British Columbia Utilities Commission Information Request No. 1.1 Dated March 19, 2018 Clean Energy Association of BC Response issued March 26, 2018	**Page 1 of 4**
British Columbia Hydro & Power Authority **Waneta 2017 Transaction**	**Exhibit C6-7**

1.0 Reference: INTRODUCTION
Exhibit C6-6, p. 1; Exhibit B-18, BCUC IR 2.81.1 and 2.83.3; Exhibit B-1, Business Case, p. 19
Long-run marginal cost (LRMC)

Clean Energy Association of BC (CEABC) states:

> There have been some significant changes in the electricity industry that are not fully reflected in B.C. Hydro's ("*BCH*") calculation of the Long Run Marginal Cost ("*LRMC*") that is used in the business case for the proposed acquisition of the remaining two thirds interest in the Waneta Generating project ("*Waneta Business Case*").
>
> …
>
> In his capacity as the Executive Director of the Clean Energy Association of B.C. ("*CEABC*") and on behalf of the CEABC, Mr. Jae Mather provides details of some of these common financial assumptions and unreflected industry changes, primarily as noted in the Site C Final Report, but also as updated by a recent competitive bidding process for renewable generation in Alberta. The use of these updated assumptions and changes in the Waneta Business Case would lead to a more balanced comparison with the renewable generating alternatives.

In BCUC IR 2.81.1, the Commission asked the following question:

> In light of the steep declines in wind costs, as shown by the recent Alberta projects, please re-*calculate* the combined energy and capacity LRMC using $60/MWh ($F2018) for Energy Greenfield IPPs for F2034 and beyond, using the 6.4 per cent (real) financing cost assumption provided in BCUC 1.10.4.

In response to that BCUC IR 2.81.1, BCH provided the following response:

Marginal Resources	Period of Applicability	LRMC (2018 real dollars)					
		Clean + Gas (Requested)	Clean + Gas (6.4% Financing)	Clean + Gas (Business Case)	Clean Only (Requested)	Clean Only (6.4% Financing)	Clean Only (Business Case)
Energy: Greenfield IPPs	F2034 and beyond	$60/MWh	$105/MWh	$106/MWh	$60/MWh	$105/MWh	$106/MWh
Capacity Resources	F2029	$75/kW-year (Industrial Load Curtailment)	$75/kW-year (Industrial Load Curtailment)	$88/kW-year (SCGT)	$75/kW-year (Industrial Load Curtailment)	$75/kW-year (Industrial Load Curtailment)	$221/kW-year (pumped storage)
Capacity Resources	F2030 and beyond	$81/kW-year (SCGT)	$81/kW-year (SCGT)	$88/kW-year (SCGT)	$176/kW-year (pumped storage)	$207/kW-year (pumped storage)	$221/kW-year (pumped storage)
Combined Cost of Energy & Capacity	Effective for F2034 and beyond	$74/MWh	$119/MWh	$122/MWh	$91/MWh	$142/MWh	$145/MWh

In BCUC IR 2.81.2, BC Hydro stated:

> The requested range of LRMCs is lower than the sensitivity scenarios in Table 11 of the Waneta *2017* Business Case, but is within the sensitivity scenarios provided in BC Hydro's response to BCUC IR 2.83.3. The response to BCUC IR 2.83.3 includes the LRMC (Clean+Gas) less 40 per cent scenario, which has an effective LRMC of $73/MWh for fiscal 2034 and beyond.

The following is an excerpt from the table provided in response to BCUC IR 2.83.3:

Basis for Post-Lease Value	Value of Assets / Lease to BC Hydro					
	Un-risked Lease Period	Default Risk Adj.	Post-Lease Value	Extension Option	Total Value	Value net of purchase
LRMC (Clean+Gas) less 40% (BCUC IR 2.81.2)	792	19	663	(33)	1,441	238

In the Business Case, BC Hydro summarized the LRMC scenarios in Table 3:

Table 3 Marginal New Resources and Related Costs

Marginal Resources	Period of Applicability	LRMC (2018 real dollars)	
		Clean + Gas	Clean Only
Energy: Greenfield IPPs	F2034 and beyond	$106/MWh	$106/MWh
Capacity Resources	F2029 and beyond	$88/kW-yr (SCGT)	$221/kW-yr (pumped storage)
Combined Cost of Energy & Capacity	Effective for F2034 and beyond	$122/MWh	$145/MWh

1.1 The $60/MWh ($F2018) price for wind energy that Commission asked BC Hydro to use in BCUC IR 2.81.1 represents a 43 percent reduction from the $106/MWh ($F2018) used by BC Hydro in Table 3 of the Business Case. This lower price translated into an LRMC (Clean

+ Gas) of $74/MWh and an LRMC (Clean) of $91/MWh, representing reductions of 39 percent and 37 percent compared to the LRMC shown in Table 3. What is CEABC's view of the LRMCs BCH re calculated for BCUC IR 2.81.1?

RESPONSE:

The CEABC accepts that the $60 price for wind, that the Commission asked BC Hydro to use, represents a more realistic proxy for the current LRMC based on large wind projects in B.C., although it may be less directly applicable to small projects. However, it should not be viewed as an outlier in a sensitivity analysis but rather as the base case.

Ideally the B.C. price would be calculated using the results of a competitive B.C. call for electricity from large renewable generating projects because there hasn't been one since 2008. In the intervening period there have been numerous consultants' reports and analysis commissioned or undertaken by BC Hydro and others such as the CEABC that have tried to identify what this B.C. price is. The most recent efforts were undertaken with respect to the Commission's review of Site C[1].

Unfortunately, all of these efforts have been theoretical and it wasn't until the prices of the Alberta wind projects were made public that actual Canadian market prices in a neighboring jurisdiction were available. These prices confirmed the significant downward trend in the cost of wind projects and the need to adjust B.C. Hydro's LRMC as it relates to these projects. The CEABC appreciates that the LRMC is a complex construct, in some cases overly complex, and that it does not solely consist of the cost of wind generation. While the $60 price is a significant improvement from BC Hydro's $85/MWh price the CEABC wishes to make the following additional points..

A. CEABC believes that a price established by actual free market competition between knowledgeable, well-financed, and experienced competitors will always provide a better benchmark than anyone's attempts at forecasting.

B. In this regard, the actual market prices tendered in Alberta ranged from $31/MWh (for the largest project) to $43, with a weighted average of $37/MWh. If converted to a levelized price (as used by BC Hydro), that $37 average price would be $32/MWh (in real levelized 2018 $). Since these are Alberta prices, and prices at the point of interconnection ("POI"), some further adjustments may be needed for comparison to B.C., namely:

1. An adjustment from Alberta to BC – It has been suggested that the mountainous terrain of BC may be more problematic for wind projects than the flat terrain of Alberta. The merits of this adjustment are discussed in more detail in the response to BCUC IR 2.1.
Nevertheless, CEABC would suggest an upper limit of about 40% of the capital cost would be the worst-case scenario. This is because at least 60% of the capital cost (and, more typically 70-75%, depending on the specific site), is for machinery and equipment that will be common to both locales. If we assume as this worst case scenario, that the balance of 40% might be subject to an upward adjustment of as much as 100%, then the impact on the total cost could be as much as 40%. This could increase the $32 average price to about $44.

