operations and maintenance costs, which in the case of a large hydro project are very small in relation to the capital costs.

Figure 5. Annual cost of Site C



This same Backgrounder indicates that the capital cost of Site C has been increased to $8.335 billion, plus a project reserve of $440 million. Based on BC Hydro's nominal discount rate of 7%, this capital cost would result in an annual cost of $620 million/year for a period of 70 years. It therefore appears that Figure 5 was prepared using the earlier, lower, estimate of the capital cost of Site C.

For a 7% discount rate over a 70-year financial life,[22] each $100 million of capital costs increases annual costs by about $7 million. Thus, the $420 million of additional capital costs mentioned in Mr. Savidant's affidavit would result in an additional annual cost of $29.7 million.

[22] The financial analysis presented to the Joint Review Panel for the approval of Site C was based on a 50-year financial life. The documents made public by the government of British Columbia in December 2014, including the one cited above, used a 70-year financial life. At the same time, the December 2014 press release referred to a "100 Year Project". For the purposes of this analysis, I use a 70-year financial life.

One of the bedrock concepts of utility ratemaking is the “used and useful” doctrine, which states that ratepayers must not be required to pay for equipment which is not “used and useful” in providing electric service.[23] Thus, only facilities currently providing service to customers can be included in rate base. Construction and financing costs prior to commissioning are capitalized and recovered from consumers once the facility is placed in service. This means that, if the commissioning of Site C is delayed from 2023 to 2024, ratepayers in 2023 will not have to pay the $620 million in costs that would otherwise have to be recovered through their rates.

Similarly, an additional annual payment will be required in 2094. This will be addressed in section 4.3.3, below.

4.2.2. Energy costs

As we have seen in section 4.1.2, a one- or two-year delay in the commissioning of Site C will result in decreased export revenues and increased power purchase costs in 2023-2025. To evaluate the impacts of these effects on ratepayers, it is necessary to forecast electricity prices during this period.

4.2.2.1. Historical energy prices

Electricity prices in the US Northwest are generally quoted at the Mid-Columbia (“Mid-C”) hub. The Mid-Columbia market is one of the largest in the world with spot and forward markets that are quoted widely. Its location is shown in here in Figure 6.

[23] The Regulation of Public Utilities 2nd Ed., Charles F. Phillips Jr., Public Utilities Reports Inc. (1988), page 302.

Figure 6. Mid-C trading hub[24]

Natural gas is the primary price-setting fuel in the Northwest Power Pool. As a result of the development of new technologies to access shale gas resources at much lower cost, the cost to generate electricity from natural gas has declined and electricity prices have fallen dramatically in recent years. Figure 7 shows the evolution of average wholesale market prices for peak electricity at Mid-C since 2001. It shows that average peak electricity prices in the Northwest fell by almost half in 2009 and have not exceeded $40/MWh[25] ever since.

[24] Source: website of the US Federal Energy Regulatory Commission (FERC)

[25] In the wholesale market, energy prices are generally quoted in dollars per megawatthour ($/MWh). Retail electricity rates are generally quoted in cents per kilowatthour (¢/kWh). $40/MWh is the same as 4¢/kWh.

Figure 7. Average Mid-C market peak prices, 2001-2015[26]

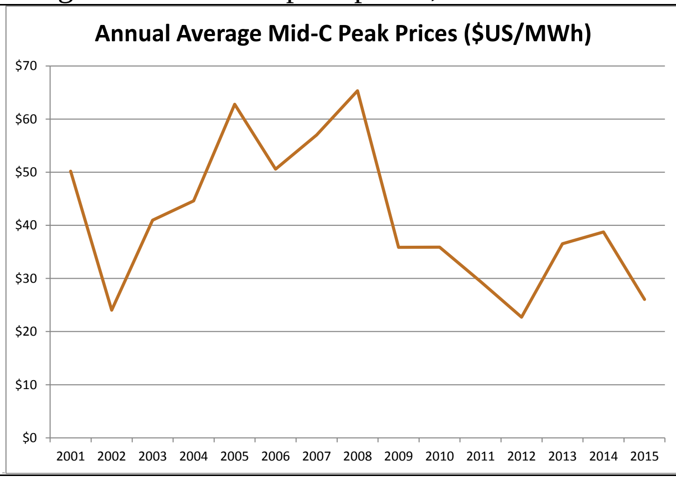
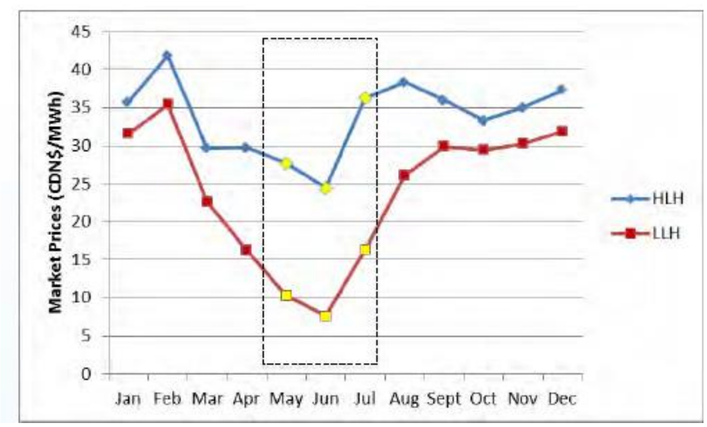


Figure 8 shows average Mid-C electricity prices, on a monthly basis, for the five-year period 2010 through 2014.

