McCullough Research

Robert F. McCullough, Jr.
Principal

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To: British Columbia Utilities Commission

From: Robert McCullough

Subject: Comments on Commission Alternative Resource Portfolios

Introduction

On October 11, 2017, the British Columbia Utilities Commission generated three very viable alternative scenarios to the construction of Site C. I recommend that the Commission adopt these scenarios although they may be a bit conservative in several areas which we address below.

The August 2, 2017 Order in Council mandated this step:

> 3(b)(iv) Given the energy objectives set out in the *Clean Energy Act*, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?[1]

Throughout this proceeding we have limited our comments to areas where we might bring a comparative advantage to the deliberations. We are following this practice in this submission, specifically addressing two issues:

1. Firming, shaping, and storage; and,
2. Economics of sales and purchases in the market of which British Columbia Hydro is a small part.

We will also address British Columbia Hydro's comments on these scenarios, presented orally on October 14, 2017.[2]

[1] Order of the Lieutenant Governor in Council Number 244, August 2, 2017, pages 2 and 3.
[2] Site C Inquiry: Presentation to Commission Panel Chris O'Riley, Randy Reimann, Tom Bechard, Andrew Watson, and Mike Savidant, October 14, 2017, page 27.

Summary and Conclusion

In light of the direction given at s. 3(b)(iv) of the Order-in-Council directing this inquiry, the assessment of alternatives is only relevant in the context of comparison to the unit energy cost of Site C. Based on our assessment, the alternative portfolio put forward by the Commission is reasonable and defensible, if conservative, and compares favorably as against Site C. As we set out below, there are further measures that may be considered to increase the favorability of the base alternative portfolio as against Site C.

Comparison of Alternatives:

		Commission Scenarios		
	Site C	Low LF	Medium LF	High LF
Original Cost	$ 8,775			
Plus, Cost Overrun	$ 610			
Minus Sunk Costs	$ (2,100)			
Cost of Continuation	$ 7,285	$ 1,851	$ 2,889	$ 3,441
Termination Cost		$ 1,200	$ 1,200	$ 1,200
Actual Cost	$ 7,285	$ 3,051	$ 4,089	$ 4,641
Termination Advantage		$ 4,234	$ 3,196	$ 2,644

Our response demonstrates, contrary to BC Hydro's submission, that the October 11th portfolio:

- Is less expensive than a portfolio with Site C, even considering sunk and termination costs
- includes resources that are commercially feasible, and
- does provide superior firming, shaping and storage capability as Site C to meet forecast need.

Firming, Shaping, and Storage:

Background

British Columbia Hydro has commented on the significant benefits of Site C's reservoir on many occasions in this proceeding. Their definition of these services can be found early in their initial submission:

> - "Firming capability is the ability of resources to quickly change output in response to changes in customer demand and output from variable generation resources that fluctuate within the hour (e.g., wind or solar). The best resource for this capability is large hydro, but it can also be also [*sic*] supplied by pumped storage and gas-fired generation. Variable resources like wind, solar and run-of-river hydro, the output of which depends on environmental factors, do not have this capability;
>
> - Shaping capability is the ability of resources to reduce their generation supply within the day to allow the electricity system to absorb variable resource electricity (e.g., wind, run of river, solar) when our customers do not need it and then to release that energy later in the day when it is required. Large hydro and pumped storage have this ability and other storage methods are being developed such as batteries or compressed air; and
>
> - Storage capability is the ability of resources to adjust their generation supply at certain periods within the year to respond to seasonal changes in variable generation resources (e.g., run-of river hydro output is highest during the spring freshet and lower in the late summer). Only large hydro resources have the capability to store electricity seasonally."[3]

It should be noted that Site C does not meet all three of these definitions which a further quotation from British Columbia Hydro's Appendix F to the initial submission makes clear:

> The Project reservoir, with a normal operating range of 1.8 m and an active storage volume of 0.4 per cent of the active storage volume of Williston Reservoir, <u>does not have sufficient storage volumes to provide seasonal shaping of generation</u>.[4] (emphasis added)

The Commission's proposed scenarios use batteries to meet this requirement. Given British Columbia Hydro's definitions above, this is an appropriate choice. It is not the only choice, however. Nor is it a particularly inexpensive choice when British Columbia Hydro already has a surplus of resources designed to meet these three storage standards.

There have been many mentions of the Canadian Entitlement under the Columbia River Treaty in this proceeding. British Columbia Hydro rejects the Canadian Entitlement for a

[3] BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project, British Columbia Hydro, August 30, 2017, Page 42.
[4] Ibid., Appendix F, page 2.

variety of reasons as a source for energy and capacity other than "for a short-term bridging or contingency resource."[5]

Perhaps because the subjects of the Columbia River Treaty and the Canadian Entitlement are so challenging, British Columbia Hydro's discussion neglected to address the surplus resources on their own system – specifically those currently addressed by the Columbia River Non-Treaty Storage Agreement.[6]

This agreement covers considerably more firming, shaping, and storage than Site C and has been valued at US$8 million per year.[7,8]

The context for the Non-Treaty Storage is, of course, the Columbia River Treaty. The Treaty is currently in the early stages of renegotiation. Outside of the negotiators at British Columbia Hydro, the Bonneville Power Administration, and the U.S. Army Corps of Engineers, few understand its complex mechanics and financial implications. Below, the history and the operations of the treaty will be briefly addressed.

The geography of the Northwest Power Pool includes massive hydroelectric potential provided by the U.S. and Canadian Rocky Mountains. The headwaters of the Columbia River extend into British Columbia and then cross Washington State until emptying into the Pacific near Astoria, Oregon. The Columbia Gorge provides many excellent locations for hydroelectric dams since the river passes through a relatively narrow canyon. Although this is excellent for dams and generators, it is not ideal for storage. The storage opportunities are on the Canadian side of the border.

[5] Ibid., page 48.

[6] Contract No. 12PG-10002 COLUMBIA RIVER NON-TREATY STORAGE AGREEMENT executed by the BONNEVILLE POWER ADMINISTRATION and BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, April 10, 2012.

[7] ADMINISTRATOR'S DECISION RECORD NON-TREATY STORAGE AGREEMENT WITH BC HYDRO, Bonneville Power Administration, March 23, 2012, page 6.

[8] BPA's valuation occurred five years ago when energy prices were higher than they are today. The total agreement would be valued at least 20% less in today's markets. The non-treating storage is considerably larger than Site C's. The contract covers 1.5 million-acre feet (MAF) with an option for an additional 1 MAF. Site C is 4/10ths of 1% of Williston's 40 MAF or .16 MAF.

Figure 1: Map of dams along the Columbia river.[9]

British Columbia's negotiators have provided an excellent discussion of the system:

> The Columbia River in Canada has three dams in series – Mica, Revelstoke, and Hugh Keenleyside. The upstream most project – Mica – is the largest storage on the whole Columbia system with 12 MAF of active storage. It

[9] Columbia River Treaty 2014/2024 Review, U.S. Entity, April 2013, page 2.

> should be noted that Revelstoke Dam is not a Treaty dam and is operated for daily/weekly shaping.
>
> Mica and Revelstoke will have a combined generating capacity of approximately 5,700 megawatts (MW) by 2024, or 50% of BC Hydro's generating capacity, and are critical in reliably meeting British Columbia domestic load. Hugh Keenleyside Dam is the third project in the series. It is a low head dam and despite being the third largest reservoir in British Columbia with 7 MAF of active storage, it has relatively little power generation. The primary purpose of this dam was to provide flood control and power benefits to the U.S. under the Treaty. In 2002, the 185 MW Arrow Lakes Generating Station was installed adjacent to the dam.
>
> Duncan Dam (1.4 MAF) on the Kootenay River is the third Canadian Treaty dam and does not currently have any power generating capability.[10]

The basic logic of the treaty was to tie the operations of storage in British Columbia to the generation in Idaho, Montana, Oregon and Washington.

This was a very prudent solution to the extreme variability of flows along the Columbia River. Unlike many other hydroelectric systems, the Columbia River's annual flows can vary dramatically. Without extensive storage, the firm generation along the Columbia would be significantly diminished. The total generation might be roughly the same, but the amount of dependable generation would be considerably less.

The treaty also created the "Canadian Entitlement", which compensates British Columbia for the use of their reservoirs:

> This delivery [of the Canadian Entitlement] ranges from 1,176 to 1,369 megawatts (MW) of capacity and 465 to 567 annual average megawatts (aMW) of energy.[11]

The U.S. Entity has a variety of materials available on the treaty and its benefits:

> Before the Columbia River Treaty, high springtime flows on the Columbia River frequently overwhelmed the ability of the United States' downstream infrastructure to generate power and manage flood risk. The four dams built under the terms of the 1964 Columbia River Treaty (three in Canada and a

[10] U.S. Benefits from the Columbia River Treaty – Past, Present and Future: A Province of British Columbia Perspective BC Ministry of Energy and Mines, June 25, 2013. Page 8.
[11] Canadian Entitlement, U.S. Entity, April 2013, page 2.