2. An adjustment from POI to the Lower Mainland – In the Site C Inquiry, the LUEC method for evaluating projects was identified, by both BC Hydro and the Commission, as being inferior to a portfolio analysis, with regard to calculating most cost adjustments. This is precisely because the UEC analysis attempts to attach costs to individual projects that are much more effectively handled by the portfolio optimizer in the aggregate.

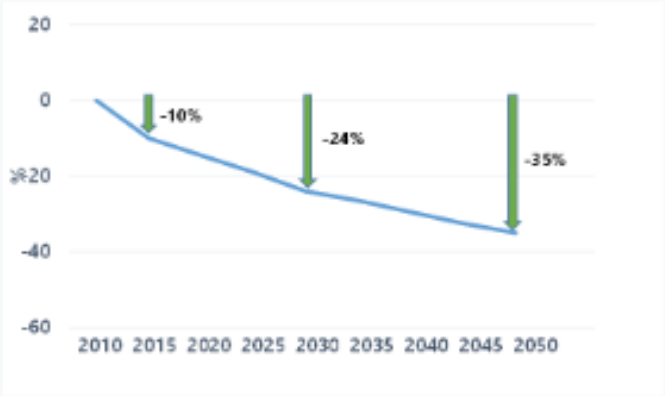
[1] For example see Exhibit F104-1, a report prepared by Power Advisory for CEABC and CanWEA and in part A-22, the Commission's Alternative Portfolio.

CEABC notes that this additional cost constitutes a worst-case assumption. It assumes that the new generation is delivered to the Lower Mainland, which need not necessarily be the case. If the BC Climate Action Plan results in the aggressive electrification of the northeastern gas fields,[2] new wind energy could be located proximally to the gas fields and never require transmission to the Lower Mainland.

Nevertheless, if we make a further adjustment to add 10% for losses and $1 for integration costs, then that would increase the $44 average cost to $49/MWh, as a proxy for current market prices in British Columbia.

3. **An adjustment from 2018 prices to 2039 prices – BC Hydro's analysis assumes the real cost is flat from 2018 to 2039, but expert analysis quoted in the Site C Inquiry indicates that real costs would continue to decline by some 35% by 2050. The following chart, taken from a joint CEABC and CanWEA submission in the Site C Inquiry, illustrates this trend:[3]**

Figure 2 : Reduction in LUECs for Onshore Wind



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

When this adjustment is also factored in, it would reduce the 2019 proxy price of $49 to $32 in terms of the real 2018 $ cost for a wind plant to be built in 2039. This is a significantly lower LRMC assumption than BC Hydro is using for its valuation modeling for the Waneta 2017 Transaction.

C. **A further adjustment for capacity. The $60 price proposed by the Commission is a proxy for the current cost of energy, before any additional adjustment for the cost of capacity. To make this final adjustment, BC Hydro adds another $14/MWh, based on the capital and operating cost of a single cycle gas turbine ("SCGT").**

A portfolio optimizer would be a superior method for estimating if this cost is even required. It is premature to assume that capacity would even be needed, or that an SCGT would be the most cost-effective capacity at that future date. Expert evidence from the Site C Inquiry indicated that battery power may be sufficiently well developed to be the capacity alternative of choice by 2039.[4]

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[2] https://news.gov.bc.ca/files/Natural_Gas_Technical_Briefing_Final.pdf, slide 27.
[3] Exhibit F 104-1, page 5
[4] Ibid, page 12

1.0 Reference: INTRODUCTION
Exhibit C6-6, p. 1; Exhibit B-18, BCUC IR 2.81.1 and 2.83.3; Exhibit B-1, Business Case, p. 19
Long-run marginal cost (LRMC)

1.1 The $60/MWh ($F2018) price for wind energy that Commission asked BC Hydro to use in BCUC IR 2.81.1 represents a 43 percent reduction from the $106/MWh ($F2018) used by BC Hydro in Table 3 of the Business Case. This lower price translated into an LRMC (Clean + Gas) of $74/MWh and an LRMC (Clean) of $91/MWh, representing reductions of 39 percent and 37 percent compared to the LRMC shown in Table 3. What is CEABC's view of the LRMCs BCH re calculated for BCUC IR 2.81.1?

1.1.1. Please explain what further market changes, if any, CEABC views should be included in the calculation of the LRMC and how the resulting LRMC would differ from the LRMC in the BC Hydro response to BCUC IR 2.28.1. Please explain these differences and provide supporting data.

RESPONSE:

CEABC believes the reference cited in IR 1.1.1 was meant to be to BCUC IR 2.81.1, rather than 2.28.1.

See CEABC response to BCUC IR 1.1 for the detailed discussion of further market changes and adjustments in calculating an LRMC to be applied to the post 2039 time period.

1.0 Reference: INTRODUCTION
Exhibit C6-6, p. 1; Exhibit B-18, BCUC IR 2.81.1 and 2.83.3; Exhibit B-1, Business Case, p. 19
Long-run marginal cost (LRMC)

1.2 In the case that CEABC agrees the LRMCs recalculated for BCUC IR 2.81.1 reflect the changes in the electricity industry as well as the other adjustments noted in Exhibit C6-6, does CEABC agree with BC Hydro's recalculated value of the net purchase at $238 million, when taking into account default risk, extension option, and an LRMC set at 40 percent lower than the LRMC (Clean + Gas), which encompasses the wind energy price of $60/MWh? Please explain.

RESPONSE:

In view of CEABC's response to BCUC IR 1.1, in particular the opportunity to mark the cost of wind energy to a current market-based benchmark, and also the opportunity to reflect the downward future cost trend, the $238 million present value could be subjected to a significant reduction, perhaps even becoming negative. To confirm an exact value, a further evaluation using BC Hydro's valuation model would be required.

2.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 1 and 2

In BCUC IR 2.80.1, BCH states:

Factors 1 and 2 are clear differences between B.C. and Alberta. […]

> 1. Location and Terrain – Location and terrain affect cost factors such as construction, interconnection, transportation, labour and accessibility, and hence have an impact on installed capital costs as well as the operations and maintenance costs. B.C.'s terrain is generally much more complex and wind sites much more remote in comparison to Alberta's rolling hills and ranch land. An example of the difference in installed capital cost between Alberta and B.C. can be found by examining the capital costs published by Capital Power[2] for two wind projects, one built in Alberta, the other in B.C. The two projects, which were both commissioned in 2012, are roughly of the same size, and use the same turbine model. Analysis shows that the installed capital cost for the B.C. wind project was $790/kW or 38 per cent higher than the wind project in Alberta. It is likely that most of this difference in cost is attributable to location and terrain. Keeping all other factors constant, this amounts to an almost $20/MWh difference in the wind price.
>
> 2. Wind service sector – Having an established wind service sector allows for lower operations and maintenance costs due to economies of scale. Southern Alberta has an established wind service sector with 1480 MW of installed capacity. Northeast B.C.'s installed wind capacity is 570 MW and has not seen the same economies of scale as Southern Alberta.