Figure 8. Average Mid-C market prices, 2010-2014[27]



This figure shows that, even for peak (High Load Hour) periods, average monthly prices rarely exceeded CAD$40/MWh. During off-peak (Low Load Hour) periods, they ranged between $20

[26] Data from U.S. Energy Information Administration, http://www.eia.gov/electricity/wholesale/?scr=email#history

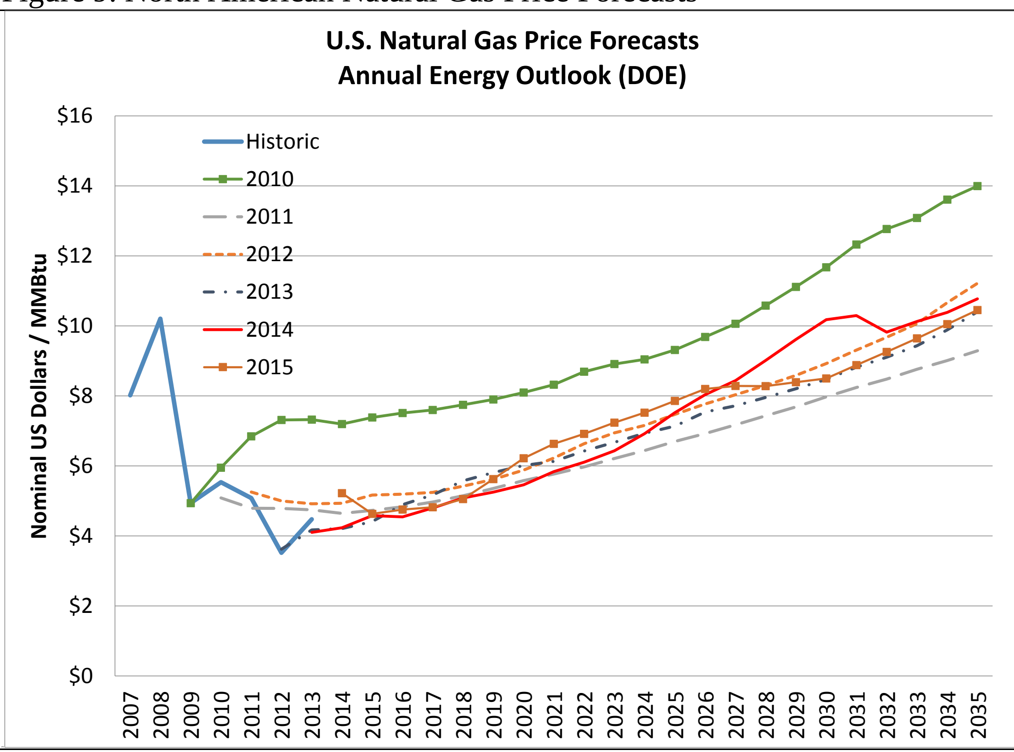
[27] BC Hydro, 2015 Rate Design Application (RDA): Transmission Service Rates, Presentation dated May 7, 2015, page 21.

and $30/MWh, and have fallen well below $20 (2¢/kWh) during summer months when water runoff from the region's numerous hydroelectric facilities is high.

4.2.2.2. Energy price forecasts

Recent forecasts suggest that the shale gas revolution is here to stay, and that it will be a long time before electricity prices return to the levels seen in the previous decade. Electricity prices are to a large extent driven by natural gas prices. Figure 9 shows the evolution of U.S. natural gas price forecasts, based on the Annual Energy Outlook of the U.S. Department of Energy. It shows that, since 2011, there has been little change in long-term gas price forecasts, which are projected to increase slowly over the next 20 years.

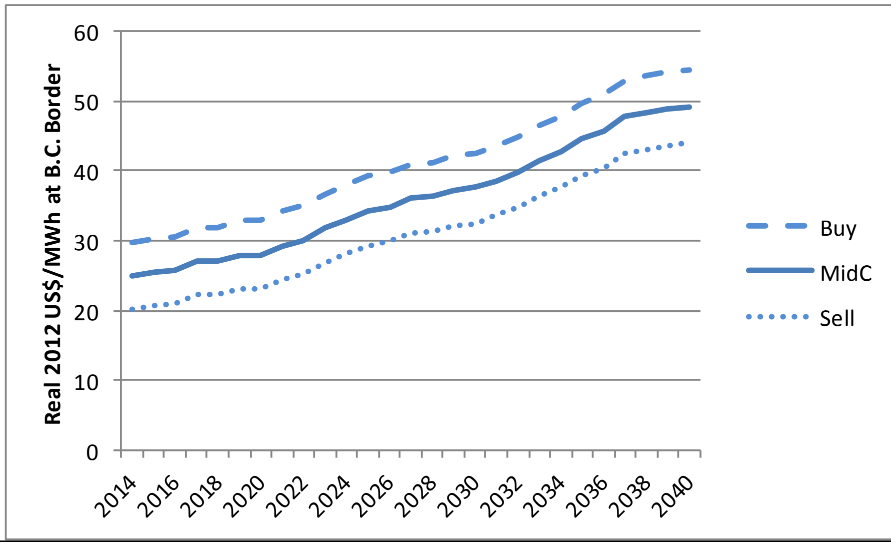
Figure 9. North American Natural Gas Price Forecasts[28]



28 Compiled from Tables 3 and 20 of the DOE's Annual Energy Outlook, 2010 through 2015. https://www.eia.gov/forecasts/aeo/tables_ref.cfm

In its 2013 IRP (and in the draft versions that preceded it), BC Hydro presented forecasts of energy market prices through 2040, under several scenarios. In these forecasts, BC Hydro presented separate forecasts for the Mid-C price and for the "buy" and "sell" prices available to BC Hydro.[29] Its medium forecasts for these three values are shown in Figure 10.

