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March 18, 2021

Mr. Patrick Wruck
Commission Secretary and Manager
Regulatory Support
British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Mr. Wruck:

RE: Project No. 1599164
British Columbia Utilities Commission (BCUC or Commission)
British Columbia Hydro and Power Authority (BC Hydro)
Fiscal 2022 Revenue Requirements Application (the Application)

BC Hydro writes to provide undertakings resulting from the March 4 and 5 Review Session in accordance with the timetable set out in BCUC Order No. G-345-20 as well as Revision No. 1 to the Application, to provide a revised Draft Order, as explained in our response to Undertaking No. 19.

Exhibit B-9	Responses to Review Session Undertakings (Public Version)
Exhibit B-9-1	Responses to Review Session Undertakings (Confidential Version)
Exhibit B-10	Responses to Review Session In Camera Undertakings (Confidential)
Exhibit B-2-7	Revision No. 1 to the Application filed on December 22, 2020 – Appendix B

BC Hydro also wishes to provide the following clarifications on testimony given during the March 4 and 5 Review Session.

1 Mr. Layton's testimony, Volume 1 of Transcript, page 86, lines 14 to 18

In response to a question from Mr. Keen, Mr. Layton stated that interest is not applied to the pension regulatory accounts. This is correct; and to ensure clarity, we note the following excerpts from section 5G.9.2 of the Previous Application:

Page 5G-17 lines 18 - 19:

> Non-current service costs are comprised of plan income on pension plan assets and interest expense on post-employment benefit liabilities.

Page 5G-18, lines 8 – 16:

> Interest expense, also known as interest accretion, relates to the expected increase in the discounted pension benefit obligation to recognize the passage of time. Interest expense is calculated by multiplying the discount rate by the amount of the pension obligation at the beginning of the fiscal year adjusted for the accrual of current service costs and expected benefit payments during the year. A decrease in the discount rate will result in a decrease in interest expense, while an increase in the discount rate will result in an increase in interest expense.

Page 5G-19, lines 3 - 4:

> Non-current service costs are included in finance charges, as shown in Appendix A, Schedule 8.0, line 17.

2 Mr. Anderson's testimony, Volume 1 of Transcript, page 134, lines 10-17

In response to a question from Ms. Worth, Mr. Anderson stated that there is one community with a charging equipment lease arrangement with BC Hydro that charges users of the electric vehicle station a fee. BC Hydro wishes to provide an update. As of February 25, 2021, the fee that was previously charged by the Cowichan Valley Regional District for the use of the electric vehicle charging station in the community of Duncan has been removed. The use of this station will be free until a BCUC approved rate is in place. The account for the charging station is in the name of BC Hydro.

3 Mr. Anderson's testimony, Volume 1 of Transcript, page 132, lines 2-3

In response to a question from Ms. Worth about charging equipment leasing, Mr. Anderson stated that all 30 stations during BC Hydro's phase 1 electric vehicle charging stations were subject to an equipment lease agreement. BC Hydro wishes to clarify that the station located at the Powertech Lab site (to be decommissioned by the end of fiscal 2021), which was part of phase 1 deployment, was not subject to an equipment lease arrangement.

4 Ms. Daschuk's testimony, Volume 2A of Transcript, page 8, lines 21-25

In response to a question from Mr. Ratlich during the in-camera session, Ms. Daschuk stated that [redacted]

For further information, please contact Chris Sandve at 604-974-4641 or by email at bchydroregulatorygroup@bchydro.com.

Yours sincerely,

Fred James
Chief Regulatory Officer

cs/rh

Enclosure

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 1

HEARING DATE: March 4, 2021

REQUESTOR: AMPC, Mr. M. Keen

TRANSCRIPT REFERENCE: Volume 1, Page 71, line 5 to Page 72, line 3

TRANSCRIPT EXCERPT:

> MR. KEEN: Q: It's not everyone that follows along the Excel cells of a spreadsheet, so well done, Mr. Layton. But the question is this, we've got a trend in the mid 200s up to 305 for fiscal 2021 and then in F2022 the forecast is 808 gigawatt hours for tier 2. Can you tell me what the basis for that is? That's a big jump in the most expensive part of the rate and I'm curious why.
>
> MR. LAYTON: A: Yes, this is Ryan Layton again. Mr. Keen, I don't have that level of detail at my fingertips. I agree with you it's a sizable increase but I don't have a handy explanation as to the methodology or why that's the case.
>
> MR. KEEN: Q: All right. Are you able to get back to us on that?
>
> MR. LAYTON: A: Yes, I can undertake to provide you with an explanation as to the increase in the tier 2, the stepped rate tier 2, line that we've been discussing in this schedule as between the recent years' fiscal 20, fiscal 21 and the jump to the plan of 808 in fiscal 2022. Would that meet what you're asking for?
>
> MR. KEEN: Q: Yes, thank you.
>
> MR. LAYTON: A: Okay, we'll undertake to do that.

QUESTION:

Provide an explanation as to the increase in the tier 2, the stepped rate tier 2, line that we've been discussing in this schedule as between the recent years' fiscal 2020, fiscal 2021 and the jump to the plan of 808 GWh in fiscal 2022.

RESPONSE:

The increase in the stepped rate tier 2 sales from 248 GWh in fiscal 2020 actual and 305 GWh in fiscal 2021 RRA to the fiscal 2022 Plan of 808 GWh is primarily due to an increase in the load forecast for individual customer accounts served under Rate Schedule 1823 Energy Charge Part B (RS 1823B).

As noted in section 3.2.3 of the Application, the industrial load forecast is prepared on a customer site-specific basis using information from customers,

market research, and industry experts. Consistent with previous applications, BC Hydro applies the customer's site-specific Energy Customer Baseline Load (Energy CBL), to the site-specific load forecast to derive the forecast mix of tier 1 and tier 2 energy sales and revenue. This approach is also used with aggregated accounts. As the fiscal 2022 Plan was based on the interim fiscal 2020 Energy CBLs filed with the BCUC in January 2020, which were the most recent Energy CBLs available at the time the forecast was prepared, the higher fiscal 2022 load forecast, driven by the expected economic recovery from the COVID-19 pandemic, resulted in a higher mix of tier 2 sales for several large customer accounts.

BC Hydro notes that customer Energy CBLs, site aggregations, and movement of customer accounts between RS 1823B (stepped rate energy pricing) and RS 1823 Energy Charge Part A (flat rate energy pricing) is dynamic and can impact the mix of tier 2 energy sales. Energy CBLs are subject to revision annually and at other times, including customer requests related to load increases due to increased plant capacity or restart of existing equipment in an operating plant. Furthermore, customers may take action to reduce their load consumption, which would result in less tier 2 energy sales.

BC Hydro acknowledges that in the past customers have taken action to reduce tier 2 load and may do so again. However, given there is still uncertainty with COVID-19 and that there remains uncertainty in BC Hydro's overall load forecast, BC Hydro does not consider an adjustment to the forecast is warranted. Any variance between forecast and actual load in fiscal 2022 will be deferred to the Load Variance Regulatory Account. This ensures that ratepayers only pay for actual costs.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 2

HEARING DATE: March 4, 2021

REQUESTOR: AMPC, Mr. M. Keen

TRANSCRIPT REFERENCE: Volume 1, Page 81, line 19 to Page 83, line 7

TRANSCRIPT EXCERPT:

MR. LAYTON: A: We have the table, 519.

MR. KEEN: Q: Great. And so if we look at the current service costs, and the change from the F2021 RRA column, which is the far right-hand column, and this is the bottom of page 5-103, PDF page 239 for those who follow along electronically now or later, there we see a $56 million change. Mr. Layton, can you help me understand what that relates to, and compare that to the $9 million that you referenced in response to the AMPC IR?

MR. LAYTON: A: So, Mr. Keen, if I understand correctly, you are referring to $56 million you are deriving by looking at the F21 RRA, versus the F22 planned column? So, I think I'm with you. What I was referring to just now in responding to -- or mentioning AMPC IR 1.2.2, is the difference between the F21 RRA column and the F21 forecast column. That's the $9.7 million I was mentioning. That's the actual result for Fiscal '21, and ratepayers will get the benefit of the lower amount through the regulatory account. The variance to which you are referring is between the F21 RRA and the F22 plan, and that is explained by the discount rates which you can see for each of those periods in the case of fiscal '21 RRA 3.33 percent. In the case of fiscal '22 plan, 2.59 percent. That large drop is the main difference in the large increase between those two time periods for the current service pension costs.

MR. KEEN: Q: Okay, that's helpful. And in terms of the timing of that refund through the regulatory account, can you tell us how that cycles through back into rates? When do customers see the benefit of that?

MR. LAYTON: A: Yes, bear with me a moment. Yes, subject to check, but I'm quite certain it is over this test period as a variance account.

MR. KEEN: Q: Okay, if you could confirm that for us as well, that would be helpful.

MR. LAYTON: A: Certainly.

QUESTION:

What is the timing of that refund (lower amount for the regulatory account) through the regulatory account and how that cycles through back into rates? When do customers see the benefit of the refund?

RESPONSE:

BC Hydro confirms its testimony.

Variances between forecast and actual costs related to the operating cost portion of current service costs are deferred to the PEB Current Pension Costs Regulatory Account and are recovered over the next test period. Therefore, the favourable forecast variance deferred to the PEB Current Pension Costs Regulatory Account in fiscal 2021 is being refunded to ratepayers over the fiscal 2022 test period.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 3

HEARING DATE: March 4, 2021

REQUESTOR: RCIA, Ms. L. Thompson

TRANSCRIPT REFERENCE: Volume 1, Page 107, line 7 to Page 112, line 13

TRANSCRIPT EXCERPT:

MS. THOMPSON: Q: Perfect, yes. Thank you very much. So I will move onto my next set of questions which have to do with metrics. So in the response to RCIG IR 1.12.1, which begins on pdf page 1238 of Exhibit B-5, so BC Hydro provided an attachment that includes a detailed matrix of all the historical trends for a number of different matrix. First, I just like to say thank you for providing this detailed matrix, it's very informative. And I just a couple follow-up questions on some of the data, as well as some of the trends that we're seeing in this metric. So, for one, there are a couple negative values that show up for two metrics in particular. One being the distribution growth capital expenditures divided by incremental distribution kilometres added. So the negative cost shows up in year 2019 of approximately 2.3 million. And the other metric that I'm referring to is the generation growth capital expenditures divided by incremental generation capacity added. And so this one has the negative number of approximately 1.2 million in 2016. I was just wondering if BC Hydro could please explain how these negative values came about?

MR. LAYTON: A: Ms. Thompson, we have the exhibit here in front of us. I'm wondering if you could help me, just on the far left of the attachment you'll see a number for each particular metric. I wonder if you could tell me which line items you're looking at there, please?

MS. THOMPSON: Q: So line items 16 as well as 21. And then it's the only negative cost that shows up in the historical trends for each of those metrics.

MR. LAYTON: A: Okay, great, thank you. That's helpful. So, and I can undertake to provide specific detail here, but I know that sometimes when you're looking at incremental changes, here in the case of metric 16, incremental distribution kilometres added, or in the case of line 21, incremental generation capacity, that that's considering the overall results for the corporation. And so in a given year if you actually had fewer distribution kilometres than you get the prior year, then it's going to look like a negative metric and so you can get what, I agree, is strange looking results because of those kinds of strange occurrences that may happen from time to time. And, as you point out, it's relative rare occurrence in this spreadsheet but it can happen.

MS. THOMPSON: Q: Okay, is the panel able to undertake to just confirm that that is the case?

MR. LAYTON: A: Yes, and so again I'll recite the undertaking just so that we are clear. It's in respect of line item 16 and line item 21, in particular, to confirm the reason for the negatives in the two cells in those two lines. We're happy to undertake to do that.

MS. THOMPSON: Q: Wonderful, thank you very much, I appreciate it. And so on this same table we've looked at the numbers provided and some of the results show trends that we don't really understand and we just have a couple follow-up questions. So the first metric is the distribution operating cost per distribution kilometre, which is shown in line 12. So here for this trend we're seeing quite a large increase for this metric over time and it looks like it has more than doubled over the 2012 to 2020 period. I'm just wondering if you can explain why this trend has increased so significantly over this period?

MR. LAYTON: A: So, Ms. Thompson, this is Ryan Layton speaking again. I don't think we have that level of detail around the table. We are happy to provide this for you, but we haven't gone through and looked at each number and each trend and why those are occurring. I'm happy to undertake to provide you with an explanation as to the trend in row 12, if that would be helpful?

MS. THOMPSON: Q: Yes, that would be very helpful, thank you. And if -- so I had a couple of additional questions on different metrics and I'm assuming that it would be probably hard to answer right away. So if we can maybe, I'll just -- I think there are three other metrics that I had questions on. So one of them being the – sorry, just bear with me one second – the distribution net capital base rate per customer, which is in line 15. So there we're seeing an odd trend as well, so we're just wondering if you can explain, sort of, what was happening for this metric.

MR. LAYTON: A: Line 15?

MS. THOMPSON: Q: Correct.

MR. LAYTON: A: And can you identify which years you're looking at in terms of the trend?

MS. THOMPSON: Q: Just the overall trend. So we see, sort of, an increase happening between 2012 to 2014 and then there's a decrease again between 2015 to 2017 and then another increase to 2022. So we're -- just, kind of, it's pattern that we don't really understand, so we were just wondering if BC Hydro can explain the reason for this pattern.

MR. LAYTON: A: Okay, so we can undertake to do that. Again, just for clarity for the record, that's line 15, we will discuss the trends across the time horizon provided here.

MS. THOMPSON: Q: Wonderful, that's very helpful, thank you. And then the one other one is generation growth capital expenditures divided by incremental generation capacity added. And this one is -- so it's again line 21, but rather than the negative number, it's the last number that we're seeing in 2019. There's a very large jump to 212 million. And so we're just wondering if you can explain whether that's, you know, driven by Site C or if there's another reason for that large increase.

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MR. LAYTON: A: Okay, we will undertake to provide you in respect of line 21 an explanation as to the last number provided, the $212 million.