CEABC states that:

> **4.1 Location and terrain** – Using data for projects built in B.C. and Alberta in 2012 to conclude that the location and terrain in B.C. account for a 38% price differential is a sample set of n= 1 and thus not a terribly useful exercise. How Capital Power allocates costs as between its projects, particularly in the same year, is completely unknown.
>
> **4.2 Wind service sector** – The four large wind projects in northeast B.C. have already resulted in the establishment of a wind service sector in this portion of B.C.

2.1 Please provide, if available, a comparison of wind project costs in Alberta and BC, including an identification of the causes of any cost differentials, as well as any studies or research papers CEABC is aware of that have investigated the wind cost differential by geographic regions in Canada.

RESPONSE:

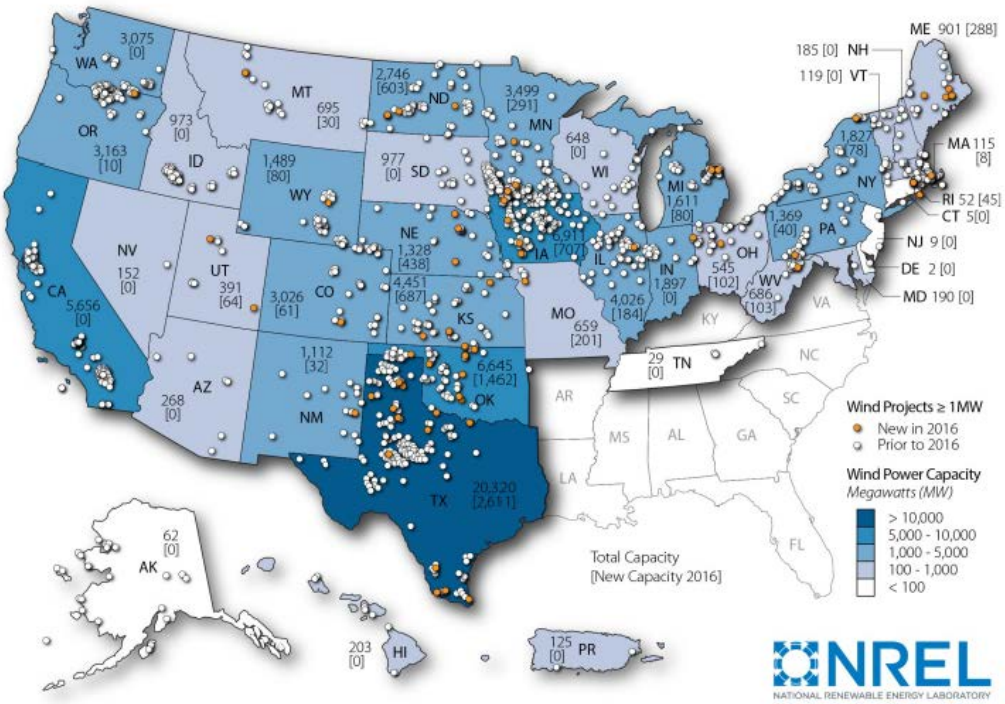
The CEABC is not aware of any studies that compare the wind project costs in Alberta and B.C. or across the geographic regions in Canada in particular with respect to location and terrain. Given the time available it is not possible to initiate such a study and given the rapidly changing market conditions its value might be very limited. However the CEABC wishes to make the below comments.

Generally about 60% of the cost of large wind project in B.C. will be attributable to the wind turbine generators and the remainder to the balance of plant. These figures are based on informal discussions with CEABC members and they are highly dependent on site conditions. By contrast in the State of Washington, estimated balance of plant costs, where there is less complex terrain, reasonable access etc. range from 24% to 31%[5].

Generally wind turbine costs are going to be the same as between B.C. and Alberta as are other material factors such as the cost of financing. The off taker in Alberta is the Alberta Government and there is no material difference in its credit rating and that of the B.C. Government which guarantees BC Hydro's debt.

As a result any material difference in the cost of developing wind generation in B.C. and Alberta would have to be accounted for by the difference in balance of plant costs ie. 40%. GIVE MORE EXAMPLE If these costs in B.C. were double those of Alberta, the result would be a 40% increase, raising the $32 average price to about $44."

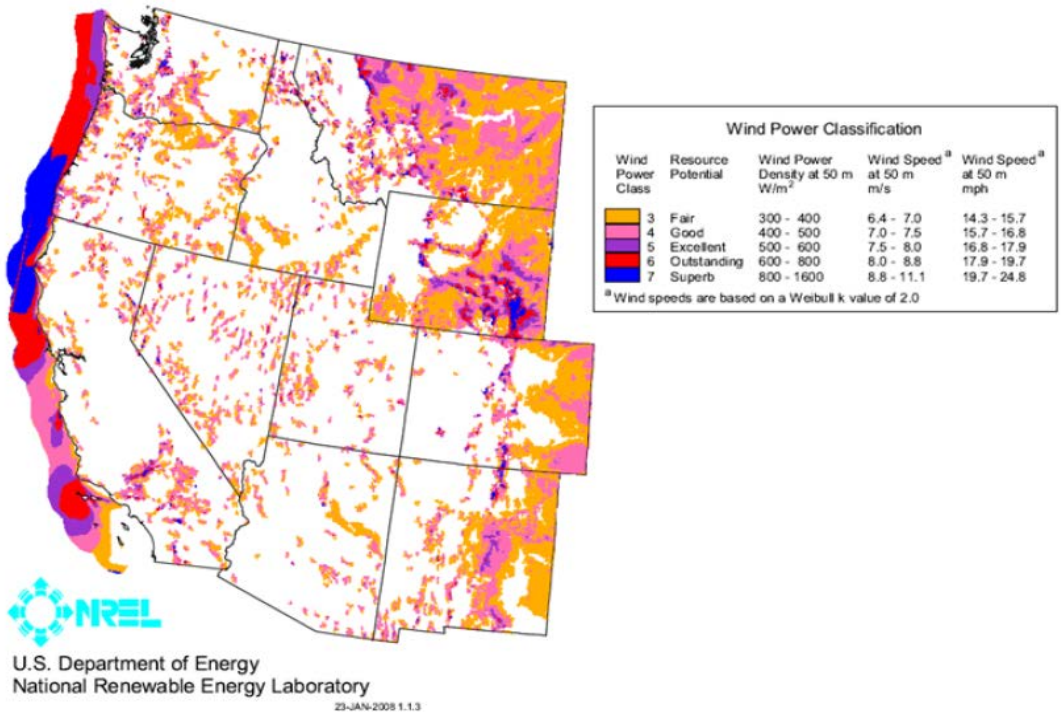
As noted in the below map, the more complex terrain of Washington, and Oregon, with each of these states having over 3,000 MW of wind power generation as compared to the less complex terrain of Montana which has only 700 MW does not appear to be major impediment to development. The wind projects in Montana are located in areas that have similar terrain to those located in Alberta.



Note: Numbers within states represent cumulative installed wind capacity and, in brackets, annual additions in 2016.

[5] https://pse.com/aboutpse/EnergySupply/Documents/IRP17_AppM.pdf

The following map further illustrates the location and quality of Montana's wind resources, indicating that Montana has plenty of good wind resources, and yet the more difficult terrain of Washington State has a much greater degree of wind development..