Figure 10. BC Hydro forecasts of Mid-C market prices (real 2012 US$)



The forecast purchase price for buying electricity is always higher than the Mid-C hub price, since wheeling charges and losses resulting from transmission from Mid-C to B.C. load centres must be added to the Mid-C price. Similarly, the price for selling electricity is always lower, because wheeling charges and losses must be subtracted from the Mid-C price.[30] The data presented in the IRP demonstrates that BC Hydro expects this spread to reman relatively stable, increasing gradually from ±$4.80/MWh in the short term to ±$5.30/MWh by the mid-2020s.[31]

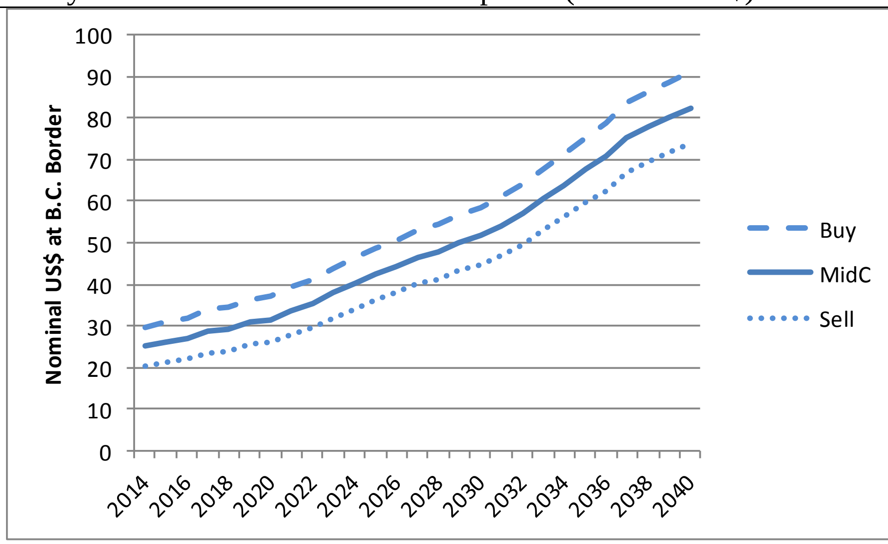
[29] A copy of the relevant pages from Appendix 5A BC Hydro's Final IRP 2013 are attached as Appendix C.

[30] BC Hydro, Integrated Resource Plan, Appendix 5A, pages 5A-6 and 5A-7, notes 1 and 2.

[31] Derived by comparing the "buy" and "sell" prices year to year, according to Appendix 5A of the Final Integrated Resource Plan, Tables 5 and 6 on pages 5A-5 and 5A-6.

It should also be noted that these forecasts are presented in real 2012 US dollars. Figure 11 shows the equivalent in nominal US dollars, assuming an inflation rate of 2% per year.[32] Thus, in 2040, the Mid C sales price is expected to reach $73.80/MWh, and the purchase price to reach $91.40/MWh.

Figure 11. BC Hydro forecasts of Mid-C market prices (nominal US$)



These forecast prices are far below the historical levels shown in Figure 7. According to these BC Hydro forecasts, the $60 prices seen in 2005-2008 will not be seen again before the 2030s.

For the years 2023 to 2025, BC Hydro forecasts an average selling price of less than US$30/MWh in real 2012 dollars. In nominal dollars, this is about US$40; in nominal Canadian dollars, at the exchange rate used by BC Hydro, [33] it is about CA$41.50.

Before the announcement of the B.C. Government's 10-Year Plan for BC Hydro, the unit cost of electricity from Site C was estimated at CAD$83/MWh. After the 10-Year Plan, which reduces

[32] The value of money declines constantly, due to inflation. "Nominal dollars" simply refers to the amount of money spent (or earned) at some future time. "Real dollars" represents the value of that amount, expressed in constant dollars of a particular year.

[33] The Final Integrated Resource Plan relies on a forecast exchange rate of 0.9693 USD/CAD. BC Hydro, Final Integrated Resource Plan, page 4-63.

the government revenue expected from the Site C Project, among other changes, BC Hydro now considers that the final cost to ratepayers of Site C will be between $64 and $67/MWh.[34] These figures are expressed in real 2013 Canadian dollars. The equivalent cost in nominal dollars in 2024 would be $103 (before the announcement) and $81 (after the announcement).

With a forecast market sales price of CA$41.50, it is clear that the value of electricity on the export markets in 2023-2025 will be considerably less than the cost of producing it at Site C, regardless of which of the two figures is used. This means that the portion of Site C electricity that is surplus to British Columbia's needs in any given year will inevitably result in a financial loss.

4.2.2.3. Energy costs related to a one-year and a two-year delay

Using BC Hydro's market price forecasts, we can quantify the costs resulting from a delay in the commissioning of Site C, both with respect to costs of purchasing energy to meet BC's energy needs and foregone revenues from the sale of surplus energy.

Combining the figures in Table 2 with the 2012 buy and sell prices shown in Figure 10, we can calculate the energy-related costs under each scenario.

Table 3. Implications of delay (energy) (000s of real 2012 US$) – medium scenario

Revenue (cost) (2012$)	**2023**	**2024**	**2025**	**TOTAL**	**DIFFERENCE**
Original schedule	56,200	87,700	79,132	223,032	
1-yr delay	-61,252	50,130	79,132	68,010	-155,022
2-yr delay	-61,252	-75,316	40,092	-96,477	-319,508

Table 3 shows that, under the original schedule, the expected revenues from the sale of surplus electricity in 2023-2025 would amount to $223 million (in constant 2012 US dollars). With a one-year delay, these revenues would fall to $68 million, a drop of $155 million. With a two-

[34] Supra, note 2.

year delay, they would be replaced by a three-year cost of $96 million, which represents a loss of $319 million, compared to the base case.