> fourth in Montana) approximately doubled the water storage capacity on the Columbia River system. The Treaty and Treaty dams enhanced the cooperation between the U.S. and Canada, helping to ensure mutually advantageous operation of the dams by improving the ability to regulate the timing of streamflows by capturing high spring flows and releasing this water more gradually over the summer, fall and winter months. Overall, the coordinated storage and regulation of flows between the United States and Canada vastly improved both hydropower production and flood mitigation in the Columbia Basin.
>
> The increased power generation in the United States resulting from the operation of additional storage capacity created by the three Treaty dams built in Canada is referred to as the downstream power benefits. The Treaty negotiators in the early 1960s agreed that the United States and Canada would equally share these benefits, which are calculated annually according to a complex method negotiated among the Treaty's authors. It is essentially a theoretical value placed on the additional generation. Canada's half of these calculated downstream power benefits is called the Canadian Entitlement.[12]

British Columbia's three dams provide more storage than is covered by the treaty:

> Coordination of the Pacific Northwest and BC Hydro systems began in 1964 with ratification of the Columbia River Treaty (Treaty). Under the Treaty, Canada was required to construct and operate 15.5 million acre-feet (MAF) of storage in Canada at Mica, Arrow, and Duncan projects. The United States was allowed to construct 5 MAF of storage at Libby Dam. BC Hydro designed and built Mica dam to store more water than the 7 MAF required under the Treaty. As a result, an additional 5 MAF of usable storage is available at Mica.
>
> This extra storage is referred to as non-Treaty storage and is not operated under the terms of the Treaty. The Treaty limits use of non-Treaty storage to actions that do not reduce Treaty flood control and power benefits. Within that constraint, BC Hydro has used the storage space for its benefit by redistributing water among its reservoirs. BPA access to this storage is obtained only through negotiation of operational agreements that provide mutual benefits to the BPA and BC Hydro. Absent an agreement, the benefits

[12] What is the Canadian Entitlement and how did it come to be? Columbia River Treaty 2014/2024 Review, United States Entity, April 2013, page1.

> of releasing water from Arrow across the Canada-U.S. border cannot be achieved. [13]

Non-Treaty Storage at the Mica Dam is a less costly alternative to battery storage

To describe the Non-Treaty Storage Agreement very concisely, British Columbia built more storage at Mica than is required by the treaty and has rented this storage to the Bonneville Power Administration (BPA) for the past fifty years under a series of agreements that are due to expire in 2024.

BC Hydro has rented 1.5 MAF (million-acre feet) of storage capacity with an option for another 1 MAF to the Bonneville Power Authority (BPA). This agreement is due to expire in 2024.

Instead of renewing this agreement, BC Hydro could choose to use this Mica storage capacity in addition to or as a replacement for battery storage in the alternative portfolio.

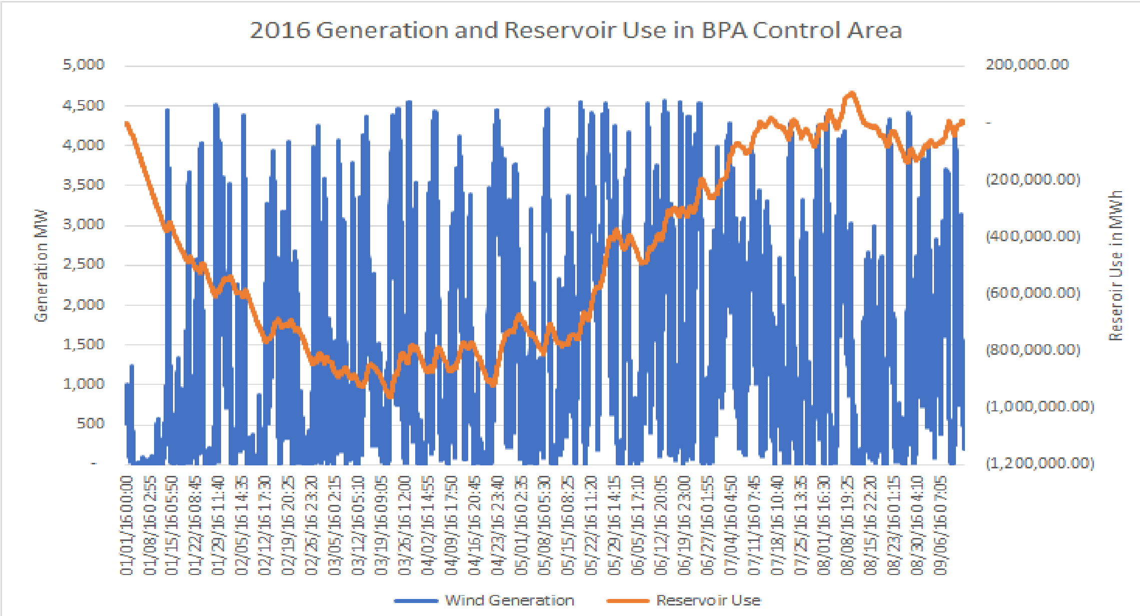
Assuming that BPA's share of the non-treaty storage was purchased at BPA's valuation (adjusted for the falling value between 2012 and 2017) and calculated according to the methodology in the Commission's spreadsheet, the cost of this much larger resource would only be $125 million compared to the Commission's cost of batteries of $146 million.

We estimate that 1 MAF of Mica storage capacity will firm 4,782 MW of wind over one year. This is more than enough to back up the 444-685 MW of wind included in the alternative portfolio. Our analysis is set out below.

It is a reasonable assumption that the wind farms in the Commission's scenarios will operate roughly comparably to wind farms across the border in Oregon and Washington.

Bonneville Power Authority provides data on wind generation in five-minute increments. For 2016, we can see how many megawatt-hours it would take to firm the 4,782 MW of wind in their control area over one year. The following chart shows the actual wind generation for twelve time increments in each hour. Charted in orange is the draw on the region's reservoirs.

[13] ADMINISTRATOR'S DECISION RECORD NON-TREATY STORAGE AGREEMENT WITH BC HYDRO, Bonneville Power Administration, March 23, 2012, page 1.



The maximum draw on the reservoirs comes at 6:45 P.M. on March 21, 2016. At that point, if the system wanted to maintain a minimum generation level of 1,414 MW from wind, the reservoirs would have been tapped for 986,235 megawatt-hours. After that date, the reservoirs would gradually refill.

In terms of Mica's storage, this is roughly equivalent to 1 MAF.

I have attached both the Non-Treaty Storage Agreement and BPA's Record of Decision to this submission.

Economics of sales and purchases in the market

The Commission's assumptions in A-22 placed the value of exported capacity at zero and the value of energy at Can$25/MWh. These are prudent values given the current market and reasonable market forecasts.

We note this is also consistent with BC Hydro's own approach in its 2013 IRP, where it determined it was not appropriate to assign any surplus value to capacity:

> **Note that BC Hydro has conservatively not assigned any value to surplus capacity**. In the recent John Hart Generating Station Replacement Project CPCN proceeding, BC Hydro provided evidence that while the market **value of capacity is uncertain because of illiquidity in the current Western Electricity Coordinating Council (WECC) region,** BC Hydro

> estimated a range of market values of categories of about $75/kW-year to $110/KW-year, based on recent Bonneville Power Administration (BPA) tariffs, transaction and market analysis. BC Hydro further estimates that U.S. market access transmission constraints could reduce the market value of capacity to $37/kW-year for the low end of the market range. These benefits associated with capacity surplus from Site C would add to its cost advantage described above.[14]

This is in stark contrast to the revised and speculative approach BC Hydro has taken to future capacity value in the present proceeding (F1-1 p. 64 and Appendix S), as we discuss below.

Forecasting the future is difficult and imprecise. The assumption that British Columbia Hydro can sell energy and capacity above the market[15] is, at best, speculative. In previous submissions[16] we have pointed out that existing transactions in forward market at Mid-Columbia are significantly less than British Columbia Hydro's undocumented forecasts. With a rapidly declining market in energy across North America, it is likely that British Columbia's forecast is dated.

On October 14, 2017, Mr. Bechard presented a rebuttal to the use of actual forward prices in his oral presentation.[17] He misspoke on a number of points.

First, he questioned whether the forward markets at Mid-Columbia are liquid through 2025. This is a fair concern. Forward markets, by their very nature, are more liquid in early years than later years. More parties are interested in the immediate future than periods further on the horizon.

This same argument was raised in the context of LNG future markets in F1-12 Appendix C and disproved in my remarks on October 14, 2017.[18]

In this case, Mr. Bechard went beyond questioning the depth of the market after 2022, he denied that there were any transactions that had ever occurred after 2022.[19] In doing so, he misspoke. The InterContinental Exchange [ICE] has a number of forward markets in energy. The data I have cited comes from the daily reports provided by the exchange. If

[14] BCH 2013 IRP, November 2013, pages 6-43.
[15] F1-1 p. 103 and Appendix S
[16] F35-5 and September 13, 2017, pp. 27, 28 Figures 17 & 18 and F 35-7, September 24, 2017, p. 2 Fig 1
[17] Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1658.
[18] Critical Review of British Columbia Hydro Appendix C, Robert McCullough, October 13, 2017, page 10.
[19] Technical presentation transcript, October 14, T p. 1657 l. 8-17

Mr. Bechard had checked, he would have found that there are open interests through to December 2025.[20,21]

COMMODITY NAME	CONTRACT MONTH	DAILY PRICE RANGE				SETTLE		VOLUME AND OI TOTALS						
		OPEN#	HIGH	LOW	CLOSE#	PRICE	CHANGE	TOTAL VOLUME	OI	CHANGE	EFP	EFS	BLOCK VOLUME	SPREAD VOLUME
MDC-Mid-Columbia Day-Ahead Peak Fixed Price Future - Mid Columbia														
MDC	MAY-24					25.00	.00	0	25	0	0	0	0	0
MDC	JUN-24					25.35	.00	0	25	0	0	0	0	0
MDC	JUL-24					34.45	.00	0	25	0	0	0	0	0
MDC	AUG-24					39.20	-.05	0	25	0	0	0	0	0
MDC	SEP-24					34.90	.00	0	25	0	0	0	0	0
MDC	OCT-24					30.55	.00	0	25	0	0	0	0	0
MDC	NOV-24					33.50	.00	0	25	0	0	0	0	0
MDC	DEC-24					40.55	-.05	0	25	0	0	0	0	0
MDC	JAN-25					40.75	-.05	0	25	0	0	0	0	0
MDC	FEB-25					34.70	.00	0	25	0	0	0	0	0
MDC	MAR-25					28.45	.00	0	25	0	0	0	0	0
MDC	APR-25					27.55	.00	0	25	0	0	0	0	0
MDC	MAY-25					26.20	.00	0	25	0	0	0	0	0
MDC	JUN-25					26.50	.00	0	25	0	0	0	0	0
MDC	JUL-25					35.65	.00	0	25	0	0	0	0	0
MDC	AUG-25					40.45	.00	0	25	0	0	0	0	0
MDC	SEP-25					36.10	.00	0	25	0	0	0	0	0
MDC	OCT-25					31.70	.00	0	25	0	0	0	0	0

Figure 2: Screenshot of CME's energy market report showing open interest for Mid-C going out to 2025.