2.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 1 and 2

2.2 In CEABC's view, what types of services are comprised in a wind service sector?

RESPONSE:

All moving and electrical parts can require regular servicing to maintain performance and reliability. Moving parts usually require lubrication and occasional parts replacement. These services are usually included in the purchase contract from the manufacturer, although some larger firms may have enough turbines installed to warrant an in-house servicing department.

Apart from those mechanical/electrical services and repairs roads may need clearing or trees pruning, but these services can usually be contracted locally.

2.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 1 and 2

2.3 Please provide supporting data to the statement that a wind service sector is established in northeast BC (e.g., number of firms/employees operating, part-time versus full-time employment, annual dollar amount of services generated in this industry, and any other relevant socio-economic data).

RESPONSE:

CEABC does not have all of those statistics at its disposal, but we can give an example of how costs can be very comparable between BC and Alberta.

Any sizable wind farm project will involve enough turbines to justify a local servicing facility. In the case of VESTAS turbines, there are now 127 turbines, located at the Dokie and Quality wind farms. With this number of turbines, the manufacturer has established a local service facility with a parts inventory and staff continuously active in the area in order to fulfill the manufacturer's performance and reliability guarantees.

The cost of these services is generally agreed at the time of the turbine purchase contract and so it is factored into the bid prices.

2.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 1 and 2

2.3 Please provide supporting data to the statement that a wind service sector is established in northeast BC (e.g., number of firms/employees operating, part-time versus full-time employment, annual dollar amount of services generated in this industry, and any other relevant socio-economic data).

2.3.1. How does the wind industry compare to that of Alberta using the same metrics?

RESPONSE:

CEABC does not have access to these specific statistics.

2.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 1 and 2

2.4 In CEABC's view, has the BC industry already achieved the lower operations and maintenance costs due to economies of scale referred to by BC Hydro? Please explain why or why not.

RESPONSE:

Any sizable wind farm project will involve enough turbines to justify a local servicing facility. With 4 large wind farms consisting of well over 200 wind turbines currently operating in the Peace River region of BC, this scale is already sufficient to justify a local service industry.

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

BCH states that "[t]he other factors may or may not be applicable to B.C. or repeatable in another acquisition processes."

CEABC provides the following comments regarding Factors 3 to 7:

> **4.3 Size of developer** – CEABC's members include some of the same large national or global developers that participated in the Alberta bidding process and/or were awarded contracts.
>
> **4.4 Brownfield vs greenfield development** – There are large wind sites in B.C. that are considered to be brownfield sites. However, with advances in technology this does not necessarily mean the brownfield sites have a cost advantage.
>
> **4.5 Financing assumptions** – Large national or global developers have already participated in the development of large wind projects in B.C. Their financial resources are not exclusive to Alberta.
>
> **4.6 Terminal Value** – BCH's decision to not assign a terminal value of at least 30% at end of life is not realistic. The reality is that at the end of a 25 - year contract there is considerable terminal value in a large wind site including infrastructure, local relationships and knowledge of wind conditions.
>
> **4.7 Bidding Strategy** – Developers are not in the business of developing projects to achieve sub-optimal returns. For example, there is no evidence that building one large wind project will necessarily result in the development of another immediately adjacent large project. It depends on the circumstances including technological advances.

3.1 Please elaborate on CEABC's comment 4.3. Can CEABC quantify the cost differential achievable by a medium size wind developer versus a large national or global developer? Please provide your assumptions and calculations.

RESPONSE:

It was BC Hydro's response to BCUC 2.80.1 that indicated that one of the possible reasons why the prices forecast in its Resource Options Report ("ROR") might be higher than those reflected in the competitive market prices recently posted in Alberta might be due to the fact that the ROR forecasts assumed only smaller and medium sized developers, whereas the market prices reflected bids from larger national or global developers, who could achieve lower costs.

CEABC merely pointed out that the same large developers are equally able to bid projects in BC as in Alberta, should BC Hydro request such bids.

Whenever market price benchmarks are available, they should always be used in preference to theoretical forecasts such as those contained in the ROR.

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

3.2 Before the advances in technology referenced in CEABC's comment 4.4, what was the cost differential due to brownfield versus greenfield sites. Please provide the supporting data/sources.

RESPONSE:

The CEABC does not have the requested information. It would also be very difficult, if not impossible, to determine this cost differential because of the difference in site characteristics. For example a brownfield large wind generating site may have had a cost differential advantage when it first achieved commercial operation as compared to greenfield wind sites. However this advantage may have only applied as against greenfield wind sites in the immediate area. Subsequently through the collection of wind monitoring data, superior wind generating sites may have been discovered elsewhere in the same region where the brownfield site is located or an entirely different region of the Province.

Superior greenfield sites may evolve due to wind generation technology improvements which can yield higher capacity factors from lower wind speed regimes. Superior sites may also evolve because of road building activity by unrelated sectors such as oil and gas and logging or because of electrical transmission upgrades by BC Hydro

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

3.3 Please clarify the kind of technological advances that have, in CEABC's view, eliminated the cost advantage of brownfield sites.

RESPONSE:

The cost advantage at a particular point in time for a brownfield site may be the result of a high wind regime when the corresponding best available technology is a 1.5 MW turbine. Subsequently if 3 MW low to moderate wind-speed turbines become available then low to moderate greenfield sites may have a cost advantage over a high wind-speed brownfield site where smaller turbines are only available. The development of the technology might not only provide a technology cost advantage but may also allow the development of sites that have superior transmission and transportation access.

The largest onshore turbine is now 7.5 MW[6] and a 12 MW[7] offshore turbine is under development. In areas such as B.C. where there are potential onshore and offshore wind sites, a 12 MW offshore turbine has the potential to make offshore sites commercially superior to onshore brownfield and greenfield sites. It depends on the cost of this technology and its operating capabilities.

Similarly the continuing development of solar technology may result in this technology becoming commercially superior to onshore and offshore wind generation. There are plans for a large scale solar facility in the State of Washington[8].

CEABC's point was simply that a new "greenfield" site, using newer and more efficient wind turbines, can rival the expansion of an existing brownfield site using older technology. It is also true that BC has brownfield sites as well as Alberta. In a competitive bidding process, all factors will be incorporated, and the project with the best combination of factors will have the best chance to prevail.

[6] https://www.enercon.de/en/products/ep-8/e-126/

[7] https://www.gerenewableenergy.com/wind-energy/turbines/haliade-x-offshore-turbine

[8] http://www.chronline.com/business/transalta-has-plans-for-largest-solar-project-in-state-at/article_7a79fd70-2714-11e8-bd31-87136236f2b6.html

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

3.3 Please clarify the kind of technological advances that have, in CEABC's view, eliminated the cost advantage of brownfield sites.

3.3.1. Please provide supporting data/sources showing that the cost differential was indeed eliminated by these technological advances.

RESPONSE:

See response to 3.3.

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

3.4 Please clarify the link between CEABC's comment 4.5 and BC Hydro's statement on Factor 5, taking into account EDC Associates' WACC analysis attached in Footnote 3 (pages 3–4) of BC Hydro's response to BCUC IR 2.80.1.