MS. THOMPSON: Q: Okay, thank you very much. And then the last one is on line 223, which is FTEs per megawatt hour delivered. So for this one it just -- we asked the wrong question, we should have asked per gigawatt hours delivered, because (audio drops) for us to see any trends, so I was just wondering if you could also undertake to provide a revised data set of FTEs per gigawatt hours delivered.

MR. LAYTON: A: Certainly. So, again for the record, line 23 we will provide an additional set of figures which will be FTEs per gigawatt hour delivered. I'm happy to do that.

MS. THOMPSON: Q: Okay, perfect.

QUESTION:

Regarding Attachment 1 in BC Hydro's response to RCIG IR 1.12.1, provide the following information requested:

3.1 For line 16 and line 21, confirm the reason for the negatives in the two cells in those two lines;

3.2 Provide an explanation as to the increasing trend in line 12 during the 2012 to 2020 period;

3.3 For line 15, discuss the trends (decrease between 2015 to 2017 and then another increase to 2022) across the time horizon;

3.4 For line 21, provide an explanation as to the last number provided, the $212 million; and

3.5 For line 23, provide an additional set of figures which will be FTEs per gigawatt hour delivered.

RESPONSE:

Item 3.1

The negative result in line 16 in fiscal 2019 is because there was a decrease in the number of kilometers of distribution lines in that year. This can occur in a given year as a result of system improvements (e.g., reconfigurations or upgrades) or end of life assets (e.g., lines that are decommissioned).

The negative result in line 21 in fiscal 2016 is because there was a net reduction in capacity resulting from the termination of generation at the Burrard Thermal generating facility.

Item 3.2

The increasing trend in line 12 over the period is primarily due to an increasing allocation of business support costs to distribution related to the following:

- **IFRS ineligible capital overhead costs, which are being absorbed into operating costs over a 10-year period starting in fiscal 2013 in accordance with BCUC Order No. G-77-12A; and**
- **The recovery of amounts in various regulatory accounts related to prior periods that are being recovered in the current period in accordance with the approved recovery mechanisms for the accounts (e.g., Non-Current Pension Costs Regulatory Account, SMI Regulatory Account, IFRS Property Plant and Equipment Regulatory Account, IFRS Pension Regulatory Account).**

Item 3.3

The trend in line 15 has been relatively stable over the period. Changes from year to year are primarily related to changes in the distribution mid-year rate base as a result of changes in net distribution assets in service.

Item 3.4

The high result in fiscal 2019 is primarily as a result of BC Hydro's purchase of the remaining two-thirds interest in the Waneta generating station (BC Hydro previously owned one third) and the ramp-up of capital expenditures on the Site C project.

Item 3.5

Please refer to the Attachment 1 to this undertaking, which provides the calculation of this metric per GWh (instead of MWh) delivered.

Undertaking No.	Line Item Ref No.	RCIG IR No.	Metric	Data Inputs	Source	Actual F2012	Actual F2013	Actual F2014	Actual F2015	Actual F2016	Actual F2017	Actual F2018	Actual F2019	Actual F2020	RRA F2021 [1]	RRA F2022
3.5	23	1.29.2.2	FTEs per ~~MWh~~ GWh delivered	- FTEs (Schedule 16.0, ln 53). - MWh delivered equals Domestic Sales volume. - (1 GWh = 1,000 MWh)	- Appendix A - Schedule 16.0, ln 53. - Appendix A - Schedule 14, ln 11.	0.1241	0.1217	0.1212	0.1233	0.1222	0.1217	0.1269	0.1366	0.1419	0.1438	0.1430

NOTE:

[1] "RRA F2021" aligns with the information in F2021 RRA columns in the Application and reflects BC Hydro's Compliance Filing and the BCUC Decision on the Previous Application.

BC HYDRO UNDERTAKING NO. 4

HEARING DATE: March 4, 2021

REQUESTOR: RCIA, Ms. L. Thompson

TRANSCRIPT REFERENCE: Volume 1, Page 106, line 13 to Page 107, line 7

TRANSCRIPT EXCERPT:

> MS. THOMPSON: Q: …So now if we go back to the corporate risk matrix that was provided in RCIG 1.31.1, on the righthand side a little bit further down, it explains how to use the risk matrix and under point 5 it is stated that based on the risk zone, BC Hydro is to review the risk communication guidelines to determine action. So I'm just wondering if BC Hydro could please direct me to where I could find the risk communication guidelines that are referenced in this matrix?
>
> MR. LAYTON: A: This is Ryan Layton speaking. I don't believe it's on the record in the proceeding. We will take a look and see if we can provide that for you.
>
> MS. THOMPSON: Q: Perfect. Yeah, if you could undertake to provide that, that would be great. I really appreciate that.
>
> MR. LAYTON: A: Just so we're clear, we'll undertake to provide the risk communication guidelines referred to in point 5 on RCIG IR 1.31.1, attachment 1.
>
> MS. THOMPSON: Q: Perfect, yes.

QUESTION:

Provide the risk communication guidelines referred to in point 5 of Attachment 1 in BC Hydro's response to RCIG IR 1.31.1.

RESPONSE:

The "Risk Communication Guidelines" refers to the table in the top right-hand section of the risk matrix document and provides guidelines for each risk zone. In other words, it does not refer to a separate document. For ease of reference, BC Hydro has placed a red border around this table in the modified version of Attachment 1 to BC Hydro's response to RCIG IR 1.31.1 which is provided as Attachment 1 to this response.

BC Hydro Corporate Risk Matrix

FREQUENCY (YEARLY)	FREQUENCY OF CONSEQUENCE								
f ≥ 100	At least 100 times every year	L9	10	11	12	13	14	15	16
10 ≤ f < 100	At least 10 times every year	L8	9	10	11	12	13	14	15
1 ≤ f < 10	At least once every year	L7	8	9	10	11	12	13	14
1/10 ≤ f < 1	At least once every 10 years	L6	7	8	9	10	11	12	13
1/100 ≤ f < 1/10	At least once every 100 years	L5	6	7	8	9	10	11	12
1/1,000 ≤ f < 1/100	At least once every 1,000 years	L4	5	6	7	8	9	10	11
1/10K ≤ f < 1/1,000	At least once every 10,000 years	L3	4	5	6	7	8	9	10
1/100K ≤ f < 1/10K	At least once every 100,000 years	L2	3	4	5	6	7	8	9
1/1M ≤ f < 1/100K	At least once every 1,000,000 years	L1	2	3	4	5	6	7	8

CONSEQUENCE TYPE		CONSEQUENCE SEVERITY						
		S1	S2	S3	S4	S5	S6	S7
Safety	Worker	First Aid	Treatment by Medical Professional	Temporary Disability	Permanent Disability	Fatality	Multiple Fatalities	
	Public	Near Miss	First Aid	Treatment by Medical Professional	Temporary Disability	Permanent Disability	Fatality	Multiple Fatalities
Environmental *		Minor	Low	Moderate	High	Extreme	Catastrophic	
Financial Loss		$10K to $100K	$100K to $1M	$1M to $10M	$10M to $100M	$100M to $1B	$1B to $10B	> $10B
Reputational *		Limited complaints to company or shareholder	Negative local profile	Small but vocal minority of customers critical	Many customers critical	Loss of trust- strategic change imposed by regulator and/or shareholder	Loss of consent to operate	
Reliability	Supply	N/A	N/A	Require voluntary load reduction	Localized load shedding	Significant load shedding required	BC load shedding spreads to WECC	
	Customer (hours lost per event)	< 5K	5K to 50K	50K to 500K	500K to 5M	5M to 50M	50M to 500M	> 500M

*Additional criteria available to determine Consequence Severity on the back page

Corporate June 2014

Risk Zone	Risk Communication Guidelines
3) Executive	Detailed analysis and discussion within business group at EVP or SVP level. Input from Executive Team generally should be sought.
2) Senior Managers	Analysis and discussion within business unit, with decision making at Senior Manager level. Consider seeking input from EVP or SVP.
1) Managers	Risk generally analysed and discussed within business group, with decision making at Manager level.

Purpose of the Risk Matrix

1. To provide a standard representation of the results of risk analyses for use in the evaluation and communication of risks.

2. As a risk governance tool. The Risk Zone relates to the level of management discussion to aid in decision-making.

3. Not used to describe risk tolerance.

4. A comparison of differing risks may also be conducted based on the Risk Levels.

To use the Risk Matrix

1. Select the Consequence Type.

2. Select the highest appropriate Consequence Severity.

3. Select the Frequency level of the Consequence Type and Severity.

4. Plot the Consequence severity and Frequency level pair to determine the Risk Level and associated Risk Zone.

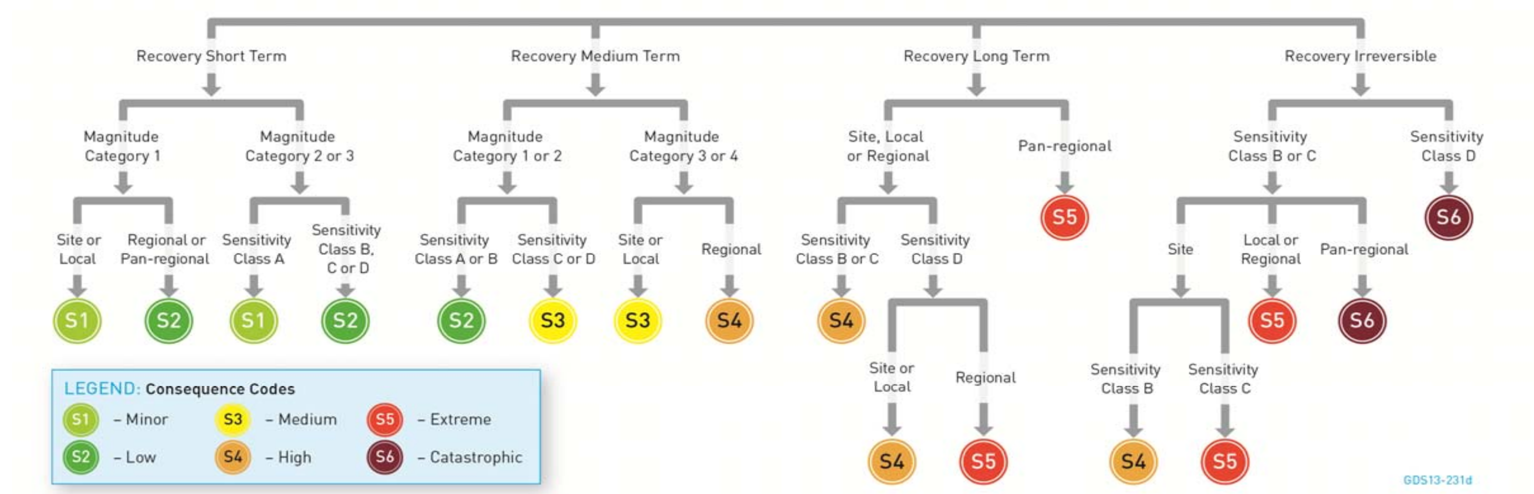
5. Based on the Risk Zone, review Risk Communication Guidelines to determine action.

NOTE: The rigour of analysis in analyzing consequence and frequency should be commensurate with the Risk Zone. This may be an iterative process.

Detailed descriptors (Dimensions) for Reputational Consequence are included below to assist in determining consequence severity. To identify the severity, first review and select the Reputational consequence for each dimension, and then select the highest severity dimension.

CONSEQUENCE TYPE	DIMENSION	CONSEQUENCE SEVERITY					
		S1	S2	S3	S4	S5	S6
Reputational	**Public response**	Complaints to company shareholders, regulator	Small minority of public critical	Small but vocal minority of customers critical	Many customers critical	Majority of customers critical	Customers nearly unanimous in public criticism
	Media/Opinion Leaders' Response	No coverage	Brief negative or mixed local media coverage	Possible isolated "one-off" major media coverage	Some negative media coverage at provincial level.	Widespread and sustained negative media coverage.	Opinion leaders nearly unanimous in public criticism. Sustained very negative media coverage. National media coverage.
	Response of Public Officials	None	Issue brought to attention of public officials	Questions raised by MLAs and/or municipal officials	Conduct questioned in legislature	BC Hydro subject of sustained criticism of government in legislature	Public inquiry/criminal investigation
	Impact	None	Short-term delays to projects or minor modifications to work plan(s)	Medium-term delays in project or major modifications to plan. Significant dedication of resources to move forward	Cancellation of a major project or program, regulatory authority or shareholder imposed operating changes	Strategic change imposed by regulator or shareholder	Loss of shareholder support leading to massive organizational change.

Environmental consequence severities are determined by a combination of rankings for event sensitivity (the importance of the effected habitat/species), magnitude (the degree of impact on the habitat/species), spatial extent and recovery duration. To identify the severity, select the ranking for each of these criteria and follow the appropriate pathway in the Consequence Severity Decision Tree (below). Directions on selecting criteria rankings are provided at Environmental Consequence Severity Scale – Application Guide.



NOTE: The Reputational descriptors have been consistent since the June 2009 Corporate Risk Matrix. The Environmental scale was updated in May 2014.

Dated: June, 2014

BC HYDRO UNDERTAKING NO. 5

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 120, line 23 to Page 121, line 25

TRANSCRIPT EXCERPT:

> MS. WORTH: Q: Okay, because specifically what we are looking for is in each of those, and you know, obviously we're not going to be looking for specifics, because there are commercial concerns, but just sort of, you know, in the, lets say, in a specific line item, in table 4-6, what relates to any contract that was entered into under B.C. Utilities Commission supervision or oversight, and what figures relate to those that were not. So, it would just be sort of an exempt and non-exempt breakdown for each of those.
>
> MR. WONG: A: Yeah, so we'll get that information on breaking out 4-6 into the exempt and non-exempt.
>
> MS. WORTH: Q: Great, thank you. And I just wanted to confirm that those costs are included in the exempt category of the table that was provided in response to BCOAPO 1.21.3 in Exhibit 5. There's the fiscal 2021 exempt cost and then the forecast and then the plan. So there's all of those commitments, those costs are included there, correct? So any of the ones that are listed in 4-6, those are reflected in the actual BCOAPO 1.21.3, correct?
>
> MR. WONG: A: We're going to have to get the IRs.
>
> MS. WORTH: Q: Okay.
>
> MR. WONG: A: Sorry, just a second. Yeah, the two tables, both 4-6 and the response to the IR tie to each other.
>
> MS. WORTH: Q: Okay, great, thank you.