The same analysis, using nominal US dollars, is presented in Table 4.

Table 4. Implications of delay (energy) (000s of nominal US$) – medium scenario

Revenue (cost) nominal	2023	2024	2025	TOTAL	DIFFERENCE
Original schedule	67,164	106,906	98,391	272,460	
1-yr delay	-73,202	61,109	98,391	86,297	-186,163
2-yr delay	-73,202	-91,810	49,849	-115,163	-387,623

Here, we see a revenue loss of $186 million (nominal) with a one-year delay, and of $387 million with a two-year delay.

4.2.2.3.1. Exchange rates

To compare these costs with the avoided cost of the Site C project, during the delay period, they must be converted to Canadian dollars. As noted above, in the IRP, BC Hydro used a constant exchange rate of 0.9693 USD/CAD throughout the planning period.[35] In November 2014, BC Hydro indicated that it still used that same value for all years of study,[36] despite the fact that the exchange rate had already fallen by 10% by that time, to 0.87519 USD/CAD.

Since then, the value of the Canadian dollar in relation to the US dollar has fallen still further. At this writing, it stands at 0.7206 USD/CAD, 25% lower than the figure used in BC Hydro's analysis.

As we shall see below, the analysis of the financial impacts of delay is very sensitive to exchange rate variations. However, for this initial analysis, in the absence of any credible exchange rate forecast extending to the mid-2020s, I use the exchange rate assumptions used by BC Hydro.

[35] IRP, page p. 4-63.

[36] BC Hydro Responses to Questions from the Treaty 8 Tribal Association, November 6, 2014, page 11.

Using this rate to convert the costs shown in Table 4 to Canadian nominal dollars results in the values shown Table 5.

Table 5. Implications of delay (energy) (000s of nominal CA$) – medium scenario

Revenue (cost) nominal CA$	2023	2024	2025	TOTAL	DIFFERENCE
Original schedule	69,291	110,292	101,507	281,090	
1-yr delay	-75,521	63,044	101,507	89,030	-192,059
2-yr delay	-75,521	-94,718	51,428	-118,811	-399,900

Thus, the additional energy costs resulting from a one-year delay would amount to about CA$192 million, and those resulting from a two-year delay would amount to about CA$400 million, based on BC Hydro's medium scenarios for load growth and market prices, and on the exchange rates in effect in 2013.

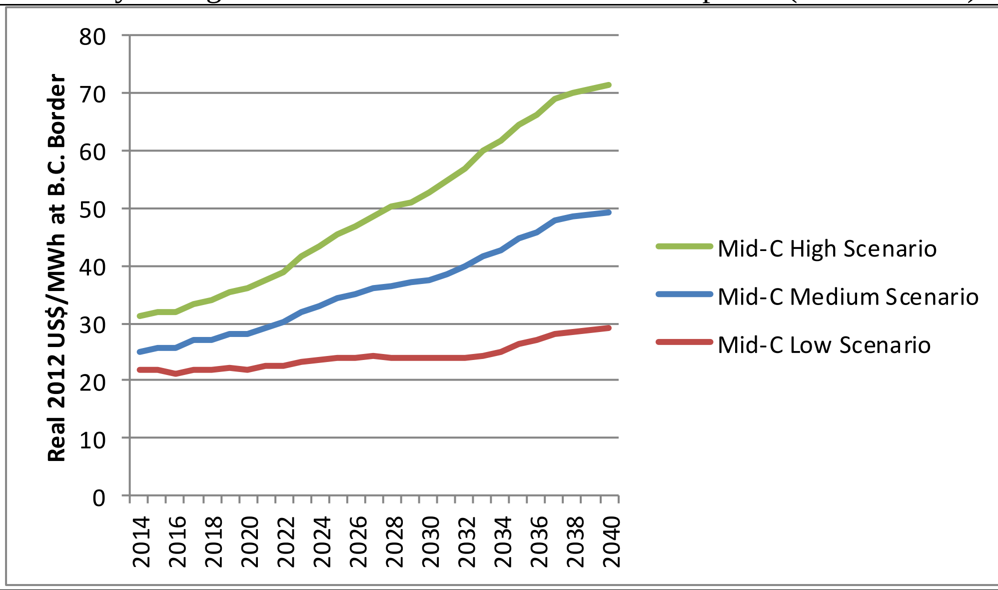
These costs are substantial. Nevertheless, as we shall see, they are much lower than the ratepayer benefits in 2023 and 2024 resulting from the deferral of the construction and commissioning of Site C.

4.2.2.3.2. High and low scenario price forecasts

In addition to these "medium" forecasts, BC Hydro also presented high and low forecast scenarios.[37] These high and low price forecasts are shown in Figure 12. The spread between the "buy" and "sell" prices described in the previous section applies to these scenarios as well.

[37] It also presented two additional scenarios, based on a national GHG market, but indicated that it considered these scenarios very unlikely (IRP, page 5-39).

Figure 12. BC Hydro high and low forecasts of Mid-C market prices (nominal US$)



The wide spread between the low, medium and high price scenarios reflects the profound uncertainty that affects energy market forecasts. Under the high scenario, prices would recover their 2008 levels by the middle of the next decade. Under the low scenario, average Mid-C prices would remain under $30/MWh to the end of the planning period. BC Hydro considers the probability that future prices will remain between the high and low forecasts to be 80%.