RESPONSE:

BC Hydro's response to BCCUC IR 2.80.1 was simply a further indication that the assumptions being used in the Resource Options analysis do not always reflect the realities in the competitive market place. In particular, the ROR analysis had been assuming the developers would be smaller and less able to achieve the lower costs of capital being reflected by the low bidders in Alberta. This is simply a further indication that market based benchmarks will be superior to any attempts at forecasting.

It is highly likely that successful bidders in Alberta are employing the latest technologies as well as the most cost effective financing assumptions. Actual market prices are more likely to be up to date regarding the latest technologies and the latest financing capabilities. Whenever actual market prices are available, they offer superior guidance to that achieved by theoretical analyses. Accordingly, the more theoretical Resource Options analyses will always be lagging. This comparison of actual market bid prices to theoretically predicted prices simply shows how great that lag has become.

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

3.5 For CEABC's comment 4.6, please provide supporting data/sources for the terminal value of at least 30 percent at end of life.

RESPONSE:

CEABC is not aware of any studies that have been undertaking show the terminal values, but it is simply logical that a certain portion of a project's initial expenditures will not need to be repeated when the project is refurbished after its initial contract period.

In fact, BC Hydro relies upon this in all of its negotiations over the renewal of existing EPAs. BC Hydro assumes that those projects will not need to replicate their initial project expenditures at the time of renewal.

Accordingly, this question might be better answered by BC Hydro with an analysis of the renewal prices it has been able to negotiate with existing IPPs.

At any rate, since the alternative projects being considered in the Transaction would only be built following the expiry of the lease period in 2039 (or 2049 at Teck's option), it is unlikely that the existence of a terminal value will have much impact on the analysis. The points listed earlier, in the response to IR 1.1, will have much more significant impacts.

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

3.5 For CEABC's comment 4.6, please provide supporting data/sources for the terminal value of at least 30 percent at end of life.

3.5.1. Please also provide CEABC's estimate of the cost differential in MWh resulting from not assigning a terminal value to the BC wind projects.

RESPONSE:

See the response under BCUC IR 3.5.

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

3.6 For CEABC's comment 4.7, please clarify whether CEABC's premise for sub-optimal returns is an individual project or a portfolio of projects (or multi-phase)?

RESPONSE:

Here, again, BC Hydro was simply indicating that all of the assumptions used in its Resource Options analyses do not necessarily reflect all of the potential forces that could occur in an actual competitive marketplace.

CEABC believes it is unlikely that a developer would artificially under-price his project based on some unsubstantiated expectation that this would automatically advance the cause of some future project.

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

3.6 For CEABC's comment 4.7, please clarify whether CEABC's premise for sub-optimal returns is an individual project or a portfolio of projects (or multi-phase)?

3.6.1. Please confirm, otherwise explain, that in CEABC's view it could be possible for a developer to achieve sub-optimal returns on an individual project with the hope of achieving optimal return for the portfolio of projects.

RESPONSE:

See response under IR 3.6.

3.0 Reference: COMMENTS ON BCH'S RESPONSE TO BCUC IR 2.80.1
Exhibit C6-6, p. 5; Exhibit B-18, BCUC IR 2.80.1
Wind cost estimates: Factors 3 to 7

3.7 Please clarify why the Commission should attribute more weight to CEABC's comment 4.7 on potential bidding strategy than to BC Hydro's comment on potential bidding strategy.

RESPONSE:

If a bidding process is truly competitive, a bidder will have no means of recovering the losses on a project that has been under-bid, by over-pricing a subsequent bid.

However, CEABC reiterates that the essence of BC Hydro's statement was to indicate that the assumptions used in its Resource Options analyses do not necessarily reflect all of the potential forces that could occur in an actual competitive marketplace. CEABC has no issue with accepting that proposition from BC Hydro. It simply reconfirms that the prices established in a competitive market auction provide a better benchmark than those from an academic forecasting analysis.

1.0 Reference: Exhibit C6-6 Section 4 Comments on BCH's Response to BCUC Information Request ("IR") 2.80.1

1.1 Please list which CEABC members were awarded contracts in the recent Alberta Renewable Energy Procurement process.

RESPONSE:

It is immaterial whether any or all of the 12 proponents who participated in the Alberta REP process are members of CEABC. Several are members, but all could potentially be members if they so choose. Regardless of membership in the CEABC, any or all of them are capable and qualified to participate in any future call for power in British Columbia which BC Hydro might choose to initiate.

1.0 Reference: Exhibit C6-6 Section 4 Comments on BCH's Response to BCUC Information Request ("IR") 2.80.1

1.1 Please list which CEABC members were awarded contracts in the recent Alberta Renewable Energy Procurement process.

1.1.1. Please provide the awarded contract prices for the CEABC members that were awarded contracts in the recent Alberta Renewable Energy Procurement process.

RESPONSE:

It is not within the mandate of CEABC to solicit such detailed project information from its members.

1.0 Reference: Exhibit C6-6 Section 4 Comments on BCH's Response to BCUC Information Request ("IR") 2.80.1

1.1 Please list which CEABC members were awarded contracts in the recent Alberta Renewable Energy Procurement process.

1.1.2. For these projects, please provide a breakdown of the total capital cost in terms of $/kW (e.g., pre-construction costs including permitting, development, consultation/engagement and land costs; total wind turbine cost including turbine equipment, transportation, commissioning, and SCADA system; balance of plant costs, transmission/interconnection costs and owner's costs during construction) as well as any fixed/variable costs in terms of $/kW-year.

RESPONSE:

It is not within the mandate of CEABC to solicit such detailed project cost information from its members.

1.0 Reference: Exhibit C6-6, CEABC Evidence

1.1 Please confirm, or otherwise explain, that CEABC's evidence in Exhibit C6-6 goes exclusively to the size of the LRMC that should be used in the business case analysis of the Waneta 2017 Transaction.

RESPONSE:

Confirmed, that the principal purpose of the evidence was to highlight the differences that exist between actual market prices and forecasts derived from the theoretical analyses that are attempted within the context of utility planning exercises such as BC Hydro's Resource Options inventory.

While forecasting may be a necessary exercise in planning, it must be brought into alignment with market realities on a frequent basis, especially in areas of rapidly changing technology, such as renewable energy generation or storage technology.

1.0 Reference: Exhibit C6-6, CEABC Evidence

1.2 CEABC says the LRMC value used in the financial analysis should be lower than the value that BC Hydro uses in its base case analysis. Has CEABC considered BC Hydro's sensitivity analyses in which it provides the results of assuming lower LRMC values? Does CEABC say that the proper LRMC value for use in the financial analysis is below the "LRMC – 40%" figure?

RESPONSE:

Confirmed. The proper LRMC value to be used for alternative energy options for future dates beyond 2039 is highly likely to be well below that used by BC Hydro, and also below the 40% sensitivity value.

Furthermore, that value should not be treated as a "sensitivity", but rather as the Base Case, with sensitivities done above and below it.

1.0 Reference: Exhibit C6-6, CEABC Evidence

1.3 What LRMC (in $2018) does CEABC say should be used in the financial analysis of the Waneta 2017 Transaction?

RESPONSE:

See CEABC response to BCUC IR 1.1. When the continuing trend to declining real cost is included, the evidence presented indicates a cost in the mid $40 range would be appropriate, even after a charge for capacity is included.