Several other of his comments also appear to be misstatements. He explained that British Columbia Hydro has been "20 to 25 percent of the spot trades that occur at mid-C every day."[22] According to the Federal Energy Regulatory Commissions mandatory data on energy transactions, Powerex is less than 2% of transactions at the Mid-Columbia hub in 2016.[23,24]

Mr. Bechard then goes on to state:

> So, you know, I think it's incorrect to say that you can plot a forward curve out to 2026 based on actual traits [*sic*]. I don't think you can do that. I do think that ICE has some marks for those. I'm not sure where ICE gets those

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20 ICE. "End of the Day Report," October 12, 2017, p.1078.

21 Open Interests are forward contracts currently in force. An open interest can be extinguished by offset – selling the contract -- or performance.

22 Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1656, lines 17 and 18.

23 https://eqrreportviewer.ferc.gov/

24 See Appendix A for detailed answer to the conflicting evidence between Mr. McCullough and Mr. Bechard on this point.

marks from. I suspect it may be nothing more than an extension of the 2021-2022 prices.[25]

A forward curve is the set of future values for a commodity. Trading floors update their forward curves on the basis of actual trades every day at the close of the day shift.

A subsidiary of Standard & Poors, Platts, is a very significant information source in commodities markets. Traders, regulators, consultants, and ultimate large-scale consumers read many of their newsletters. One of Platts' many journals, Megawatt Daily publishes forward curves for hubs across the U.S. and Canada.

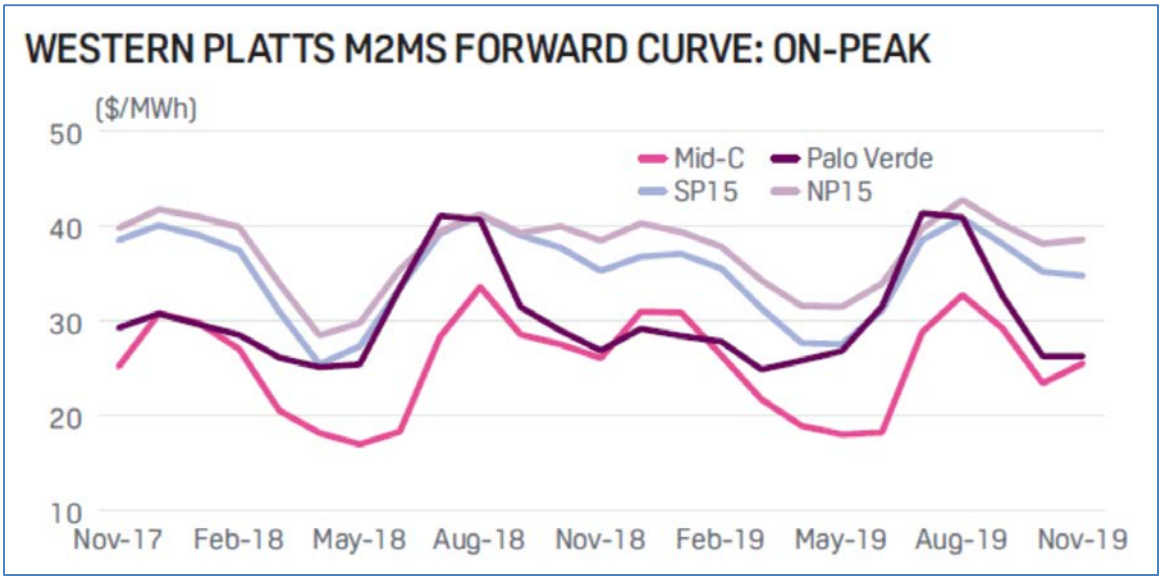

Figure 2: Megawatt Daily West Coast Forward Curves[26]

Platts uses ICE trading data and their own models to generate forward curves for a large variety of commodities and locations. It is the practice of significant journals like Platts to publish their methodology so that users of their data can judge the accuracy and honesty of their estimates.[27] Regulatory agencies like the Federal Energy Regulatory Commission have a continuing interest in this as well since a number of the Enron trading strategies involved falsifying market data.

[25] Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1657, lines 19 through 25.

[26] Megawatt Daily, Platts, October 18, 2017, page 14.

[27] METHODOLOGY AND SPECIFICATIONS GUIDE PLATTS-ICE FORWARD CURVE – ELECTRICITY (NORTH AMERICA), Platts, April 2015.

Platts issues a widely used set of forward curves every day. This product, M2MS, is a proprietary service, so was not available for us to provide in the Site C process. We have, however, relied on the prices in the forward markets that are close but not exactly the same, as set out below.

In submission F1-17, British Columbia Hydro has finally identified the source and date of their wholesale price forecasts at Mid-Columbia.[28] As expected, the forecasts relied upon so far in this proceeding are dated in 2015 and 2016.[29]

The following chart adds a thick red line to represent current forward prices on the same chart as prepared by British Columbia Hydro. As expected the prices diverge considerably – largely due to the use of vintage price forecasts:

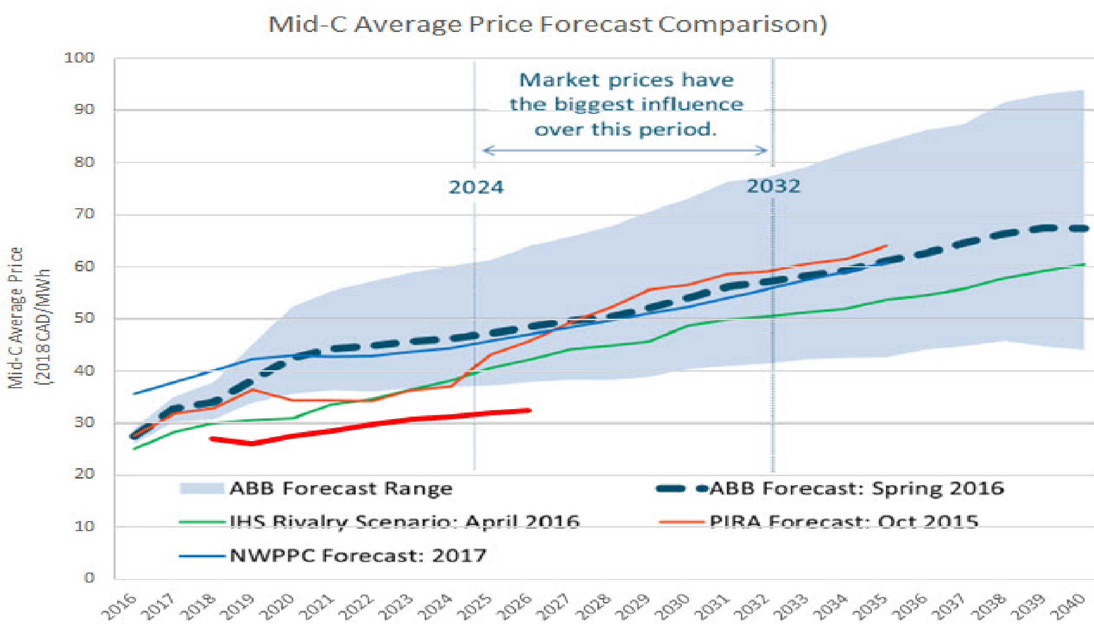

Figure 3: Depiction of forward curve from October 12th (bold red) and BCH price forecast.

[28] F1-17, October 18, 2017, page 23.
[29] The forecast identified as the NWPPC Forecast: 2017 is somewhat mysterious. It is not clearly available on the NWPPC web site.