4.2.3. Capacity costs

4.2.3.1. Capacity price forecasts

While markets for energy are highly structured and liquid, that is not true for the capacity markets. According to BC Hydro:

> There is no open capacity-only market in the Western Electricity Co-ordinating Council (WECC) region. Capacity-only sales are infrequent, prices can be unpredictable and capacity contracts are highly customized, as evidenced by the fact that there is no capacity index in the WECC region. <u>BC Hydro has conservatively not attributed a value to surplus capacity in the portfolio analysis</u>. In Certificate of Public Convenience and Necessity (CPCN) applications to the BCUC, BC Hydro noted that there is <u>a broad range of 'market-based capacity' values of $37/kW-year to $107/kW-year</u> based on recent Bonneville Power Administration tariffs, transactions and market analysis, and potential U.S. market access transmission constraints. Applying even the low end of the capacity market value range

> would result in the Project portfolio looking even more cost-effective than the Clean and Clean +Thermal portfolios.
>
> BC Hydro has not carried out sensitivity analysis regarding the market value of capacity for reasons described above.[38] (underlining added)

In another response, BC Hydro wrote:

> If a resource is surplus to the capacity LRB [Load Resource Balance] set out in Table 5.9 of the EIS, <u>the surplus capacity has been given no value in the portfolio evaluations</u>. This is a conservative assumption, because as set out in the response to ab_0001-068, capacity has some albeit varying value in the market. Applying even the low end of the capacity market value range ($37/kW-year) described in that response would result in the Project portfolio looking even more cost-effective than the Clean and Clean +Thermal portfolios.[39] (underlining added)

As there is no liquid capacity market in the Northwest, there are no long-term price projections that can be used for this analysis. For purchasing capacity, I will use the midpoint of the range of costs mentioned by BC Hydro ($72/kW-year). For capacity surpluses, BC Hydro applies a zero value in its portfolio analysis, but indicates that this choice was conservative, mentioning again a value of $37/kW-year. Thus, for sale of capacity, I will use the midpoint of the two values, $18.50/kW-year, will all figures in real 2012 US dollars.

Calculations similar to those used in the energy analysis above yields the following results, in nominal dollars.

Table 6. Implications of delay (capacity) (000s of nominal CA$)— medium scenario

Revenue (cost) nominal CA$	2023	2024	TOTAL	DIFFERENCE
Original schedule	13,617	11,028	24,645	
1-yr delay	-30,981	11,028	-19,953	-44,599
2-yr delay	-30,981	-42,738	-73,720	-98,365

[38] Response to Comments on the Site C Clean Energy Project Environmental Impact Statement, January 25, 2013, Submitted by BC Hydro on May 8th, 2013, Response ab_0001-068.

[39] Ibid., Response ab_0001-142.

4.3. Ratepayer implications of delay

My analysis of the ratepayer implications of a delay in the commission of Site C are presented in three parts:

- Effects prior to commissioning
- Effects during the first decade
- End effects.

4.3.1. Effects prior to commissioning

Using the analysis presented in the previous section, we can evaluate the ratepayer implications of delay prior to commissioning, based on BC Hydro's planning assumptions.

We have seen in Table 5 that a one-year delay would result in reducing export revenues by \$116.5 million, from \$179.6 million (\$110.3 million in 2023 + \$69.3 million in 2024) to \$63 million (in 2024 only), and adding additional energy costs of \$75.5 million (in 2023), for a net energy cost of \$192 million. In addition, there would be a capacity cost estimated at \$31 million, and, hypothetically, a lost revenue for the sale of surplus capacity of \$13.6 million. These additional costs would have to be supported by ratepayers. At the same time, ratepayers would be spared one year of the annual cost of Site C, \$619.7 million, for a net gain of \$383 million, compared to the costs they would face under BC Hydro's planning scenario.

Similarly, a two-year delay would result in a net reduction of ratepayer costs of \$741.1 million, over two years. These figures are summarized in Table 7.

Table 7. Ratepayer impacts of delay prior to commissioning (nominal $CA)

	1-yr Delay	2-yr Delay
Site C Annual Cost	619,686,351	1,239,372,702
Lost export revenues (energy)	-116,538,718	-229,662,114
Lost export revenues (capacity)	-13,617,249	-24,645,169
Additional energy costs	-75,520,653	-170,238,267
Additional capacity costs	-30,981,416	-73,719,790
TOTAL	**383,028,316**	**741,107,362**

These very substantial reductions in ratepayer costs in 2023 and 2024 (and 2025, for a two-year delay) are due to the large proportion of Site C's output that would be surplus to BC needs during those years, and to the wide gap between the cost of producing that power and its value in the export market.

4.3.2. Ratepayer implications of delay during the first decade

The results shown in the previous section consider only the impacts of delay prior to commissioning, and do not reflect the additional costs caused by the delay, as described in the Savidant affidavit.

As noted above on page 25, any increase to the Project's capital cost would be reflected in its annual costs, and would be felt in each year after commissioning. Table 8 shows the annual ratepayer costs and savings from 2023 to 2032 taking these delay-related costs into account, assuming a one-year delay in the commissioning of Site C. As before, only costs and revenues that vary due to a one-year delay are indicated.