1.0 Reference: Exhibit C6-6, CEABC Evidence

1.4 Please confirm, or otherwise explain, that CEABC does not disagree with BC Hydro's use of two methods of analyzing the Waneta 2017 Transaction, i.e., as a commercial transaction and in terms of ratepayer impact.

RESPONSE:

CEABC has no issue with the fundamental principle of analyzing the Transaction from these two different perspectives. However, CEABC reserves the right to take issue, in argument, with some of the underlying assumption being used by BC Hydro in those analyses, in particular the appropriate cost for BC Hydro's capital and its assumed discount rate.

1.0 Reference: Exhibit C6-6, CEABC Evidence

1.5 Please explain why CEABC's evidence is silent regarding the Lease and the Lease revenues (to BC Hydro).

RESPONSE:

CEABC reserves the right to deal with those matters in argument.

1.0 Reference: Exhibit C6-6, CEABC Evidence

1.6 Does CEABC acknowledge that the Lease means that the Transaction does not provide BC Hydro with a new supply-side resource for up to 20 years or, at Teck's option, 30 years unless Teck defaults on the Lease?

RESPONSE:

Acknowledged, BC Hydro will obtain no new energy or capacity from this Transaction for at least 20 years, barring default by Teck. Up until the end of the lease period, Teck is entitled to all of the same energy and capacity as it is entitled to currently, as the owner, and this Transaction operates as if it were a low-interest loan to Teck in exchange for a series of payments over 20 to 30 years. However, BC Hydro does appear to be assuming new obligations for capital expenditures during the lease period and these may or may not be partially reimbursed by Teck.

1.0 Reference: Exhibit C6-6, CEABC Evidence

1.7 Does CEABC acknowledge that a substantial component of the value of the Waneta 2017 Transaction, in both investment and rates terms, is the Lease revenues?

RESPONSE:

CEABC acknowledges, but does not necessarily accept this value, as it is presented by BC Hydro. As presently valued by BC Hydro, the lease revenues appear to have a present value in excess of the initial purchase cost. However, this is an area of the analysis that CEABC reserves the right to challenge in argument.

1.0 Reference: Exhibit C6-6, CEABC Evidence

1.8 Does CEABC take issue with BC Hydro's analysis of the probability and consequences of Teck defaulting on the Lease?

RESPONSE:

The probability and consequences of a default by Teck is a matter that is well out of the scope of CEABC's evidence.

1.0 Reference: Exhibit C6-6, page 1

1. Introduction

There have been some significant changes in the electricity industry that are not fully reflected in B.C. Hydro's ("*BCH*") calculation of the Long Run Marginal Cost ("*LRMC*") that is used in the business case for the proposed acquisition of the remaining two thirds interest in the Waneta Generating project ("*Waneta Business Case*"). As noted in BCH's evidence[1]:

> "LRMC is a proxy for the avoided cost of purchasing new greenfield clean or renewable resources. The determination and usage of BC Hydro's LRMC is outlined in Chapter 3 of BC Hydro's Fiscal 2017 to Fiscal 2019 RRA."

In the British Columbia Utilities Commission's ("*BCUC*") Final Report to the Government of B.C. ("*Final Report*") regarding the Site C Inquiry, there is an extensive analysis of the evolving electricity industry and the impact this evolution has had, and is expected to have, on the cost of the alternatives to the Site C project. Illustrative Draft Alternative Portfolios ("*Alternative Portfolio*") were modeled and used as a comparator to this project. In addition to the industry changes, the Alternative Portfolio contained common financial assumptions for the Site C project and the Alternative Portfolio.

In his capacity as the Executive Director of the Clean Energy Association of B.C. ("*CEABC*") and on behalf of the CEABC, Mr. Jae Mather provides details of some of these common financial assumptions and unreflected industry changes, primarily as noted in the Site C Final Report, but also as updated by a recent competitive bidding process for renewable generation in Alberta. The use of these updated assumptions and changes in the Waneta Business Case would lead to a more balanced comparison with the renewable generating alternatives.

For reference Mr. Mather's resume is appended as Attachment 1.

1.1 Please provide CEABC's recommendation of the appropriate LRMC to be used and provide justification.

RESPONSE:

See CEABC's response to BCUC IR 1.1 and BCSEA IR 1.2

1.0 Reference: Exhibit C6-6, page 1

1.2 Please provide quantification of the overall change to the Waneta business case that CEABC recommends as a result of all the evidence provided, and provide justification.

RESPONSE:

See CEABC's response to BCUC IR 1.2

2.0 Reference: Exhibit C6-6 page 2 and page 4

2. Site C Determinations

In the Final Report there are a number of Determinations that if included in the Waneta Business Case would lead to a more balanced comparison with the renewable generating alternatives. It is recognized that some of the Determinations are evidence of trends rather than hard business case inputs. However, given the Waneta Business Case is for a 40 year term, trends are as important as hard inputs. The selection by BCH of the Waneta project as an investment opportunity will effectively be "*locking out*" other alternatives that are becoming superior on an exponential trend line.

Although the Waneta project is much smaller in scale than Site C the underlying asset being purchased is, similar to Site C - a complex and longer term asset for which most of the benefits will not be realized for 20 to 30 years. It represents "*locking in*" to an old technology, during a period while the competing alternative technologies are improving exponentially.

2.1 Please provide a description of each of the other alternatives that are becoming superior.

RESPONSE:

The key technological changes that are progressing exponentially are wind and solar generation technology and energy storage technology. See CEABC's response to BCUC IR 1.1 and the evidence cited there that was submitted during the Site C Inquiry.

2.0 Reference: Exhibit C6-6 page 2 and page 4

2.2 Please describe the metrics used to define the superiority of the other alternatives.

RESPONSE:

The pertinent metrics are the rapidly declining capital costs, combined with rapidly increasing productivity, which are combining to yield a continuing decline in the cost per unit of energy generated.

2.0 Reference: Exhibit C6-6 page 2 and page 4

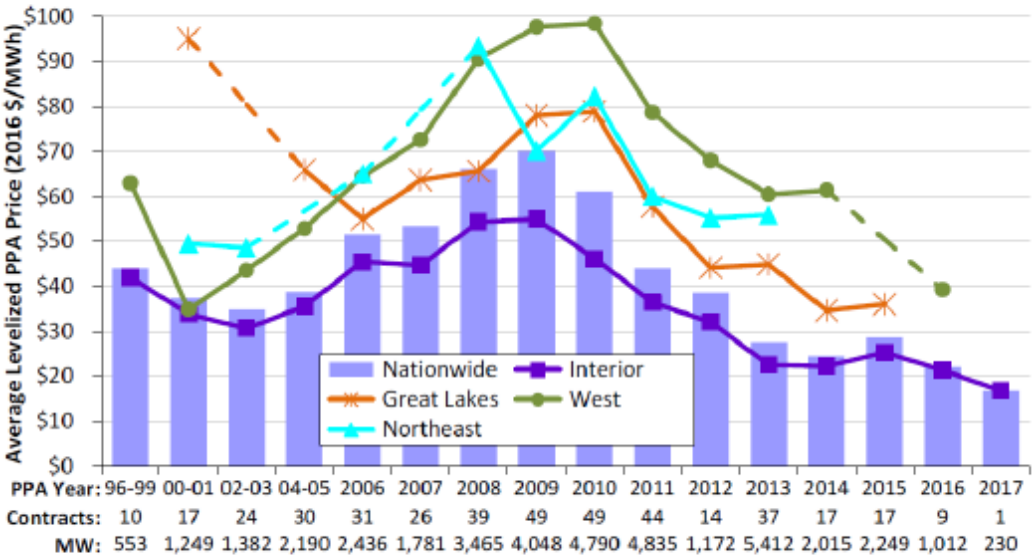
2.3 Please provide evidence of the 'exponential trend' lines that are demonstrating superiority of the other alternatives.