Mr. Bechard also states:

> The other thing you can say about the forward curve is that it's not really valid to take a snapshot of the forward curve on a particular day and compare that to some market forecast that was done, you know, six months ago or a year ago. You could take a snapshot six months from now and it will look completely different than the snapshot today.[30]

This is somewhat true. Traders are Bayesians and update their opinions of the future with information they receive every day.[31] However, these forwards respond to the market conditions, and the market outlook six months ago are remarkably similar to the outlook today:

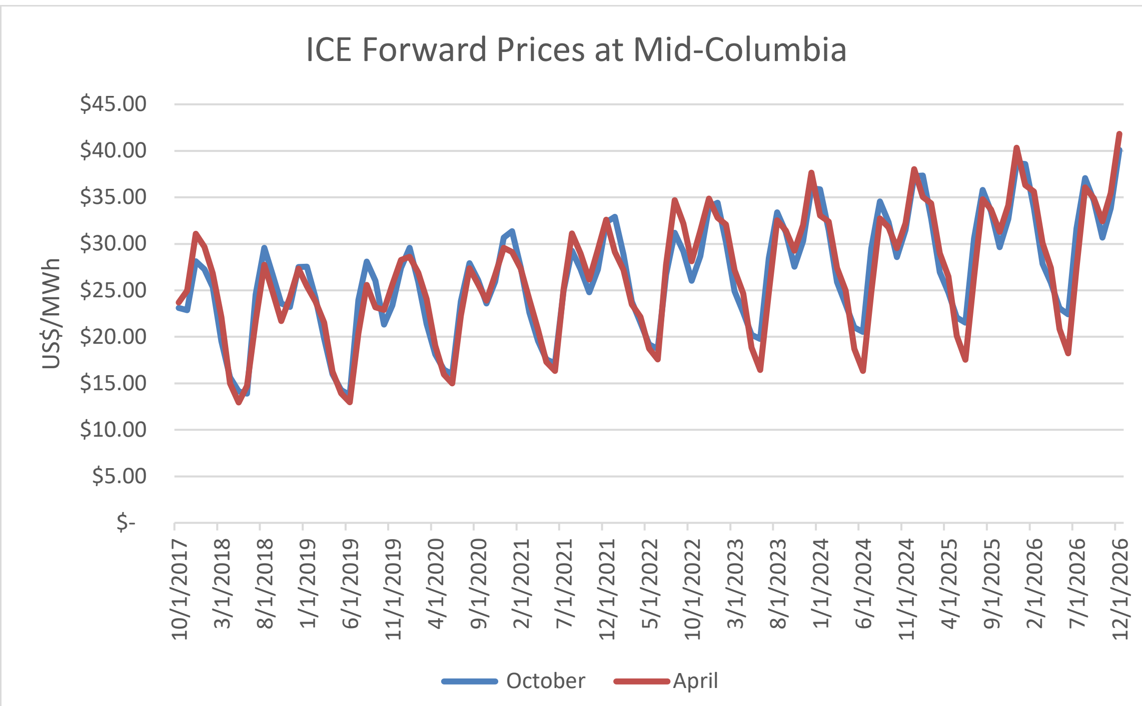

Figure 3: Comparison April and October ICE Forward Prices.[32]

[30] Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1658, lines 1 through 7.

[31] Reverend Thomas Bayes (1601-1761) was the inventor of a statistical theory that now bears his name. In Bayesian statistics, estimates are updated with new data as opposed to classical statistics where a point estimate does not consider past and new data explicitly.

[32] CME forward prices for October 14th and May 24th.

As can be seen these forward prices are very comparable.

This dialog has largely focused on energy prices. The Commission spreadsheet also recommends that capacity prices be assumed to be zero for exports. There are good reasons to believe that capacity is not going demand high prices in the Northwest Power Pool in days to come.

NWPP: Case 1 – Existing/Class 1 Resources Winter	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Net Internal Demand	71,071	71,945	72,844	73,504	74,122	75,069	75,722	76,308	76,994	77,374
Anticipated Internal Capacity	88,752	89,866	90,412	90,470	90,753	91,065	91,475	91,471	90,634	90,575
Wind Expected On-Peak MW	3,006	3,515	3,865	3,867	3,869	3,870	3,872	3,881	3,882	3,884
Percentage of Capacity	21.5%	23.4%	22.5%	22.5%	22.5%	22.5%	22.5%	22.4%	22.4%	22.4%
Solar Expected On-Peak MW	0	0	0	0	0	0	0	0	0	0
Percentage of Capacity	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro Expected On-Peak MW	34,358	34,379	34,400	34,488	34,382	34,386	34,392	35,385	35,838	35,841
Percentage of Capacity	65.1%	64.8%	64.6%	64.7%	64.5%	64.4%	64.4%	64.9%	65.1%	65.1%
Imports	6,760	6,700	6,800	6,766	7,517	8,188	8,598	8,694	8,966	9,419
Exports	1,700	0	0	0	0	0	0	100	993	1,161
Anticipated Resource Reserve Margin MW	5,812	5,906	5,403	4,690	4,252	3,459	3,107	2,419	782	279
Anticipated Resource Reserve Margin %	24.9%	24.9%	24.1%	23.1%	22.4%	21.3%	20.8%	19.9%	17.7%	17.1%

Figure 4: 2017-2026 NWPP Winter Reserve Margins[33]

The winter reserve margin is high by industry standards. The summer reserve margin is very high – so high that the ability to demand premiums in the California market will be diminished due to extensive competition.[34]

Despite appropriately attributing no value to capacity surplus in its 2013 IRP (2013 IRP p. 6-43 Nov 2013) because of inherent uncertainty arising from illiquidity, BC Hydro has now changed course, and attributes aspirational value to surplus capacity based on hoped for 'emerging opportunities". In its August 30 2017 F1-1 filing in the present proceeding at p.103 BC Hydro plainly asserts that BC Hydro anticipates obtaining above average prices from export markets for capacity and flexibility.

8.6 The Flexibility of Site C Can Obtain Above Average Prices from Export Markets

> The extensive lead time associated with new generation additions, and the challenges inherent in forecasting demand years into the future, give rise to the potential that new generation resources enter service in advance of actual need. This is a risk inherent in resource

[33] NWPP, "Northwest Power Pool Area Assessment of Reliability and Adequacy 2016-2017," October 17, 2016, page 12.
[34] NWPP, "Northwest Power Pool Area Assessment of Reliability and Adequacy 2016 Summer Operating Conditions," May 2, 2016.

> planning. As described in **Appendix S**, BC Hydro through its trading subsidiary Powerex would be able to optimize the trade benefits of any surplus. As a result it is likely that we would be able to sell any surplus on the energy spot market **for more than the Unit Energy Cost of completing the Project on the current schedule.** Two sensitivities were modelled with respect to recovery of costs in the spot electricity markets: (1) the benefit of capacity and flexibility; and, (2) the lower band of BC Hydro's market price forecast. The results show that there could be significant up-side to exporting surplus capacity and flexibility benefits associated with Site C. The benefits of completing Site C are still significant even in a scenario with low market prices for surplus exports.

However, a look at Appendix S does not provide any detail of this new analysis[35] Appendix S states, aspirationally and without evidence:

> "Specifically, in addition to any short -term surplus energy sales, there **may also be emerging opportunities** to sell surplus ***capacity and flexibility*** from the BC Hydro system supported by new flexibility and capacity from Site C. Together, sales of surplus energy, capacity and flexibility **may partially, or wholly**, offset the cost of Site C generation until its full capability is required to meet BC Hydro needs.
>
> The expected prices for short term energy sales from 2024 to 2030 are estimated by **ABB** to be around CAD$41/MWh. (p 1) However, as discussed in Appendix F, surplus energy sales supported by the addition of highly flexible resources, such as Site C, can be expected **to exceed prevailing average wholesale energy prices**, through sales in the higher priced hours of the year.[36]
>
> …
>
> In addition to potential emerging opportunities to sell capacity and flexibility in the Pacific Northwest and Alberta, **there is a rapidly emerging need** for ***flexibility*** and ***capacity*** products in California… **There is thus a growing potential** that surplus hydro capacity and flexibility could be monetized either through sales of new capacity and/or flexibility products in California's organized markets, or through a direct transaction with a California party.[37]

[35] And Appendix F, which is referred to in Appendix S, at F p 8 Table 1 shows that it is calculated based on Mid-C day ahead index, but only for 2014-2017; it provides no data about future prices for capacity.
[36] Ibid., page 1.
[37] Ibid., page 2.

> …
> Accordingly, the costs associated with the addition of ***capacity*** and ***flexibility*** rich resources, such as Site C, **may be partially or wholly offset**, until it is needed, through short -term energy sales and/or through longer-term market transactions that include capacity and/or flexibility commitments in western wholesale energy markets.
>
> **If the decision is made to proceed with completing Site C, BC Hydro would continue to closely monitor domestic needs** for the resource and Powerex would likewise continue to monitor the market opportunities for surplus flexible generation. If it becomes clear at some point that the Site C generation will not be fully required in 2024, and an opportunity arises to make a commitment in the external market that aligns with the expected surplus capability and expected timeframe of that surplus, Powerex **could seek to enter into sales that maximize the value of the surplus capabilities**.[38] (bold emphasis added, bold italics in BC Hydro original)

In sum, the correct step for the Commission is to use the best evidence of export prices and not dated forecasts that have not been documented or speculative hope for an emerging market, unsupported by data.

Finally, Mr. Bechard has stated that British Columbia Hydro has a large profile of U.S. transmission rights to move 2,500 megawatts of capacity from the Northwest into California.[39] This seems a bit large given the transmission constraints set out in the WECC's 2016 power supply assessment.

[38] Ibid., page 3.
[39] Technical Input Proceedings Vancouver, Volume 12, Allwest Reporting, October 14, 2017, pages 1656 through 1663, lines 22 through 25.