QUESTION:

Provide a break down of IPP costs for each line item in Table 4-6 from the Application into Exempt (from BCUC oversight) and Non-Exempt (overseen by BCUC) to correspond with the table provided BC Hydro’s response to BCOAPO IR 1.21.3.

RESPONSE:

In BC Hydro's response to BCOAPO IR 1.21.3, we provided the following breakdown for IPPs and Long-Term Commitments:

		F2021 RRA	F2021 Forecast	F2022 Plan	F2021 RRA	F2021 Forecast	F2022 Plan
		GWh			$M		
IPPs and Long-Term Commitments	Exempt	9,206	8,025	8,975	$ 1,018	$ 936	1,012
	Non-exempt	6,032	6,442	7,005	514	557	589
	Total	**15,238**	**14,467**	**15,980**	**1,533**	**1,493**	**1,601**

While reviewing the data for the purpose of responding to this undertaking we found that for fiscal 2021 there were two EPAs which were categorized as "Non-exempt" which should have categorized as "Exempt". A corrected table is provided below:

		F2021 RRA	F2021 Forecast	F2022 Plan	F2021 RRA	F2021 Forecast	F2022 Plan
		GWh			$M		
IPPs and Long-Term Commitments	Exempt	9,237	8,025	8,975	$ 1,022	$ 936	1,012
	Non-exempt	6,000	6,441	7,005	511	557	589
	Total	**15,238**	**14,467**	**15,980**	**1,533**	**1,493**	**1,601**

As requested, the table below provides a breakdown of the forecast costs for each of fiscal 2021 RRA, fiscal 2021 Forecast, and fiscal 2022 Plan for each line item in Table 4-6 of the Application further broken down into the "Exempt" and "Non-exempt" categories. Please note that for the "F2021 RRA" column this data reflects the forecast used for BC Hydro's F2020/F2021 Evidentiary Update which relied on BC Hydro's June 2019 forecast data; whereas the "F2021 Forecast" and "F2022 Plan" columns are based on the forecast costs and actual costs used for this application which relies on August 2020 information.

As explained on Page 4-12 of the Application, the volume associated with an EPA renewal is generally included in the total for the procurement call process in which the IPP project was originally provided an EPA by BC Hydro. For example, if a pre-2003 EPA is renewed, for the purpose of Table 4-6 of the Application, the renewal EPA remains in the pre-2003 EPA category even though the renewal EPA is a Negotiated Electricity Purchase Agreement. This approach was taken for Table 4-6 for ease of comparison to the Previous Application and although it may not necessarily reflect the existing breakdown by call process, it does accurately reflect the Exempt/Non-exempt categorization for each project (or potential project) based on August 2020 forecast information.

BC Hydro Fiscal 2022 Revenue Requirements Application

Call Process ($Million)	No. of EPAs[1]	F2021 RRA	F2021 Forecast	F2022 Plan
Exempt		172	177	178
Non-exempt		109	100	106
Pre-2003 Electricity Purchase Agreements[2]	**29**	**281**	**278**	**284**
Exempt		11	11	11
Non-exempt		24	24	24
2003 Green Power Generation Call	**6**	**35**	**35**	**35**
Exempt		18	18	18
Non-exempt		179	177	178
2006 Open Call	**17**	**197**	**195**	**195**
Exempt		-	-	-
Non-exempt		20	19	18
2008 Bioenergy Call - Phase 1	**2**	**20**	**19**	**18**
Exempt		55	49	61
Non-exempt		-	-	-
2008/10 Standing Offer Program[3]	**27**	**55**	**49**	**61**
Exempt		78	75	88
Non-exempt		-	-	-
2010 Bioenergy Call - Phase 2	**4**	**78**	**75**	**88**
Exempt		351	320	349
Non-exempt		-	-	-
2010 Clean Power Call	**20**	**351**	**320**	**349**
Exempt		146	112	113
Non-exempt		-	30	19
2010 Integrated Power Offer	**7**	**146**	**142**	**132**
Exempt		189	174	194
Non-exempt		177	206	245
Negotiated Electricity Purchase Agreements[4]	**15**	**366**	**381**	**439**
Exempt		1.8	-	-
Non-exempt		2	-	-
Expected Standing Offer Program Projects and other First Nations Commitments[5]	**4**	**4**	-	-
Exempt		1,022	936	1,012
Non-exempt		511	557	589
Total	**131**	**1,533**	**1,493**	**1,601**

1. **Number of EPAs with IPPs on the integrated system as of August 1, 2020. The numbers in this row may not align with the number of EPAs which were associated with fiscal 2021 values because some EPAs expired/terminated, and some EPAs became operational since the filing of the Previous Application.**
2. **The costs in this row (Pre-2003 EPAs) also include miscellaneous energy purchases, such as energy purchases for border accommodations. The number of EPAs on this row has decreased from 31 EPAs in the Previous Application to 29 EPAs due to two EPAs which have been terminated.**
3. **The number of EPAs in this row (2008/10 Standing Offer Program) has increased by one since the Previous Application; two EPAs which have executed and one EPA that was terminated.**
4. **The costs in this row (Negotiated EPAs) also include two other energy supply contracts which are not considered to be IPP EPAs. These are the Surplus Power Rights Agreement between Teck and BC Hydro and the Residual Capacity Agreement between FortisBC Inc. and BC Hydro. The number of EPAs in this row has increased due to an EPA which was executed related to a First Nations Commitment.**
5. **The costs shown are expected costs for future EPAs. Once an EPA is executed, the costs are included in the appropriate call process.**

As provided in BC Hydro's response to BCOAPO IR 1.21.3, BC Hydro notes the following with respect to the information provided in the table above:

- **The IPPs and Long-Term Commitments category generally includes the costs of EPAs that BC Hydro has entered into with IPPs for supply to the integrated system and these forecast costs are included in Appendix A, Schedule 4.0, lines 5 and 33 of the Application;**

- **As noted in Notes 2 and 4 of Table 4-6, in Chapter 4 of the Application, and as noted above, there are miscellaneous energy purchases and two other energy supply contracts which are not considered to be IPP EPAs but are included as part of IPP Long Term Commitments. These additional agreements are generally not exempt energy supply contracts (and some are rates as approved by the BCUC), but for simplicity BC Hydro has included these agreements as "Non-Exempt"; and**

- **BC Hydro has included Biomass Energy Program energy supply contracts as "Non-Exempt" as part of IPP Long-Term Commitments because these agreements are filed with the BCUC under section 71 of the *Utilities Commission Act*, as discussed in BC Hydro's response to BCOAPO IR 1.20.1.**

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 6

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 128, line 2 to Page 129, line 6

TRANSCRIPT EXCERPT:

MS. WORTH: Q: Okay, thank you. So I'm going to be moving on here. There was a table provided in BC Hydro's response to BCUC IR 1.1.4 and that's in Exhibit B-4. And that sets out the history of capital expenditures for EV stations. So it starts at Fiscal 2013, goes to Fiscal 2020 in actuals, and then here's a forecast for Fiscal 2021 and 2022. So my question is can you provide on the record or refer us to where in your evidence the Fiscal 2022 opening and closing net book values associated with the EV stations that are prescribed undertakings as defined in the GGRR?

MR. LAYTON: A: So, Ms. Worth, this is Ryan Layton speaking again. I'm just reading that response, I have it in front of me, and you can see that there's a line item to remove the non-prescribed undertakings and so you can see the net capital expenditures in the row below that. But those are capital expenditures. I think your question is about net book values?

MS. WORTH: Q: Yes, it is.

MR. LAYTON: A: Yeah. Okay, so I understand your question. Those are not provided here in this table.

MS. WORTH: Q: Would BC Hydro be prepared to provide that, either in an expansion of this particular table or in a separate table as an undertaking today?

MR. LAYTON: A: Yes, I think we can do that. So just so we're clear, we will undertake in respect of BCUC IR 1.1.4 to add information regarding the net book value related to these capital expenditures. Is that -- would that provide what you're looking for?

MS. WORTH: Q: Yes, please. Thank you.

QUESTION:

In respect of BC Hydro’s response to BCUC IR 1.1.4, provide information regarding the Fiscal 2022 opening and closing net book values associated with the capital expenditures for EV stations that are prescribed undertakings as defined in the GGRR.

RESPONSE:

The table provided below shows the forecast fiscal 2022 opening and closing net book values (NBVs) of electric vehicle charging stations that are prescribed undertakings as defined in the GGRR.

($ million)	Fiscal 2022 Opening	Fiscal 2022 Closing
Capital Assets in-service (net of contributions, less non-prescribed undertakings)	5.0	5.4
Accumulated Amortization	(0.7)	(1.2)
Net Book Value of Capital Assets in-service	**4.3**	**4.2**
Capital Expenditures (Work in Progress)	5.5	5.0
Total including Capital Expenditures	**9.8**	**9.2**

As shown in the table above, the NBV of electric vehicle charging infrastructure in fiscal 2022 is an opening balance is $4.3 million and a closing balance is $4.2 million.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 7

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 129, line 8 to Page 130, line 4

TRANSCRIPT EXCERPT:

> MS. WORTH: Q: Now, I'm continuing to refer to the BCUC IR series, but I'm going to be now BCUC IR 1.1.3. So it's the same exhibit, Exhibit B-4. And BC Hydro's response to that provided a table that listed the operating and maintenance costs, labour, contract services, and then the total operating and maintenance costs, including depreciation cost of energy for electric vehicle infrastructure costs. And I'm wondering why in response to this IR there are no financing or interest costs associated with the EV station, and if BC Hydro has information about what that figure would be?
>
> MR. LAYTON: A: Yeah, so I think it goes back to what we were discussing before where we don't allocate our finance charges to this level of granularity. If you'd like us to make a calculation in that regard, I think we could do that.
>
> MS. WORTH: Q: Yes, please.
>
> MR. LAYTON: A: So we'll undertake in respect of BCUC IR 1.1.3 to estimate a finance charge component associated with these costs.
>
> MS. WORTH: Q: Great.

QUESTION:

Regarding BC Hydro’s response to BCUC IR 1.1.3, why in response to this IR are there are no financing or interest costs associated with the EV stations. Provide the calculation of the financing or interest costs associated with the EV stations.

RESPONSE:

BC Hydro did not remove finance charges associated with electric vehicle charging infrastructure from its revenue requirements for the fiscal 2020 and fiscal 2021 test period because Directives 27 and 28 of the BCUC’s Decision on the Previous Application did not direct that associated finance charges be removed. BC Hydro complied with Directives 27 and 28 which directed BC Hydro to remove associated operating costs and cost of energy from its revenue requirements and associated capital expenditures from its rate base, for fiscal 2020 and fiscal 2021.

BC Hydro manages its debt on a portfolio basis and does not attribute specific debt or finance charges to specific items such as electric vehicle charging infrastructure.

Notwithstanding the above, BC Hydro has calculated an estimate of the finance charges for the electric vehicle charging infrastructure using BC Hydro's Weighted Average Cost of Debt (WACD) as shown in the table below:

	($ million)	Appendix A Reference	Fiscal 2022 Opening	Fiscal 2022 Closing	Fiscal 2022 Mid-year
1	Capital Assets in-service (net of contributions, less non-prescribed undertakings)		5.0	5.4	5.2
2	Accumulated Amortization		(0.7)	(1.2)	(1.0)
3	**Net Book Value of Capital Assets in-service**		**4.3**	**4.2**	**4.2**
4	Capital Expenditures (Work in Progress)		5.5	5.0	5.2
5	**Total including Capital Expenditures**		**9.8**	**9.2**	**9.5**
6	**Weighted Average Cost of Debt**	8.0, L52			3.09%
7	**Estimated Finance Charges**				**0.3**

As shown in the table above, BC Hydro estimates that fiscal 2022 finance charges in respect of electric vehicle charging infrastructure are $0.3 million.

BC HYDRO UNDERTAKING NO. 8

HEARING DATE: March 4, 2021

REQUESTOR: CEC, Mr. C. Weafer

TRANSCRIPT REFERENCE: Volume 1, Page 171, line 24 to Page 172, line 20

TRANSCRIPT EXCERPT:

> MR. C. WEAFER: Q: No, I'm looking to what would have been -- if you had actually operated without the hedge, what would your cost of borrowing be for that 75 percent of anticipated borrowing.
>
> MR. WONG: A: Yeah, so we can provide that information to you, but I think that we do show in some of the schedules that a realized loss has incurred and I think it's around $300 million. I'm looking out to about December, $300 million. And so that would be the differential between the actual rate and the rate that we locked in at.
>
> MR. C. WEAFER: Q: So that -- sorry, that is on the record? Then I apologize if I missed that. The difference between what rates you would have paid versus what you paid on the hedge --
>
> MR. WONG: A: That's correct. That's about, around $300 million. I don't know if it's specifically on the record, but we can -- I can undertake to specifically give you the exact number as of September 30th.
>
> MR. C. WEAFER: Q: Thank you.

QUESTION:

Provide the actual realized loss (cost of borrowing) that has occurred from operating without a hedge versus with a hedge as of September 30, 2020.

RESPONSE:

Please refer to Attachment 1 to BC Hydro's response to BCUC IR 1.62.6. For hedged debt that has been issued, the column marked "Settlement Value" shows the gains or losses on a hedge at the time it is unwound. These benefits (i.e., gains) or costs (i.e., losses) represent the realized gains or losses on a hedge, and therefore the incremental benefit or cost as compared to the cost had hedging not been undertaken. As shown at the bottom of the table, the total net costs of the settled hedges were $298.2 million as of September 30, 2020.