Table 8. Ratepayer impacts of a one-year delay, 2023 – 2032 (000s of nominal $CA)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2,032
Site C Annual Cost Savings	619,686	0	0	0	0	0	0	0	0	0
Site C delay-related costs		-29,660	-29,660	-29,660	-29,660	-29,660	-29,660	-29,660	-29,660	-29,660
Lost export revenues (energy)	-69,291	-47,248	0							
Lost export revenues (capacity)	-13,617									
Additional energy costs	-75,521	0	0	0	0	0	0	0	0	0
Additional capacity costs	-30,981	0	0	0	0	0	0	0	0	0
Ratepayer savings (cost)	430,276	-76,908	-29,660	-29,660	-29,660	-29,660	-29,660	-29,660	-29,660	-29,660

The costs shown in Table 8 are presented in nominal dollars. However, in order to compare costs over time, costs and revenues must be discounted to account for inflation and the time value of money. Table 9 shows the total ratepayer savings and costs from the last line of Table 8, discounted using BC Hydro's 7% nominal discount rate, which includes an implicit inflation rate of 2%.[40]

Table 9. Discounted ratepayer impacts of a one-year delay, 2023 – 2032 (000s of nominal $CA)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2,032
Ratepayer savings (cost)	430,276	-76,908	-29,660	-29,660	-29,660	-29,660	-29,660	-29,660	-29,660	-29,660
Discounted ratepayer savings (cost	430,276	-71,877	-25,906	-24,212	-22,628	-21,147	-19,764	-18,471	-17,263	-16,133
Cumulative discounted ratepayer s	430,276	358,399	332,493	308,282	285,654	264,507	244,743	226,272	209,009	192,876

The last line of Table 9 thus shows the cumulative effect of a one-year delay, in constant 2023 Canadian dollars. In financial terms, this last line represents the present value of the revenue/cost stream in the first line. It shows that the cumulative ratepayer benefit, 10 years after the Project's in-service date, is still over $192 million, taking into account the additional costs of delay.

Table 10 presents the same analysis with respect to a two-year delay in the commissioning of Site C, making the conservative assumption that the additional capital cost resulting from a two-year delay would be double the amounts indicated in the Savidant affidavit.

40 BC Hydro, Final IRP, page 4-63.

Table 10. Discounted ratepayer impacts of a two-year delay, 2023 – 2032 (000s of nominal $CA)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Site C Annual Cost Savings	619,686	619,686	0	0	0	0	0	0	0	0
Site C delay-related costs			-59,320	-59,320	-59,320	-59,320	-59,320	-59,320	-59,320	-59,320
Lost export revenues (energy)	-69,291	-110,292	50,079							
Lost export revenues (capacity)	-13,617	-11,028								
Additional energy costs	-75,521	-94,718	0	0	0	0	0	0	0	0
Additional capacity costs	-30,981	-42,738	0	0	0	0	0	0	0	0
Ratepayer savings (cost)	430,276	360,911	-9,241	-59,320	-59,320	-59,320	-59,320	-59,320	-59,320	-59,320
Discounted ratepayer savings (cost	430,276	337,300	-8,072	-48,423	-45,255	-42,295	-39,528	-36,942	-34,525	-32,266
Cumulative discounted ratepayer s	430,276	767,576	759,504	711,081	665,826	623,531	584,003	547,062	512,537	480,270

Following the same logic described above, we see here that ratepayers in the 2020s will avoid two years' annual cost of Site C. However, once the project is in service, the annual payment toward the delay-related costs will increase to $59.3 million per year. By 2032, the cumulative discounted ratepayer savings amount to $480 million.

Thus, for the decade 2023-2032, the financial impact on ratepayers of a one- or two-year delay would be decidedly positive.

4.3.3. End effects

To fully describe the impacts of a one-year delay, one must carry this analysis through to the end of the Project's financial life. This is complicated by the very long time periods involved and the accompanying uncertainties.

As we have seen above in section 4.2.1, the annual cost of the Site C project, based on the capital cost estimate announced in December 2014, is about $620 million. Delaying commissioning by one year would increase the annual cost by $29 million for each year through 2094. In addition, an annual payment of $620 million in 2023 would be replaced by one of $649 million in 2094.

For a two-year delay, annual payments of $620 million in 2023 and 2024 would be replaced by payments of $678 million in 2094 and 2095.

These additional annual payments are not insignificant. As we have seen in Table 9 and Table 10, they gradually erode the initial benefit of delay. For a one-year delay, under the assumptions used in the BC Hydro IRP, the net benefit becomes negative after 2060.[41]

However, we have not yet taken into account the end effects related to energy production. As we saw in section 4.1.2, a one-year delay means there will be less energy available in 2023 and 2024, resulting in additional costs. But such a delay would also mean that the Project would continue to produce power one more year in the future. Assuming a 70-year project life, this would add 5.1 TWh of electricity generation in 2094 (and also in 2095, in the event of a two-year delay).[42]

The figures presented in Table 9 and in Table 10 already take account of the cost of the lost energy in 2023 and 2024 (and 2025, for a 2-year delay), but not the additional energy in 2094 (and 2095, for a 2-year delay). So to complete the analysis, we will have to estimate the value of electrical energy and capacity 80 years from now.

In its Final Integrated Resource Plan, BC Hydro presented forecast electricity prices through 2040. There are no credible electricity price forecasts over a 70-year horizon. However, because of discounting, the results of this analysis are not very sensitive to the assumptions used regarding electricity prices in the 2090s. For the purposes of this analysis, we will therefore assume that price forecast by BC Hydro's for 2040 will grow at 1% per year (in contant dollars) thereafter.