Figure 1 - Summer Zonal Topology Diagram

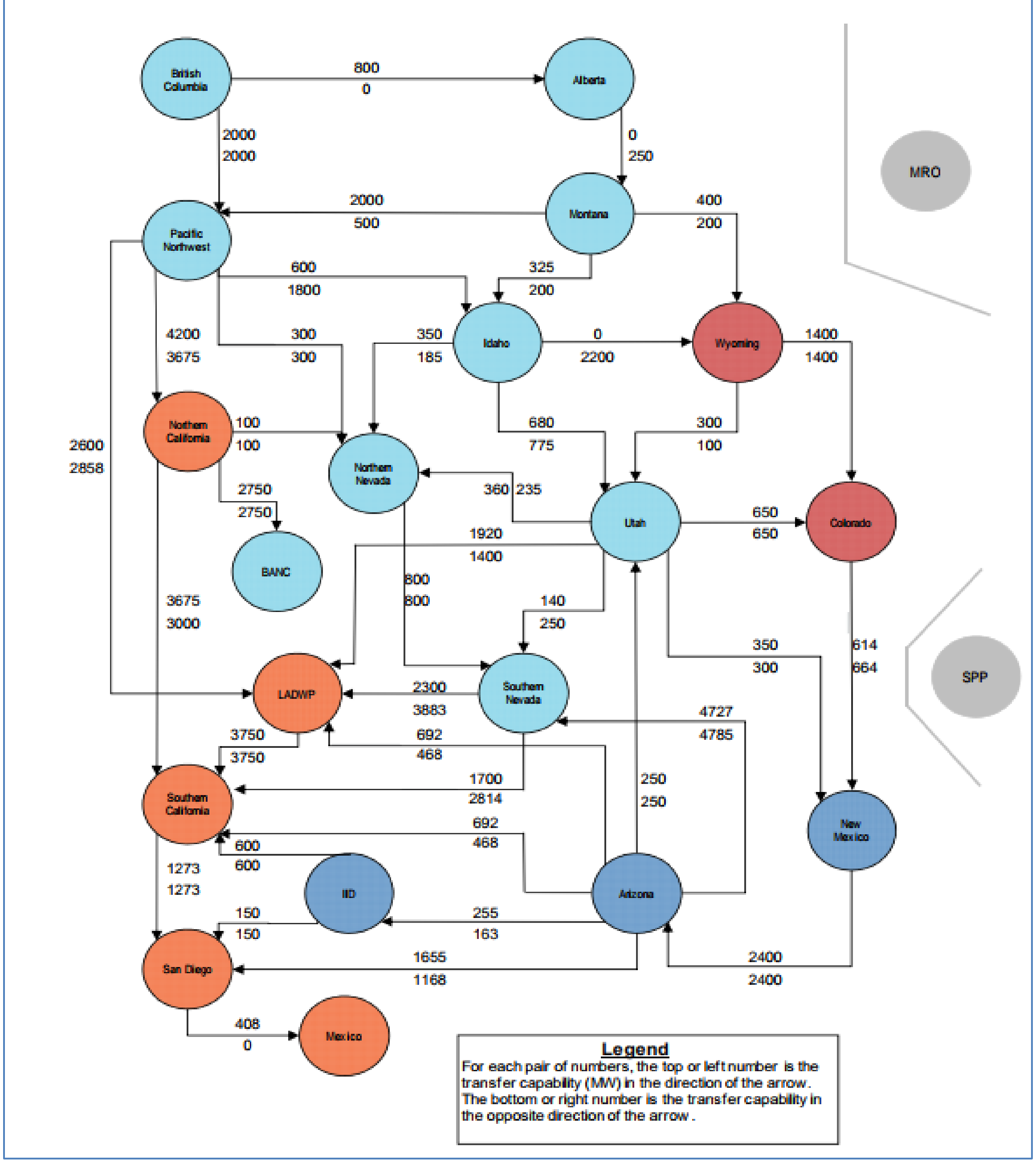

Figure 4: WECC Summer Transmission Capacity Limits[40]

[40] WECC, "2016 Power Supply Assessment," December 2016, page 19.

Addressing British Columbia Hydro's October 14, 2017 Comments

British Columbia Hydro found five implicit and explicit assumptions in the BCUC's alternative scenarios to be unrealistic.

1. **<u>Treats DSM as an alternative when it is included in all portfolios.</u>**

BC Hydro suggests that the BCUC has wrongly assumed in its alternative portfolio that "we cease DSM if we build Site C" (slide 27, October 14 2017). This significantly oversimplifies the issue. BC Hydro will clearly not "cease" DSM if Site C is approved. It is not permitted to do so. The question is, what can BC Hydro achieve by ***maximizing*** DSM efforts and expenditures, and is this a valid component of an alternative portfolio. In our view it is, and the Commission should retain DSM measures in its alternative portfolio. The evidence is that BC Hydro has been scaling back on DSM expenditures since 2014, driven in part by surplus capacity and revenue requirements.

British Columbia Hydro has warned the BCUC that they are "currently reviewing its DSM expenditures in light of changes to several initiatives and actual spending may vary from estimates."[41]

The BCUC clearly considers DSM a central policy choice. British Columbia Hydro admits that it's elective. We see from BC Hydro's 2016 Revenue Requirement Application, Appendix C p. 9 that BC Hydro's expenditures on DSM decline significantly between 2014 and 2016:

[41] BC Hydro. "BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project," August 30, 2017, page 8.

APPENDIX A

F2014 – F2016 DSM Expenditure Schedule

$ MILLION	F2014	F2015	F2016
Codes and Standards	2.4	4.0	4.2
Rate Structures	6.5	2.0	1.7
Programs			
Residential	30.4	17.7	18.9
Commercial	66.4	39.5	40.0
Industrial	101.9	64.3	42.9
Total Programs	198.7	121.5	101.8
Supporting Initiatives	28.7	20.6	20.3
Total Energy Efficiency Portfolio	236.3	148.0	128.0
Capacity Focused DSM	0.0	2.4	3.1
Total	236.3	150.5	131.1

APPENDIX B

Figure 5: 2016 RRA, Appendix C, page 9.

The evidence of the UBC Program on Water Governance filed in this proceeding F106-1 (at pp. 82-83) demonstrates credibly that this is linked to drops in BC Hydro's load forecasts and revenues. Therefore, it is a legitimate component of the Commission's alternative portfolio that BC Hydro resume enhancing DSM expenditures rather than diminishing them.

Indeed, in its initial filing, BCH used planning for DSM as evidence for the need to increase capacity, implying they see Site C as an alternative to sustained future DSM programs.[42]

2**. BC Hydro builds and finances all alternative resources**

The Commission has criticized British Columbia Hydro's decision to assume 100% debt financing for Site C, but more costly financing for other resources:

> Financing costs: The reduction of financing costs of $26/MWh, which is enabled by transferring some of the financing costs from BC Hydro ratepayers to taxpayers, does not appear to be built into the Alternative Block

[42] BC Hydro. "BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project," August 30, 2017, Appendix B, page 11.

> UEC. If two portfolios are being compared, it is important to ensure that the basis of comparison is the same. If the same debt financing assumption is not being applied to the Alternative Portfolio, and a full weighted-average cost of capital is assumed instead, the Panel also draws a preliminary conclusion that this reflects an implicit assumption that the Alternative Portfolio will not be constructed by BC Hydro. This results in an "apples to oranges" comparison. The Panel finds that the reduction of the UEC to account for reduced financing costs distorts the analysis of unit energy costs comparisons.[43]

The Commission did not make this assumption in their alternative portfolio analysis. It was unclear from Mr. Reimann's presentation on October 14th as to why BC Hydro pursued this point given the Commission's comments in the preliminary report. Mr. O'Riley commented:

> So I think what we're saying here is there was a suggestion in these analysis that perhaps it made sense for BC Hydro to kind of reverse the policy that had been in place for, you know, almost 30 years and go back to developing all the resources or perhaps financing all the resources, and I think what we're saying is we think that would be a mistake. <u>We think that's not our core competency and we don't think we bring expertise and we think we'd run into a lot of challenges if we were starting to develop small, lower resources around the province</u>. So that's the point we're trying to make with this.[44] (emphasis added)

Mr. O'Riiley's comments appear to be a detour around the clear statement of the problem that the Commission's plain question highlighted:

> Well, let me ask you tough question then. So there's not enough load growth to justify any more IPP contracts, but there is enough load growth to justify the construction of a large dam project? [45]

BC Hydro's response reveals the Corporation's paradigmatic resistance to fairly considering alternatives to Site C. Fortunately, neither the Commission's preliminary report, nor the Alternative Portfolio described in A-22 suffer the same flaw.

[43] Preliminary Report to the Government of British Columbia, British Columbia Utilities Commission, September 20, 2017, page vii
[44] BCUC. "Technical Input Proceedings" October 14, 2017, page 1647
[45] Ibid., page 1646, lines 22-26.

If British Columbia Hydro actually has access to 100% debt financing, a project developer will depend on British Columbia Hydro's credit support to build their project. In this case, the windmill, geothermal, or solar project will also enjoy low cost financing.

It is a well-known principle of project financing that the credit support flows from the customer to the project. Customers with tax recourse powers enjoy a lower cost of capital than those without the ability to tax. Windmills built for public utilities with these powers enjoy lower project financing than those without since the investors know that their investments are more secure.

Ownership of the project does not, in itself, determine the cost of capital – the cost of capital is based on the guarantee of repayment.[46]

3. Battery costs are low

As I have noted above, the choice to supply firming and shaping from batteries is likely to be more costly than using the non-treaty storage at Mica. However, battery costs have been declining markedly in recent years.

Lazard has published ten summaries of the Levelized Cost of Energy for a variety of generation types. These studies are highly regarded since they do not represent advocacy. Instead, they represent a balanced attempt to document the major changes the industry has seen over the past decade.