Hedging benefits or costs related to hedges for future debt that has not yet been issued will not be known until that debt is issued and the hedge is settled.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 9

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 179, line 17 to 18 and Page 180, line 26 to Page 182, line 15

TRANSCRIPT EXCERPT:

MS. WORTH: Q:… table that BC Hydro provided in response to our IR, BCOAPO IR 1.13.2 in Exhibit B-5…

MS. WORTH: Q: Well, I didn’t do it for all of them, but I noticed that when I did the percentage of deltas for the rate impacts gigawatt hours, my figure varied slightly from yours. So I was just wondering if there were any other instances in there when I'm going through it, where it does vary that it would be solely do to kind of rounding in the figures that had been presented in the first three rows where you've given figures for the forecasts? If I could have a confirmation of that, that would be great. I don’t anticipate there will be any significant differences, but I just want to make sure that if there is a difference, it is solely due to that.

MR. RICH: A: Sorry, I'm not sure what your question is. Just to confirm that any differences with what you have are due to rounding?

MS. WORTH: Q: Yes.

MR. RICH: A: Could you send me yours so I have something to compare to?

MS. WORTH: Q: Okay, I'll give you a quick -- so the percentage of deltas is basically you take the first value, [and subtract] the second value. Then you take the answer, divide that by the first value and multiply it by a hundred and that gives you a percentage expression of the difference between the two numbers. Thank you, Google. So what I did is I did that calculation for the rate impact column and I actually came up with a round number, I think it was 300 percent instead of

301.4. As I said, I didn't have the time and patience at that point to go through all of the figures to ensure that any minor deviations -- or any deviations might be minor, but in that particular case and any other case where it may come up, I want to just confirm that that's due to rounding of the figures used in order to make that calculation. I apologize for the lines.

MR. RICH: A: Yeah, no problem, Ms. Worth. So I've written that particular number down and I'll take it back and do that confirmation.

BC Hydro Fiscal 2022 Revenue Requirements Application

QUESTION:

Regarding the table in BC Hydro's response to BCOAPO IR 1.13.2 in Exhibit B-5, please confirm the delta calculations for the rate impact column is 300 per cent and if any differences are due to rounding.

RESPONSE:

BC Hydro confirms that the difference between the 300 percent calculated by Ms. Worth and the 301.4 per cent in BC Hydro's response to BCOAPO IR 1.13.2 is due to rounding. The excel spreadsheet used to develop the table for BC Hydro's response to BCAOPO IR 1.13.2 includes additional decimal points, which were not shown in the table.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 10

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 182, line 17 to Page 183, line 22

TRANSCRIPT EXCERPT:

> MS. WORTH: Q: All right, thank you. Now, I have a further question about this table, probably a little more substantive. So the response to BCOAPO IR 1.13.2 in Exhibit B-5 states: "Since developing the October 2018 load forecast, BC Hydro's further analysis of the codes and standards overlap adjustment indicated that the estimated codes and standards overlap was greater than what was used in the October 28 [sic] loads forecast. We incorporated this updated information into this subsequent March 2020 load forecast which is the basis for developing the COVID-19 scenario A." But when I'm looking at this table, the adjustment for codes and standards impact in fiscal 2022 looks lower than the current forecast than it was in the October 2018 load forecast, and I'm wondering can you either show me why my read of that is wrong or explain why that is the case?
>
> MR. RICH: A: I'd have to take that to confirm, but I suspect because it's relative to a smaller incremental DSM assuming for that year relative to the October 2018 forecast.
>
> MS. WORTH: Q: Okay, would you be able to provide a full answer to that in an undertaking?
>
> MR. RICH: A: Sure. So you're asking to confirm why the estimated codes and standards overlap appears to be lower notwithstanding our methodologies suggest that there was a greater overlap between the two forecast vintages.
>
> MS. WORTH: Q: Yes.

QUESTION:

Regarding BC Hydro's response to BCOAPO IR 1.13.2 in Exhibit B-5, please confirm why the estimated codes and standards overlap appears to be lower notwithstanding our methodologies suggest that there was a greater overlap between the two forecast vintages.

RESPONSE:

The codes and standards overlap calculation is sensitive to the start year of the forecast. The start year of the October 2018 Load Forecast was fiscal 2019, which

makes fiscal 2022 the fourth year of the forecast. The start year of the March 2020 Load Forecast was fiscal 2020, which makes fiscal 2022 the third year of the forecast. Since the overlap adjustment increases year over year, it is not appropriate to compare year 4 of a forecast to year 3. The fiscal 2022 codes and standards overlap used in the October 2018 Load Forecast must be adjusted by the base year (i.e., fiscal 2019) to account for the base year's savings persistence in the future years. As shown in the table below, with this adjustment, the March 2020 Load Forecast methodology results in a higher codes and standards overlap for fiscal 2022.

Fiscal Year	October 2018 Residential Codes and Standards Overlap (GWh)	March 2020 Residential Codes and Standards Overlap (GWh)
F2019	33	
F2020	81	50
F2021	114	87
F2022	149	127
F2020 Adj	48	50
F2021 Adj	81	87
F2022 Adj	116	127

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 11

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 185, line 13 to Page 187, line 12

TRANSCRIPT EXCERPT:

MS. WORTH: …would BC Hydro be willing to re-estimate the light industrial load for fiscal 2021 and 2022 based on the Ministry of Finance's December 2020 fall update?

MS. DASCHUK: A: Hi, this is Maureen Daschuk speaking. We believe that the current scenario A is a reasonable forecast on which to base a one-year revenue requirement application. There are a number of factors that go into creating a load forecast and this particular scenario A has been tracking very well. And in fact over the ten months we are within one percent and slightly better. Also, any differences between the load forecast that we have and the actual revenue would be caught in deferral accounts. We're also in a period of very high uncertainty and so for us to try and predict the various levels of uncertainty, it's going to have very limited to no value for -- we believe. Also, just as a reminder, we're filing our next revenue requirements application in the summer, likely in August. That revenue requirements application is going to be based off a new load forecast that we've just recently taken to our board of directors. And we found that there's very little difference between our forecasts. So, you know, I think that it's not something that we would consider would have any type of an impact on this revenue requirements application.

MS. WORTH: Q: Would you then be willing to file in an undertaking a document that shows the tracking that you're talking -- that you've referenced, that within the last, I think, ten months you said it's tracking within one percent? Would you be willing to file that on the record in this revenue requirement?

MS. DASCHUK: A: Yes, we can file that.

MS. WORTH: Q: Thank you.

MR. RICH: A: It's John. I think it's actually on the record for the --

MS. WORTH: Q: Is it? My apologies if it is.

MR. RICH: A: Yeah, for ten months. I would have to find the reference but I think it's there.

MR. WONG: A: I think, John, we have something in the application out to a period, it may be about September, but we can provide all the way out to January.

MR. RICH: A: I think we do have an IR response that goes right up to ten months but --

MS. DASCHUK: A: Irrespective, we'll commit to providing it. Either it's already there and we'll make reference to it or we'll provide it.

MS. WORTH: Q: Thank you very much,

QUESTION:

Provide the reference where BC Hydro shows that actuals are tracking within 1 per cent of COVID-19 Scenario A.

RESPONSE:

BC Hydro provided 10 months of year-to-date actuals (i.e., April 1, 2020 to January 31, 2021) in response to two information requests.

In BC Hydro's response to BCOAPO IR 1.12.3, we show that, on a temperature-normalized basis, year-to-date actuals for the first 10 months of fiscal 2021 are 1.1 per cent greater than COVID-19 Scenario A for the combined major customer sectors.

In BC Hydro's response to ZONE II RPG IR 1.3.1, we show that, on a non-temperature normalized basis, year-to-date actuals for the first 10 months of fiscal 2021 are 0.7 per cent greater than COVID-19 Scenario A for the combined major customer sectors.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 12

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 192, line 19 to Page 194, line 4

TRANSCRIPT EXCERPT:

MS. WORTH: Q Okay, all right. So basically what I'm wondering is, because I believe that Mr. O'Riley was saying that there could've been other factors that could explain the difference between the Fiscal 2020 forecast which is solely attributable to Fort Nelson, and what was the experience in Fiscal 2019 and Fiscal 2020. And the reason why -- and what I'm asking BC Hydro to do is to explain because there hasn’t been -- or at least not to my knowledge, the circumstances that led to -- you know, they had planned forced outages and capacity deratings that were referred to in BC Hydro's response to our IR 1.23.2. So I was asking BC Hydro to explain any differences between the experience in Fiscal 2019 and Fiscal 2020 and what we're looking at as the Fiscal 2022, whether that is, you know, Fort Nelson being derated during those years or an increase, solely an increase in generation, or something else.

MR. WONG: A: Okay.

MS. WORTH: Q So if you could provide whatever clarification that is in an undertaking, that would be helpful.

MR. WONG: A: Sure. And your question is about there's Heritage generation which just applies to Prince Rupert and Fort Nelson, and there's our thermal generation which applies to Island generation at McMahon in addition to the other two. So I think we'll go look at that and I think we can answer your question.

MS. WORTH: Q Yeah, it's solely to do with the cost of Heritage energy, because that what was refenced in Table 4-2.

MR. WONG: A: Okay, okay, so just -- okay.

MR. O'RILEY: A: Just Fort Nelson.

MR. WONG: A: It should be just Fort Nelson, so we can explain that.

MS. WORTH: Q Okay. Okay, great, thank you.

BC Hydro Fiscal 2022 Revenue Requirements Application

QUESTION:

Explain any differences between the experience in fiscal 2019 and fiscal 2020 and what we're looking at as the fiscal 2022, whether that is from Fort Nelson being derated during those years or an increase, solely an increase in generation, or something else.

RESPONSE:

BC Hydro notes that the BCOAPO IR referenced in the transcript excerpt of this Undertaking should be to 1.23.1 instead of 1.23.2.

The variation in heritage thermal energy between fiscal 2019 to fiscal 2022 is due to changes in generation at the Fort Nelson generating station (FNG):

- **FNG consists of two units: a primary open cycle gas turbine and a secondary steam turbine that only operates when the primary unit is running;**
- **In fiscal 2019 both units were out of service for 47 days and the secondary unit was out of service for an additional 33 days;**
- **In fiscal 2020, both units were out of service for approximately 42 days and the secondary unit was out of service for an additional 323 days;**
- **In fiscal 2021 both units are forecast to be out of service for 15 days and the secondary unit is forecast to be out of service for an additional 25 days. In addition, the secondary unit is forecast to operate at reduced capacity for most of fiscal 2021, which further reduces the total amount of generation from the plant; and**
- **The fiscal 2022 forecast does not include any forecasts for outages. As a result, FNG is forecast to run more than in the previous three years.**

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 13

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 200, line 20 to Page 203, line 1

TRANSCRIPT EXCERPT:

MS. WORTH: Q: Okay, all right, thank you. I'll move on from that. I've got a question about trade income. The response to BCOAPO IR 1.62.1, in Exhibit B-5 explains that the $55.7 million difference between the 6.7 million recorded as an addition to the trade income variance account in Appendix A, and that's schedule 2.1, line 17, and the 13 million referenced in the current application is due to the impact of Directive 53 of the BCUC's decision on the previous application. And that required BC Hydro to update its planned trade income for Fiscal 2020 and Fiscal 2021, using a five-year average of actual results from Fiscal 2015 to Fiscal 2019, rather than using the Fiscal 2014 to Fiscal 2018 actuals, as had been done in the previous application. And I'm just going to, as an aside here, apologize on behalf of my cat which seemed to be making a lot of noise at the moment, if anybody is distracted by the racket going on in the background. As a result of this change, the planned trade income increased from 120.6 million to 176.3 million for each Fiscal 2020 and Fiscal 2021, and that added up to the 55.7 million for each year of the test period. So, because BC Hydro's Fiscal 2020 audited financial statements were finalized prior to the BCUC's decision on the previous application, the adjustments related to fiscal 2020 were made in Fiscal 2021, and therefore the Fiscal 2020 actual column of Appendix A in the application was not updated for the impacts of BCUC's decision. Instead in this application BC Hydro has included this amount in the Fiscal 2021 forecast column as part of the adjustment to the opening balance shown on Appendix A, schedule 2.1, line 16. I feel that should be something there that should be a requirement for pronunciation purposes. So however -- I note that the value line 16 is 51.9 million there and not 55.7 million and I'm just wondering if you can just clarify why that is the case.

MR. WONG: A: We just want to grab Appendix A first.

MS. WORTH: Q: Absolutely, take all the time you need.

MR. LAYTON: A: Hi, Ms. Worth. Thank you for the time there. We were just looking at Appendix A. This is Ryan Layton speaking by the way. I'm not sure of the answer to your question. I understand your question. I will undertake to give you an answer. And for the record, to make sure I'm understanding what you're looking for, we're referencing BCOAPO IR 1.62.1 and we're comparing that to Appendix A, Schedule 1, page 3, row 16, the F21 difference column which shows $51.9 million and your question is to reconcile why those are not the same amount. Is that a fair summary?

MS. WORTH: Q: That is, thank you.

MR. LAYTON: A: Okay, we'll undertake to provide that.

MS. WORTH: Q: Okay, thank you very much.

QUESTION:

Please reconcile BC Hydro's response to BCOAPO IR 1.62.1, in Exhibit B-5 and Appendix A, Schedule 1, page 3, row 16, the F21 difference column, which shows $51.9 million and explain why those are not the same amount.

RESPONSE:

The table below shows the components of the $51.9 million total Adjustment to Opening Balance (Appendix A, Schedule 2.1, line 16) of the Trade Income Deferral Account.

	$ millions
Impact from updated 5-Year Average Trade Income	55.7
Interest impact	1.0
Change in F2021 amortization to maintain F2020 rates	(4.8)
Total Fiscal 2021 Opening Balance Adjustment	51.9

As shown in the table above, in addition to the $55.7 million related to the impact of Directive 53 of the BCUC's Decision on the Previous Application from using the fiscal 2015 to fiscal 2019 five-year average to forecast Trade Income, there were other adjustments related to amortization and interest which resulted in the $51.9 million opening balance adjustment.

Directive 53 of the BCUC's Decision on the Previous Application resulted in higher additions to the account of $55.7 million related to fiscal 2020. The higher balance in the account due to this addition resulted in an additional $1.0 million of interest applied to the account for fiscal 2020.