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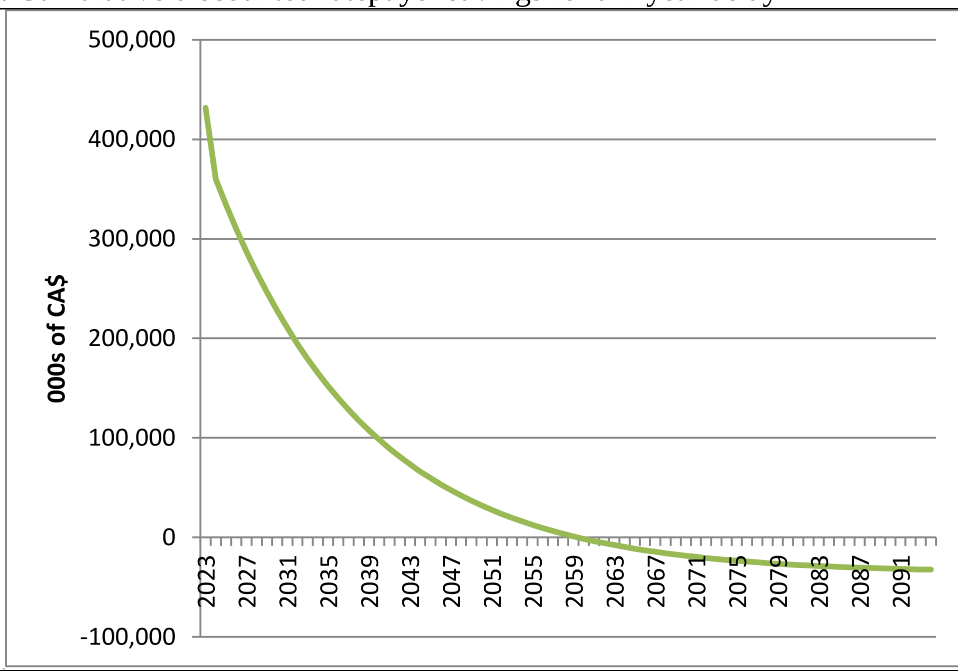
41 This result is very sensitive to the choice of discount rate.

42 We make the simplifying assumption here that the Project's physical life is identical to its financial life.

4.3.4. Cumulative implications of delay

Figure 13 illustrates the results of this exercise for a one-year delay. It shows that cumulative ratepayer savings (costs) become negative after 2060, and reach at cumulative cost of $33.9 million by 2094.

Figure 13. Cumulative discounted ratepayer savings for a 1-year delay



It is important to note that there is a very considerable degree of uncertainty surrounding every aspect of this projection. These uncertainties include the following elements:

<u>Inflation</u>: Any significant variation in the actual inflation rate from the 2% used as a planning assumption would affect the actual present value of this cost stream. If future inflation is higher, then the actual value of the money used to make those annual payments would decrease, and the project would turn out to have cost ratepayers less (in real dollars) than was projected. Conversely, if future inflation is lower, then the actual value of the money used to make those annual payments would increase, and the project would turn out to have cost ratepayers more (in real dollars) than was projected.

Real cost of capital: BC Hydro's nominal discount rate of 7% assumes a real cost of capital of 5%. This is a reasonable choice, consistent with values used by other entities, but it remains an estimate of future economic conditions. If current economic conditions, including very low interest rates, were to prevail over the long term, this rate would be probably be seen to be too high. Should real interest rates rise again in the future, it could be too low. Either outcome would dramatically affect the long-term ratepayer effects of a one- or two-year delay.

Capital cost: It can be expected that some of the construction costs include components that are priced in US dollars. Given the 18% devaluation of the Canadian dollar since the December 2014 announcement, it would be surprising if BC Hydro's estimate of the capital cost has not increased. (The Savidant affidavit does not include an updated capital cost estimate.) Cost overruns are common in large hydro projects. For example, the Muskrat Falls project, currently under construction in Labrador, has seen its construction cost estimates increase from $6.2 billion when the project was approved to $7.7 billion last September, an increase of 24%.[43]

Load forecast: If electric demand in British Columbia grows faster or slower than the forecasts used here (dated November 2014), or if demand-side management efforts are more or less successful than predicted, the energy surpluses after Site C commissioning would be smaller or greater, with corresponding impacts on the ratepayer impact analysis presented above.

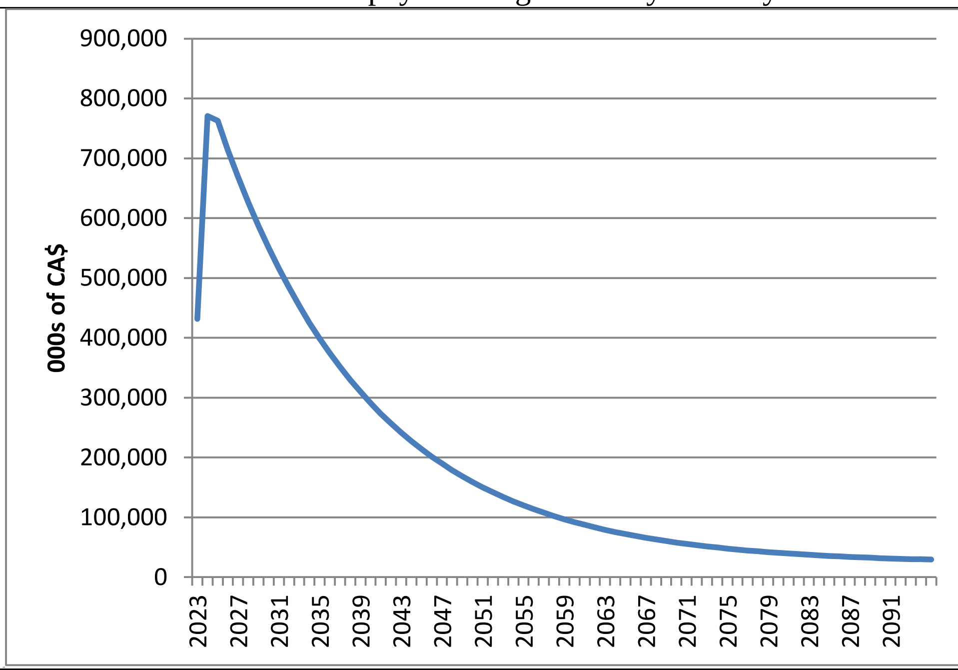
Exchange rates and market prices: The values used for additional energy and capacity costs, and for lost export revenues, are extremely sensitive to the USD/CAD exchange rate and to electricity market prices.