In November 2015, Lazard commenced a new set of annual studies on storage.[47] Their unsubsidized summary indicates that storage options are about to overtake aeroderivative turbines:

[46] Wind Power: The Industry Grows Up, Rebecca Busby, page 119.
[47] Lazard's Levelized Cost of Storage Analysis — Version 1.0, November 2015.

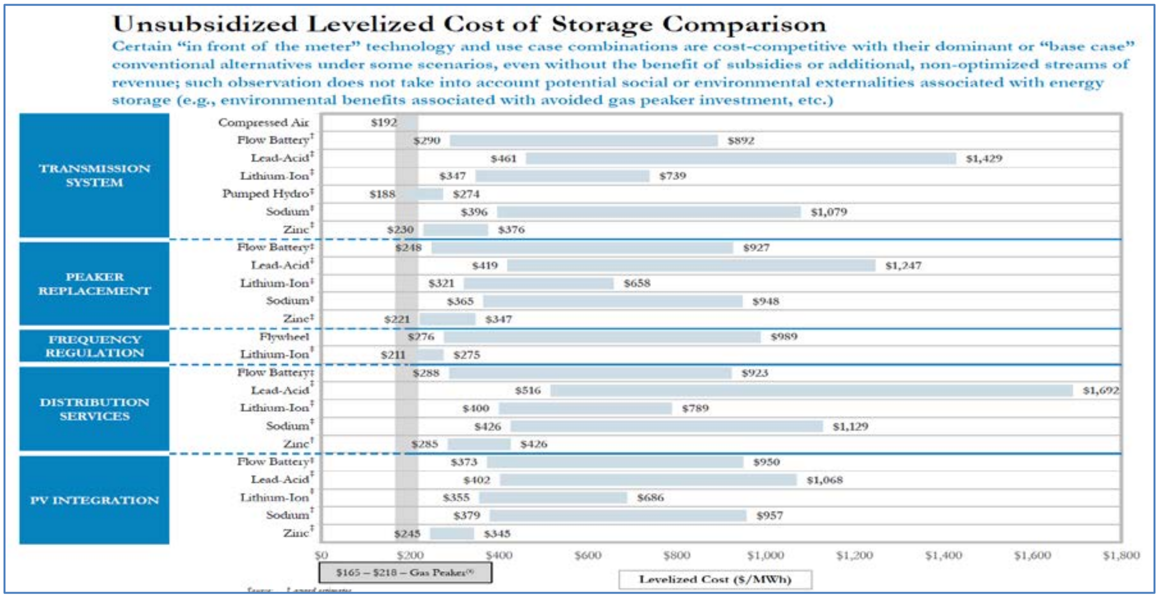

Figure 6: Lazard 1.0 Estimates of Storage Cost[48]

Last year Lazard published version two of their study:

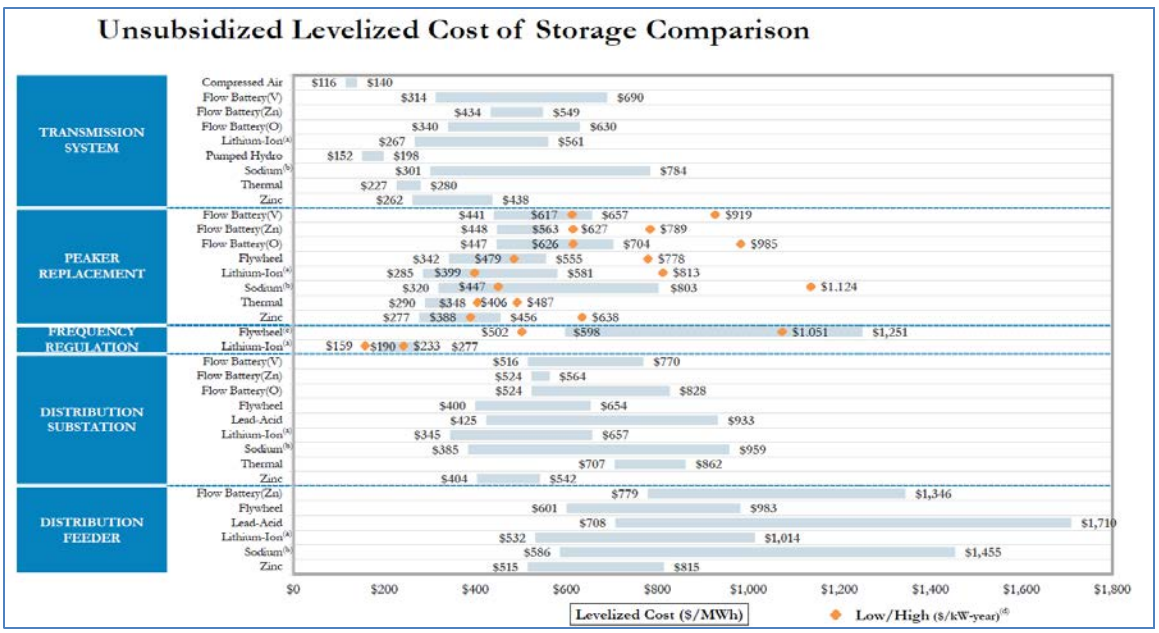

Figure: Lazard 2.0 Estimates of Storage Cost[49]

[48] Ibid., page 9.
[49] Lazard's Levelized Cost of Storage Analysis — Version 2.0, December 2016, page 11.

The highest profile turbine replacement storage option – lithium ion – has fallen from a range of US$347/kw/year to US$749/kw/year down to US$285/kw/year to US$581/kw/year.

These are dramatic decreases as I noted in a previous submission, Duke has announced a regulatory filing for a 13 MW utility scale project for approximately $200/kw/year.[50]

4. Optional time-of-use estimates are dated with significant deliverability risk

These rates would mostly apply to industrial customers and not residential ones. As we have discussed in previous submissions and as BC Hydro admitted in their technical presentation on October 14, the load required by industrial customers has declined significantly since 2008.[51,52] The only tangible way this might affect residential rate payers is if electric vehicles begin to form a significant portion of transportation infrastructure. Time-of-use payments would push electric vehicle owners to charge their cars overnight.

5. Wind cost declines are optimistic

All of these predicted cost declines are supported by precedent and authoritative sources.

A variety of industry sources provide a favorable picture of wind and solar cost declines than that assumed by British Columbia Hydro. The following two charts have been taken from the most recent Lazard study on the Levelized Cost of Energy (LCOE) generation.[53]

[50] Duke Energy. Duke Energy to invest $30M in Ashevill battery energy storage systems. September 21, 2017. page 2.
[51] BC Hydro. Site C Inquiry: Presentation to Commission Panel. October 14, 2017. Slide 14
[52] Costs of Continuing Site C and the Alternatives, Robert McCullough, August 30, 2017, pages 36-38.
[53] Lazard's Levelized Cost of Energy Analysis – Version 10.0, Lazard, December 2016, page 10.

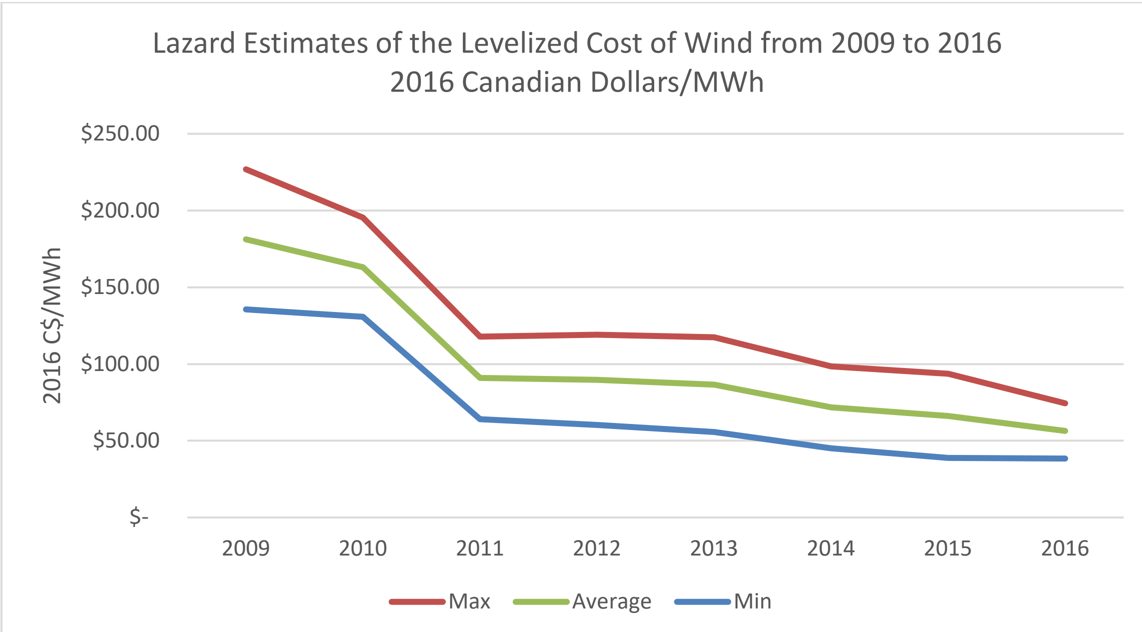

Figure 2: LCOE of wind generation from 2009-2016.