The ($4.8) million change in the amortization amount was to keep the fiscal 2020 bill increase at 1.76 per cent, which was achieved by adjusting the split between fiscal 2020 and fiscal 2021 of the amounts returned to ratepayers (amortized) from the Cost of Energy Variance Accounts.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 14

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 204, line 7 to Page 205, line 8

TRANSCRIPT EXCERPT:

MS. WORTH: Q: Okay. All right. Can you please confirm what the 712 million would mean in terms of the ROE percent based on your actual forecast equity for fiscal 2022?

MR. LAYTON: A: Ms. Worth, I don't have that at my fingertips and I'm not quite that good at math, so I'll be happy to undertake to provide that for you. But what you are looking for is what the $712 million would provide based on forecast actual equity in terms of a return on equity percentage, is that correct?

MS. WORTH: Q: Yes. Because based on the information we've got, the forecast equity component for its capital structure in fiscal 2022 that you've provided in BCUC IR 1I.60.3 was 21.3 percent and based on BC Hydro's actual equity percent, that works out to an ROE of over 14 percent, although that's not math that I would go to the bank with. So I was just wondering if BC Hydro could confirm that. What the 712 million means in terms of the ROE.

MR. LAYTON: A: Yeah, so just clarifying, if we use 712 on a -- in reference to actual equity, what ROE percentage that would be in Fiscal '22?

MS. WORTH: Q: Yes.

MR. LAYTON: A: Okay, yeah, we'll undertake to do that, sure.

MS. WORTH: Q: Thank you.

QUESTION:

Please provide what the ROE percentage would be in fiscal 2022 if the return on equity was $712 million and actual equity was used.

RESPONSE:

The ROE percentage in fiscal 2022 would be 10.6 per cent using planned actual equity and using the same mid-year equity approach as that used in the Application. The components of the calculation are provided in the table below.

BC Hydro Fiscal 2022 Revenue Requirements Application

	$ millions	($)	Appendix A Schedule 9 Reference
	Fiscal 2022 Plan Net Income	712.0	Line 32, Column 10
	Fiscal 2021 Forecast Shareholder’s Equity	6,345.6	Line 17, Column 8
	Fiscal 2022 Plan Shareholder’s Equity	7,057.6	Line 17, Column 10

Aveage Planned F2022 Shareholder's Equity =
($6,345.6 million + $7,057.6 million) / 2 = $6,701.6 million

Fiscal 2022 Plan Net Income = $712 million

Fiscal 2022 Return on Planned Actual Equity =
$712 million / $6,701.6 million = 10.6 per cent

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 15

HEARING DATE: March 4, 2021

REQUESTOR: BCOAPO, Ms. L. Worth

TRANSCRIPT REFERENCE: Volume 1, Page 205, line 15 to Page 207, line 4

TRANSCRIPT EXCERPT:

> MS. WORTH: Q: Okay, thank you. I've got a few more questions. I've gone through a lot of my subject matter, so, so I've got a question about the point-to-point revenues and Powerex. It is my understanding from Exhibit B-2, figure 9-1, that PTP revenues for Fiscal 2022 are 86.3 million, and when I looked at BCUC IR 1.66.5 there is confirmation that the cost associated with the use of BC Hydro's transmission system for system export, pursuant to the OATT, the Open Access Transmission Tariff, is 27.5 million. So, I'm wondering if you can confirm whether that means that the cost to Powerex for the use of the transmission system is 47.7 million?
>
> MR. WONG: A: Yeah, we don’t have all the material in front of us. Perhaps we will take that as an undertaking and confirm.
>
> MS. WORTH: Q: Okay. Just to add to that, if that is not the case, I was just wondering if BC Hydro could breakdown the use PTP revenues as between those that are attributed to BC Hydro versus Powerex, or other OATT customers?
>
> MR. WONG: A: Yeah, I believe we can get that information.
>
> MS. WORTH: Q: Great, thank you. I just wanted to confirm, because PTP revenues -- or sorry, the variance of PTP revenues from forecast are captured in a regulatory account for either refund or recovery from BC Hydro's domestic customers, whether each of the customers, whether it's BC Hydro, Powerex, or another external customer, is given the same treatment in that particular circumstance?
>
> MR. WONG: A: Well, as it relates to Powerex, if there is any inter-company, the one side would be captured on the Heritage accounts. Well, I should say not the Heritage. The deferral accounts on BC Hydro's side versus the trade income deferral accounts for the Powerex side. Of course if the external customer takes more or less transmission, that solely is the ratepayer adjustment, because that is something that we would get from outside.

QUESTION:

Exhibit B-2, Figure 9-1 shows that PTP revenues for fiscal 2022 are $86.3 million. When referring to BC Hydro’s response to BCUC IR 1.66.5, the cost associated with BC Hydro’s transmission system for system export (for OATT) is $27.5 million. Can you confirm if that means the cost for Powerex to use the transmission system is $47.7 million?

If the above is not the case, can BC Hydro breakdown the PTP revenues between BC Hydro versus Powerex and versus other OATT customers?

RESPONSE:

Not confirmed. The fiscal 2022 planned Powerex PTP charges are $34.4 million (shown on line 2 of the table below), not $47.7 million.

	$ million	App. A Reference	F2022 Plan
1	BC Hydro PTP Charges	3.4 L13 + L20	43.4
2	Powerex PTP Charges	3.4 L19	34.4
3	External OATT Customers PTP Revenues	3.4 L69	8.5
4	**Total**	**3.4 L70**	**86.3**

The forecast “Domestic Transmission – Export” cost of $27.5 million referred to in BCUC IR 1.66.5 is included in the BC Hydro PTP Charges of $43.4 million on line 1 of the table above. This line also contains BC Hydro’s transmission charges for delivery of energy to Seattle City Light.

BC Hydro notes that PTP charges in the table above take into account both export and import reservations.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 16

HEARING DATE: March 4, 2021

REQUESTOR: CEABC, Mr. D. Austin

TRANSCRIPT REFERENCE: Volume 1, Page 219, line 26 to Page 220, line 17

TRANSCRIPT EXCERPT:

> MR. AUSTIN: Q: Thank you, and I appreciate that, I just have one question in addition to the questions I've asked about the non-treaty storage agreements, and it will probably be something that is subject of an undertaking. And the question that I have is, how do you translate KSFDs to acre feet of storage? I didn't expect anybody would be able to answer it, but in certain documents there is references to acre feet of storage, but in response to the B.C. Utilities Commission IR 1.14.1 in Exhibit B-14, the concept of KSFD's is raised.
>
> MR. O'RILEY: A: Well, if I had my phone, I'd Google it, but we weren't allowed to bring our phones to this, so I am technology-less. We'll get you back, Mr. Austin, a definition of both -- or reconciliation of a term KSFD against acre feet of storage.
>
> MR. AUSTIN: Q: Thank you.

QUESTION:

How do you translate KSFDs to acre feet of storage? Provide reconciliation or the definition of both terms KSFD and acre feet of storage.

RESPONSE:

The acronym ksfd stands for "thousand cubic feet per second – day". It represents the volume of water that would occur over one day if the flow rate was one thousand cubic feet per second.

An acre foot is a volume equivalent to an acre covered one foot deep in water.

One million acre feet is equivalent to 504.167 ksfd.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 17

HEARING DATE: March 4, 2021

REQUESTOR: CEABC, Mr. D. Austin

TRANSCRIPT REFERENCE: Volume 1, Page 237, line 18 to Page 238, line 7

TRANSCRIPT EXCERPT:

> MR. AUSTIN: Q: Thank you. My final question is just more of a housekeeping question. It's in relation to BCUC IR 1.3.3. in Exhibit B-4 and BC Hydro's response, and there's a large attached table to the response to BCUC IR 1.3.3 and it's very difficult, if not impossible, to read and the Clean Energy Association of B.C. is wondering whether that table could be provided in a working Excel version.
>
> MR. LAYTON: A: Hi, Mr. Austin, it's Ryan Layton again. I see no reason why we wouldn't be happy to do that.
>
> MR. AUSTIN: Q: Thank you. I have no -- go ahead.
>
> MR. LAYTON: A: Just for the record I'll be clear. We'll undertake to provide a working Excel version of attachment 1 to BCUC IR 1.3.3.
>
> MR. AUSTIN: Q: That's correct.

QUESTION:

Provide a working Excel version of Attachment 1 to BC Hydro's response to BCUC IR 1.3.3.

RESPONSE:

The Excel version of Attachment 1 to BC Hydro's response to BCUC IR 1.1.3 is provided in the Attachment 1 to this undertaking.

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(Accessible by opening the Attachments Tab in Adobe)

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 18

HEARING DATE: March 4, 2021

REQUESTOR: ZONE II RPG, Mr. M. Fox

TRANSCRIPT REFERENCE: Volume 1, Page 257, line 15 to Page 258, line 5

TRANSCRIPT EXCERPT:

> MR. O'RILEY: A: Just to confirm that all the street lights in the province, the non-LED lights, are going to be replaced, the ones that BC Hydro owns. And it's a three-year program. So we've already started, we started in the north. The Hudson Hope lights were switch out, and we're going around the province. So, there is no suggestion that the NIA street lights won't be taken out, we just haven't confirmed the schedule, and we appreciate the suggestion around factoring in the diesel reductions.
>
> MR. FOX: Q: Thank you. And just as a very brief follow up to that, can BC Hydro indicate when they might have that schedule in place?
>
> MS. DASCHUK: A: I don't have that information at hand, but I can undertake to let you know when the schedule will be ready.
>
> MR. FOX: Q: Thank you.

QUESTION:

Provide the approximate timing for when the NIA Light-Emitting Diode (LED) street light replacement program schedule will be available.

RESPONSE:

BC Hydro's Street Light Replacement Program has a high-level and preliminary deployment schedule for converting all BC Hydro-owned street lights under Rate Schedule 1701 (Overhead Street Lights) to LEDs over the next two and a half years. BC Hydro has based this schedule on BC Hydro's installation service contractors and internal crews' installation capacity.

BC Hydro recognizes that communities in the Non-Integrated Areas (NIA) rely on Diesel generation and that there would be immediate benefits from converting street lights to LEDs, such as reduced diesel consumption and reduced greenhouse gas emissions.

BC Hydro is engaging with our street light customers, installation service contractors, and internal field resources to refine the deployment schedule

specifically related to NIA communities and anticipates having a tentative schedule for NIA around this summer.

BC Hydro is also looking for opportunities to convert the street lights in NIA communities earlier, for example, by leveraging other planned trips to complete work in these communities.

Additionally, BC Hydro is now completing all repairs to our street lights under Rate Schedule 1701 with LEDs, including in NIA communities. As of March 1, 2021, BC Hydro has converted 45 of the approximately 1,400 street lights in NIA communities to LEDs.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 19

HEARING DATE: March 5, 2021

REQUESTOR: BCUC Staff, Ms. T. Lai

TRANSCRIPT REFERENCE: Volume 2, Page 267, line 1 to Page 268, line 14 and Page 293 line 26 to Page 294, line 10

TRANSCRIPT EXCERPT:

MS. LAI: … I will start with EV charging stations as my first topic. In this revenue requirement application BC Hydro is requesting the recovery of EV charging infrastructure costs, which includes depreciation expenses. Can you please tell me what is the estimated useful life for the EV charging infrastructure that is used to calculate the depreciation expense and how this useful life was determined?

MR. LAYTON: A: Good morning, Ms. Lai. This is Ryan Layton speaking, I'll start here and then maybe Mr. Anderson will have more comments on this. I believe it relates -- it depends on the vintage of the charging stations. So we've implemented those in different phases. The ones that are coming in service now are assumed to have a ten-year useful life. As I said, Mr. Anderson may have some more comments on that.

MR. ANDERSON: A: No, nothing further, Mr. Layton.

MS. LAI: Q: And when this useful life was determined was it compared to other public utilities who own and operate similar EV charging infrastructure?

MR. LAYTON: A: I'm not aware of that.

MS. LAI: Q: Thank you. Is BC Hydro seeking approval of the depreciation rate in this application or is this more appropriate to address in the EV rate design BCH F2022 application?

MR. LAYTON: A: I don't believe that we've asked for specific approval of a class, so I'm not sure if we have a depreciation class already that we're using. I will take that away and think about that and perhaps it is -- it probably is something to be discussed in the other application as well. But, yeah, I'm not sure off the top of my head the answer to that.

MS. LAI: Q: Okay, thank you.

MR. GHIKAS: It's Matt Ghikas. We can revisit that, I'll have discussion offline and just provide you the further answer and we can also deal with it in final argument, if that works, instead.

MS. LAI: Q: Okay, thank you.

….

MR. GHIKAS: Before Mr. Kiesling jumps in, it's Matt Ghikas, I just wanted to clarify one thing that came out of Ms. Lai's questions about the EV. There was an exchange that I had the last time I interjected about EV depreciation rates. We'll treat that as an undertaking and go away and just explain how the deprecation rates are addressed and I just wanted to make sure that was clear on the record.

THE CHAIRPERSON: Thank you, Mr. Ghikas.

MS. LAI: Thank you.

QUESTION:

Is BC Hydro seeking approval of the depreciation rate for electric vehicle charging stations in this application or is this more appropriate to address in the EV rate design or in the next revenue requirements application?

RESPONSE:

BC Hydro did not seek approval of the depreciation rate for electric vehicle charging stations in the Application. BC Hydro has included the assessment of the useful life (which will drive the depreciation rate) for electric vehicle charging stations in the scope of the depreciation study. BC Hydro expects to seek approval of the useful life (depreciation rate) for the electric vehicle charging stations as part of its submission of the depreciation study to be filed with the next Revenue Requirements Application. In addition, in the Application, BC Hydro proposes to defer variances resulting from the depreciation study in fiscal 2022 to the Amortization of Capital Additions Regulatory Account. This means that to the extent the depreciation study determines a different useful life for the electric vehicle charging stations than that included in the Application, resulting variances will be deferred to the regulatory account such that ratepayers only pay the costs associated with the depreciation rate determined in the depreciation study.

Notwithstanding the above, and notwithstanding that section 18 of the *Clean Energy Act* mandates cost recovery in respect of costs associated with prescribed undertakings, BC Hydro considers that it should have sought approval and therefore, requests approval for the depreciation rates used for electric vehicle charging stations in the Application. BC Hydro is submitting an amended Draft Order as Exhibit B-2-7 and respectfully requests that the BCUC consider this as an update to the approvals sought in the Application.