RESPONSE:

See CEABC's response to BCUC IR 1.1.

The following charts indicate the decline in wind and solar costs since 2009.[9]

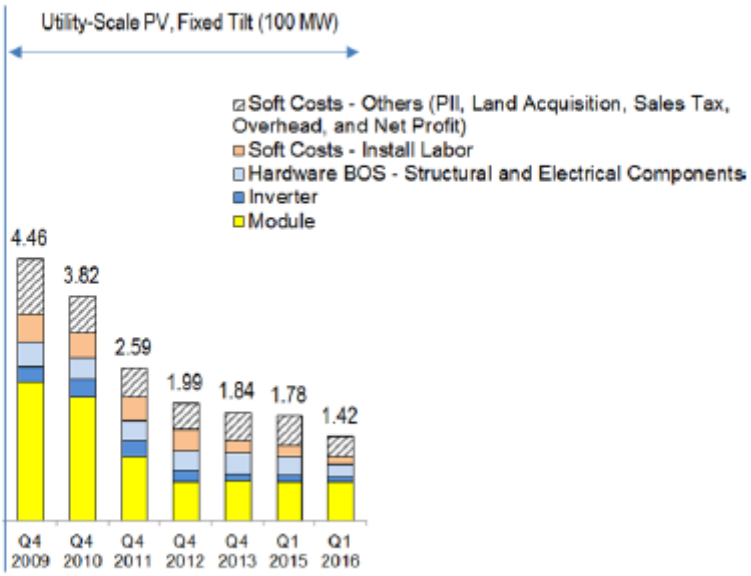
Figure 1: Levelized PPA Prices by Execution Date and Region



Source: Berkley Lab, Energy Information Administration

[9] Site C Inquiry, Exhibit F104-1, page 4 and page 9

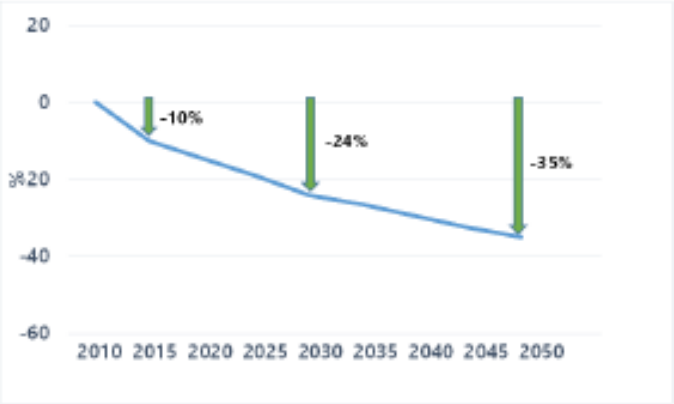
Figure 5: PV System Cost Summary (2016 USD/Watt DC) [36]



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

And the following chart indicates the projected decline in LUECs for onshore wind over the next 30 years.[10]

Figure 2 : Reduction in LUECs for Onshore Wind



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

[10] Ibid, page 5

2.0 Reference: Exhibit C6-6 page 2 and page 4

2.4 Please discuss the trend towards electric vehicles and its likely impact on the BC Hydro load forecast.

RESPONSE:

The trend towards electric vehicles is outside the scope of the evidence presented by CEABC.

2.0 Reference: Exhibit C6-6 page 2 and page 4

2.5 How would a low, medium and high electric vehicle scenario affect the 'lock out' of other alternatives.

RESPONSE:

The trend for electric vehicle sales is irrelevant to the Waneta 2017 Transaction. Regardless of what growth rate is experienced for electric vehicles, the purchase of the 2/3 interest in Waneta commits BC Hydro to spending potentially billions of dollars on an older technology in the face of the rapidly declining cost new alternatives.

2.0 Reference: Exhibit C6-6 page 2 and page 4

2.6 Please provide CEABC's views as to how much weight the Commission should place on the trends rather than 'hard inputs' and provide justification for the weight.

RESPONSE:

BC Hydro is not providing 'hard-inputs'. It is simply trying to forecast loads and prices and costs 20 to 30 years in the future, using methods that have consistently failed to forecast them accurately for much shorter periods. The forecasts of the NREL, Bloomberg New Energy Finance, or the US Energy Information Administration utilize much more extensive data collection and analysis and should be considered the best available forecasts in the energy industry today.

The only inputs that could be considered 'hard inputs' are the recent bid prices from the Alberta REP, and those are considerably out of alignment with the simulated costs in BC Hydro's Resource Options inventory.

3.0 Reference: Exhibit C6-6, page 2-3

2.1 "The Panel finds the capital and operating costs and capacity assumptions used for wind generation in the Illustrative Draft Alternative Portfolio to be reasonable. However, the Panel agrees with BC Hydro that it is appropriate to apply a cost adder to capital and operating costs to account for network upgrades[2].

The Panel notes that BC Hydro believes the assumed unit energy cost figure for wind to be too low. However, it also considers that other submissions hove highlighted further cost reductions that may be possible beyond the levelized cots assumed in the Illustrative Draft Alternative Portfolio {for example CanWEA, CEABC, McCullough). The Panel agrees with CanWEA and CEABC in finding that the NREL 2017 Annual Technology Baseline represents on appropriate resource for estimating the levelized cost of wind, and believes that this estimate strikes an appropriate balance with regard to future cost forecasts.

BC Hydro submitted that a $6/MWh network upgrade cost should be added to the cost of wind power. The Panel notes that the Cost of Incremental Firm Transmission (CJFT) is not included in BC Hydro's portfolio analysis, but rather BC Hydro models specific transmission upgrade requirements and their associated costs. The Panel therefore finds that it is appropriate to update the Illustrative Draft Alternative Portfolio so that capital costs and operating costs also account for transmission and road costs with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet. The Panel considers the network upgrades would have a lifetime of 50 years, therefore capital cost adders are not assumed to apply to the first tranche of refurbished wind generation.

Regarding the cost of wind integration, the Panel determines that the cost in the Illustrative Draft Alternative Portfolio should be reduced from $2.50/MWh to $1.0/MWh. The Panel also determines that Site C should receive a "wind integration credit" of $1/MWh for each MWh of wind generation it is able to integrate.

3.1 Should the Commission develop and/or utilize a specific cost for wind generation and wind integration in its determinations related to the Waneta dam purchase? Please explain why or why not.