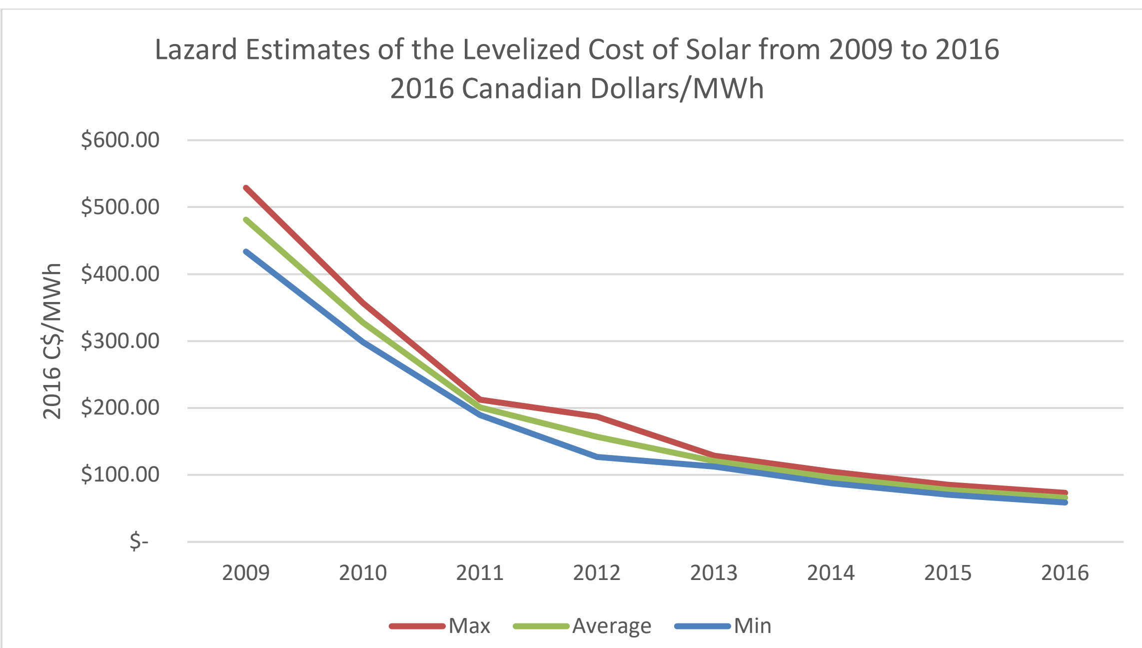

Figure 3: LCOE of solar generation from 2009-2016.

Not only are the rates of decline in cost remarkable, the absolute levels reported by Lazard are declining below traditional fossil fuel generation.

A number of studies point to additional future reductions. One very authoritative study was issued by the International Energy Agency last year.[54] The IEA bases its quantitative figures on the mean response of over one hundred industry experts, and nearly all agree that wind costs will decrease significantly over time from current levels.

According to the report, the LCOE of onshore wind energy is expected to continue falling until at least 2050. While offshore turbines will become practical sources of energy in the medium-term, onshore wind is currently competitive with all major sources of energy generation.

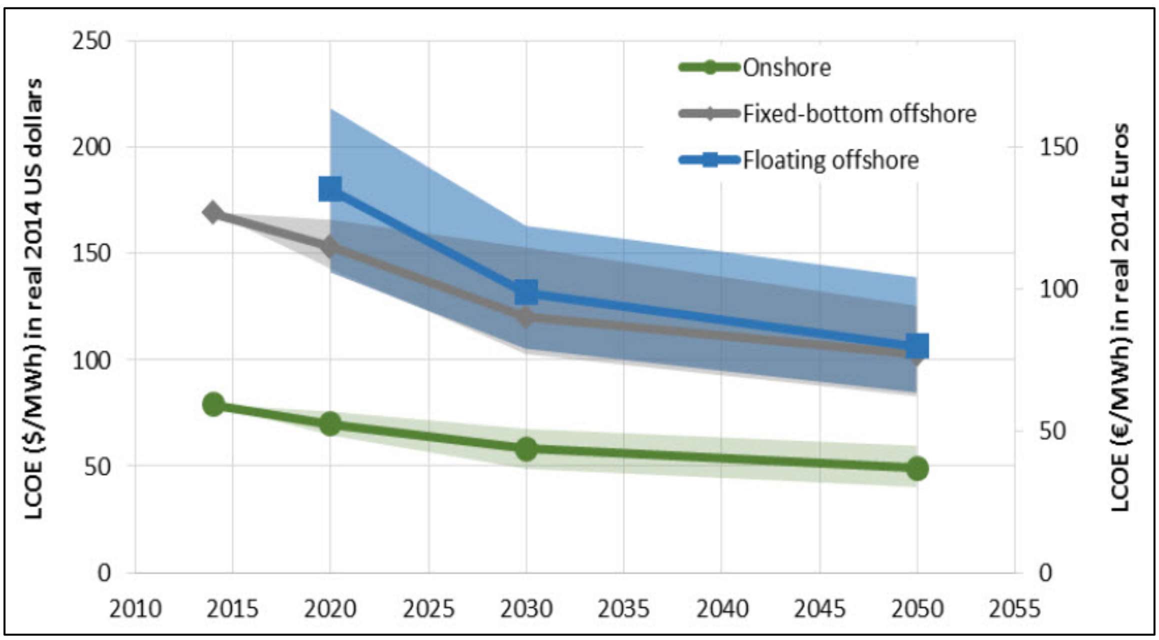

Figure 4: IEA predicted LCOE of wind turbines from 2014-2050 in 2014 US$.[55]

The IEA expects that most of these cost reductions will come about as a result of wind turbines operating for longer, being more efficient at generating power, and a lower cost of production and operation. The table below summarizes the IEA's estimate of the percent change of certain statistics of onshore wind from 2014 to 2030:

[54] Forecasting Wind Energy Costs and Cost Drivers: The Views of the World's Leading Experts, International Energy Agency, Ryan Wiser, Karen Jenni, Joachim Seel, Erin Baker, Maureen Hand, Eric Lantz, and Aaron Smith, June 2016.
[55] Ibid., page 7.

Specification	% change by 2030
Capacity Factor	+10%
Project Life	+10%
CapEx	-12%
OpEx	-9%

Table 1: IEA's predicted change in key wind project statistics/specifications.

Except in the most pessimistic scenario, this technological improvement will result in a dramatic reduction in the LCOE for producing wind power.

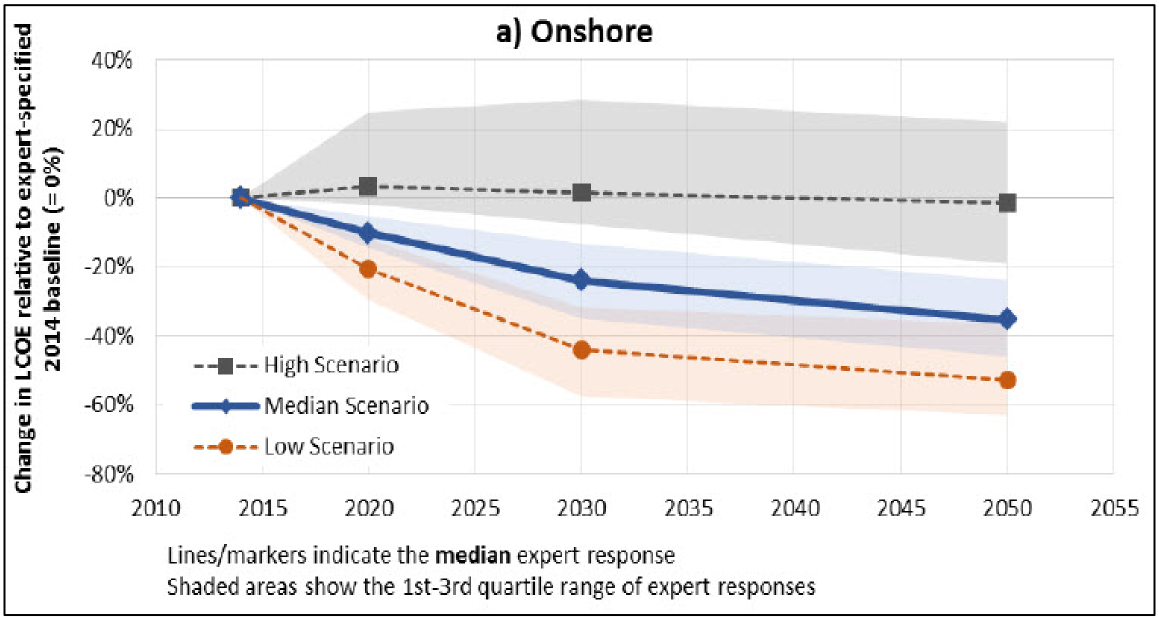

Figure 5: IEA's predicted percent change in cost of onshore wind projects 2014-2050.[56]

The LCOE of wind is already competitive with nearly all sources of convention electrical generation, and the experts that spoke with the IEA predicted that a number of innovations will gradually reduce the price of generation. Most of these innovations, summarized below, are not the fanciful dreams of science fiction writers, but easily attained with this and the next decade's technology.

[56] Ibid., page 11.

	Wind technology, market, or other change	Percentage of experts rating item "Large expected impact"	Mean Rating , Rating Distribution 3- large impact 2- median impact 1- small impact 0- no impact	
Onshore Wind	Increased rotor diameter such that specific power declines	58%	2.5	
	Rotor design advancements	45%	2.3	
	Increased tower height	33%	2.2	
	Reduced financing costs and project contingencies	32%	2.1	
	Improved component durability and reliability	31%	2.1	
	Increased energy production due to new transmission to higher wind speed sites	31%	2.0	
	Extended turbine design lifetime	29%	2.0	
	Operating efficiencies to increase plant performance	28%	2.0	
	Increased turbine capacity and rotor diameter (thereby maintaining specific power)	28%	1.9	
	Turbine and component manufacturing standardization, efficiencies, and volume	27%	2.0	
	Improved plant layout via understanding of complex flow and high-resolution micro-siting	27%	2.0	
	Integrated turbine-level system design optimization	23%	2.0	

Figure 6: Predicted cost-saving innovations in onshore wind generation.[57]

The table below summarizes the predicted change in the LCOE of wind energy according to various sources. While BC Hydro forecasts no reduction, other authoritative agencies forecast a reduction of between 10 and 17% over the planning period.