The table below provides the net book values for the electric vehicle charging infrastructure assets in-service by asset category for the purposes of the depreciation discussion that follows the table.

($ million)	Fiscal 2022 Opening	Fiscal 2022 Closing
Electric Vehicle Charging Stations in-service (10 years amortization)	3.3	3.6
Electric Vehicle Charging Stations in-service (5-7 years amortization)	0.5	0.5
Electric Vehicle Charging Stations (fully amortized)	0.5	0.5
Subtotal Electric Vehicle Charging Stations	**4.3**	**4.6**
Other Distribution Assets in-service	0.7	0.8
Total Capital Assets in-service	**5.0**	**5.4**
Accumulated amortization	(0.7)	(1.2)
Total Net Book Value of Capital Assets in-service	**4.3**	**4.2**

In the Application, BC Hydro used a 10-year useful life (10 per cent depreciation rate) based on the manufacturers' recommended life for the majority of the electric vehicle charging stations. For the remaining electric vehicle charging stations, a shorter life of five years (20 per cent depreciation rate) or seven years (14 per cent depreciation rate) was used due to the poor reliability experienced for charging stations supplied by one manufacturer. The Other Distribution Assets (e.g., transformers, cables, ductbanks) are amortized using existing asset classes and have varying depreciation rates.

In the next Revenue Requirements Application, BC Hydro will request approval for an ongoing depreciation rate for electric vehicle charging stations based on the rate (life) recommended in the depreciation study.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 20

HEARING DATE: March 5, 2021

REQUESTOR: BCUC Staff, Ms. T. Lai

TRANSCRIPT REFERENCE: Volume 2, Page 268, line 14 to Page 270, line 4

TRANSCRIPT EXCERPT:

MS. LAI: In response to BCUC IR 2.1, in Exhibit B-4, BC Hydro states that it considers it owns the eight stations identified as constructed by Community Energy Association and that BC Hydro and Powertech are expected to execute a bill of sale shortly to make it clear that these stations are BC Hydro's assets. Can you tell me, are these eight charging stations currently recorded in BC Hydro's books? Or Powertech's books?

MR. LAYTON: A: This is Ryan Layton speaking again. Mr. Anderson may have more to add. I believe that until a sale occurs, they would be on Powertech's books, but I'll say subject to check, because I'm not 100 percent certain on that.

MS. LAI: Q: Okay.

MR. ANDERSON: A: Yes, Mr. Layton, I can add some more. I believe that the bill of sale between Powertech and BC Hydro has been completed. I can't tell you anything about whose books they would be recorded in, but I can tell you that part.

MS. LAI: Q: Okay, was it completed recently?

MR. ANDERSON: A: Yes, just completed recently. I got notice of it a day or two ago.

MS. LAI: Q: Okay, and do you know if the costs of these stations were previously recovered from BC Hydro's ratepayers?

MR. ANDERSON: A: I'm not aware of that, but I don’t know. Mr. Layton, if you're --

MR. O'RILEY: A: Could we just caucus for a moment?

MS. LAI: Q: Sure.

MR. LAYTON: A: Hi, Ms. Lai, this is Ryan Layton speaking again. We'll undertake to get you an answer to your question, and for the record, if we understand it correctly, it is in respect of these particular stations, were they recovered in BC Hydro rates in prior years. Is that a fair representation of your question?

MS. LAI: Q: Yes, that's correct, thank you.

MR. LAYTON: A: Okay, we'll undertake to provide an answer to you.

BC Hydro Fiscal 2022 Revenue Requirements Application

QUESTION:

In respect of the eight stations identified as constructed by Community Energy Association, confirm if they were recovered in BC Hydro rates in prior years.

RESPONSE:

BC Hydro confirms that the costs of the eight stations prior to fiscal 2020 have been recovered in BC Hydro's rates in prior years, as described further below.

BC Hydro has had the opportunity to check Mr. Layton's testimony that: "I believe that until a sale occurs, they would be on Powertech's books, but I'll say subject to check, because I'm not 100 per cent certain on that." In fact, the eight stations were on BC Hydro's books prior to the bill of sale being executed.

The eight stations have been on BC Hydro's books because BC Hydro owns the eight stations. Powertech purchased the stations on BC Hydro's behalf, and it was always intended that the stations would be assets of BC Hydro. That BC Hydro in fact purchased and has owned these stations is reflected in the following:

- **BC Hydro paid Powertech in full for its costs of purchasing the stations in fiscal 2018 and fiscal 2019;**
- **BC Hydro has been operating and maintaining the stations;**
- **The electricity to the station is to the account of BC Hydro;**
- **BC Hydro has signed an operation and maintenance agreement with the regional districts/townships in the Kootenay area, the necessary licences of occupation, and an equipment restoration service agreement with a third-party; and**
- **Operating and maintenance costs and cost of energy amounts incurred prior to fiscal 2020 have been recovered in rates in prior years. The operating and maintenance costs, cost of energy and depreciation related to these stations for fiscal 2020 and fiscal 2021 were deferred to the Electric Vehicle Costs Regulatory Account and BC Hydro has proposed to recover these costs over the test period (i.e., in fiscal 2022). These amounts are shown in BC Hydro's response to Undertaking No. 21. BC Hydro recorded the capital additions of these eight stations at the end of fiscal 2020 and depreciation expense began to be incurred in fiscal 2021 in BC Hydro's financial statements. These stations will be amortized over 10 years.**

To document the parties mutual understanding that these stations are, and have been, assets of BC Hydro, BC Hydro and Powertech executed a Bill of Sale on February 25, 2021.

BC HYDRO UNDERTAKING NO. 21

HEARING DATE: March 5, 2021

REQUESTOR: BCUC Staff, Ms. T. Lai

TRANSCRIPT REFERENCE: Volume 2, Page 270, lines 5 to 23

TRANSCRIPT EXCERPT:

> MS. LAI: Q: Okay, and my next question is, I was wondering what the cost of service for these eight stations for Fiscal '20 to Fiscal '22, is -- what the cost of service BC Hydro is seeking to recover, and I guess you would need to provide this as an undertaking. If you could provide that information by year, broken down by the cost categories? So operating and maintenance, depreciation, cost of energy, and finance if applicable?
>
> MR. LAYTON: A: Certainly, and we'll undertake to do that, and we'll provide it in the categories that you mentioned, which are the same categories in BCUC IR 1.1.1. So, if I understood your question correctly, we'll undertake to provide in respect of those eight sections, the costs by fiscal year, for Fiscal 2020, Fiscal 2021 and Fiscal 2022 for those particular eight stations.
>
> MS. LAI: Q: Yes, thank you.

QUESTION:

Provide the cost of service for these eight stations for Fiscal 2020, Fiscal 2021 and Fiscal 2022– (i.e., the cost of service BC Hydro is seeking to recover). Provide this information by year, broken down by the same cost categories in BC Hydro’s response to BCUC IR 1.1.1, including operating and maintenance, depreciation, cost of energy, and finance, if applicable.

RESPONSE:

BC Hydro does not track operating and maintenance costs by individual electric vehicle charging station. Therefore, the amounts reflected in the table below are an allocation of the total operating and maintenance costs pro-rated for the eight stations as a proportion of the total number of stations that meet the definition of prescribed undertakings under the Greenhouse Gas Reduction (Clean Energy) Regulation.

Depreciation costs are based on BC Hydro’s portion of the capital costs for these eight stations. These assets were recorded as capital additions in BC Hydro’s financial system at the end of fiscal 2020 and depreciation began to be recorded in fiscal 2021. These stations will be amortized over 10 years.

BC Hydro Fiscal 2022 Revenue Requirements Application

As noted in BC Hydro's response to Undertaking No. 7, BC Hydro manages its debt on a portfolio basis and does not attribute specific debt or finance charges to specific items such as electric vehicle charging infrastructure.

Notwithstanding the above, BC Hydro has calculated an estimate of the finance charges for these eight stations using BC Hydro's Weighted Average Cost of Debt (WACD) as shown in the tables below.

Electric Vehicle Charging Station Costs (for eight stations)

$ million	Fiscal 2020 Actual	Fiscal 2021 Forecast	Fiscal 2022 Forecast
Operating & Maintenance Costs			
Labour	0.08	0.06	0.05
Contract Services	0.15	0.09	0.06
Total Operating & Maintenance	0.23	0.15	0.11
Depreciation	0.00	0.05	0.05
Cost of Energy	0.02	0.03	0.02
Estimated Finance Charges	0.01	0.02	0.01
Total	**0.26**	**0.25**	**0.19**

Calculation of Estimated Finance Charges (for eight stations)

	$ million	Appendix A Reference	Fiscal 2020 Opening	Fiscal 2020 Ending	Fiscal 2020 Mid-year
1	Capital Assets in Serivce		-	0.5	0.2
2	Accumulated Amortization		-	-	-
3	**Net Book Value of Capital Assets in Service**		-	0.5	0.2
4	**Weighted Average Cost of Debt**	8.0 L52			3.74%
5	**Estimated Finance Charges**				0.01

	$ million	Appendix A Reference	Fiscal 2021 Opening	Fiscal 2021 Ending	Fiscal 2021 Mid-year
1	Capital Assets in Service		0.5	0.5	0.5
2	Accumulated Amortization		-	(0.0)	(0.0)
3	**Net Book Value of Capital Assets in Service**		0.5	0.4	0.5
4	**Weighted Average Cost of Debt**	8.0 L52			3.37%
5	**Estimated Finance Charges**				0.02

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	$ million	Appendix A Reference	Fiscal 2022 Opening	Fiscal 2022 Ending	Fiscal 2022 Mid-year
1	Capital Assets in Service		0.5	0.5	0.5
2	Accumulated Amortization		(0.0)	(0.1)	(0.1)
3	**Net Book Value of Capital Assets in Service**		0.4	0.4	0.4
4	**Weighted Average Cost of Debt**	8.0 L52			3.09%
5	**Estimated Finance Charges**				0.01

Tables may not add due to rounding

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 22

HEARING DATE: March 5, 2021

REQUESTOR: BCUC Staff, Ms. T. Lai

TRANSCRIPT REFERENCE: Volume 2, Page 276, lines 2 to 21

TRANSCRIPT EXCERPT:

> MS. LAI: Q: Okay, great, thank you. Now I'd like to switch topics to the deferral account rate rider. Now, here I'm just going to request a few undertakings, if I can. The first undertaking is I would like a table that shows what the DARR rate in each year of the past ten years would have been if the proposed DARR mechanism was used and what the ending balances in the cost of energy variance accounts would have been in each of those years. And also, in that same table, provide what the equivalent rate impact would have been in each of those years if those amounts were amortized into the revenue requirement instead of being recovered through a rate rider.
>
> MR. LAYTON: A: Okay, thank you, Ms. Lai. This is Ryan Layton speaking. I think you've very clearly described what you're looking for, I'm not going to try and paraphrase it back. I think the record will show very clearly and we will undertake to do that.
>
> MS. LAI: Q: Perfect, thank you.

QUESTION:

Provide a table that shows what the DARR rate in each year of the past 10 years would have been if the proposed DARR mechanism was used and what the ending balances in the cost of energy variance accounts would have been in each of those years. Also, in that same table, provide what the equivalent rate impact would have been in each of those years if those amounts were amortized into the revenue requirement instead of being recovered through a rate rider.

RESPONSE:

The table below provides the requested information:

- **Lines 1-6 – ending balances of the individual and total Cost of Energy Variance Accounts;**
- **Line 7 – DARR percentage rates in each year (determined by the prior year ending balances against the DARR threshold table);**

- **Line 8 – total Cost of Energy Variance Accounts amortization in each year based on the DARR percentage on line 7;**
- **Line 9-11 – annual rate increase/(decrease), DARR percentage and bill impact if the Cost of Energy Variance Accounts amortization was recovered using a rate rider; and**
- **Line 12-14 – annual rate increase/(decrease), DARR percentage and bill impact if the Cost of Energy Variance Accounts amortization was recovered in rates through the revenue requirements instead of using a rate rider.**

	Scenario 1: DARR Table Mechanism	Actual	F12-F14 RRA			F15-F16 RRA		F17-F19 RRA			F20-F21 RRA	
		F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021
		Cost of Energy Variance Account Ending Balance ($ million)										
1	Heritage		214.2	40.5	81.2	144.0	(42.4)	(66.4)	(110.6)	(492.7)	(400.7)	(35.2)
2	Non-Heritage		326.2	423.8	309.6	474.3	863.8	690.5	385.1	49.5	199.8	(482.4)
3	Trade Income		154.1	166.9	298.4	212.4	218.5	163.8	99.0	(269.6)	(245.2)	(84.9)
4	Load Variance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	380.4
5	Biomass Energy Program Cost		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.1)
6	**Total**	**797.3**	**694.5**	**631.2**	**689.2**	**830.7**	**1,040.0**	**787.9**	**373.5**	**(712.8)**	**(446.2)**	**(230.1)**
7	**DARR %**	**3.5%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**	**5.0%**	**3.5%**	**(5.0%)**	**(4.0%)**
8	Cost of Energy Variance Account Amortization		176.0	180.5	188.0	199.0	210.5	224.3	233.1	168.9	(276.0)	(205.7)
		Cost of Energy Variance Account Amortization (via DARR)										
9	Annual Rate Increase/(Decrease)		8.0%	3.9%	1.5%	9.0%	6.0%	4.0%	3.5%	3.0%	13.6%	(2.9%)
10	DARR %	3.5%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	3.5%	(5.0%)	(4.0%)
11	**Bill Impact**		**9.5%**	**3.9%**	**1.5%**	**9.0%**	**6.0%**	**4.0%**	**3.5%**	**1.5%**	**4.2%**	**(1.9%)**
		Cost of Energy Variance Account Amortization (via Revenue Requirement)										
12	Annual Rate Increase/(Decrease)		13.4%	3.9%	1.5%	9.0%	6.0%	4.0%	3.5%	1.5%	4.2%	(1.9%)
13	DARR %	3.5%	-	-	-	-	-	-	-	-	-	-
14	**Bill Impact**		**9.5%**	**3.9%**	**1.5%**	**9.0%**	**6.0%**	**4.0%**	**3.5%**	**1.5%**	**4.2%**	**(1.9%)**

As shown in the table, the bill impact under BC Hydro's proposed DARR methodology (line 11) and the bill impact if the Cost of Energy Variance Account amortization amounts were recovered in rates through the revenue requirements instead of a rate rider (line 14) are the same in all years.