[43] Globe and Mail, "Muskrat Falls becoming an overbudget burden on Newfoundland," by Konrad Yakabuski, December 17, 2015.

These uncertainties serve as a reminder that long-term analysis at best represents an estimate of what might occur, not a prediction.

Figure 14 demonstrates a similar analysis to that in Figure 12, but for a two-year delay. Here, we see that, while the present value (cumulative discounted ratepayer savings) also decline, they never become negative. At the end of the project's life, in 2095, there is a net ratepayer **benefit** of $26.3 million.

Figure 14. Cumulative discounted ratepayer savings for a 2-year delay



These numbers are very small in relation to the size of the investment and the uncertainties underlying the analysis, and they are very sensitive to the assumptions used. For example, using BC Hydro's low market price scenario, rather than its medium scenario, would increase these figures dramatically, whereas the use of its high market price scenario would lower them, as seen in 11.

Table 11. Net discounted ratepayer benefit of delay (cost) (millions of CA$)

	market price scenario		
	low	medium	high
1-yr delay	38.1	-23.5	-93.1
2-yr delay	147.2	46.8	-64.4

Together, these results demonstrate that the additional costs of delay identified in the Savidant affidavit, when combined with the substantial positive ratepayer impacts that delay would produce, are not significant.

5. STATEMENT OF CONCLUSIONS

My analysis demonstrates that:

- During the years prior to commissioning of the Site C Project, a one- or two-year delay would result in very significant ratepayer benefits;
- In the case of a one-year delay, during the first four decades after commissioning, ratepayer impacts of said delay would continue to be positive. From that point on, the cumulative effect would be negative, resulting in a present value ratepayer cost of $33.9 million by the end of the Project's financial life, based on the BC Hydro's most recent forecasts and assumptions. This amount represents approximately one-third of one percent of total project costs;
- In the case of a two-year delay, ratepayer of said delay would continue to be positive for the full 70-year financial life of the Project for a two-year delay, producing a present value ratepayer **benefit** of $26.3 million by the end of the Project's financial life, under the same assumptions. This amount also represents approximately one-third of one percent of total project costs; and
- These values are highly dependent on the input assumptions. Using BC Hydro's low market price scenario, both values become positive; using the high market price scenario, they both become negative.

I conclude from this analysis that, given the very substantial and unavoidable uncertainties in every element of these projections, the additional costs of delay identified in the Savidant affidavit, when combined with the very substantial positive ratepayer impacts that delay would produce prior to commissioning and in the first decades thereafter, are not significant.

This result reflects the fact that delaying commissioning will tend to reduce the losses that result from selling Site C surplus power in the export market at prices far below its production cost. This benefit tends to counterbalance the increased capital cost resulting from the delay. Whether the net result is slightly positive or slightly negative depends on the evolution into the distant future of parameters such as market prices, exchange rates and interest rates, the future values of which are highly uncertain and effectively unknowable.

6. LIST OF SOURCES

6.1. BC Hydro documents

Affidavit #1 of Michael Savidant, January 28, 2016, including Exhibits A and B.

Environmental Impact Statement for the Site C Hydroelectric Project

Final Integrated Resource Plan (IRP), November 2013, in particular:

- Chapter 4, Sections 4.1 and 4.4 (Attachment 1)
- Appendix 5A (Attachment 2)
- Appendix 9A (Attachment 3)

Response to Comments on the Site C Clean Energy Project Environmental Impact Statement, January 25, 2013, Submitted by BC Hydro on May 8th, 2013, in particular (Attachment 4):

- Response ab_0001-068
- Response ab_0001-142fa

"BC Hydro Responses to Questions from T8TA in letter of October 22, 2014, Package #1," November 6, 2014. (Attachment 5)

Updated Energy and Capacity Balances, provided in response to Questions from the Treaty 8 Tribal Association, November 19, 2014. (Attachment 6)

2015 Rate Design Application (RDA): Transmission Service Rates, Presentation dated May 7, 2015.

6.2. British Columbia Government documents

Government of British Columbia, Backgrounder, Comparing the Options, December 16, 2004. (Attachment 7)

Government of British Columbia, Backgrounder, Site C Capital Cost Estimate, December 16, 2004. (Attachment 8)

6.3. US government sources

US Federal Energy Regulatory Commission (FERC) (http://www.ferc.gov/market-oversight/mkt-electric/northwest.asp)

US Department of Energy, Annual Energy Outlook (http://www.eia.gov/forecasts/aeo/)

6.4. Other sources

Treaty 8 Tribal Association, Letter to Ministers Bill Bennett and Michael de Jong, re Need for and Alternatives to BC Hydro's Proposed Site C Project (undated) (Attachment 9)

Globe and Mail, "Muskrat Falls becoming an overbudget burden on Newfoundland," by Konrad Yakabuski, December 17, 2015. (Attachment 10)

The Regulation of Public Utilities 2nd Ed., Charles F. Phillips Jr., Public Utilities Reports Inc. (1988).