Overall, British Columbia Hydro's current estimates are high – very high – compared with industry estimates and actual wind farms operating nearby in Washington State. Industry expectations indicate a continued decline in costs – even after the rapid declines in recent years.

Source	2017 C$/MWh	2020 % change in costs	2025 % change in costs	2030 % change in costs	2035 % change in costs	2040 % change in costs
BCH [58]	C$104.77-C$315.48[59]	-	-	-	-	-
Deloitte	-	-	-10-12%[60]	-	-	-
Lazard	C$69.04[61]					
IEA	C$76.97[62]	-	-	-12%[63]	-	-
EIA	C$72.13[64]	-	-	-	-	-17%[65]

The Commission's three scenarios use wind prices that are within the Lazard range. [58]

[57] Ibid pg. 30

Initial wind builds	Name	Size	Cost
Wind - PC 18	F2039	138	$1,895
Wind - PC 48	F2040	150	$1,893
Wind - PC 20	F2041	156	$1,888

Lazard's most recent range for on-shore wind is C$1,500 to $C2,040.[59]

[59] Lazard's Levelized Cost of Energy analysis – Version 10.0, December 2016, page 19.

APPENDIX A
MR. McCULLOUGH REPLY TO BC HYDRO REGARDING FORWARD MID-C MARKETS

At several times during the Site C Inquiry, British Columbia Hydro has stated that it can sell surplus energy and capacity at the Mid-Columbia hub at prices high enough to cover Site C's costs. In BCH's August 30, 2017 Submission in this Inquiry (F1-1), they forecast that by 2024, Mid-c will likely be $45/MWh in 2017 Canadian dollars.[60]

The best evidence of the accuracy of British Columbia Hydro's price forecast are actual transactions. If the price forecast is vintage, current transactions will differ. This is the case here. The forward price of Mid-C electricity is markedly different from BCH's BCUC submission forecast. In our September 13, 2017 (F35-5) filing in this proceeding[61] as well as in our September 24, 2017 submission to the BCUC (F35-7),[62] we included the 10-year forward price of Mid-C and compared it to the forecast BC Hydro produced, implying the existence of forward markets going out 10 years.

Additionally, on October 13, 2017 I stated that "No, but we can buy the power ten years out. So, I don't have to forecast it. I can actually call up Morgan Stanley or Powerex and put it in order, and it will be delivered 10 years from now, at a set price."[63]

On October 14, 2017, Mr. Bechard stated it was untrue that you could purchase a contract with a phone call.[64] He goes on to say that his traders are in constant contact with brokers.[65]

Bechard claims for "2023, 2024, 2025, 2026, we don't see a record of that ever trading on the exchange,"[66] saying he doesn't think it is possible to do a forward curve from the forward trades.[67] Later Bechard argues that forward markets may be entirely different over six months.[68]

The statements are incorrect.

[60] BC Hydro. BCH BCUC submission F1-1. August 30, 2017. Page 64
[61] McCullough Research Submission F35-5, September 13, 2017, pp. 27, 28 Figures 17 & 18
[62] McCullough Research Submission F35-7, September 24, 2017, p. 2 Fig 1
[63] October 13 Technical presentation transcript. Page 1232:6.
[64] October 14 Technical presentation transcript. Page 1656:17.
[65] Ibid. Page 1656:23.
[66] Ibid. 1657:11.
[67] Ibid. 1657:21.
[68] Ibid. 1658:5.

First, commodity brokers who are active at ICE and CME can indeed place orders immediately. As in any market, the current posted prices may or may not yield a transaction. However, the point is that these are real prices for a real product. This is not a forecast. This is better than a forecast. In actual trading, the posted prices are part of the forward curve computations that drive risk analysis and day end market to market calculations.

I have attached several pages from a textbook for traders showing this process.[69]

Second, it is not clear why Mr. Bechard called New York to find whether Intercontinental Exchange was relevant to the market. British Columbia Hydro specifically references ICE in some of their tariffs as well as their important OATT tariff at the U.S. Federal Energy Regulatory Commission, not to mention orders from this very commission.[70,71] Clearly, British Columbia Hydro is familiar with ICE and utilizes data from ICE.

The claim that there is no trading post 2023 is particularly puzzling. This effectively repeats the complaint in F1.12 Appendix C that natural gas has no forward trades. In my comments on that submission, I submitted the actual market report from CME to show the opposite.[72] In this case, I have reproduced the market report from Platts that shows ongoing activity through to December 2025 earlier in this submission.[73]

Regarding his point that you cannot generate a forward curve from this data, this contradicts common practice at every trading floor I have ever visited or worked with. Forward curves are updated daily in order to evaluate risk limits and mark to market gains and losses.[74] However, this is not a matter that requires debate since ICE/Platts provides this

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[69] Satyajit Das. Traders, Guns, and Money. July 17, 2017. Page 25-27

[70] BC Hydro. *BC Hydro Submission to the British Columbia Utilities Commission Inquiry into the Site C Clean Energy Project*. August 30, 2017. Appendix F Page 7.

[71] British Columbia Hydro and Power Authority ~ Amendments to the Electric Tariff and the Open Access Transmission Tariff ~ Final Order

Collection	Orders
Date	2015-03-12
Document No.	G-36-15
Order Type	G-General
Company Name	BC Hydro

[72] October 14 Technical presentation transcript. Page 1567:4.

[73] ICE MDC contract report on October 12, 2017.

74 ICE. MID-COLUMBIA DAY-AHEAD PEAK FIXED PRICE FUTURE
<https://www.theice.com/products/6590351/Mid-Columbia-Day-Ahead-Peak-Fixed-Price-Future>

exact service based on forward prices to the industry.[75] I have attached the Platts methodology document to this affidavit.

In sum: British Columbia Hydro has made incorrect statements concerning my submissions in the Site C Inquiry.

Relevant Oral Testimony reproduced for convenience:

Mr. McCullough Oral Testimony Oct 13:

> "The last area where we have a comparative advantage is the Mid-Columbia. The Mid-Columbia has been around for 30 years. I helped start the Mid-Columbia market as a boy. We went to FERC, we got permission to have market pricing. That started right here in the northwest power pool. That was regarded as very adventurous in 1987. It is now the largest such market in the world, it is a completely open outcry market. Unlike some of the other markets, it is not subject to bureaucratic management. It is distinctly a laissez faire undertaking. It is so deep that it has futures and derivatives on all the major exchanges. For the next ten years I could take out my cell phone and actually buy a block of power for 2025. The price is out there. They might want more than my credit card, but the fact is we don't have to speculate on those prices." [76]
>
> "In the Northwest power pool where we live, it was so surplus on capacity for now into the foreseeable future, you can't sell capacity. I checked whether Powerex had sold any capacity on the west coast, and it was minuscule. And that's going to continue for quite a while, according to the authoritative materials from the North American Electric Reliability Council, who have the legal responsibility for maintaining that." (T p 1228 lines 15-23)
>
> …
>
> COMMISSIONER COTE: Just one question. I believe I heard you say that we are pretty good at forecasting future market prices about 10 years out. Is that true?
>
> MR. McCULLOUGH: No, but we can buy the power ten years out. So, I don't have to forecast it. I can actually call up Morgan Stanley or Powerex and put it in order, and it will be delivered 10 years from now, at a set price. And that's the right economic calculation for us, because we know that our

[75] S & P Global, Platts. *Methodology and specifications guide Platts ICE Forward Curve electricity.* February 2017.

[76] Transcript pages 122-1224, lines. 22-12.

> magic 8 ball is limited. I, by the way, keep a magic 8 ball on my desk to remind me that my forecasting is limited. But the good news about mature and deep commodity markets is I don't have to make that guess, so long as there is a deep market out there, and get a firm estimate of what those prices are all the way out.[77]

BC Hydro Mr. Bechard (October 14, 2017

> The presenter left the impression that mid-C regularly trades in the open market ten years out, and in fact I think he said you could call up on your cell phone and get a ten-year contract today.
>
> That's just simply not true. We trade mid-C power every day. We're 20 to 25 percent of the spot trades that occur at mid-C every day. So, we watch that market very, very carefully. We have term traders that are constantly looking at those markets.
> ...
> What really is the case for mid-C power, the front three years trade on a fairly regular basis.
> And I'd say they're fairly liquid. The fourth and fifth year trade sporadically. 2022 -- our records show 2022 last traded in August. So, you'd get a feel for how often that trades.
>
> 2023, 2024, 2025, 2026, we don't see a record of that ever trading on the exchange. I asked
> our term trader yesterday, he sits right next to me, to shout over to the broker in New York to see if he sees any trades on -- in history, for 2023, 2024, 2025, and '26. His answer was, you know, a flat no. They've never seen that either.[78]

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77 Transcript page 1232 lines 3-18
78 Transcript page 1656 l. 12-23 & 1657 l.5-17

List of attachments:

1) Traders, Guns and Money (pages 4-6)
2) U.S. benefits from Columbia River Treaty
3) Non-treaty storage agreement
4) Platts methodology document
5) Columbia River Treaty Factsheet
6) Administrators decision record