The scenario analysis assumes the following:

1. **The starting point for the analysis is the fiscal 2011 actual ending balance in the Cost of Energy Variance Accounts of $797.3 million and the actual DARR percentage that year (3.5 per cent). These values can be seen in the F2011 column in the table;**

2. **For all subsequent years, BC Hydro used actual additions to the Cost of Energy Variance Accounts that occurred, and calculated interest (for further information, see No. 3) in determining the ending balances;**

3. **Interest applied to the balances in the Cost of Energy Variance Accounts was calculated using BC Hydro's actual weighted average cost of debt (WACD) rate in each year. We assumed there would be no change to the WACD rates due to changes in the recovery mechanism of the Cost of Energy Variance Accounts;**

4. **The ending balances in the Cost of Energy Variance Accounts in a given year are thus a mix of actual balances and additions, adjusted for the calculated interest and amortization amounts that occur under the scenario;**

5. **The DARR percentage in each year was determined based on the calculated ending balance of the prior year (e.g., the fiscal 2015 DARR rate was determined based on the calculated fiscal 2014 ending balance) except for fiscal 2012 when the actual fiscal 2011 ending balance of $797.3 million was used. While we realize that in practice the DARR percentages could be set at the beginning of the test period for each year in such test period, in this scenario we assumed that the DARR percentages would be set using a prior year ending balances in the Cost of Energy Variances Accounts in each year of the period in question.**

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 23

HEARING DATE: March 5, 2021

REQUESTOR: BCUC Staff, Ms. T. Lai

TRANSCRIPT REFERENCE: Volume 2, Page 276, line 21 to Page 278, line 16

TRANSCRIPT EXCERPT:

MS. LAI: Q: Perfect, thank you. And then as the second undertaking for this topic, I would like another table under a scenario where the cost of energy variance accounts were to be amortized over a three-year period, can BC Hydro please provide a table that shows what the DARR rate would be in fiscal '22 and each of the past ten years, as well as the amount amortized in each of the cost of energy variance accounts, the ending balances of the cost of energy variance accounts for each of those years, as well as provide what the equivalent rate impact would have been for those years if those amounts were amortized into the revenue requirement instead of being recovered through the rate rider.

MR. LAYTON: A: Okay, maybe -- this is Ryan Layton again, maybe I'll ask just a clarifying question. So, in respect of this undertaking you're looking for it to always be a three-year recovery period regardless of where that falls within test periods?

MS. LAI: Q: That's right.

MR. LAYTON: A: Okay, I think that's complicated but I think I understand what you're looking for and we'll undertake to do that.

MS. LAI: Q: Okay, perfect. And then my last undertaking request for this topic, it's the same as the previous undertaking, but instead of using a three-year amortization period, can you use a five year amortization period?

MR. LAYTON: A: Yes, I think we can do that. Maybe just one additional clarification question for you, Ms. Lai, would be as you'll know from our application we've proposed to set the DARR based on forecast balances. I think it may be hard to go back in time and recreate a forecast that wasn’t perhaps made at the same time before. So we may make a simplifying assumption like using an actual balance since we have the luxury of knowing what that was at the end of fiscal years. I'm just thinking aloud of some of the complications that may arise from the undertaking. Does that sound a reasonable approach, as long as we clearly articulate our assumptions in so doing, following with your broad principle? Does that sound reasonable?

MS. LAI: Q: Yes, that would work, thank you.

BC Hydro Fiscal 2022 Revenue Requirements Application

QUESTION:

Provide a table under a scenario where the cost of energy variance accounts were to be amortized over a three-year amortization period and a five year amortization period.

Provide a table that shows what the DARR rate would be in fiscal 2022 and each of the past ten years, as well as the amount amortized in each of the cost of energy variance accounts, the ending balances of the cost of energy variance accounts for each of those years, as well as provide what the equivalent rate impact would have been for those years if those amounts were amortized into the revenue requirement instead of being recovered through the rate rider.

RESPONSE:

Two scenarios are considered in this response:

1. **Scenario 2: Recover Cost of Energy Variance Account Balance over a three-year period; and**
2. **Scenario 3: Recover Cost of Energy Variance Account Balance over a five-year period**

The Cost of Energy Variance Accounts recovery amounts are determined based on the ending balance of the prior test period (e.g., the recovery amount in fiscal 2015 is based on the actual fiscal 2014 ending balance in the Cost of Energy Variance Accounts). The DARR percentages are calculated by dividing the recovery amounts by the domestic sales revenues subject to DARR (i.e., residential, light industrial & commercial, large industrial, and other customer revenues).

The tables below provide the following requested information:

- **Lines 1-6 – individual and total Cost of Energy Variance Accounts balance;**
- **Lines 7-12 – individual and total Cost of Energy Variance Accounts amortization;**
- **Line 13 – DARR percentages in each year through fiscal 2022 calculated using the three-year and five-year amortization periods;**
- **Line 14-16 – annual rate increase/(decrease), DARR percentage and bill impact if the Cost of Energy Variance Accounts amortization was recovered using a rate rider; and**
- **Line 17-19 – annual rate increase/(decrease), DARR percentage and bill impact if the Cost of Energy Variance Accounts amortization was recovered in rates through the revenue requirements instead of using a rate rider.**

BC Hydro Fiscal 2022 Revenue Requirements Application

The table below assumes a three-year amortization period (Scenario 2):

	Scenario 2: 3-Year DARR Recovery	Actual	F12-F14 RRA			F15-F16 RRA		F17-F19 RRA			F20-F21 RRA		F22 RRA
		F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022
		Cost of Energy Variance Account Ending Balance ($ million)											
1	Heritage		185.6	(16.2)	44.2	114.4	(62.7)	(75.5)	(99.1)	(86.9)	(144.6)	113.1	78.3
2	Non-Heritage		284.5	338.5	144.5	344.4	770.7	521.7	134.8	(638.3)	(277.5)	(745.2)	(531.4)
3	Trade Income		132.5	125.5	229.9	150.8	174.1	106.4	31.1	(434.1)	(374.8)	(148.9)	(103.1)
4	Load Variance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	380.4	263.4
5	Biomass Energy Program Cost		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.1)	(5.6)
6	**Total**	**797.3**	**602.6**	**447.8**	**418.6**	**609.6**	**882.1**	**552.6**	**66.8**	**(1,159.3)**	**(796.9)**	**(408.7)**	**(298.5)**
		Cost of Energy Variance Account Amortization ($ million)											
7	Heritage		82.6	81.9	(9.6)	14.7	26.2	(20.9)	(40.2)	(436.1)	(29.0)	(70.1)	37.7
8	Non-Heritage		120.7	125.5	200.9	48.2	78.8	256.9	277.6	593.4	(212.8)	(134.6)	(248.4)
9	Trade Income		62.5	58.4	74.5	76.6	34.5	58.0	56.6	136.8	(144.7)	(181.7)	(49.6)
10	Load Variance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.8
11	Biomass Energy Program Cost		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.7)
12	**Total**		**265.8**	**265.8**	**265.8**	**139.5**	**139.5**	**294.0**	**294.0**	**294.0**	**(386.4)**	**(386.4)**	**(136.2)**
13	**DARR %**	**3.5%**	**7.5%**	**7.4%**	**7.1%**	**3.5%**	**3.3%**	**6.6%**	**6.3%**	**6.1%**	**(7.0%)**	**(7.5%)**	**(2.5%)**
		Cost of Energy Variance Account Amortization (via DARR)											
14	Annual Rate Increase/(Decrease)		8.0%	3.9%	1.5%	9.0%	6.0%	4.0%	3.5%	3.0%	12.2%	(1.7%)	(3.5%)
15	DARR %	3.5%	7.5%	7.4%	7.1%	3.5%	3.3%	6.6%	6.3%	6.1%	(7.0%)	(7.5%)	(2.5%)
16	**Bill Impact**		**12.2%**	**3.7%**	**1.2%**	**5.4%**	**5.8%**	**7.3%**	**3.3%**	**2.8%**	**(1.7%)**	**(2.2%)**	**1.7%**
		Cost of Energy Variance Account Amortization (via Revenue Requirement)											
17	Annual Rate Increase/(Decrease)		16.2%	3.7%	1.2%	5.4%	5.8%	7.2%	3.3%	2.8%	(1.7%)	(2.2%)	1.7%
18	DARR %	3.5%	-	-	-	-	-	-	-	-	-	-	-
19	**Bill Impact**		**12.2%**	**3.7%**	**1.2%**	**5.4%**	**5.8%**	**7.2%**	**3.3%**	**2.8%**	**(1.7%)**	**(2.2%)**	**1.7%**

The table below assumes a five-year amortization period (Scenario 3):

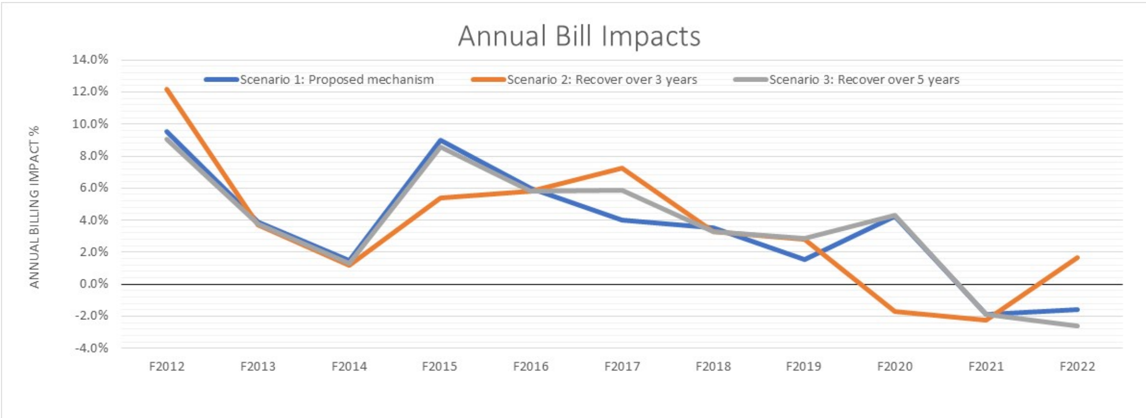
	Scenario 3: 5-Year DARR Recovery	Actual	F12-F14 RRA			F15-F16 RRA		F17-F19 RRA			F20-F21 RRA		F22 RRA
		F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022
		Cost of Energy Variance Account Ending Balance ($ million)											
1	Heritage		219.4	52.6	93.4	161.5	(13.2)	(42.7)	(94.8)	(483.4)	(487.0)	(190.5)	(157.7)
2	Non-Heritage		333.9	442.0	350.2	536.3	963.7	787.7	489.3	109.0	258.8	(392.4)	(340.3)
3	Trade Income		158.1	175.8	315.7	254.0	275.3	214.7	145.5	(243.0)	(274.5)	(161.5)	(133.7)
4	Load Variance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	380.4	314.9
5	Biomass Energy Program Cost		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.1)	(6.7)
6	**Total**	**797.3**	**711.4**	**670.4**	**759.3**	**951.8**	**1,225.8**	**959.8**	**540.0**	**(617.4)**	**(502.7)**	**(372.1)**	**(323.5)**
		Cost of Energy Variance Account Amortization ($ million)											
7	Heritage		49.5	49.2	12.5	18.7	25.8	(2.6)	(10.9)	(43.0)	(96.7)	(119.6)	(38.1)
8	Non-Heritage		72.4	74.8	105.1	70.0	85.6	192.7	201.2	222.2	21.8	63.6	(78.5)
9	Trade Income		37.5	35.4	41.8	63.1	40.5	55.1	54.9	66.1	(48.6)	(67.4)	(32.3)
10	Load Variance		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	76.1
11	Biomass Energy Program Cost		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.6)
12	**Total**		**159.5**	**159.5**	**159.5**	**151.9**	**151.9**	**245.2**	**245.2**	**245.2**	**(123.5)**	**(123.5)**	**(74.4)**
13	**DARR %**	**3.5%**	**4.5%**	**4.4%**	**4.2%**	**3.8%**	**3.6%**	**5.5%**	**5.3%**	**5.1%**	**(2.2%)**	**(2.4%)**	**(1.4%)**
		Cost of Energy Variance Account Amortization (via DARR)											
14	Annual Rate Increase/(Decrease)		8.0%	3.9%	1.5%	9.0%	6.0%	4.0%	3.5%	3.0%	12.1%	(1.7%)	(3.6%)
15	DARR %	3.5%	4.5%	4.4%	4.2%	3.8%	3.6%	5.5%	5.3%	5.1%	(2.2%)	(2.4%)	(1.4%)
16	**Bill Impact**		**9.0%**	**3.8%**	**1.3%**	**8.6%**	**5.8%**	**5.9%**	**3.3%**	**2.8%**	**4.3%**	**(1.9%)**	**(2.6%)**
		Cost of Energy Variance Account Amortization (via Revenue Requirement)											
17	Annual Rate Increase/(Decrease)		12.9%	3.8%	1.3%	8.6%	5.8%	5.9%	3.3%	2.8%	4.3%	(1.9%)	(2.6%)
18	DARR %	3.5%	-	-	-	-	-	-	-	-	-	-	-
19	**Bill Impact**		**9.0%**	**3.8%**	**1.3%**	**8.6%**	**5.8%**	**5.9%**	**3.3%**	**2.8%**	**4.3%**	**(1.9%)**	**(2.6%)**