RESPONSE:

CEABC agrees that the Commission should utilize its own independent assessment of the these costs, giving full consideration to the evidence presented by CEABC and others, as well as by BC Hydro.

3.0 Reference: Exhibit C6-6, page 2-3

3.1 Should the Commission develop and/or utilize a specific cost for wind generation and wind integration in its determinations related to the Waneta dam purchase? Please explain why or why not.

3.1.1. If yes, how should the Commission develop and apply this information?

RESPONSE:

See CEABC's response to CEC IR 3.1. To accomplish this may require the use of BC Hydro's valuation model, using the costs directed by the Commission.

3.0 Reference: Exhibit C6-6, page 2-3

3.2 If no, please provide a clear explanation as to how CEABC believes the Commission should factor the above information into its determinations regarding Waneta.

RESPONSE:

See CEABC's response to CEC IR 3.1.

4.0 Reference: Exhibit C6-6, page 3-4

2.2 "The Panel finds that utility scale solar projects have the potential to reduce the NPV of the Illustrative Alternative Portfolio, and notes the "*behind-the-meter*" residential and commercial solar also have the potential place downward pressure on BC Hydro's load forecast over time[3]."

2.3 "Regarding the use of single cycle gas turbines, the Panel finds that they could be a cost effective source of new capacity, however they have a GHG Impact if fueled by natural gas. The Panel notes, however, that the GHG impact could be small if they are only operated as peaking plants for a few hours each year, and BC Hydro could potentially offset any GHG emissions by reducing its operation of IG in order to support the Powerex trade exports[4]."

2.4 "The Panel finds that it is reasonable to exclude pumped storage from the Illustrative Alternative Portfolio. While pumped storage is a commercially feasible means of providing capacity, the Panel is concerned with the large size of the project (1,000 MW with a capital cost of $1.32 billion), facility development time of around 8 to 10 years, and environmental considerations specific to pumped storage[5]."

2.5 "The Panel finds that the utility scale battery storage has reached the early stages of commercial feasibility. However, the Panel agrees with BC Hydro and submitters that the cost estimates for batteries included in the October 11 Illustrative Alternative Portfolio model were understated and batteries should therefore be screened out of the Alternative Portfolio as a means of meeting short term capacity gaps[6].

However, over the longer term the Panel considers that batteries could become a cost competitive supply of capacity for BC Hydro as increased volumes drive down costs. For example, a report prepared for the US Department of Energy categorized 2015 as the start for a new period of utility scale battery deployment, with the 145 MW lithium ion projects coming online, more than the previous five years combined...

Regarding vehicle-to-grid applications, the Panel considers that they are currently at an early stage of development with small-scale utility and micro-grid pilot projects underway to establish proof-of-concept. The Panel therefore finds that they should not be included in the Alternative Portfolio. However, the Panel considers the vehicle-to-grid innovations could become a low cost source of capacity over the long term as BC Hydro would not have to own its own batteries... "

2.6 "The Panel has concluded the following with regard to assumptions for capacity focused DSM in the Illustrative Alternative Portfolio[7]:

- The Panel finds the assumptions for capacity reductions from optional time-based rates to be reasonable;
- The Panel has considered its appropriate to reduce the estimated capacity savings from

Capacity DSM Programs and update the cost assumptions; and

- The Panel finds that greater capacity savings can be achieved form Industrial Load Curtailment that assumed in the Illustrative Alternative Portfolio."

4.1 Please provide a detailed explanation as to relevance of each of the above items and how the Commission should factor each item into its Waneta deliberations.

A) Utility scale solar projects;

B) Single Cycle Gas Turbines;

C) Pumped storage; and

D) Utility scale pumped storage.

RESPONSE:

CEABC's evidence in Exhibit C6-6 was intended to bring some of the relevant conclusions from the Site C Inquiry into the record of this proceeding. We did not attempt to bring over the entirety of the evidence from that proceeding to this.

Every one of the above Commission conclusions from the Site C Inquiry will have a reducing effect when applied to the alleged cost of the future alternatives to the Waneta Transaction and, therefore, a diminishing effect on the perceived value of the Transaction.

However, the requested detail goes well beyond the scope of CEABC's time and manpower to fulfill. We must, therefore, rely on the Commission staff to translate each element into a quantum of effect on the cost/benefit evaluations of the Waneta 2017 Transaction, perhaps with the aid of BC Hydro's valuation model, under the direction of the Commission.

4.0 Reference: Exhibit C6-6, page 3-4

4.2 Please provide quantification of and evidence for any changes the CEABC believes are appropriately made to the Waneta business case related to the above.

RESPONSE:

See CEABC's response to CEC IR 4.1.

5.0 Reference: Exhibit C6-6, page 5

3. Other Assumptions

In addition to the above determinations, certain other assumptions were expressed in the Alternative Portfolio that should be included in the Waneta Business Case.

3.1 Financing costs - "The financing costs of the Alternative Portfolio ore assumed to be the same as BC Hydro's financing cost for Site C {100% debt financing at a cost 3.43%)…[8]"

CEABC agreed that this uniform financing cost assumption removed some of the inherent bias against the Alternative Portfolio. However, it still does not account for the vastly higher risks associated with the much larger, more complex, and longer term projects like Site C and now the Waneta Business Case.

Although the Waneta project is much smaller in scale than Site C the underlying asset being purchased is, similar to Site C - a complex and longer term, asset for which most of the benefits will not be realized for 20 to 30 years. It represents "**locking in**" to an old technology, during a period while the competing alternative technologies are improving exponentially.

It would therefore be more appropriate to have a higher financing cost assumption in the Waneta Business Case than for the competing alternatives.

5.1 What financing cost assumption does CEABC propose? Please provide quantification and justification the CEABC recommendation.

RESPONSE:

See CEABC's response to CEC IR 4.1.

CEABC agrees with the Site C Inquiry Panel that the alternatives to the Waneta Transaction should be evaluated at no worse than the same financing cost as is used for the Transaction payments. Further than that, the fact that the main perceived benefits of the Transaction are deferred for 20 to 30 years, should give rise to a risk premium on the Transaction financing cost.

6.0 Reference: Exhibit C6-6, page 5

3.2 Wind refurbishment - In the Alternative Portfolio it was assumed that: " ... Wind farms are assumed to be refurbished at the end of 25 years at a cost of 30% less than the cost of a new wind farm.[9]"

The CEABC agrees that this is a reasonable assumption that may actually be higher depending on the circumstances of a particular project. It should be included in the Waneta Business Case.

6.1 Please elaborate on how the Commission should incorporate wind refurbishment costs into the Waneta business case.

RESPONSE:

See CEABC's response to BCUC IRs 1.1 and 3.5. If all of the changes outlined in CEABC's response to BCUC IR 1.1 are followed, there is likely to be very little additional impact due to any changes to wind refurbishment costs, which are not likely to occur before 2065, beyond the period of analysis.

6.0 Reference: Exhibit C6-6, page 5

6.2 Please provide quantification with justification for the change the recommended change.

RESPONSE:

See CEABC's response to CEC IR 6.1.

6.0 Reference: Exhibit C6-6, page 5

6.3 How should the Commission weight the change?

RESPONSE:

See CEABC's response to CEC IR 6.1.