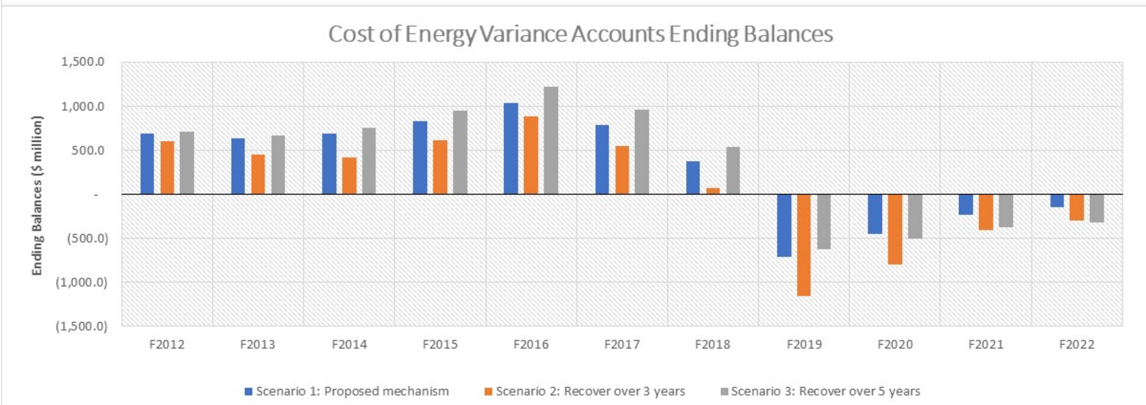
The two scenario analyses assume the following:

1. **The starting point for the two analyses is the fiscal 2011 actual ending balance in the Cost of Energy Variance Accounts of $797.3 million and the actual DARR percentage that year (3.5 per cent). These values can be seen in the F2011 column in the tables;**
2. **For all subsequent years, BC Hydro used actual additions to the Cost of Energy Variance Accounts that occurred, and calculated interest (for further information, see No. 3) in determining the ending balances;**
3. **Interest applied to the balances in the Cost of Energy Variance Accounts was calculated using BC Hydro's actual weighted average cost of debt (WACD) rate in each year. We assumed there would be no change to the WACD rates due to changes in the recovery mechanism of the Cost of Energy Variance Accounts;**
4. **The ending balances in the Cost of Energy Variance Accounts in a given year are thus a mix of actual balances and additions, adjusted for the calculated interest and amortization amounts that occur under the scenario;**
5. **The amounts of recovery of the Cost of Energy Variance Accounts are determined at the end of each test period. Actual historical test periods were used in this analysis (i.e., fiscal 2012 to fiscal 2014, fiscal 2015 to fiscal 2016, fiscal 2017 to fiscal 2019 and fiscal 2020 to fiscal 2021); and**
6. **The DARR percentage in each year was calculated by dividing the recovery amounts by the domestic sales revenues which are subject to DARR.**

The table and the graphs below compare the outcomes of the two scenarios described above (Scenario 2 and Scenario 3) with the scenario from Undertaking No. 22 (Scenario 1) with fiscal 2022 added where the proposed DARR mechanism is applied to the last 10 years.

		F12-F14 RRA			F15-F16 RRA		F17-F19 RRA			F20-F21 RRA		F22 RRA
	$ million	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020	F2021	F2022
	Scenario 1: Proposed Mechanism											
1	End of Year Balances	694.5	631.2	689.2	830.7	1,040.0	787.9	373.5	(712.8)	(446.2)	(230.1)	(142.3)
2	Annual Bill Impact	9.5%	3.9%	1.5%	9.0%	6.0%	4.0%	3.5%	1.5%	4.2%	(1.9%)	(1.6%)
	Scenario 2: Recover over 3 years											
3	End of Year Balances	602.6	447.8	418.6	609.6	882.1	552.6	66.8	(1,159.3)	(796.9)	(408.7)	(298.5)
4	Annual Bill Impact	12.2%	3.7%	1.2%	5.4%	5.8%	7.3%	3.3%	2.8%	(1.7%)	(2.2%)	1.7%
	Scenario 3: Recover over 5 years											
5	End of Year Balances	711.4	670.4	759.3	951.8	1,225.8	959.8	540.0	(617.4)	(502.7)	(372.1)	(323.5)
6	Annual Bill Impact	9.0%	3.8%	1.3%	8.6%	5.8%	5.9%	3.3%	2.8%	4.3%	(1.9%)	(2.6%)





Based on the table and charts above, BC Hydro considers that:

- **Scenarios 1 and 3 produce similar bill impacts in most years. This is not an unexpected outcome, as the DARR table mechanism normally results in balances being recovered over four to six years, and Scenario 3 had a five-year recovery period; and**
- **Scenario 2, which recovers the Cost of Energy Variance Accounts balance over a shorter three-year period, leads to more volatility in bill impacts compared to Scenarios 1 and 3 (e.g., in fiscal 2012, fiscal 2015, fiscal 2017, fiscal 2020 and fiscal 2022).**

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 24

HEARING DATE: March 5, 2021

REQUESTOR: BCUC Panel, Chairperson D. Morton

TRANSCRIPT REFERENCE: Volume 2, Page 320, line 12 to Page 321, line 13

TRANSCRIPT EXCERPT:

THE CHAIRPERSON: Okay. So I'm just wondering if you have any comment about how that -- the principle of cost causation and whether that is an appropriate treatment or whether the money from those credits should go to the person with the EV that gave rise to those credits to begin with?

MR. O'RILEY: A: Chairman Morton, perhaps I could take that. That is a policy question, as we understand. The province set up this regime and had the allocation of the credits going to the fuel supplier. So BC Hydro is the fuel supplier in this case and that's why those credits come to BC Hydro and then Hydro ratepayers get the value of that through the trade income. So we recognize there are different decisions that the government could have made on that, but this is the choice they made with respect to those credits.

THE CHAIRPERSON: Thanks, Mr. O'Riley. So if I could just ask a follow-up question to that then, would it -- in your understanding then, it would be in violation of government policy if you were to credit it directly to the EV? In other words, to use that to reduce the cost of electricity for EV charging, that would run contrary to the government policy?

MR. O'RILEY: A: My sense is the government policy was that the value of those credits go to all ratepayers and EV chargers get some portion of that, obviously, a small portion, but generally it goes back to all ratepayers. That's the -- that's what I've understood we're to implement by government policy.

THE CHAIRPERSON: So and it's -- could you point to where abouts in the legislation that understanding would come from, please?

MR. O'RILEY: A: I think we could take that as an undertaking.

QUESTION:

Provide the legislation reference that supports BC Hydro’s understanding that the low carbon fuel credits must go back to all BC Hydro ratepayers.

RESPONSE:

Under the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and the *Renewable and Low Carbon Fuel Requirements Regulation* (collectively, the Low Carbon Fuel Standard or LCFS), suppliers of low carbon fuels, such as BC Hydro, are the entities that are eligible to receive low carbon fuel credits.

Recognizing that the LCFS awards low carbon fuel credits to suppliers of low carbon fuels rather than to end users, BC Hydro's approach has been to use the revenue from the credits to reduce the overall revenue requirement for the benefit of all ratepayers. This approach recognizes that investments in clean energy infrastructure, which have been funded by all ratepayers, have resulted in low carbon electricity, which is the primary reason that BC Hydro is able to acquire credits under the LCFS.

BC Hydro transfers its low carbon fuel credits to Powerex in accordance with section 8 of the *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and section 11.11 of the *Renewable and the Low Carbon Fuel Requirements Regulation*. The transfer is made at zero cost, pursuant to an agreement between the parties, and all revenue earned by Powerex from the sale of credits flows back to BC Hydro ratepayers via Trade Income and the Trade Income Deferral Account.

The Ministry of Energy, Mines and Low Carbon Innovation is currently considering amendments to the LCFS. Further information is provided at the following link: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels/bc-lcfs-consultations

For context, BC Hydro provides the following additional information on the LCFS, sourced from the Government of B.C.'s web site, which can be accessed at the following link: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels

The basic elements of the LCFS are as follows:

- **The LCFS sets carbon intensity targets that decline each year;**
- **Fuel suppliers generate credits for supplying fuels with a carbon intensity below the targets and receive debits for supplying fuels with a carbon intensity above the targets;**
- **The debits and credits are proportional to the emissions a fuel generates over its full life cycle;**
- **Credits can be traded between fuel suppliers or banked for future use; and**

- **At the end of each compliance period, suppliers must have a balance of zero or more credits to avoid non-compliance penalties.**

As stated on the Government of B.C.'s website: "The credit market creates a financial incentive to reward low-carbon fuels in proportion to the amount of real, measurable emissions reductions they yield when substituted for conventional fuels."

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 25

HEARING DATE: March 4, 2021

REQUESTOR: AMPC, Mr. M. Keen

TRANSCRIPT REFERENCE: N/A. This is a Post - Review Session Undertaking

QUESTION:

Following the questions at the workshop the other day, Ryan Layton undertook to look into, for current service pension costs, how and when the $9.7 million arising from the discount rate change in F2021 comes back to ratepayers in fiscal 2022. We're hoping that BC Hydro's response can be structured to address the following parts of the record that are seeming discrepancies:

1. Given we are looking at the exact same discount rate swing from 3.83 per cent to 3.33 per cent in the F2020-F2021 RRA in reverse for the F2021 variance (3.33 per cent RRA approved to 3.83 per cent forecast), why is the current service pension operating cost variance at $9.7 million (as per AMPC 1.2.2) not equal to the Evidentiary Update increase of $17.1 million for F2021 in the last RRA (F2020 RRA, Exhibit B-11, page 12)
2. From Schedule 2.2 of Appendix A, line 159 (additions row for F2021 forecast) it suggests $5.8 million is the variance transferred to the PEB Current Service pension costs regulatory account and refunded to ratepayers in F2022.

RESPONSE:

Item 1

A 3.83 per cent discount rate was used in both the Previous Application and the Fiscal 2021 forecast in the Fiscal 2022 Revenue Requirements Application. Pension costs are very sensitive to changes in discount rates, but other factors also cause changes in these costs.

An actuarial valuation, which includes updated assumptions and demographic data, was performed by BC Hydro's external actuary between the two current service cost calculations and that is the reason for the difference that is unrelated to changes in discount rates. Specifically, the actuarial valuation resulted in the difference between the operating cost variance of $5.8 million (the $9.7 million referenced in the question was the <u>total</u> current service cost variance and

60 per cent or $5.8 million is the operating cost variance) and $17.1 million referenced in the question above (which was subsequently corrected to $16.1 million in BC Hydro's Errata to the Previous Application filed on January 21, 2020 (Exhibit B-11-2)). Please refer to the following table for further information on these figures:

$ million	F2021 Plan (F2020-F2021 RRA Original Application)	F2021 Update (F2020-F2021 RRA Evidentiary Update)	F2021 Forecast (F2022 RRA)
Gross Current Service Costs	105.6	132.5	122.8
Operating Portion (60%)	63.4	79.5	73.7
Change – Gross Current Service Costs	N/A	26.9	(9.7)
Change – Operating Current Service Costs	N/A	16.1	(5.8)
Discount Rate	3.83%	3.33%	3.83%

Item 2

Only the operating cost portion of the current service cost variance is transferred to the PEB Current Pension Costs Regulatory Account and recovered over the next test period. Therefore, $5.8 million (60 per cent of $9.7 million = operating cost portion) of the total current service costs variance of $9.7 million is shown in Schedule 2.2 of Appendix A, line 159.

BC Hydro Fiscal 2022 Revenue Requirements Application

BC HYDRO UNDERTAKING NO. 26

HEARING DATE: March 4, 2021

REQUESTOR: CEC, Mr. C. Weafer

TRANSCRIPT REFERENCE: Volume 1, Page 159, line 21 to Page 160, line 6

TRANSCRIPT EXCERPT:

> MR. C. WEAFER: Q: …So moving to the forecast of actual costs for negotiated EPAs, in response to CEC IR 1.21.1 it's apparent that for fiscal 2020 for the negotiated EPAs they were 41.4 million in excess of the anticipated fiscal 2020 approval. And there was some explanation provided to that in the IR, but I'd just like to get a little more -- a better understanding of that significant variance in relation to these negotiated EPAs. Is there someone who can address that?
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> MR. O'RILEY: A: We'll take an undertaking on that, Mr. Weafer.
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> MR. C. WEAFER: Q: Okay.

QUESTION:

In reference to BC Hydro's response to CEC IR 1.21.1 please provide a more detailed explanation of why the F2020 Actual costs for Negotiated EPAs were $41.4 million higher than the RRA.

RESPONSE:

The public version of the response has been redacted to maintain confidentiality. The un-redacted version of the response is being made available only to the BCUC to protect the Independent Power Producer's commercial interests. The public disclosure of the redacted information could also impact BC Hydro's commercial interests and ongoing (or future) negotiations related to the Electricity Purchase Agreements (or the renewal of the Electricity Purchase Agreements).

For fiscal 2020, there were 17 projects included in the Negotiated EPA call process category.[1] Of these 17 projects, 11 projects had higher than expected costs (with five of these projects having an increase greater than $1 million than forecast),

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[1] **These 17 projects are comprised of 15 IPP projects and two other energy supply contracts which are not considered to be IPP EPAs. As noted in footnote 4 of Table 4-6 of the Application, these two other energy supply contracts are the Surplus Power Rights Agreement between Teck and BC Hydro and the Residual Capacity Agreement between FortisBC Inc. and BC Hydro.**

five had lower than expected costs, and one project had no costs since it has not yet achieved commercial operation.

As provided in BC Hydro's response to CEC IR 1.21.1, the fiscal 2020 Actual costs for Negotiated Electricity Purchase Agreements is approximately $41.4 million higher than the Previous Application primarily because of higher than expected generation from three hydro projects for electricity delivered to BC Hydro in accordance with the terms of their existing EPAs. These projects were [redacted] were able to deliver more energy than forecast due to higher than expected water flows [redacted]. In total, these three projects contributed approximately $40 million towards the increase in forecast costs.

In addition to the three hydro projects referred to above, there were two other projects whose actual costs were each $1 million higher compared to forecast:

- **One biomass project [redacted], whose EPA was extended pursuant to the Government of B.C.'s Direction to the British Columbia Utilities Commission Respecting the Biomass Energy Program (Order in Council No. 158 issued April 1, 2019, BC Reg. 71/2019); and**
- **One wind project [redacted], which delivered more energy than forecast pursuant to the terms of its EPA.**

In total, these two projects contributed over $7 million towards the increase in forecast costs.

As noted above, there were also projects which had lower than forecast costs, which offset the total cost increases.